BLACK ROCK 1, 2, AND 3 GEOTHERMAL POWER PROJECT - MAJOR AMENDMENT

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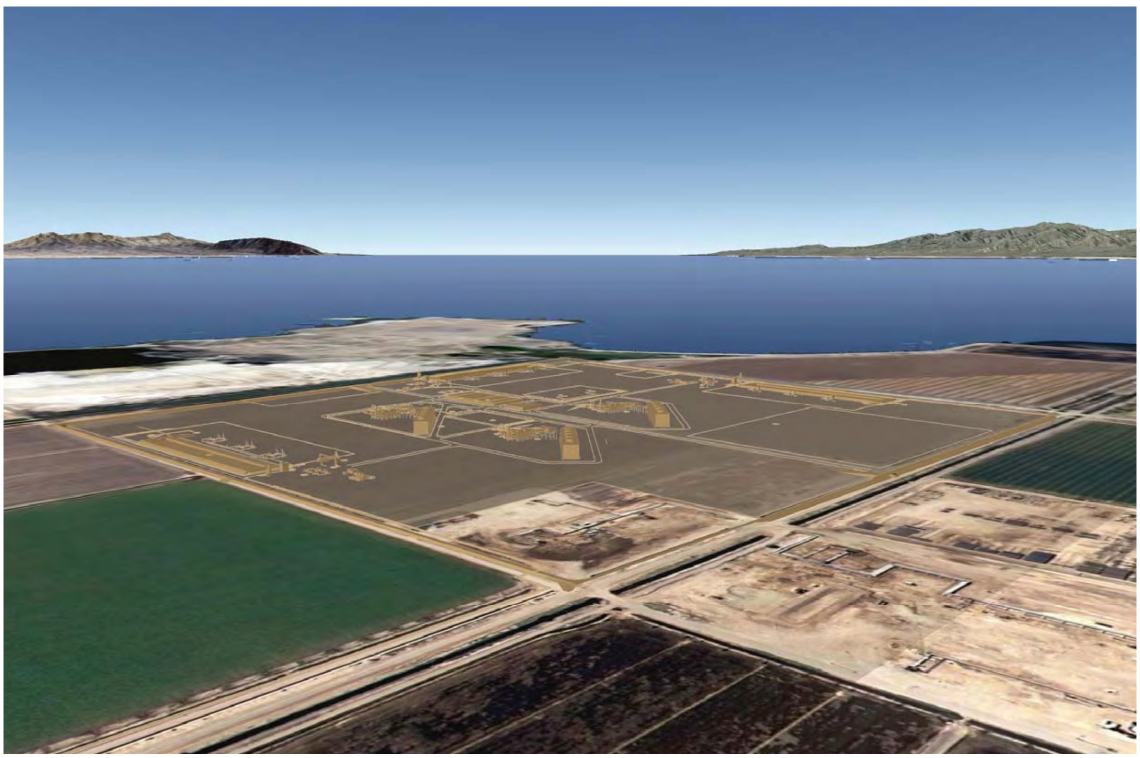
Staff Assessment



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Arnold Schwarzenegger, Governor

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BLACK ROCK 1, 2, 3, GEOTHERMAL PROJECT (02-AFC-2C)
STAFF ASSESSMENT to the AMENDMENT

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EXECUTIVE SUMMARY

Christine Stora, Amendment Project Manager

INTRODUCTION

On March 12, 2009, the California Energy Commission received a petition from CE Obsidian, LLC to amend the original December 17, 2003, Energy Commission Decision (and as amended in May 2005) for the Salton Sea Unit 6 Geothermal Power Plant (02-AFC-2C). Instead of the 215 MW multiple-flash (also called “multi-flash”) project previously approved, CE Obsidian now seeks authority to construct the Black Rock 1, 2, and 3 Geothermal Power Plant (BR123) consisting of three 53 MW single-flash facilities, for a net total of 159 MW generating capacity.

The purpose of the Energy Commission’s amendment review process in this Staff Assessment is to assess the BR123 project’s direct, indirect and cumulative impacts on the environment, public health and safety, and the electric transmission system. The Staff Assessment presents the conclusions, recommendations, and proposed conditions of certification that staff believes are necessary to mitigate or avoid potential significant adverse environmental impacts and to satisfy laws, ordinances, regulations and standards (LORS) that have changed since the original project was certified.

The review process includes an evaluation of the consistency of the proposed changes with the Energy Commission’s Decision and with current applicable LORS (Title 20, Calif. Code of Regulations, section 1769).

This Staff Assessment contains the Energy Commission staff’s evaluation of the technical areas that include: air quality; biological resources; cultural resources; land use; noise and vibration; public health; socioeconomic resources; soil and water resources; transmission line safety and nuisance; visual resources; waste management; facility design; geology and paleontology; power plant efficiency; power plant reliability; and transmission system engineering.

PROJECT LOCATION AND DESCRIPTION

The licensed facility site is located on 80 acres of agricultural land near the southern tip of the Salton Sea, about 10 miles west of the City of Calipatria in Imperial County. The original Salton Sea Unit #6 Project was certified by the Energy Commission on December 17, 2003, as a 185 MW facility. CE Obsidian in May 2005 obtained Energy Commission approval of an amendment seeking to increase generating capacity to 215 MW, but project construction was delayed due to economic circumstances beyond the applicant’s control.

The Salton Sea Unit #6 Project was certified as a single-generator 215 MW multi-flash geothermal facility with production wells located up to a mile from the generating site, including one well located on Obsidian Butte, an important cultural resource. CE Obsidian now requests to convert the Salton Sea Unit #6 Project to the BR123 project by constructing three separate 53 MW single-flash geothermal facilities, all sharing some common infrastructure, such as the substation connecting the facilities to the Imperial Irrigation District's (IID) transmission grid.

Single-flash systems have the advantage over multi-flash systems of emitting a greatly reduced visible water vapor plume, and producing a small fraction of the amount of waste requiring off-site disposal. Because single-flash facilities have significant amounts of leftover brine to inject back onto the resource, along with condensed steam coming from each turbine-generator, they also produce significantly less brine solids that require off-site disposal. The Salton Sea Unit #6 Project would have required trucking up to 142 tons per day of brine solids to a local land-fill, whereas the BR123 project is estimated to produce only a few tons of brine solids per year requiring off-site disposal.

The BR123 project would involve drilling production wells to extract the very hot brine located about 7,000 feet below the surface above a bulging mass of magma. The brine would be directed into expansion tanks at each unit where much of the liquid would flash to steam for use in each unit's single-stage turbine-generator set. The steam would then be condensed back into liquid utilizing wet cooling towers, and the condensate (along with the 420-450 degree brine that did not flash to steam in the expansion tanks) would then be injected back into the geothermal resource using injection wells.

About 90 percent of the fresh water needed for the project for cooling tower makeup and other uses would come from the condensed steam, with the remaining 10 percent supplied from the Colorado River through IID's canal and pipeline system. Total fresh water demand for the project is estimated at 355 acre-feet per year (afy) on a nominal basis, and up to 609 afy under worst-case conditions. The 215 MW Salton Sea Unit 6 (SSU6) project is currently licensed to use up to 1,000 afy of Colorado River water, and was estimated to use up to 987 afy under worst-case conditions.

The primary source of air emissions from the BR123 project would be non-condensable gases that come out of the brine and steam flowing through the system, with hydrogen-sulfide (H_2S), benzene and various volatile organic compounds (VOCs) being the components of most concern. The licensed Salton Sea Unit 6 Project calls for use of a catalyst system to control H_2S plus process humidity conditioning and carbon adsorption technology for benzene and VOC control. It would have generated up to three tons per day of sulfur potentially contaminated with mercury, requiring landfill disposal. The BR123 project instead would use a Recuperative Thermal Oxidizer (RTO) to control non-condensable gasses, including H_2S, benzene and VOCs, which does not produce any waste requiring disposal off-site. The RTO converts H_2S to sulfur dioxide (SO_2), which is converted into a soluble salt in a downstream scrubber and pumped into the brine injection stream for disposal.

These proposed modifications would require changes to the site layout concerning location of the new and existing structures, and expansion of the project site from 80 to 160 acres, though the total amount of land disturbed during construction and operation would be approximately the same.

A more complete description of the project, including maps of the project site and vicinity, is contained in the **PROJECT DESCRIPTION** section of this Staff Assessment. (See **Project Description Figure 1 & 2**)

NECESSITY FOR THE PROPOSED MODIFICATIONS

The project owner requested the proposed modifications in order to increase flexibility in obtaining financing for constructing the three facilities sequentially over a four-year period, rather than constructing a single 215 MW facility in two years. Utilizing three smaller units also allows use of standardized and proven technology, rather than the relatively unproven 215 MW single generator multi-flash system originally proposed. Use of single-flash technology with an RTO also significantly reduces operating costs because of the elimination of off-site disposal of filter cake and mercury-contaminated waste. Though initial capital costs for the BR123 project are higher than that estimated for the licensed Salton Sea Unit #6 Project , CE Obsidian's parent company (CalEnergy Operating Company), stated that data gathered from its operating single-flash and multi-flash plants over recent years shows that the BR123 project design will significantly reduce overall costs compared to the Salton Sea Unit #6 Project design, including compliance and operating costs.

PROJECT FUNDING AND OWNERSHIP

CE Obsidian Energy, LLC (CE Obsidian), would be the sole project owner of the BR123 project facility.

SUMMARY OF STAFF ANALYSIS

The **Executive Summary Table** below shows all the technical areas contained in the Staff Assessment and also indicates recommended Staff changes to the existing SSU6 license and conditions of certification. Staff believes that by requiring the proposed changes to the existing conditions, the potential impacts of the proposed conversion to combined-cycle operations would be reduced to less than significant levels. The details of the proposed condition changes can be found under the appropriate technical headings in this Staff Assessment.

Energy Commission technical staff reviewed the petition to amend for potential environmental effects and consistency with applicable LORS. Where applicable, staff referred to previous environmental assessments in the attached analyses of CE Obsidian's amendment petition. Staff determined that the technical areas of hazardous materials management, power plant efficiency and reliability, noise and vibration, public health, socioeconomics, traffic and transportation, transmission line safety and nuisance, transmission system engineering, visual resources, waste management, and worker safety and fire protection 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. Staff also determined no additional analyses are needed for the areas of Hazardous Materials Management, and Worker Safety and Fire Protection.

Executive Summary Table
Summary of Technical Sections Conditions of Certification

Technical Area	Changes to Conditions of Certification	Technical Area	Changes to Conditions of Certification
Biological Resources	Yes	Air Quality/Greenhouse Gas	Yes
Cultural Resources	Yes	Facility Design	Yes
Noise and Vibration	No	Geology and Paleontology	No
Socioeconomic Resources	No	Power Plant Efficiency	No
Soil and Water Resources	Yes	Power Plant Reliability	No
Transmission Line Safety and Nuisance	No	Transmission System Engineering	No
Traffic & Transportation	No	Waste Management	No
Visual Resources	No	Public Health	No
Land Use	Yes		

Staff determined that the following technical or environmental areas would be affected by the proposed project change to combined-cycle operations and has proposed new and revised conditions of certification in order to assure compliance with LORS and/or to reduce potential environmental impacts to a less than significant level.

- **Air Quality**: Changes to air quality conditions of certification relate largely to the changes in the conditions imposed in the Air Permit for the facility, as well as updating air quality standards and the best management practices employed to reduce project impacts.

- **Biological Resources**: Staff recommends eliminating three Conditions of Certification, modifying five other Conditions to reflect the proposed project changes and remain relevant to the proposed CE Obsidian project, and replacing one Condition with a new condition that consolidates requirements for mitigation of Burrowing Owl habitat loss.

- **Cultural Resources:** Staff recommends elimination of two Cultural Resources Conditions of Certification (**CUL-10 and 11**) because they are no longer applicable to the amended project.

- **Facility Design:** The Facility Design Conditions of Certification are modified to delete components that are not part of the new design and to add several additional components that would be installed as a result of the changed design of the project, such as single-flash tanks and the recuperative thermal oxidizers, and to note an update to the applicable Building Codes since the project was originally licensed.

- **Land Use:** Staff recommends revising Conditions of Certification **LAND-6** to update the amount of land compensation for removing important farmlands from production, and **LAND-8** to require the project owner to update its conditional use permit obtained from the county in 2003. Staff also recommends a new Condition of Certification, **LAND-9,** to ensure that the project conforms with the requirements of the Surface Mining & Reclamation Act, and the State Mining & Geology Board, concerning reclamation of the 38 acre offsite Borrow Area used for construction of project foundations and flood berms.

- **Soil & Water Resources:** The Soil & Water Resources Conditions of Certification were modified to reflect the changes in water use, and the impact mitigation for the various components of the project.

STAFF RECOMMENDATIONS AND CONCLUSIONS

Staff concludes that 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 change will be beneficial to the project owner by increasing operational efficiencies and enhancing the project's economics. Moreover, the change will be beneficial to the State of California by increasing power in an area of need (Southern California); and,

D. There has been a substantial change in circumstances since the Commission certification justifying the change. The single-flash design will provide superior environmental performance compared to the licensed multiple-flash configuration.

INTRODUCTION

Christine Stora

PURPOSE OF THIS REPORT

This Staff Assessment (SA) presents California Energy Commission (Energy Commission) staff's independent analysis of the petition filed with the Energy Commission on March 13, 2009, by CE Obsidian Energy, LLC, to modify the Black Rock 1, 2 and 3 Geothermal Power Project (BR123), originally licensed as the Salton Sea Unit 6 (SSU6) project. This SA is a staff document. It is neither a Committee document, nor a draft decision.

The SA describes the following:

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

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

The Energy Commission staff's analyses were prepared in accordance with Public Resources Code Section 25500 et seq. and Title 20, California Code of Regulation section 1701 et seq.(specifically Section 1769 pertaining to amendments), and the California Environmental Quality Act (CEQA) (Pub. Resources Code, § 21000 et seq.).

Section 1769(a)(3) authorizes the Commission's approval of the amendment petition if it can make the following findings:

A. The findings specified in section 1755 (c) [whether all significant environmental impacts can be mitigated or avoided], and (d) [if all significant impacts cannot be avoided, overriding considerations justify approving the amendment], if applicable;

B. That the project would remain in compliance with all applicable laws, ordinances, regulations, and standards, subject to the provisions of Public Resources Code section 25525;

C. The change will be beneficial to the public, project owner, or intervenors; and

D. There has been a substantial change in circumstances since the Commission certification justifying the change or that the change is based on information that was not available to the parties prior to Commission certification.

The SA contains an Executive Summary, Introduction, Project Description, and the environmental, engineering, and public health and safety analyses of the proposed amendment. The technical areas included in the SA are: air quality (including greenhouse gas analysis); biological resources; cultural resources; facility design; land use; noise and vibration; socioeconomic resources; soil and water resources; transmission line safety and nuisance; facility design; geology and paleontology; power plant efficiency; power plant reliability; and transmission system engineering.

Each of the technical area assessments includes a discussion of:

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

Staff has added new conditions of certification and in some cases modified or deleted some of the existing conditions of certification contained in the Commission Decision for the SSU6 project. Implementing the modified and existing conditions, along with the mitigation measures proposed by the project owner, will ensure that the proposed relocation and other site changes would result in no significant environmental impacts. Where conditions of certification have changed from the original Commission Decision staff displays the revised information in underline (new text) and ~~strikeout~~ (deleted text).

ENERGY COMMISSION AMENDMENT PROCESS

The California Energy Commission has the exclusive authority to certify the construction and operation of thermal electric power plants 50 megawatts (MW) or larger. The Energy Commission certification is in lieu of any permit required by state, regional, or local agencies, and federal agencies to the extent permitted by federal law (Pub. Resources Code, §25500). The Energy Commission must review Petitions to Amend to assess potential environmental and public health and safety impacts, potential measures to mitigate those impacts (Pub. Resources Code, §25519), and compliance with applicable governmental laws and standards (Pub. Resources Code, §25523 (d)). The Energy Commission's siting regulations require staff to independently review the Petition to Amend and assess whether the list of environmental impacts it contains is complete, and whether additional or more effective mitigation measures are necessary, feasible and available (Cal. Code Regs., tit. 20, §§ 1742 and 1742.5(a)). Staff's independent review is presented in this report (Cal. Code Regs., tit. 20, §1742.5).

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

Staff conducts its environmental analysis in accordance with the requirements of CEQA. The Energy Commission's site certification and amendment program has been certified by the Resources Agency as CEQA-equivalent (Pub. Resources Code, §21080.5 and Cal. Code Regs., tit. 14, §15251 (k)). The Energy Commission acts in the role of the CEQA lead agency and is subject to all other applicable portions of CEQA.

Staff uses the SA to resolve issues between the parties and to narrow the scope of adjudicated issues in the evidentiary hearings. If controversy or disagreement over the SA arises after it is published, Staff may conduct one or more workshops to discuss their findings, proposed mitigation, and proposed compliance monitoring requirements. Based on the workshop(s) and written comments, staff will refine their analyses, correct any errors, and finalize conditions of certification to reflect areas where staff has reached agreement with the parties. These refined analyses, along with responses to written comments on the SA, will be published in an errata.

The Siting Committee has oversight over compliance issues for the Energy Commission and has elected to oversee the BR123 amendment petition. If significant controversy or disagreement among parties arises following publication of this SA, all parties will be afforded an opportunity to present evidence and to rebut the testimony of other parties at one or more Committee hearings, thereby creating a hearing record on which a decision on the amendment can be based. The hearing before the Committee would also allow all parties to argue their positions on disputed matters, if any, and it provides a forum for the Committee to receive comments from the public and other governmental agencies. If no significant controversy or disagreement among parties arises following publication of the SA, the Siting Committee may choose to not hold hearings on the petition, in which case parties would still be able to address their concerns at the Business Meeting at which the Commission is scheduled to rule upon the petition.

Following any hearings, the Siting Committee's recommendation to the full Energy Commission on whether or not to approve the proposed amendment may be contained in a document entitled the Presiding Members' Proposed Decision (PMPD). Following publication, the PMPD is circulated to receive written public comments. At the conclusion of the comment period, the Committee may prepare a revised PMPD. If there is a revised PMPD, it will be circulated for a comment period to be determined by the Committee. At the close of that comment period, the PMPD would be submitted to the full Energy Commission for a decision.

To encourage public participation, Energy Commission staff mailed Notices of Receipt on April 1, 2009, to interested parties, local libraries, responsible and trustee agencies and property owners within 1000 feet of the BR123 project and 500 feet of the transmission line. Staff also contacted applicable local, regional, state and federal agencies to encourage participation in the amendment process.

AGENCY COORDINATION

As noted above, the Energy Commission's approval is in lieu of any permit required by state, regional, or local agencies, and federal agencies to the extent permitted by federal law (Pub. Resources Code, § 25500). However, the Energy Commission typically seeks comments from, and works closely with, other regulatory agencies that administer LORS that may be applicable to proposed projects or would have had permitting authority except for the Energy Commission's exclusive jurisdiction to permit thermal power plant 50 megawatts or larger. These agencies include the County of Imperial Planning Department, U.S. Environmental Protection Agency, U.S. Fish and Wildlife Service, California Department of Fish and Game, California Air Resources Board, Department of Toxic Substances Control, the Regional Water Quality Control Board, the California State Mining & Geology Board, and the Imperial County Unified Air Pollution Control District.

PROJECT DESCRIPTION

Testimony of Christine Stora

INTRODUCTION

On March 13, 2009, the California Energy Commission (Energy Commission) received a petition from CE Obsidian, LLC (CE Obsidian), a wholly owned subsidiary of California Energy Company, to amend the Energy Commission Decision for the Black Rock 1, 2, and 3 Geothermal Power Plant project (BR123), originally licensed as the Salton Sea Geothermal Unit #6 (SSU6) Power Project (02-AFC-2). The SSU6 project was certified by the Energy Commission on December 17, 2003, as a single 185 MW multiple-flash (also called “multi-flash”) geothermal power plant. Following exploratory drilling that showed additional capacity was available at the plant site, the Energy Commission approved a petition filed by CE Obsidian in May 2005, to increase generating capacity to a single 215 MW, multi-flash facility, through the use of an Organic Rankine cycle, which would utilize energy dissipated from the dilution water heater. CE Obsidian is now seeking to modify the BR123 project to consist of three 53 MW single-flash units, for a total of 159 MW generating capacity. The facility is located near the southern end of the Salton Sea, near the town of Calipatria in Imperial County. If approved by the Commission, construction of the modified facility is expected to commence in 2011 and last for 46 months, with each unit constructed sequentially.

The three 53 MW units will be co-located on the same site as the original SSU6 project and will share various common auxiliary facilities. The site is currently used for agriculture. Land uses in the surrounding area include existing geothermal power facilities, agriculture, and the Sonny Bono Salton Sea National Wildlife Refuge. The amended project site includes the original 80-acre site plus an additional 80 acres adjacent to the south, part of which was to be used for construction support in the original project. The three 53 MW units will be situated generally in the middle of the site with production well pads on the northern, western, and southern perimeters of the site. Though the site holding the generating facilities has expanded from 80 to 160 acres, the overall footprint of the project, including production and injection wells, is nearly identical, with all production wells now within the same parcel as the generating facilities, rather than scattered outside the 80-acre parcel. For instance, the project, as originally licensed, includes a production well, pipeline and access road on nearby Obsidian Butte, an important cultural resource. The amended facility avoids that well site, instead locating all well pads on disturbed agricultural lands.

The petition contains several modifications, the most notable being the construction of three 53 MW single-flash units rather than a single 215 MW multi-flash facility. All of the proposed modifications are described below.

PROJECT LOCATION

Following the completion of the certification process in December 2003, the project owner was granted permission by the Energy Commission to construct the BR123 project in an unincorporated area of Imperial County, approximately 6 miles northwest of the town of Calipatria, near the southern most reaches of the Salton Sea. The original project site was comprised of an 80–acre site bordered on the north by McKendry Road (also known as McNerney Road), on the east by Boyle Road, on the west by Severe Road, and on the south by Peterson Road. The amended project site includes the original 80-acre site plus an adjacent 80-acre parcel to the south. See **PROJECT DESCRIPTION Figures 1 and 2** for the local setting of this proposed location.

PROJECT FACILITIES

After determining that the original project configuration would be uneconomic to develop, CE Obsidian redesigned the project into three 53 MW units, totaling 159 MW net capacity. Each unit would use single-flash technology. Like all geothermal plants in the Salton Sea area, BR123 would use high-temperature brine brought up from production wells tapping into the deep reservoir of water that is pooled over a bulging pocket of magma approximately 7,400 feet below the surface. In general, brine-sourced geothermal plants direct the hot brine into large expansion tanks where much of the brine flashes to steam, which is then directed to the turbine generator.

SSU6 was designed as a single 215 MW facility using multi-flash technology which generally use three expansion tanks to produce steam at three different pressures, which then is routed to the multi-stage turbine's high, medium, and low-pressure stages. The last of the expansion tanks is generally vented to the atmosphere, producing significant visible water vapor plumes. The BR123 design instead utilizes single-flash technology, in which only one expansion tank is used, producing high-pressure steam for a single-stage turbine. Instead of venting the tank to the atmosphere, the hot brine leftover from the expansion process is directed into injection wells to replenish the brine aquifer, avoiding the production of the large plumes that characterize multi-flash plants. Single-flash units also offer the advantage of producing no filter cake, as the brine stays hot enough to keep its high silica content in the solution so it can easily be injected back into the geothermal resource. Multi-flash units often must filter out the silica that falls out of the solution in the comparable lower temperature brine, requiring management of the resultant filter cake and mitigation of resultant fugitive dust emissions.

Each of the three 53 MW units would consist of two major components: a Resource Production Facility, consisting of brine production and injection wells, associated pipelines, and ancillary facilities including a brine pond; and a Power Generating Facility, consisting of a steam turbine generator (STG), condenser, cooling tower array, non-condensable gas handling equipment and ancillary equipment, and two emergency diesel generators. The project would have three brine production well pads with three wells each; all located on the 160-acre plant site, and would have three offsite brine injection well pads, each with three wells. The 160-acre plant site would also contain infrastructure common to all three 53 MW units, including a control building, and electrical switchyard, two fire water pumps, and fire water, process water and condensate storage tanks.

By comparison, the licensed SSU6 project includes eleven production wells and eight injection wells, all of which are located off the project's 80-acre site, including one on Obsidian Butte, which would have required widening of McKendry Road and resultant impacts to area wetlands. The BR123 project (as amended) moves nine production and nine injection wells onto the 160-acre site, closer to the generating facility, thus avoiding impacts to wetlands and encroachment on the Sonny Bono Salton Sea National Wildlife Refuge.

The BR123 project would be capable of producing baseload renewable energy, operating at or near full power for months at a time, as opposed to the variable nature of wind and solar power. As with the original SSU6 project, power generated by the BR123 project would be delivered to the grid via two interconnection lines operated at 230 kV, each owned and operated by the Imperial Irrigation District (IID). One line, the “Midway” interconnection line, would connect to an existing electrical substation near Niland, California. The second line, the “L” interconnection line, would connect the BR123 project to the “L” transmission line located west of State Route 86 (SR 86) via a proposed switching station called the Bannister Switching Station.

AIR QUALITY EMISSIONS

The primary source of air emissions from geothermal plants consist of non-condensable gases that come out of the brine and steam flowing through the system, with hydrogen-sulfide (H_2S), benzene and various collative organic compounds (VOCs) being the main pollutants of concern. The licensed SSU6 project calls for use of a catalyst system, to control H_2S, and process humidity conditioning and carbon absorption technology, for benzene and VOC control. It would have generated up to three tons per day of sulfur that could be potentially contaminated with mercury, thus requiring landfill disposal. The BR123 project instead would use a Recuperative Thermal Oxidizer (RTO) to control non-condensable gases, including H2S, benzene and VOCs, which does not produce any waste requiring disposal off-site. The RTO converts H_2S to sulfur dioxide (SO_2), which is converted into a soluble salt in a downstream scrubber and pumped into the brine injection stream for disposal.

In general, the amended project would have lower emissions than the licensed project, as well as reduced indirect impacts due to avoidance of offsite disposal of waste products.

WATER SUPPLY AND WASTE WATER TREATMENT

About 95 percent of the makeup water for the project’s cooling towers would come from condensate returning from the plant turbines, which otherwise would be pumped into the injection stream. However, during times when the condensate becomes too high in salinity, additional makeup water will be needed to maintain full power operations. CE Obsidian intends to contract for additional fresh water supplies from the Colorado River through IID’s canal and pipeline system. The amended project would use up to 608.6 acre-feet per year (afy) under worst-case conditions, and 354.9 afy under nominal conditions. Unlike most power plants, single-flash facilities require the highest amount of fresh-water makeup during low power operations, and the least amount at full power operations, when sufficient brine flow and resultant condensate is available to provide all needed makeup water.

The modified project would include a 493,000-cubic-foot retention basin to prevent discharge of storm water. Because the project site is located at 225 feet below sea level on average, and is within the 100-year flood plain, it would also include an earthen berm around the entire site that averages 220 feet in elevation, providing 5 feet of protection. Soil from a borrow site located to the southwest of the project site would be used to create the berm, as well as to elevate the pads for the various structures, ponds, and well pads associated with the project. The total of about 362,000 cubic yards of fill obtained from the borrow site would be replaced with topsoil stripped from the project site in preparation for grading.

Virtually all the waste water produced by the project will be disposed of in the plant injection wells, either directly into the injection stream or into the condensate basin. The BR123 project would produce about 10 tons per year of solid waste requiring off-site disposal, consisting of brine solids that fall out of the brine during startup and shutdown operations, when brine is often temporarily discharged to ponds for injection later, rather than being injected immediately. By comparison, the SSU6 project is licensed to produce up to 200 tons of brine solids, requiring offsite disposal.

CONSTRUCTION AND OPERATION

CE Obsidian proposes construction to begin on the project in 2011, starting with grading of the entire 160 acre site and construction of the surrounding berm. Each unit of the project would then be constructed sequentially, requiring approximately 15 months per unit, about 46 months of total construction time. The construction work force is expected to peak at 572 workers in month 23. Once the new project is on line, 69 operational staff will be employed full-time. The capital cost of the project is expected to be approximately $862 million.

FACILITY CLOSURE

The planned life of the BR123 facility is 30 years or longer. Whenever the facility is closed, either temporally or permanently, the closure procedures would follow the described plan provided in the Commission Decision and any additional LORS in effect at that time.

REFERENCES

California Energy Commission (CEC). 2003. Decision approving the Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Application for Certification, Docket No. 02-AFC-2, Imperial County, published on December 19, 2003.

California Energy Commission (CEC). 2003a. Staff Assessment for Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Application for Certification (02-AFC-2), Imperial County, California, published on August 5, 2003.

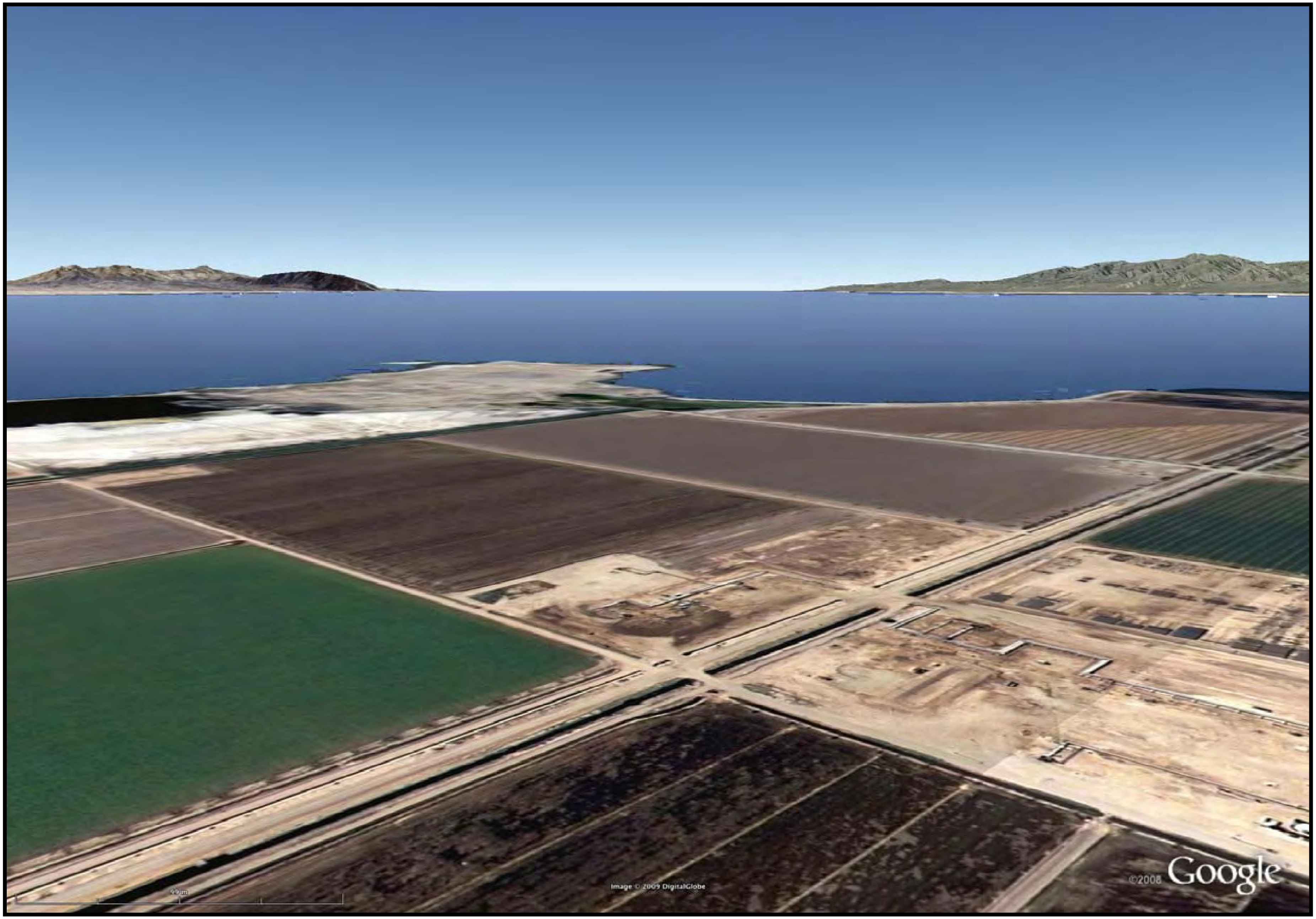
California Energy Commission (CEC). 2005b. Decision approving the Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Petition to Amend, Docket No. 02-AFC-2, Imperial County, published on May 11, 2005.

California Energy Commission (CEC). 2005b. Staff Assessment for Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Petition to Amend, (02-AFC-2), Imperial County, California, published on April 20, 2005.

CE Obsidian Energy, LLC (CE Obsidian/AECOM). 2004. Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant, Petition to Amend, to Modify Project to Add Binary Turbine and Increase Generating Capacity to 215 MW. Submitted to the California Energy Commission, December 14, 2004.

CE Obsidian Energy, LLC (CE Obsidian/AECOM). 2009. Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant, Petition for License Amendment, to Modify Project to Allow Construction of Three 53 MW Units, totaling 159 MW. Submitted to the California Energy Commission, March 10, 2009.

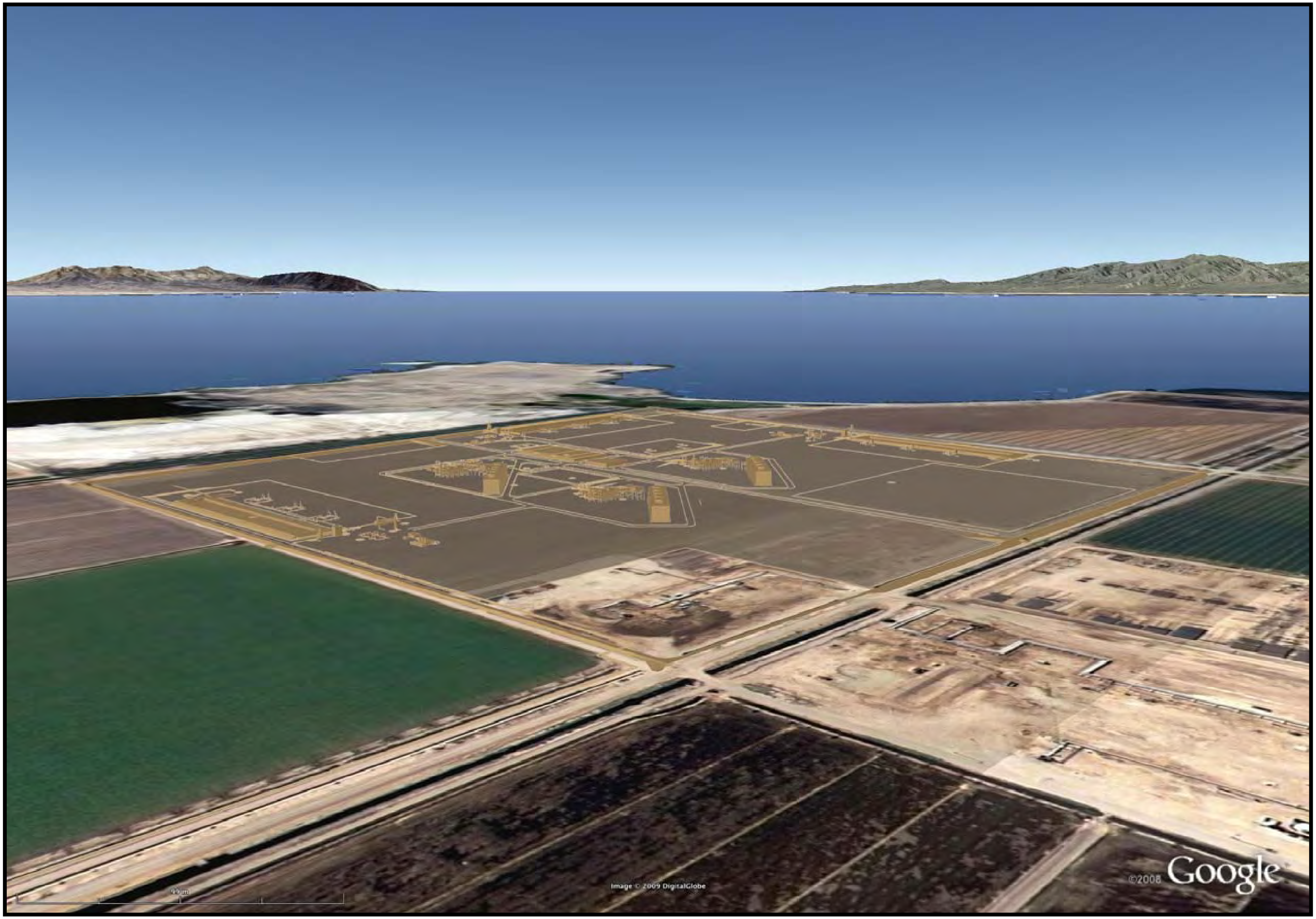
PROJECT DESCRIPTION - FIGURE 1
Black Rock 1 & 2 Geothermal Power Plant - Project Site - Existing Conditions



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: Amendment Petition

PROJECT DESCRIPTION - FIGURE 2

Black Rock 1 & 2 Geothermal Power Plant - Project Site - With Simulated Facilities



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Amendment Petition

ENVIRONMENTAL ANALYSIS

AIR QUALITY Staff Analysis
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INTRODUCTION

CE Obsidian Energy, LLC (CE Obsidian or project owner) proposes to amend the current California Energy Commission (Energy Commission) Decision to allow for the construction of three smaller geothermal plants. Total electrical generating capacity of the facility would change from 215 MW (gross) to 159 MW (gross) with the proposed amendment. The amended project, Black Rock 1, 2, and 3 Geothermal Power Project (BR123), would use single flash technology, thus dilution, which was required for multi flash, would not be required. In order to accommodate these differences in technology and electrical capacity, changes would also be made in the layout and configuration. The additional differences would include changes in plant size from 80 acres to 160 acres, relocation of the plant site, removal of a production well pad located on Obsidian Butte (OB-3), cancellation of the widening of McKendry Road (to serve OB-3), and change of location and number of production and injection wells and well pads.

The setting, project emissions, and project impacts are fully updated in this analysis and the Conditions of Certification (COCs) have been revised. All of the District conditions have been revisited by the Imperial County Air Pollution Control District (ICAPCD), and all of the District Final Determination of Compliance (FDOC) conditions including the additions and revisions required by the District are provided in this analysis. District conditions have been re-ordered in some instances. The Energy Commission staff COCs for construction emissions mitigation have been updated based on the latest version of staff-recommended measures.

ICAPCD is requiring the project owner to fund a hydrogen sulfide (H_2S) monitor that will be used to determine regional H_2S background concentrations. Currently, due to a lack of ongoing H_2S monitoring, it is unclear if the ambient H_2S concentrations do or do not meet the California 1-hour standard in the project area, which has a large amount of natural and geothermal plant H_2S emissions. Staff is recommending that the project owner offset the project's H_2S emissions, as previously agreed to by the project owner, if this new H_2S ambient monitor finds regional H_2S impacts (exceedances of the State 1-hour H_2S standard). The mitigation of H_2S is consistent with what the project owner proposed in the original 215 MW project, but in the amended project the project owner removed the H_2S offset mitigation. Staff believes that the H_2S offset mitigation would be needed if the H_2S monitor measures regional exceedances of the H_2S standard tied to the project.

BACKGROUND AND PROJECT SUMMARY

The original license to construct a geothermal generating plant on an 80-acre site in Imperial County, California was granted in 2003 as Salton Sea Geothermal Unit #6 (SSU6) for a 185 MW plant. The original 2003 license was amended in May 2005 to enable the plant to increase its capacity to 215 MW. The project owner is amending the project again into three separate single flash units that would total 159 MW.

Each of the three geothermal plant units proposed by this amendment would consist of two major components, the Resource Production Facility (RPF) and the Power Generating Facility (PGF). The RPF includes all of the brine production and injection wells, the brine handling facilities at the main project site, the associated brine pipelines from the production wells and to the injections wells, and ancillary systems. The PGF includes the steam turbine generator, cooling system, non condensable gas (NCG) removal and abatement systems, and other electrical and plant site ancillary systems.

The hot and high-pressure geothermal fluid (brine) extracted from the geothermal reservoir through the production wells flows to a steam handling system consisting of a flash vessel, scrubbers and demisters. At the steam handling system, the steam is separated from the geothermal brine to produce high-pressure steam that is sent to the PGF for use in the steam turbine. The steam turbine drives a generator and the steam leaving the turbine enters a shell-and-tube heat exchanger that condenses the steam. Cooling water for the heat exchanger would be provided by a five-cell, mechanical draft wet cooling tower (one each per PGF). Removed NCGs would be treated by venting the gases through a regenerative thermal oxidizer (RTO) and wet scrubber system to control the hydrogen sulfide, ammonia, methane, benzene, and other trace gas emissions in the NCGs and also control the sulfur dioxide emissions created through the oxidation of the hydrogen sulfide by the RTO.

Due to proposed changes in the project design, including the brine separation technology, and proposed emissions control systems, the overall emissions and air quality impacts for some of the criteria air pollutants would be reduced in comparison to the currently approved amended project, while other pollutant emissions would increase. Additionally, the project owner has updated the brine composition assumptions, which influence the NCG and cooling tower air pollutant emissions. Also, the revised project design would reduce emissions that would have been associated with the activities such as transport of waste and regeneration of spent carbon that are no longer necessary due to the changes in the project design.

In the proposed amendment, dilution water heaters are not required, since the proposed single flash technology maintains the heat energy of the brine at a sufficiently high level such that the silica crystallizes at lower temperature. Since dilution is no longer required, no filter cake would be needed as a result. Therefore, the fugitive dust and transportation emissions associated with use of filter cake would no longer occur at the amended project site.

To control H_2S and other constituents of the NCG, the project owner proposes a RTO instead of the LO-CAT/Sulfurite system with an activated carbon adsorption system. The RTO uses propane in an efficient combustion technology to oxidize both the H_2S as well as the other Volatile Organic Compounds (VOCs) in the NCG stream, which will control benzene, methane, and other volatiles. H_2S emissions would also be reduced with a chemical oxidation process (ChemOx), which would be employed in the cooling tower replacing the formerly proposed biological oxidation system.

The proposed modifications would involve substantial changes to almost every aspect of the original air quality analysis because of the substantial changes to the technology and control strategies. In addition, the project owner proposes a change to the auxiliary equipment, diesel-fired engines. The amended project will install Tier 4 diesel-fired engines which have substantially lower emission rates of criteria pollutants than the originally proposed Tier 2 engines.

To address the significant proposed changes to the facility, ICAPCD conducted an evaluation for the amended project, which under its rule requirements was evaluated as a completely new project. The ICAPCD issued a Preliminary Determination of Compliance (PDOC) on May 11, 2010 (ICAPCD 2010a). After a 30-day public comment period, a Final Determination of Compliance (FDOC) was issued by ICAPCD on July 9, 2010 (ICAPCD 2010b), which was replaced by a revised FDOC on August 19, 2010 (ICAPCD 2010c).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

At the time of certification, LORS applicable to Air Quality were identified in the Staff Assessment for the project. These LORS would continue to apply to the amended project with the following revisions as shown in **AIR QUALITY Table 1**:

AIR QUALITY Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
40 Code of Federal Regulations (CFR) Part 52	Nonattainment New Source Review (NSR) requires a permit and requires Best Available Control Technology (BACT) and Offsets. Prevention of Significant Deterioration (PSD) requires major sources or major modifications to major sources to obtain permits for attainment pollutants.
40 CFR Part 60	Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. Establishes emission standards for compressions ignition internal combustion engines, including emergency generator and fire water pump engines.
State	
Health and Safety Code (HSC) Section 40910-40930	Permitting of source needs to be consistent with Air Resource Board (ARB) approved Clean Air Plans.
HSC Section 41700	Restricts emissions that would cause nuisance or injury.
California Code of Regulations (CCR) Section 93115	Airborne Toxics Control Measure for Stationary Compression Ignition Engines. Limits the types of fuels allowed, establishes maximum emission rates, establishes recordkeeping requirements on stationary compression ignition engines, including emergency generator and fire water pump engines.
Local – Imperial County Air Pollution Control District (ICAPCD) Rules and Regulations	
ICAPCD Rule 109 Source Sampling	Establishes the requirement to provide and maintain such facilities as are necessary for sampling and testing.
ICAPCD Rule 111 Equipment Breakdown	Requires that the ICAPCD be notified of any occurrence which constitutes a breakdown condition within prescribed timeframes.
ICAPCD Rule 201 Permits Required	Requires an Authority to Construct before construction of an emission source occurs. Prohibits operation of any equipment that emits or controls air pollutants without first obtaining a permit to operate.

Local – Imperial County Air Pollution Control District (ICAPCD) Rules and Regulations	
ICAPCD Rule 207 New and Modified Stationary Source Review	Specifies BACT/Offsets technology and requirements for a new emissions unit that has potential to emit any affected pollutants.
ICAPCD Rule 208 Permit to Operate	Provides the process by which a facility with a permit to construct may receive an approved permit to operate.
ICAPCD Rule 400 Fuel Burning Equipment – Oxides of Nitrogen	Limits the emission levels of oxides of nitrogen from any source to no more than 140 lbs/hr of NOx, calculated as NO_2.
ICAPCD Rule 401 Opacity of Emissions	Applies to the opacity of discharges from any single source.
ICAPCD Rule 403 General Limitations on the Discharge of Air Contaminants	Applies to the discharge of air contaminants, combustion contaminants, and particulate matter into the atmosphere.
ICAPCD Rule 405 Sulfur Compounds Emission Standards, Limitations and Prohibitions	Limits discharge of sulfur compounds into atmosphere from equipment to specified amounts.
ICAPCD Rule 407 Nuisances	Prohibits the discharge from any source of any air contaminant that may cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public, or which endangers such persons or public or which may cause injury or damage to business or property.
ICAPCD Rule 414 Storage of Reactive Organic Compound Liquids	Establishes control and inspection requirements applicable to storage tanks with a capacity equal to or greater than 1,500 gallons used to store reactive organic compound (ROC) liquids with a true vapor pressure equal to or greater than 0.50 psia.
ICAPCD Rule 424 Architectural Coatings	Limits ROC emissions from architectural coatings.
ICAPCD Rule VIII Fugitive Dust Rules 800 through 805	These rules identify mitigation requirements to reduce fugitive dust emissions.
ICAPCD Rule 1101 New Source Performance Standards (NSPS)	Specifies that all new stationary sources of air pollution will comply with the standards, criteria, and requirements in NSPS.

SETTING

AIR QUALITY STANDARDS AND ATTAINMENT STATUS

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

The project site is located a few miles west of Calipatria and north of Westmorland in Imperial County. The project site is located within the Salton Sea Air Basin (SSAB) under the jurisdiction of ICAPCD. The SSAB in the area of the project site is designated as nonattainment for the federal and state ozone and PM10 standards[1]. This area is designated as attainment for the federal and state PM2.5, CO, NOx, and SOx standards. This area is also designated as unclassified for the state hydrogen sulfide (H_2S) standard. **AIR QUALITY Table 3** summarizes the area's attainment status for various applicable state and federal standards. The ambient air quality standards that staff uses as a basis for determining project significance are health-based standards. They are set at levels to adequately protect the health of all members of the public, including those most sensitive to adverse air quality such as the aged, people with existing illnesses, and infants and children, while providing a margin of safety.

AIR QUALITY Table 2
Federal and State Ambient Air Quality Standards

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

Source: ARB 2010a.
Notes: [a] The 2008 standard is shown above, but as of September 16, 2009 this standard is being reconsidered. The 1997 8-hour standard is 0.08 ppm.

[1] U.S. EPA has actually found that Imperial County has attained the 1997 8-hour ozone standard, but will not officially redesignate Imperial County as attainment until they approve an ozone maintenance plan. Imperial County has not yet provided an ozone maintenance plan and so is still officially designated as a moderate non-attainment area. Additionally, U.S. EPA will be finalizing a revised 8-hour ozone standard, somewhere between 0.06 and 0.07 ppm, later this year, which Imperial County would likely not be able to attain before U.S. EPA finalizes the attainment designations for this new standard in the next two to three years.

[b] The U.S.EPA is in the process of implementing their new 1-hour NO_2 standard, which became effective April 12, 2010. This standard is based on the 3-year average of the 98th percentile of the yearly distribution of 1-hour daily maximum concentrations.
[c] The U.S.EPA has recently adopted a primary 1-hour SO_2 standard which will become effective on August 23rd, 2010, and revoked the primary 24-hour and annual SO_2 standards. This new 1-hour standard is based on the 3-year average of the 99th percentile of the yearly distribution of 1-hour daily maximum concentrations.

AIR QUALITY Table 3
Federal and State Attainment Status for Imperial County[a]

Pollutant	Federal Classification	State Classification
Ozone	Moderate Nonattainment	Moderate Nonattainment
PM10	Serious Nonattainment	Nonattainment
PM2.5	Attainment[b]	Unclassified
NO_2	Attainment/Unclassifiable	Attainment
CO	Attainment/Unclassifiable	Attainment
SO_2	Attainment/Unclassifiable	Attainment
H_2S	--	Unclassified

Sources: U.S.EPA 2010a. ARB 2010b
Notes: [a] Unclassifiable or unclassified is treated as attainment for regulatory purposes.
[b] Part of Imperial County is designated as a PM2.5 nonattainment area, but the BR123 project site is located north of the nonattainment area.

CRITERIA POLLUTANT 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 (the last year that the complete annual data is currently available) at the most representative monitoring stations for each pollutant are shown in **AIR QUALITY Table 4** and the 1-hour and 8-hour ozone, 24-hour PM10 and 24-hour PM2.5 data for the years 1998 through 2009 are shown in **AIR QUALITY Figure 1**.

The closest monitoring stations from the site are the Niland-English Road monitoring station approximately 5.6 miles northeast of the project site, the Westmorland-W 1st Street monitoring station approximately 9.0 miles south of the project site, the Brawley 220 W. Main Street station approximately 14 miles south southeast of the site, the El-Centro 9th Street station approximately 26 miles south southeast of the site, and the Calexico Ethel Street station located approximately 35 miles south southeast of the project site. All ozone and PM10 data presented in the **AIR QUALITY Table 4** and in the **AIR QUALITY Figure 1** are collected from the Westmorland monitoring station. PM2.5 data are collected from the Brawley monitoring station for the years 1999, 2000, and 2001, from the Brawley 220 Main Street station for the year 2008, and from the El-Centro 9th Street station for the years 2003 through 2007, and 2009. All CO and NO_2 data presented in **AIR QUALITY Table 4** and in the **AIR QUALITY Figure 1** are collected from El-Centro 9th Street monitoring station. All SO_2 concentrations are collected from the Calexico-Ethel Street.

The Niland - English Road air monitoring station, located approximately 7.5 miles northeast of the BR123 project site, was originally established to monitor the ambient levels of H_2S in the geothermal area of the Salton Sea. Because of extensive operating and quality control issues with the H_2S monitor, H_2S monitoring at this station was discontinued. Due to a lack of data to the contrary, the area is designated as an unclassified area for H_2S. The Imperial County APCD recommended a background H_2S level of 24.6 $\mu g/m^3$ (0.018 ppm) based on an average level of the available data (1993-

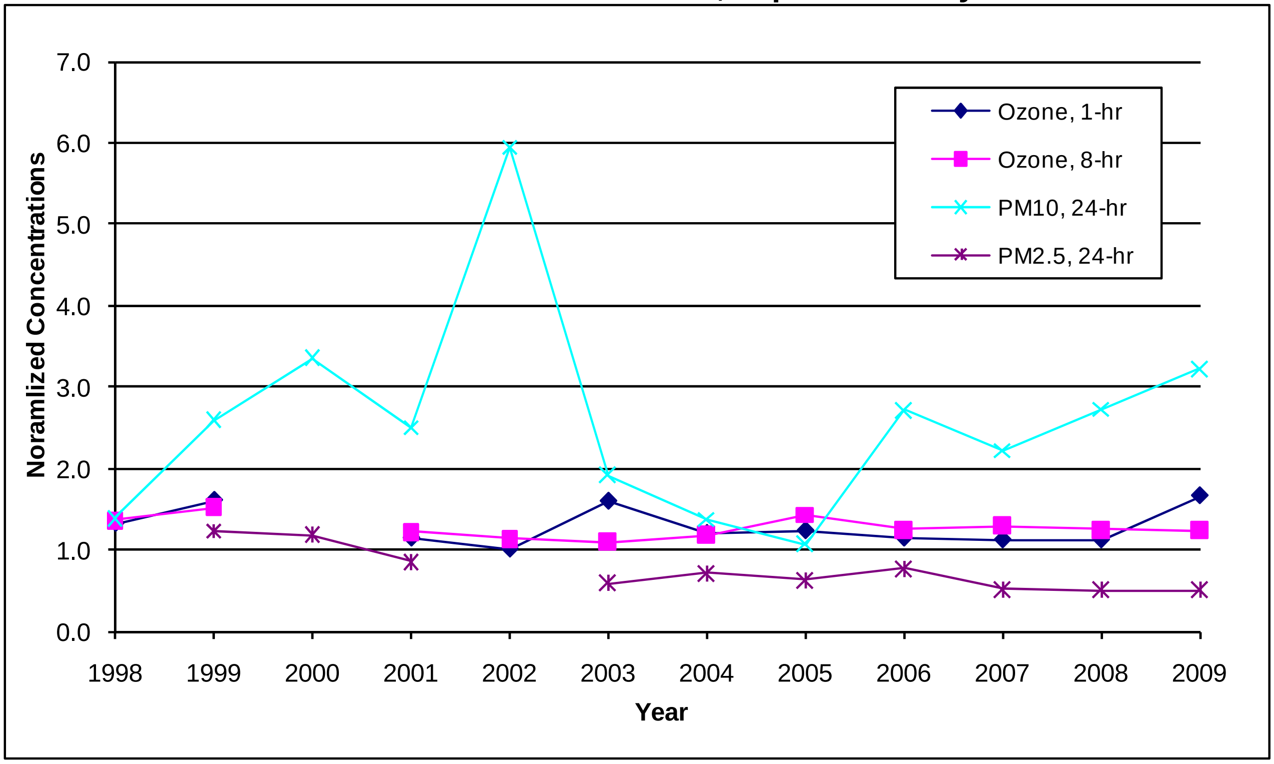
1994) that was monitored before Units 1, 2, and 3, Vulcan, and Hoch were retrofitted with biofilter controls, and also before Units 4 and 5, and CE Turbo started operation.

AIR QUALITY Table 4
Criteria Pollutant Summary
Maximum Ambient Concentrations (ppm or µg/m³)

Pollutant	Averaging Period	Units	2004	2005	2006	2007	2008	2009	Limiting AAQS [d]
Westmorland-W 1st Street Monitoring Station									
Ozone	1 hour	ppm	0.109	0.112	0.104	0.102	0.102	0.150	0.09
Ozone	8 hours	ppm	0.083	0.100	0.088	0.091	0.088	0.087	0.07
PM10 [a]	24 hours	µg/m³	69	54	136	111	136.7	161.4	50
PM10 [b]	Annual	µg/m³	36	31.4	48.5	48.8	38.5	43.4	20
Brawley 220 Main Monitoring Station									
PM2.5 [a, c]	24 hours	µg/m³	---	---	---	---	17.8	---	35
PM2.5 [b]	Annual	µg/m³	---	---	---	---	8.2	---	12
El Centro-9th Street Monitoring Station									
PM2.5 [a, c]	24 hours	µg/m³	25.1	22.1	27.1	18.2	---	17.9	35
PM2.5 [b]	Annual	µg/m³	9.6	9.3	8.7	8.4	---	8.0	12
NO_2	1 hour	ppm	0.067	0.065	0.066	0.071	0.081	0.122	0.18
NO_2	1 hour (fed)	ppm	n/a	n/a	n/a	0.057	0.053	n/a	0.10
NO_2	Annual	ppm	0.013	0.011	0.011	0.011	0.009	0.008	0.03
CO	1 hour	ppm	2.0	4.2	14.3	2.5	3.1	1.9	20
CO	8 hours	ppm	1.17	2.23	2.59	1.67	1.71	1.8	9.0
Calexico-Ethel Monitoring Station									
SO_2	1 hour	ppm	0.003	0.002	0.192	0.014	0.018	0.013	0.25 [e]
SO_2	24 hours	ppm	0.003	0.002	0.041	0.004	0.007	0.005	0.04
SO_2	Annual	ppm	0.000	0.000	0.001	0.000	0.000	0.000	0.03

Sources: ARB 2010c, ARB 2010d, U.S.EPA 2010b
n/a - data not available
Notes:
[a] Exceptional PM concentration events, such as those caused by wind storms may be included in the data presented.
[b] When state arithmetic mean is not available, instead, national annual average PM10 and PM2.5 data are used.
[c] 24-hour PM2.5 data shown are the 98th percentile concentrations.
[d] The limiting ambient air quality standard (AAQS) is the most stringent of the California AAQS or National AAQS for that pollutant and averaging period.
[e] The values presented represent the maximum hourly values, which correspond to the state standard. The 3-year average of the 99th percentile of yearly distribution of the daily 1-hour maximums, which correspond to the 0.075 ppm NAAQS are not readily available.

AIR QUALITY Figure 1
1998-2009 Historical Ozone [a] and PM [a, b] Air Quality Data [c]
Niland-English Road, Westmorland-W 1st St., Brawley-220 Main St, and El Centro 9th St. Stations, Imperial County



Sources: ARB 2010c, ARB 2010d, U.S.EPA 2010b
Notes:
[a] All ozone and PM10 data presented are collected from the Westmorland-W 1st Street monitoring station.
[b] PM2.5 data are collected from the Brawley-Main Street monitoring station for the years 1999 - 2001, from the Brawley-220 Main Street station for the year 2008, and from the El Centro 9th Street station for all other years.
[c] The highest measured ambient concentrations of various criteria air contaminants were divided by their applicable standard and provided as a graphical point. Any point on the chart that is greater than one means that the measured concentrations of such air contaminant exceed the standard, and any point that is less than one means that the respective standard is not exceeded for that year. For example the 1-hour ozone concentration in 1998 is 0.12 ppm/0.09 ppm standard = 1.33.

Ozone

Ozone is not directly emitted from stationary or mobile sources, but is formed as the result of chemical reactions in the atmosphere between directly emitted nitrogen oxides (NOx) and hydrocarbons (Volatile Organic Compounds [VOC]) in the presence of sunlight to form ozone. The Imperial County portion of the SSAB would likely have much lower ozone concentrations without the influence of transported pollutants from upwind regions, specifically Mexico, the South Coast Air Basin (Los Angeles Area) and the San Diego Air Basin.

As **AIR QUALITY Table 4** and **AIR QUALITY Figure 1** indicate, the 1-hour and 8-hour ozone concentrations measured, with some annual variability, have been fairly constant over time. The collected air quality data (not shown) indicate that the ozone violations occurred primarily during the sunny and hot periods typical during May through September.

Nitrogen Dioxide

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

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

Carbon Monoxide

The area is classified as attainment for the state 1-hour and 8-hour CO standards. The highest concentrations of CO occur when low wind speeds and a stable atmosphere trap the pollution emitted at or near ground. The project area has a lack of significant mobile source emissions and has CO ambient concentrations that are well below the state and federal ambient air quality standards.

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

Particulate Matter (PM10 and PM2.5) can be emitted directly or it can be formed many miles downwind from emission sources when various precursor pollutants interact in the atmosphere.

Respirable particulate matter, or PM10, is derived from a combination of sources including fugitive dust and combustion particulate and secondary particulate formation. Fine particulate matter, or PM2.5, is derived mainly from either the combustion of materials, or from precursor gases (SOx, NOx, and VOC) through complex reactions in the atmosphere. PM2.5 consists mostly of sulfates, nitrates, ammonium, elemental carbon, and a small portion of organic and inorganic compounds.

The area is nonattainment for the state and federal PM10 standards. As shown in **AIR QUALITY Figure 1**, PM10 concentrations were much higher than the state 24-hour PM10 standard in the recent 12-year history. Imperial County in the site area is classified as attainment for the state and federal PM2.5 standards. This divergence between the PM10 and PM2.5 attainment status indicates that a substantial fraction of the ambient particulate matter levels are most likely due to localized fugitive dust sources, such as vehicles travel on unpaved roads, agricultural operations, or wind-blown dust[2].

[2] 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

Sulfur Dioxide

The entire air basin is classified as attainment for the state and federal SO_2 standards. Sulfur dioxide is typically emitted as a result of the combustion of a fuel containing sulfur. The project area's SO_2 concentrations are below the state and federal ambient air quality standards. The SO_2 attainment status could change due to the new federal 1-hour standard, although a review of the existing Calexico monitoring data suggest this would not occur for the SSAB.

Hydrogen Sulfide

The entire air basin is classified as unclassified for the state H_2S standard. Hydrogen sulfide is emitted as part of natural geologic and biologic processes, and is emitted from manmade sources such as oil production and refining, wastewater treatment, geothermal power plants, etc. Hydrogen sulfide is a highly toxic and flammable gas. Being heavier than air, it tends to accumulate at the bottom of poorly ventilated spaces. Hydrogen sulfide has a very low odor threshold, and a very unpleasant rotten egg odor, but with continuous low level exposure or at higher concentrations a person can lose their ability to smell the gas even though it is still present. Additionally, hydrogen sulfide can also cause irritation of the eyes, nose, and throat and cause respiratory effects at low concentrations, and is lethal at high concentrations[3]. Additional odor, nuisance, and health effect levels for hydrogen sulfide exposure are provided below:

Concentration	Effect
0.11-0.33 ppb	Average U.S. Background Levels
0.5 ppb	2% of population can detect odor
0.72 ppb	EPA reference dose for no lifetime risk (average lifetime exposure)
2 ppb (2.8 $\mu g/m^3$)	Odor threshold for 14% of the population and lower annoyance level
4 ppb (5.6 $\mu g/m^3$)	Odor threshold for 30% of the population and annoyance level for 5% of the population
5 ppb (7 $\mu g/m^3$)	World Health Organization 30-minute advisory level
8 ppb (11.2 $\mu g/m^3$)	Odor threshold for 50% of the population and annoyance level for 11% of the population
10 ppb (14 $\mu g/m^3$)	Neurophysical health effect level and eye and nasal symptoms, average daily concentration level.
30 ppb (42 $\mu g/m^3$)	California Ambient Air Quality Standard, 1-hour standard
40 ppb (56 $\mu g/m^3$)	Annoyance level for 50 percent of the population

Note: Concentrations are instantaneous concentrations unless otherwise noted.

Summary

In summary, staff recommends the background ambient air concentrations in **AIR QUALITY Table 5** for use in the modeling and impacts analysis. The maximum criteria pollutant concentrations from the past three years of available data collected at the most representative monitoring stations are used to determine the recommended background values.

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from fugitive dust emission sources, rather than from combustion particulate or secondary particulate emission sources.

[3] The concentration designated as immediately dangerous to life and health (IDLH) is 100 ppm and concentrations higher than 1,000 ppm result in unconsciousness, cessation of respiration, and death in a few minutes of exposure.

AIR QUALITY Table 5
Staff Recommended Background Concentrations (µg/m³)

Pollutant	Averaging Period	Recommended Background	Limiting Standard	Percent of Standard
NO_2	1 hour (Calif.)	229.8	339	68%
	1 hour (Fed.)	100.2	189	53%
	Annual	20.9	57	37%
PM10	24 hour	161.4	50	323%
	Annual	48.8	20	244%
PM2.5	24 hour	18.2	35	52%
	Annual	8.4	12	70%
CO	1 hour	3,565	23,000	16%
	8 hour	2,000	10,000	20%
SO_2	1 hour [a]	47.2	655	7%
	3 hour	42.4	1,300	3%
	24 hour	14.0	105	13%
	Annual	1.3	80	2%
H_2S	1 hour	24.6	42	59%

Sources: ARB 2010c, ARB 2010d, U.S.EPA 2010a, CE Obsidian Energy 2009, and Energy Commission Staff Analysis
Note:
[a] – This maximum hourly value is conservatively being used to show compliance with both the State and federal 1-hour standards.

Where possible, staff prefers that the recommended background concentrations come from nearby monitoring stations with similar characteristics. For this project, the PM10 background concentrations were collected from the Westmorland-W 1st street monitoring station located, which is located approximately 9 miles south of the project site. For PM2.5, the background concentrations were collected from the El Centro 9th Street monitoring station which is located approximately 26 miles south of the project site. The Brawley station, which is located approximately 14 miles south southeast of the project site, only has one year of available PM2.5 data, for the year 2008, and since the concentrations from El Centro in 2007 are marginally higher than the Brawley station concentrations they were selected to represent the worst-case background for PM2.5. The background concentrations for NO_2 and CO are collected from the El Centro 9th Street monitoring station and SO_2 background concentration are collected from Calexico monitoring station, located right above the U.S-Mexico border approximately 35 miles south of the project site. These last two monitoring stations, particularly Calexico, provide more conservative air quality data due to the influence of pollutants from Mexico. The H_2S background is derived, per Imperial County APCD recommendation, as an average hourly concentration from monitoring conducted at the Niland - English Road air monitoring station during 1993-1994[4]. The Niland-English Road air monitoring station is located approximately 7.5 miles northeast of the BR123 project site. Due to the age and the use of an average concentration rather than a

[4] As noted previously the monitoring conducted during 1993-1994 was completed before the installation of H2S controls on five of the seven geothermal facilities in existence during that time. However, since that time another three geothermal facilities have started operation, so it is unclear if using the average hourly monitored concentration would be more appropriate than using the maximum concentration as is normally done to demonstrate compliance with the other CAAQS.

maximum hourly concentration, staff is concerned that this background could cause an underestimation of worst-case ambient air quality impacts for H_2S.

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

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

ANALYSIS

EQUIPMENT DESCRIPTION CHANGES

Electricity would be produced by the three power generation blocks, each of which includes following equipment (CE Obsidian 2009, CE Obsidian 2009a).

- Steam Turbine Generator (STG): Three nominally rated at 53MW (net) STG would generate total of 159 MW for the amended project. The STG would only use geothermal steam from the Resource Production Facility (RPF). The turbine generator would be fully equipped with auxiliary systems for turbine control and speed protection, lubricating oil, gland sealing, generator excitation, and cooling.

- Condenser: A stainless steel shell-and-tube type heat exchanger would condense exhaust steam received from the STG. Cooling water would be supplied by the cooling tower, and the warmed circulating water would be returned to the cooling tower.

- Regenerative Thermal Oxidizer H_2S/Benzene Emissions Control System (RTO): The amended project would install one RTO per Power Generating Facility (PGF) to control emissions. In addition, a SO_2 scrubber and mercury emissions abatement device would be used downstream of the RTO.

- Cooling Tower: The project would include one five-cell cooling tower per power block, each of which has an inlet circulating water flow rate of 89,112 gpm and would be equipped with high efficiency mist eliminators. The process condensate used for cooling water make-up will be treated with a ChemOx system to reduce the amount of dissolved H_2S in the condensate that would otherwise be emitted in the cooling tower exhaust.

- 1.5 MW Emergency Power Generator: Each power block would have one 1.5 MW, 4,160V Tier 4 diesel-fired emergency internal combustion engine emergency generator.

- 1.0 MW Emergency Power Generator: Each power block would have one 1.0 MW, 480V Tier 4 diesel-fired emergency internal combustion engine emergency generator.

- The emergency generators are sized to accommodate critical loads (brine injection pumps, air compressor, DC lube oil pump, turbine turning gear, emergency lighting, and other vital loads) associated with the PGF and common facilities and maintain reduced operation of the RPF for each of the three separate Black Rock units.

- 200 hp Firewater Pump Engine: A 200 hp, 2,400 gpm Tier 4 diesel-fired emergency internal combustion engine, one engine for all three power blocks, is proposed instead of the originally proposed Tier 2 engine.

EMISSION CONTROLS

The air pollutants in the non condensable gas (NCG) would be controlled using an RTO system. The proposed RTO system reduces emissions of hydrogen sulfide by 95 percent and volatile organic compounds (VOCs) by at least 98 percent[5]. Evacuated NCGs from the condenser heat exchanger would be routed to the RTO for control. The H_2S, methane, benzene, and other trace gas emissions would be oxidized using an efficient combustion technology. During the oxidizing process, benzene and methane would be converted into CO_2 and water while H_2S would be oxidized to SO_2. The SO_2 gas and ammonia in the NCG would further be controlled in a caustic scrubber. The scrubber blowdown will be directed to the cooling tower basin, and the cooling tower blowdown will be injected back into the geothermal brine source via one of the two plant injection wells. Mercury would be controlled and separated from the NCGs downstream of the caustic scrubber.

The H_2S emissions in the condensate cooling tower water will be controlled by a 95 percent efficient chemical oxidation process (ChemOx). Use of the ChemOx system eliminates the formation and management of biomass and the potential for plugging and corrosion of the cooling towers due to formation of sulfur or iron sulfide sludge that would have occurred in the formerly proposed biological oxidation H_2S emissions control process.

AMENDED PROJECT EMISSIONS AND IMPACTS

Construction Activities and Emissions

The amended project would include construction of three power blocks, an approximately 500-ft water supply line, earth moving work, and wellfield. Earth work includes the construction of three brine ponds, a storm water retention basin and a perimeter berm for flood protection, soil stabilization and foundation support. For well construction, nine geothermal production wells would be drilled on three well pads, nine brine injection wells on three well pads, and four plant injection wells on two pads. The construction duration would be 46 months for the three power blocks and earth moving work and 34 months for the production and injection wells. These construction periods would overlap and the total construction duration would be 53 months.

The original project required two new transmission lines, which are the “Midway” and “L” interconnection lines. These transmission lines are already licensed, and there would be no changes in these transmission lines with the proposed amendment.
In the construction emissions estimates shown in **AIR QUALITY Table 6**, it was assumed that the construction equipment would operate 8 hours per day, 365 days

[5] The project owner originally proposed 95 percent for VOC control, but accepted the District’s BACT determination of 98 percent control.

annually. The maximum daily construction emissions for each pollutant would occur at different times. Maximum daily emissions would occur during Month 30 for CO, VOC, and VOD; during Month 29 for NOx; during Month 26 for PM10; and during Month 23 for PM2.5. The maximum annual construction emissions represent the consecutive 12-month period out of the 53-month construction schedule with the highest emissions. The 12-month period with the highest predicted total emissions is the period from month 22 through month 33. Total construction emissions during 53 months are presented in **AIR QUALITY Table 7**.

AIR QUALITY Table 6
Maximum Daily and Annual Construction Emissions

Maximum Daily Emissions (lbs/day)						
	NOx	CO	VOC	SOx	PM10	PM2.5
Power Blocks						
Onsite	137.84	160.54	19.90	0.16	136.42	34.01
Offsite	175.02	625.38	68.30	0.48	127.65	25.79
Well Construction						
Onsite	180.80	917.19	105.27	1.74	48.81	29.16
Offsite	180.80	917.19	105.27	1.74	48.81	29.16
Offsite Vehicle	37.91	77.99	9.34	0.08	17.38	4.00
Earthwork						
Onsite	86.52	31.99	9.78	0.09	51.30	13.57
Offsite	107.08	64.98	11.53	0.12	77.61	19.85
Maximum Concurrent[a]						
Onsite	348.13	1,090.63	128.86	1.93	213.15	65.46
Offsite	437.77	1,605.67	184.64	2.33	196.02	68.32
Offsite Vehicle	28.77	73.00	8.12	0.06	16.13	2.95
Total	814.67	2,769.29	321.61	4.31	425.30	136.73
Maximum Annual Emissions (ton/year)						
	NOx	CO	VOC	SOx	PM10	PM2.5
Power Blocks						
Onsite	16.73	20.73	2.49	0.02	16.66	4.18
Offsite	21.58	74.80	8.29	0.06	15.53	3.21
Well Construction						
Onsite	29.22	148.56	17.05	0.28	6.72	4.47
Offsite	29.22	148.56	17.05	0.28	6.72	4.47
Offsite Vehicle	5.05	12.30	1.43	0.01	2.66	0.59
Earthwork						
Onsite	5.74	2.09	0.65	0.01	3.73	0.98
Offsite	9.70	5.81	1.05	0.01	6.99	1.79
Maximum Concurrent[a]						
Onsite	47.78	169.55	19.74	0.30	25.36	9.18
Offsite	58.07	227.37	26.09	0.35	26.93	8.90
Offsite Vehicle	3.65	11.49	1.29	0.01	2.39	0.50
Total	109.50	408.40	47.12	0.66	54.68	18.59

Source: CE Obsidian Energy 2009a (Data Response 15)
Note: a – This table presents the maximums for each activity regardless of when they occur within the construction schedule and the maximum concurrent emissions which totals all of the activities concurrent maximum daily and annual (rolling 12 month) emissions, which are not quite the same as the addition of the maximum daily emissions for each activity, as those maximums are not concurrent..

AIR QUALITY Table 7
Total Construction Emissions (tons)

	NOx	CO	VOC	SOx	PM10	PM2.5
Power Blocks						
Onsite	35.01	43.61	5.37	0.04	46.54	11.40
Offsite	46.66	174.40	19.17	0.14	35.89	7.31
Well Construction						
Onsite	46.34	235.25	27.00	0.45	12.02	7.37
Offsite	47.19	235.54	27.08	0.45	12.28	7.45
Offsite Vehicle	9.58	26.42	3.02	0.02	5.60	1.21
Earthwork						
Onsite	9.14	3.39	1.04	0.01	6.48	1.68
Offsite	24.93	12.49	2.73	0.03	17.55	4.52
Total	218.86	731.10	85.41	1.13	136.35	40.95

Source: CE Obsidian Energy 2009a (Data Response 15)

The original Staff Assessment found that mitigation measures would be necessary to avoid the potentially significant impacts of particulate matter and ozone concentrations during construction, and various Conditions of Certification were identified and adopted. This conclusion remains applicable for this amendment, and staff recommends COCs, updated to current staff recommendations, to mitigate both fugitive dust and equipment exhaust emissions during construction.

Commissioning Activities and Emissions

After the wells are drilled, they would be flushed to remove any contaminates from well drilling. This process would occur for up to 24 hours per well at the maximum flow back flushing rate. The flow back fluid used in this activity would be half brine and half water and drilling fluids (clay and water). Total of 510,000 gallons of flow back fluid would be required for production wells, and less for injection wells. After flow back activities are completed, wells would be closed with control valves until the power plant construction is completed. All wells would be flushed after they are completed prior to their use, but only the production wells would be flow-tested prior to their operational use. Emission controls, beyond the use of the rock muffler, to reduce the H_2S, particulate and VOC emissions from the released brine, are not feasible during the flow back and well-testing commissioning activities. Emissions estimates from the production well flow tests are presented in **AIR QUALITY Table 8**.

AIR QUALITY Table 8
Production Well Testing Emissions (lbs/event)

NOx	CO	VOC	SOx	PM10	PM2.5
42	24	60	166	176	176

Source: CE Obsidian Energy 2009b (Data Response 2). Please note that the project owner did not provide the expected H_2S emissions from production well testing.

The commissioning of the amended project would consist of three phases, as each power block would be commissioned separately, approximately 10 months apart. The commissioning would involve the following general steps:

- Production wells have a warm-up duration of 12 to 16 hours for the first well, followed by 16 to 24 hours for the next two wells (combined). Steam from well warm-ups vents to the Production Test Unit (PTU) at a rate of 250,000 pounds per hour (lbs/hr) per well.

- Production piping and equipment have a warm-up duration of 24 to 32 hours. Steam is vented at a rate of 350,000 lbs/hr to the rock muffler. No emission control from the brine steam release is assumed for the rock muffler, which is designed to reduce noise pollution.
- Steam blow has a duration of 16 to 24 hours with steam venting at 750,000 lbs/hr to the rock muffler.
- Turbine and auxiliary loops preheat for a duration of 18 to 24 hours. The total steam flow rate is 350,000 lbs/hr; 50,000 lbs/hr of steam flows through the turbine, condenser and RTO with the emissions being controlled in the same manner as during normal operation, and the balance of 300,000 lbs/hr of steam flows to the rock muffler and is uncontrolled.
- Turbine load test with a duration of 18 to 24 hours, full steam flow rate of 750,000 lbs/hr through the turbine, condenser and RTO, with no venting of steam directly to atmosphere.
- Turbine performance test has a duration of 18 to 24 hours, with a steam flow rate of 750,000 lbs/hr through the turbine, condenser and RTO, with no venting of steam to atmosphere.

In conjunction with steam flow rates, the project owner used information about the ratio of NCG to brine, NCG to steam, and the composition of the NCG that are derived from existing geothermal power plants in commissioning emission estimates. **AIR QUALITY Table 9** summarizes the commissioning criteria emissions for each power block.

AIR QUALITY Table 9
Commissioning Emissions per Power Block (lbs/event)

NOx	CO	VOC	SO_2	PM10	PM2.5	NH_3	H_2S
30.69	17.70	171.57	88.63	129.39	129.39	22,763	4,476

Source: CE Obsidian Energy 2009a, Table 5.2-21 and Appendix E.3, Table 2.19.

The per power block commissioning emissions presented above in **AIR QUALITY Table 9** also include well flow back testing and injection and plant well testing emission events.

Operational Phase and Emissions

The normal operating emission sources of the amended project would include three propane-fired RTO control systems, three cooling towers, six emergency generators and a fire pump. In addition, emissions from periodic operational vehicle travel and equipment would occur for maintenance, inspections and repairs.

Normal operating emission estimates for all three power blocks are presented in **AIR QUALITY Table 10**. Start-up and shutdown emission estimates are shown in **AIR QUALITY Table 11**. Startup would consist of several activities that are similar to the commissioning steps. Startup would start with warm up of production wells, piping, and equipment, followed by turbine and auxiliary loops preheat. After preheat, auxiliary equipment startup would take place, and full functional trip test and steam delivery to the turbine would follow. During shutdown, turbine would be off and steam would be vented to rock muffler as the flow rate is gradually reduced. After shutting down all three wells, the pipeline is drained of brine, and there would be no steam or other emissions.

AIR QUALITY Table 10
Normal Operating Emission Rates (Three Power Blocks)

	NOx	CO	VOC	SO_2	PM10	PM2.5	NH_3	H_2S
Hourly (lbs/hr)	1.28	0.74	0.21	5.36	5.39	5.39	216.05	9.99
Daily (lbs/day)	30.69	17.70	5.04	128.66	129.39	129.39	5,185.27	239.83
Annual (tpy)	5.60	3.23	0.92	23.48	23.61	23.61	946.31	43.77

Source: CE Obsidian Energy 2009b, and FDOC (ICAPCD 2010c)
Note: Emissions are based all three power blocks, 24 hours per day, and 8,760 hours per year.

AIR QUALITY Table 11
Start-up/Shutdown Emission Rates (One Power Block)

	NOx	CO	VOC	SO_2	PM10	PM2.5	NH_3	H_2S
Cold Startup (lbs/event)	18.0	10.35	124.65	12.15	75.60	75.60	16,000	3,290
Warm Startup (lbs/event)	1.72	1.00	15.64	4.48	7.20	7.20	1,940	410
Shutdown (lbs/event)	0.00	0.00	15.24	0.00	0.00	0.00	1,660	400

Source: CE Obsidian Energy 2009a, and FDOC (ICAPCD 2010c)

Daily emissions are based on 24 hours of normal operation and 24 hours of cooling tower operation. Daily emissions from emergency generators and fire pump are based on 1 hour of operation per day for each. The project owner's short-term operating emission estimates are provided in **AIR QUALITY Table 12**.

AIR QUALITY Table 12
Black Rock 1, 2, and 3 Geothermal Power Amended Project
Short-Term Emissions

Hourly Emissions (lbs/hour)								
	NOx	**CO**	**VOC**	**SO_2**	**PM10**	**PM2.5**	**NH_3**	**H_2S**
Normal Operation	1.29	0.75	0.18	5.37	0.06	0.06	32.41	6.00
Cooling Tower	--	--	0.03	--	6.39	6.39	183.64	3.99
1.5 MW Emergency Generator	2.43	12.69	1.45	0.02	0.36	0.36	--	--
1.0 MW Emergency Generator	1.62	8.48	0.97	0.02	0.24	0.24	--	--
Emergency Fire Pump	0.13	1.13	0.06	0.002	0.01	0.01	--	--
Well Drilling	2.43	12.69	1.45	0.02	0.36	0.36	--	--
O&M Equipment & Vehicles	4.69	5.53	0.76	0.01	22.60	4.92	--	--
Offsite Vehicles	0.87	3.38	0.39	0.01	3.74	0.80	--	--
Total Project	13.46	44.65	5.29	5.45	33.76	13.14	216.05	9.99
Daily Emissions (lbs/day)								
	NOx	**CO**	**VOC**	**SO2**	**PM10**	**PM2.5**	**NH_3**	**H_2S**
Normal Operation	30.96	18.0	4.32	128.88	1.44	1.44	777.80	144.0
Cooling Tower	--	--	0.72	--	127.44	127.44	4407.6	95.76
1.5 MW Emergency Generator	2.43	12.69	1.45	0.02	0.36	0.36	--	--
1.0 MW Emergency Generator	1.62	8.48	0.97	0.02	0.24	0.24	--	--
Emergency Fire Pump	0.13	1.13	0.06	0.002	0.01	0.01	--	--
Well Drilling	7.29	38.08	4.35	0.07	1.09	1.00	--	--
O&M Equipment & Vehicles	37.55	44.24	6.12	0.05	180.79	39.36	--	--
Offsite Vehicles	6.95	27.03	3.12	0.05	29.88	6.42	--	--
Total Project	86.93	149.65	21.11	129.09	341.25	176.27	5,185.4	239.76

Source: CE Obsidian Energy 2009b (Data Response 4), FDOC (ICAPCD 2010c), and staff correction for O&M vehicles and staff analysis for offsite vehicles, which include employee and delivery vehicles.

Staff made the following corrections to the O&M Vehicle and Offsite Vehicle emission estimates:

- Staff made minor corrections to the emission factors used for the on-road O&M vehicles to match trip average emission rates (lbs/mile) for the specified vehicle classes. This was a minor correction that generally reduced the emission factors.
- Staff extracted information from the electronic copy of the project owner's operation emissions spreadsheet to obtain the offsite vehicle (employee and delivery vehicles) emissions estimate, which also incorporated the corrected vehicle class emission factors. The project owner did not provide these emission estimates in their printed emission estimate.

The basis for maximum annual emissions is 8,460 hours of normal operation, 3 cold startup events, 9 warm startup events, and 3 shutdown events, 8,760 hours of cooling tower operation, 20 hours of each emergency generator operation, and 50 hours of fire pump operation. Three emergency generators and a fire pump would only be operated for test and non emergency purposes. The project owner's annual operating emission estimates are provided in **AIR QUALITY Table 13**.

AIR QUALITY Table 13
Black Rock 1, 2, and 3 Geothermal Power Amended Project
Annual Emissions (tons/year)

	NOx	**CO**	**VOC**	**SO_2**	**PM10**	**PM2.5**	**NH_3**	**H_2S**
Normal Operation	5.65	3.29	0.79	23.52	0.26	0.26	141.95	26.28
Startup/Shutdown	0.04	0.02	0.37	0.05	0.15	0.15	35.27	9.80
Cooling Tower	--	--	0.13	--	23.26	23.26	804.36	17.48
1.5 MW Emergency Generator	0.07	0.38	0.04	0.00	0.01	0.01	--	--
1.0 MW Emergency Generator	0.05	0.25	0.03	0.00	0.01	0.01	--	--
Emergency Fire Pump	0.00	0.03	0.00	0.00	0.00	0.00	--	--
Well Drilling	4.81	25.13	2.87	0.05	0.72	0.66	--	--
O&M Equipment & Vehicles	1.54	1.75	0.22	0.00	15.76	3.38	--	--
Offsite vehicles	1.27	4.93	0.57	0.01	5.45	1.17	--	--
Total Project	13.43	35.78	5.02	23.63	45.62	28.89	981.58	53.56

Source: CE Obsidian Energy 2009b (Data Response 4), FDOC (ICAPCD 2010c), and staff correction for O&M vehicles and staff analysis for offsite vehicles, which include employee and delivery vehicles.

The 185-MW SSU6 Project was originally certified on December 17, 2003. In 2005, the SSU6 project site was relocated with an addition of a binary-cycle turbine, resulting in a 215-MW geothermal project. **AIR QUALITY Table 14** presents the maximum annual average onsite stationary source emissions estimated for the modified SSU6 project in 2005. Estimated NOx, SOx, particulate (PM10/PM2.5) and H_2S emissions for the proposed amendment are increased from the emissions estimates in 2005, and the CO, VOC, and ammonia emissions for the proposed amendment are estimated to be lower than what were predicted in 2005.

AIR QUALITY Table 14
2005 Modified SSU6 Project
Estimated Maximum Annual Average Emissions (tons/year)

	NOx	CO	VOC	SO_2	PM10	NH_3	H_2S
Normal Operation	1.72	11.28	0.61	0.35	0.3545	--	--
Cooling Tower	--	--	2.08	--	15.85	3,226	27.75
Emergency Generator	0.24	0.01	0.0025	0.01	0.0015	--	--
Emergency Generator	1.71	0.11	0.04	0.06	0.03	--	--
Emergency Fire Pump	0.18	0.01	0.003	0.01	0.002	--	--
ORC Binary System	--	--	11.86	--	--	--	--
Filter Cake	--	--	--	--	0.0017	--	--
Total Project (tons/year)	3.82	11.43	14.59	0.43	16.30	3,226	27.75

Source: CEC 2005a

The comparison of the total annual criteria air pollutant emission rates for the stationary sources proposed for the currently licensed amended project compared to the proposed amended project and incremental emissions increases and decreases are provided in **AIR QUALITY Table 15**.

AIR QUALITY Table 15
Comparison of 2005 SSU6 Project and Proposed BR 123 Project
Stationary Source Annual Emissions (tons/year)

	NOx	CO	VOC	SO_2	PM10/2.5	NH_3	H_2S
2005 SSU6 Project	3.8	11.4	14.6	0.4	16.3	3,226	27.8
BR 123 Project	5.8	4.0	1.4	23.6	23.7	982	53.6
Incremental Emissions (tons/year)	2.0	-7.4	-13.2	23.1	7.4	-2,244	25.8

Sources: CEC 2005a; and CE Obsidian Energy 2009b (Data Response 4), FDOC (ICAPCD 2010c).

As **AIR QUALITY Table 15** shows, the BR 123 amendment (if approved as proposed) would increase the licensed emissions of NOx, SO_2, PM10/2.5, and H_2S; and decrease the licensed emissions of CO, VOC, and NH_3.

AMENDED PROJECT IMPACTS

DISPERSION MODELING APPROACH

In the analysis of the initial SSU6 project (2003) and the expanded SSU6 project (2005), the U.S.EPA Industrial Source Complex Short Term Version 3 (ISCST3) (version 00101 & 02035) air dispersion model was used to estimate the impacts of the project's criteria pollutants emissions. For the proposed amendment, the impact analysis is prepared using the U.S.EPA-approved AERMOD (version 07026) model, which is now U.S.EPA's guideline model, and five years (2002-2006) meteorological data collected at the Imperial County Airport, approximately 22 miles south from the project site. For NO_2 impact, the Ambient Ratio Method (ARM) was used first, and then the Ozone Limiting Model (OLM) was applied if 1-hour NO_2 standards were exceeded based on the ARM. The annual average was calculated using the ARM with the national default value of 0.75 for the annual NO_2/NOx ratio.

The background concentrations used in the dispersion modeling analysis were chosen from the highest ambient concentrations from the most recent 3 years of data (see **Air Quality Table 4** and **5**). The impacts from the amended project were added to the background concentrations for the evaluation of impacts on ambient air quality as shown in **Air Quality Tables 16**, **17**, **18**, **19** and **21**.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Analysis of Construction Phase Impacts

For the construction impacts analysis, the project owner modeled three activities separately since not all of these activities would occur concurrently. However, onsite and offsite well drilling construction activities were modeled cumulatively, expecting that there would be overlap on an hourly and daily basis. Daily construction activities are assumed to occur for 8 hours from 8 AM to 4 PM.

For power block construction, the emissions were divided into onsite exhaust impacts and fugitive dust impacts. All exhaust emissions from onsite motor vehicle and construction equipment were modeled collectively as 20 point sources. Fugitive dust impacts were modeled as an area source with an effective plume height of 0.5 meters. The modeling results for power block construction shown in **AIR QUALITY Table 16** indicate that maximum construction impacts would not exceed the most stringent SO_2, CO, and NO_2 standards. However, PM10 and PM2.5 modeled impacts combined with the background concentration would be potentially significant due to the potentially significant increase to existing PM10 exceedances and the creation of new PM2.5 exceedances. However, the new PM2.5 exceedances would be very limited in extent, essentially at and just past the project site fence line. H_2S emissions and emission impact modeling during construction were not provided by the project owner.

AIR QUALITY Table 16
Maximum Power Block Construction Impacts

Pollutant	Averaging Period	Impacts (µg/m³)	Background (µg/m³)	Total Impact (µg/m³)	Standard (µg/m³)	Percent of Standard
NO_2	1-hour (Calif.)	48.8	229.8	278.6	339	82%
	Annual	1.3	20.9	22.2	57	39%
CO	1-hour	35.1	3,565	3,600	23,000	16%
	8-hour	15.5	2,000	2,016	10,000	20%
SO_2	1-hour	0.06	47.2	47.3	665	7%
	1-hour fed	0.06	47.2	47.3	196	24%
	3-hour	0.03	42.4	42.4	1,300	3%
	24-hour	0.01	14.0	14.0	105	13%
PM10	24-hour	82.2	161.4	243.6	50	487%
	Annual	14.2	48.8	63.0	20	315%
PM2.5	24-hour	17.5	18.2	35.7	35	102%
	Annual	3.0	8.4	11.4	12	95%

Source: CE Obsidian Energy 2009b (Data Response 15), and staff revised background concentrations from **Air Quality Table 5**.

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For well construction, the emissions were divided into three categories: combustion emissions from drilling rig and bulldozers, onsite motor vehicle emissions, and fugitive dust emissions. The project owner anticipated two drill rigs would be used simultaneously and the emissions from drilling rig and bulldozer were modeled using the drill rig stack parameters with a point source for each of three engines per each drilling rig. Onsite motor vehicle emissions were modeled as four point sources. Fugitive dust impacts were modeled as an area source with an effective plume height of 0.5 meters, covering the entire area of each of two drilling locations. Drilling activities for each power block were modeled separately as source groups. The source group that produced the largest impacts was used to represent the total impacts from this construction activity.

The modeling results for power block construction shown in **AIR QUALITY Table 17** indicate that maximum construction impacts would not exceed the most stringent SO_2, CO, and NO_2 standards. However, PM10 and PM2.5 modeled impacts combined with the background concentration would be potentially significant due to the potentially significant increase to existing PM10 exceedances and the creation of new PM2.5 exceedances.

AIR QUALITY Table 17
Maximum Onsite and Offsite Well Drilling Construction Impacts

Pollutant	**Averaging Period**	**Impacts (μg/m³)**	**Background (μg/m³)**	**Total Impact (μg/m³)**	**Standard (μg/m³)**	**Percent of Standard**
NO_2	1-hour	79.0	229.8	308.8	339	91%
	Annual	6.2	20.9	27.1	57	48%
CO	1-hour	384	3,565	3,949	23,000	17%
	8-hour	285	2,000	2,285	10,000	23%
SO_2	1-hour	0.7	47.2	47.9	665	7%
	1-hour fed	0.7	47.2	47.9	196	24%
	3-hour	0.6	42.4	43.0	1,300	3%
	24-hour	0.2	14.0	14.2	105	14%
PM10	24-hour	171	161.4	332.4	50	665%
	Annual	41.3	48.8	90.1	20	451%
PM2.5	24-hour	37.3	18.2	55.5	35	159%
	Annual	8.6	8.4	17.0	12	142%

Source: CE Obsidian Energy 2009b (Data Response 15), and staff revised background concentrations from **Air Quality Table 5**.

For earthwork construction, the emissions were divided into four groups. The combustion emissions from equipment and onsite motor vehicles were modeled as point sources. Onsite and offsite construction activities were modeled cumulatively as nine and seven point sources evenly spaced over the entire area. The fugitive dust emissions were modeled as area sources with an effective plume height of 0.5 meters.

The modeling results for power block construction shown in **AIR QUALITY Table 18** indicate that maximum construction impacts would not exceed the most stringent SO_2, CO, NO_2, and PM2.5 standards. However, PM10 modeled impacts combined with the background concentration would be potentially significant due to the existing PM10 exceedances.

AIR QUALITY Table 18
Maximum Earthwork Construction Impacts

Pollutant	Averaging Period	Impacts ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hour	31.5	229.8	261.3	339	77%
	Annual	1.71	20.9	22.6	57	40%
CO	1-hour	15.0	3,565	3,580	23,000	16%
	8-hour	6.8	2,000	2,007	10,000	20%
SO_2	1-hour	0.04	47.2	47.2	665	7%
	1-hour fed	0.04	47.2	47.2	196	24%
	3-hour	0.02	42.4	42.42	1,300	3%
	24-hour	0.006	14.0	14.0	105	13%
PM10	24-hour	22.2	161.4	183.6	50	367%
	Annual	7.8	48.8	56.6	20	283%
PM2.5	24-hour	4.3	18.2	22.5	35	64%
	Annual	1.6	8.4	10.0	12	83%

Source: CE Obsidian Energy 2009b (Data Response 15), and staff revised background concentrations from **Air Quality Table 5**.

The project area is designated nonattainment area for PM10, and the selected background concentrations exceed the most stringent current PM10 standards. The selected PM2.5 annual background concentrations are below the most stringent current PM2.5 standards. In order to minimize the constructional impacts of PM10 and PM2.5, best available control measures are recommended to be used throughout the 53-month construction period.

Construction Mitigation

Project Owner's Proposed Mitigation

Since this project is an amendment, the project owner has already adopted the CEC's Conditions of Certification for the original project.

Staff Proposed Mitigation

Staff generally agrees with the project owner's proposed mitigation measures. However, because of the predicted potentially significant contribution to both the short- and long-term PM10 and PM2.5 exceedances, staff believes additional construction mitigation measures are necessary.

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

Staff recommends **AQ-SC1** to require the project owner to have an on-site construction mitigation manager who would be responsible for the implementation and compliance of the construction mitigation program. The documentation of the ongoing implementation and compliance with the construction mitigation program would be provided in the monthly construction compliance report that is required in staff's recommended Condition of Certification **AQ-SC2**. Recommended Condition of Certification **AQ-SC3** formalizes the fugitive dust control requirements. Recommended Condition of Certification **AQ-SC4** would limit the potential offsite impacts from visible dust emissions, to respond to situations when the control measures required by **AQ-SC3** are not working effectively to control fugitive dust from leaving the construction site area.

Staff recommends Condition of Certification **AQ-SC5** to mitigate the PM and NOx emissions from the large diesel-fueled construction equipment. Implementation of this mitigation measure would provide additional primary and secondary PM mitigation to supplement the recommended fugitive dust mitigation measures. This condition requires the use of U.S.EPA/ARB Tier 3 compliant engines for equipment with engines over 50 horsepower and Tier 2 compliant engines for equipment with engines 750 horsepower where available, and also includes equipment idle time restrictions and engine maintenance provisions. The Tier 2 standards include engine emission standards for NOx plus non-methane hydrocarbons, CO, and PM emissions; while the Tier 3 standards further reduce the NOx plus non-methane hydrocarbons emissions. The Tier 2 and Tier 3 standards became effective for engine/equipment model years 2001 to 2004 and models years 2006 to 2008, respectively, for engines between 50 and 750 horsepower.

Analysis of Commissioning Phase Impacts

Since this amendment proposes separate initial commissioning for each of three smaller power blocks rather than the originally proposed single larger power block, the brine flow and steam flow for each power block are decreased by two thirds. Therefore, the short-term worst case commissioning emissions for the amended project would be reduced substantially.

The ambient air quality modeling for the original project concluded that there would be unavoidable short-term significant PM10 and H_2S impacts during commissioning as shown in **AIR QUALITY Table 19**. Although the project owner expects reduced emissions during the commissioning phase compared to SSU6, the proposed project amendment would still be expected to exceed the 1-hour state H_2S ambient air quality standard and will have the potential to cause nuisance odors and minor health impacts. Because commissioning emissions would be lower than in the original project, the commissioning impacts modeling was not completed by the project owner for the amended project.

AIR QUALITY Table 19
Maximum Original SSU6 Project Commissioning Impacts

Pollutant	Averaging Period	Impacts ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Standard ($\mu g/m^3$)	Percent of Standard
PM10	24-hour	16	161.4	177.4	50	355%
H_2S	1-hour	78.5	24.6	103.1	42	245%

Source: CEC 2003b, and updated PM10 background concentration from **Air Quality Table 5**.

Analysis of Operating Phase Impacts

The operating impacts were modeled using a total of 25 point sources. Exhaust emissions from the RTOs were modeled as three point sources and the emergency generator engines and fire pump were modeled as seven point sources. For PM10 and

PM2.5, emissions from the cooling towers were modeled as 15 point sources. The modeling results for project operation shown in **AIR QUALITY Table 20** indicate that maximum impacts would not exceed the most stringent SO_2, CO, NO_2, PM2.5, and H_2S standards, although the results for NO_2 are close to the new federal short-term standard. However, PM10 modeled impacts combined with the background concentration would be potentially significant. The selected PM10 background concentrations exceed the most stringent ambient standards without adding the operational impacts. Therefore, PM10 emissions, if unmitigated, would further contribute to existing exceedances and would be potentially significant.

AIR QUALITY Table 20
Maximum Project Operating Impacts

Pollutant	Averaging Period	Impacts ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hour (Calif.)	85.2	229.8	315.0	339	93%
	1-hour (Fed.)	85.2[b]	100.2	185.4	189	98%
	Annual	0.17	20.9	21.1	57	37%
CO	1-hour	419.97	3,565	3,985	23,000	17%
	8-hour	22.35	2,000	2,022	10,000	20%
SO_2	1-hour	9.1	47.2	56.3	665	8%
	1-hour fed	9.1	47.2	56.3	196	29%
	3-hour	7.73	42.4	50.1	1,300	4%
	24-hour	4.18	14	18.2	105	17%
PM10	24-hour	3.44	161.4	164.8	50	330%
	Annual	0.81	48.8	49.6	20	248%
PM2.5	24-hour	2.39	18.2	20.6	35	59%
	Annual	0.81[a]	8.4	9.2	12	77%
H_2S	1-hour	13.18	24.6	37.8	42	90%

Source: CE Obsidian Energy 2009a, and staff revised H_2S modeling analysis and background concentrations from **Air Quality Table 5**.
Notes:
a – Project owner did not provide an annual PM2.5 concentration, so staff has applied the PM10 concentration which is conservative.
b – Maximum 1-hour modeled value is used with the 98th percentile background value as the project owner did not complete a separate modeling analysis for the federal 1-hour NO_2 standard. This provides a conservative assessment for compliance with this standard.

Concentrations for periods of less than one hour can be determined by a conversion using a power law correction[6] (Wang and Skipp 1993), which would provide peak offsite H_2S concentrations during normal operations as high as 202.0 $\mu g/m^3$ and 51.6 $\mu g/m^3$ for 1 second and one minute average concentrations, respectively. This shows that concentrations well above the mean odor threshold (11.2 $\mu g/m^3$) and above the mean annoyance level (56 $\mu g/m^3$) for H_2S are expected to occur at least for short periods beyond the project fence line.

Indirect Pollutant and Secondary Pollutant Impacts

The proposed project would have direct emissions of chemically reactive pollutants (NOx, SOx, and VOC), but would also have indirect emission reductions associated with

[6] These correction factors, which were determined for different stability classes in the ISCST3 model, are based on a power law correction of the difference in an hour and a shorter-term period, where the power law ranges from 1/6 to 1/2 depending on the stability class. Staff used a power law of 1/3 which represents a median atmospheric stability case.

the reduction of fossil-fuel fired power plant emissions due to the proposed project displacing the need for their operation, since geothermal renewable energy facilities would operate on a must-take basis[7]. The exact nature and location of such reductions is not known, so the discussion below focuses on the direct emissions from the proposed project within the northern Imperial County portion of the Salton Sea Air Basin.

Ozone Impacts

There are air dispersion models that can be used to quantify ozone impacts, but they are used for regional planning efforts where hundreds or even thousands of sources are input into the modeling to determine ozone impacts. There are no regulatory agency models approved for assessing single source ozone impacts. However, because of the known relationship of NOx and VOC emissions to ozone formation, it can be said that the emissions of NOx and VOC from the Amended Project do have the potential (if left unmitigated) to contribute to higher ozone levels in the region. These impacts would be cumulatively significant because they would contribute to ongoing violations of the state and federal ozone ambient air quality standards.

PM2.5 Impacts

Secondary PM10 formation, which is assumed to be 100 percent PM2.5, is the process of conversion from gaseous reactants to particulate products. The process of gas-to-particulate conversion, which occurs downwind from the point of emission, is complex and depends on many factors, including local humidity and the presence of air pollutants. The basic process assumes that the SOx and NOx emissions are converted into sulfuric acid and nitric acid first, and then react with ambient ammonia to form sulfate and nitrate. The sulfuric acid reacts with ammonia much faster than nitric acid and converts completely and irreversibly to particulate form. Nitric acid reacts with ammonia to form both a particulate and a gas phase of ammonium nitrate. The particulate phase will tend to fall out, however the gas phase can revert back to ammonia and nitric acid. Thus, under the right conditions, ammonium nitrate and nitric acid establish a balance of concentrations in the ambient air. There are two conditions that are of interest, described as “ammonia rich” and “ammonia poor.” The term “ammonia rich” indicates that there is more than enough ammonia to react with all the sulfuric acid and to establish a balance of nitric acid-ammonium nitrate. Further ammonia emissions in this case will not necessarily lead to significantly increased ambient PM2.5 concentrations. In the case of an “ammonia poor” environment, there is insufficient ammonia to establish a balance and thus additional ammonia will tend to increase PM2.5 concentrations.

The overall emissions balance from Imperial County sources can be characterized as ammonia rich, considering significant agricultural and geothermal ammonia emission sources and the comparatively small population and industry base. However, there are no substantial data available to support that Imperial County is considered to be ammonia rich and pollutant transport from Mexicali and the San Diego Air Basin would

[7] This refers to the fact that the contract between the owner of this geothermal power facility and the utility will require that the utility take all generation from this facility with little or no provisions for the utility to direct turn down of generation from the facility.

be assumed to be ammonia poor. This implies that Imperial County may not be ammonia rich in all areas of the county all of the time.

The project owner originally proposed that there is no economically feasible ammonia control system. Unlike the original proposal, the project owner now proposes to use a caustic scrubber following the RTO, which would reduce the project-wide ammonia emissions by 70 percent. Therefore, significant reductions in proposed ammonia emissions would occur for BR 123 in comparison with the currently licensed amended SSU6 project. However, because of the known relationship of NOx and SOx emissions to PM10/PM2.5 formation, it can be said that the increased emissions of NOx and SOx from the Amended project do have the potential (if left unmitigated) to contribute to higher PM10/PM2.5 levels in the region.

Operations Mitigation

Project owner's Proposed Mitigation

Emission Controls[8]

As discussed in the air quality section of the Amended project (CE Obsidian 2009), data responses (CE Obsidian 2009a), and FDOC from the Imperial County Air Quality Management District (ICAPCD 2010c), the project owner proposes the following emission controls on the stationary equipment associated with the amended BR123 operation:

NCG Stream – RTOs and Caustic Scrubber

The project owner proposed RTOs followed by caustic scrubbers as the Best Available Control Technology (BACT) for the NCG streams for each power block. The proposed RTO system would control emissions of VOC by 98 percent and hydrogen sulfide by 95 percent. The caustic scrubber is estimated to control SO_2 emissions by 97.5 percent and ammonia emissions by 95 percent. The hourly emissions for the controlled NCG stream are as follows:

- NOx: 0.43 lbs/hour
- CO: 0.25 lbs/hour
- VOC: 0.06 lbs/hour, RTO with 98% efficiency
- PM10/2.5: 0.023 lbs/hour
- SO_2: 1.79 lbs/hour, Caustic Scrubber with 97.5% efficiency[9]
- H_2S: 2.0 lbs/hour, RTO with 95% efficiency
- NH3: 10.8 lbs/hour, Caustic Scrubber with 95% efficiency

[8] The emissions values presented are all per emission source and are not totaled for the three separate BR 123 units.

[9] Please note that the District permit condition only requires 95% efficiency for SO_2 removal by the caustic scrubber, so the actual permitted emissions are twice as high as estimated for this emission source.

Cooling Tower with ChemOx

Drift rate, percent of recirculation rate: 0.0005 percent, using a mist eliminator

- PM10/2.5: 2.13 lbs/hour
- VOC: 0.01 lbs/hour
- H_2S: 1.33 lbs/hour - 95% removal efficiency with ChemOx

1.5 MW Emergency Engine (4160V)

Tier 4 emergency diesel generator engine

- NOx: 0.67 grams/kW-hour, 2.43 lbs/hour
- CO: 3.5 grams/kW-hour, 12.69 lbs/hour
- VOC: 0.4 grams/kW-hour, 1.45 lbs/hour
- PM10/2.5: 0.07 grams/kW-hour, 0.36 lbs/hour
- SO_2: 15 ppm sulfur diesel fuel, 0.02 lbs/hour

1.0 MW Emergency Engine (480V)

Tier 4 emergency diesel generator engine

- NOx: 0.67 grams/kW-hour, 1.62 lbs/hour
- CO: 3.5 grams/kW-hour, 8.48 lbs/hour
- VOC: 0.4 grams/kW-hour, 0.97 lbs/hour
- PM10/2.5: 0.07 grams/kW-hour, 0.24 lbs/hour
- SO_2: 15 ppm sulfur diesel fuel, 0.02 lbs/hour

200 HP Emergency Fire Water Pump Engine

Tier 4 emergency fire water pump engine

- NOx: 0.4 grams/kW-hour, 0.13 lbs/hour
- CO: 3.5 grams/kW-hour, 1.13 lbs/hour
- VOC: 0.19 grams/kW-hour, 0.06 lbs/hour
- PM10/2.5: 0.015 grams/kW-hour, 0.01 lbs/hour
- SO_2: 15 ppm sulfur diesel fuel, 0.00 lbs/hour

Offsets

The project owner has removed all previously proposed emission offsets (existing Condition of Certifications **AQ-5** and **AQ-C17**) from this amended project proposal. The offsets that are currently required to be obtained in AQ-5 for the amended SSU6 project are as follows:

Pollutant	Quantity
H_2S	35.94 tons
PM10	19.6 tons (permanent)
PM10	32.3 tons (temporary during well testing)
PM10	6.25 tons (temporary during initial commissioning)
VOC	14.59 tons

Staff agrees with the project owner that VOC emission offsets are unnecessary since the BR123 project's emissions are one-tenth of the amended SSU6 VOC emissions (only 1.4 tons/year), and due to the fact that the primary source of ozone pollution is pollutant transport from San Diego County and from Mexico and not from ozone precursor emissions occurring within Imperial County. Staff also agrees with the project owner that PM10 offsets are unnecessary since the project's direct PM10 emissions would not substantially increase the existing exceedances of the PM10 standards, and since the proposed BR123 project's total secondary pollutant emissions would decrease substantially (due to the over 2,000 ton decrease in ammonia emissions) from those estimated and permitted for the amended SSU6 project. Staff also recognizes the potential indirect effect of this project in reducing direct and secondary pollutant emissions from fossil fuel fired power plants within Imperial County and the adjacent San Diego and Mexico pollutant transport areas.

However, staff disagrees with the project owner's arguments for removing the requirement for H_2S offsets. The proposed BR123 project's H_2S emissions are almost double that of the amended SSU6 project, and two additional projects of the same size and emissions of BR123 have been proposed for construction in the same general area. Staff believes that without appropriate H_2S emission reduction mitigation that the project area would have the potential for significant H_2S emissions impacts. Since the project owner has not made a compelling argument in favor of removing this existing mitigation requirement, staff recommends that appropriate H_2S emission reductions, in a revised condition that allows the project owner more flexibility than the existing condition, continue to be required for this amended project. This condition requires cost effective offset mitigation be provided, in quantities no greater than the BR123 annual emissions of H_2S, if monitoring data shows exceedances of the H_2S standard and it is determined that BR123 contributes to those exceedances.

Summary of Staff Changes to Recommended Mitigation

Staff is recommending the elimination of several staff conditions from the amended SSU6 project license due to the District incorporating such conditions in the FDOC for this project. Existing license conditions **AQ-C7** through **AQ-C9**, **AQ-C11**, and **AQ-C14** through **AQ-C16** are no longer necessary due to project design revisions and new District conditions/regulatory requirements. Staff is also recommending the deletion of staff condition **AQ-C17**. It was added to the staff air quality conditions during the SSU6 amendment due to the higher VOC emissions from the amended SSU6 project's ORC unit, which is no longer proposed. Staff recommends the addition of condition **AQ-SC11**, which replaces the District's removed offset condition AQ-5, that addresses H_2S emission offsets, if needed. This new proposed staff condition is discussed in more detail directly below and in the Cumulative Impacts Section.

ODOR IMPACTS

The amended project design does not reduce staff's concerns, as noted in the original staff assessments for the original project (CEC 2003b) and for the amended project (CEC 2005a), regarding the potential for odor impacts, both direct project impacts and cumulative project impacts that are discussed below in the Cumulative Impacts section. Staff recommends that an amended version of the mitigation proposed for the currently approved SSU6 project amendment be retained, as **AQ-SC8**, to mitigate the short-term direct odor impacts from production well testing.

Additionally, since the project owner is proposing to nearly double the annual H_2S emissions and has eliminated their proposal to offset the project's H_2S emissions, staff is proposing a new condition **AQ-SC11**, which replaces the former SSU6 District condition **AQ-5** that required H_2S offsets be obtained at a ratio of 1.2 to 1 for the normal operating H_2S emissions. Condition **AQ-SC11** would require the project owner to create H_2S emissions reductions, if it is determined that BR123 contributes to H_2S standard exceedances, as determined by the H_2S monitoring conducted by the District, using the monitor that is required to be obtained by the project owner (**AQ-72**). The emissions reductions, if required, would be limited to providing H_2S emissions reductions from BR123 emissions sources[10] or otherwise from within the Salton Sea Known Geothermal Resource Area (SSKGRA). Also, the required emission reductions are proposed to be limited as follows: to reduce annual H_2S emissions up to but not exceeding the lowest of: 1) the H_2S emissions reduction that is determined to be cost effective; or 2) equivalent to the permitted annual H_2S emissions for the Black Rock 1, 2, and 3 Geothermal Power Project; or 3) sufficient to ensure ongoing attainment of the H_2S standard[11]. Additionally, if exceedances of the H_2S standard continue after implementation of the cost effective emission reductions and the total amount of cost effective emission reductions achieved are less than the emissions from BR123, then this condition also contains a requirement to analyze and implement cost effective emission reductions every three years until either the emission reductions achieved equal the BR123 emissions or the H_2S standard exceedances stop occurring. It is staff's position that with the implementation of this condition that BR123 would not cause any new exceedances of the CAAQS H_2S standard and would mitigate its contribution to existing exceedances and to nuisance odor impacts.

CUMULATIVE IMPACTS

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

[10] Examples of emission reduction techniques that could be used to reduce emissions at the BR123 facility include: 1) discontinue use of the condensate water as cooling tower water makeup, which would eliminate the H_2S emissions from the cooling tower; 2) increase the efficiency of the H_2S control system for the condensate water that is used as cooling tower water make-up; and 3) increase the efficiency of the H_2S control efficiency of the non-condensable gases emissions control system (RTO and caustic scrubber).

[11] Please note that if staff would have recommended retaining the same emission reduction requirements as those required by existing SSU6 condition **AQ-5**, then project owner would be required to obtain somewhere on the order of 65 tons of H_2S emission reduction credits. The more flexible staff proposed amended condition would require an absolute maximum of no more than 53.8 tons of H_2S emissions reductions.

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

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

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

SUMMARY OF PROJECTIONS

Imperial County in the area of the project site is designated as nonattainment for both federal (8-hour) and State ozone and PM10 standards. All other criteria pollutants (NO_2, and SO_2, and PM2.5) are considered to be in attainment by the State, and in attainment and/or unclassified under federal standards.

Imperial County failed to meet federal attainment for the 8-hour ozone NAAQS by June 15, 2007, for marginal nonattainment areas, and was reclassified as a moderate nonattainment area[12]. Due to this reclassification ICAPCD was required to develop a modified 8-hour ozone attainment plan. The modified 8-hour ozone Air Quality Management Plan (AQMP) was published on July 13, 2010 (ICAPCD 2010d). This AQMP contains control measures or strategies for the reduction of NOx and VOC emissions from stationary and mobile sources. The control measures contain either or both Reasonably Available Control Measures (RACM) and/or Reasonably Available Control Technology (RACT) for stationary sources such as gas turbines, process heaters and steam generators. The stationary source control measures adopted and amended, but not expected to be fully implemented by the end of 2010, include ICAPCD Rule 424 Architectural Coatings, ICAPCD Rule 217 Large Confined Animal Facilities Permits Required, ICAPCD Rule 400.1 Stationary Gas Turbines (RACT) and

[12] Current State Implementation Plans (SIPs) are required to address the federal 1997 8-hour ozone standard. The revised federal 2008 8-hour ozone standard is being reconsidered which has stopped all implementation requirements such as SIP submittals.

ICAPCD Rule 400.2 Boilers, Process Heaters and Steam Generators (RACT). The transportation control measures include carpool/vanpool measures and facility design measures to enable the use of public transportation and reduce business and personal traffic trips.

Ozone nonattainment areas, classified as moderate or above, are required to implement RACT for all sources that are subject to a Control Techniques Guideline (CTG) document and all major sources of VOC and NOx that are not subject to a CTG. ICAPCD became subject to this requirement after they were redesignated as a moderate nonattainment area and ICAPCD published their RACT Implementation Plan on July 13, 2010 (ICAPCD 2010e). This plan requires emissions controls that are economically and technologically feasible assuring that ozone precursor emissions of VOC and NOx from major sources in Imperial County are controlled to a reasonably possible extent.

U.S.EPA reclassified Imperial County from “moderate” to “serious” nonattainment for the 24-hour PM10 NAAQS on August 11, 2004. Due to this reclassification Imperial County was required to develop a PM10 Attainment Plan that provides at least 5 percent annual reductions in PM10 or PM10 precursor emissions until it reaches attainment. Imperial County completed a new PM10 State Implementation Plan (SIP) on August 11, 2009 (ICAPCD 2009). This plan discusses the impact of PM10 transport from the South Coast Air Basin, the San Diego Air Basin, and international PM10 transport from Mexicali, Mexico; the impact of PM10 generated by natural events such as wind and wildfire; and the impact of stationary and mobile emission sources within ICAPCD jurisdiction. This plan states that the PM10 NAAQS has been attained but for international emissions. The plan relies on control measures already adopted as District rules. The core of the PM10 control program is based on the Imperial County Regulation VIII fugitive dust rules, most provisions of which became effective January 2006. Regulation VIII includes Rule 801 (Construction and Earthmoving Activities), Rule 802 (Bulk Materials), Rule 803 (Carry-Out and Track-out), Rule 804 (Open Areas), Rule 805 (Paved and Unpaved Roads), and Rule 806 (Conservation Management Practices).

Summary of Conformance with Applicable Air Quality Plans

The applicable air quality plans do not outline any new control measures applicable to the proposed project’s operating emission sources that are not already included in the staff or ICAPCD Conditions of Certification. Therefore, compliance with existing District rules and regulations would ensure compliance with those air quality plans.

LOCALIZED CUMULATIVE IMPACTS

The proposed project’s contributions to localized cumulative impacts can be reasonably estimated through air dispersion modeling (see the “Operation 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 Environmental Setting section), referred to as the “background”.

The staff undertakes the following steps to estimate what are additional appropriate "present projects" that are not represented in the background and "reasonably foreseeable projects":

- First, the Commission staff (or the project owner) 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 Commission staff (or the project owner) 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 (EIR) that are prepared for those sources. The initiation of the EIR process is a reasonable basis on which to determine what is "reasonably foreseeable" for new area sources.
- The data submitted, or generated from the applications with the air district for point sources or initiating the EIR process for area sources provides enough information to include these new emission sources in air dispersion modeling. Thus, the next step is to review the available EIR(s) and permit application(s), determine what sources must be modeled and how they must be modeled.
- Sources that are not new, but may not be represented in ambient air quality monitoring are also identified and included in the analysis. These sources include existing sources that are co-located with or adjacent to the proposed source (such as an existing power plant). In most cases, the ambient air quality measurements are not recorded close to the proposed project, thus a local major source might not be well represented by the background air monitoring. When these sources are included, it is typically a result of there being an existing source on the project site and the ambient air quality monitoring station being more than 2 miles away.
- The modeling results must be carefully interpreted so that they are not skewed towards a single source, in high impact areas near that source's fence line. It is not truly a cumulative impact of BR123 if the high impact area is the result of high fence line concentrations from another stationary source and BR123 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, which completes the modeling portion of the cumulative assessment. Staff typically assists the project owner 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 project owner to complete. There are several reasons for this; modeling analyses take time to perform and require significant expertise, the project owner has already performed a modeling analysis of the project alone (see Operational Modeling Analysis section), and the project owner can act on its own to modify the project as the results warrant. Once the cumulative project emission impacts are determined, the necessity to mitigate the project emissions can be evaluated, and the mitigation itself can be proposed by staff and/or Project Owner (see Operations Mitigation section).

The project owner worked with the ICAPCD to identify recently built or proposed stationary source projects within a six mile radius of the project site, and found that the Hudson Ranch I Geothermal Project was recently permitted and is scheduled to be constructed approximately four miles from the BR123 project site. The project owner included the proposed project's normal operating emissions and the proposed Hudson Ranch Project's cooling tower and rock muffler in the cumulative air dispersion modeling analysis for particulate emissions (PM10/PM2.5) and H_2S shown in **AIR QUALITY Table 21**.

AIR QUALITY Table 21
BR123 Cumulative Impacts Modeling Results

Pollutant	Averaging Period	Project Impacts ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Standard ($\mu g/m^3$)	Percent of Standard
PM10	24-hour	3.44	161.4	164.8	50	330%
	Annual	0.81	48.8	49.6	20	248%
PM2.5	24-hour	2.39	27.1	29.5	35	84%
H_2S	1-hour	59.73	24.6	84.3	42	201%

Source: CE Obsidian Energy 2009b (Data Response 21), and updated PM10 background concentration from **Air Quality Table 5**.

The modeling results indicate that the cumulative air quality impacts are not expected to cause new PM2.5 violations or significantly contribute to the existing violations of PM10 standard[13]. The modeled cumulative impacts for H_2S do show exceedances. However, the maximum predicted impacts occur due to the Hudson Ranch project emissions where at the maximum impact location and time BR123's contribution is only 0.0006 $\mu g/m^3$, which is only 0.001 percent of the total impacts. Unfortunately, the project owner's modeling analysis used overly conservative modeling inputs for the Hudson Ranch project and was not performed in a manner to determine if the Hudson Ranch project would contribute cumulatively to the maximum modeled impacts for BR123. Staff revised the project owner's AERMOD modeling input files to model both the project's normal operating H_2S impacts and the cumulative impacts near the maximum BR123 impacts. Staff also corrected the Hudson Ranch inputs to reflect a multiple cell cooling tower. The results of staff's revised cumulative modeling analysis determined that the maximum 1-hour project related H_2S concentrations near the BR123 project site during normal operation would be 13.2 $\mu g/m^3$, and the maximum cumulative impact with Hudson Ranch near the BR123 site would be 14.1 $\mu g/m^3$. These results suggest that during normal operations these projects cumulative impacts (38.7 $\mu g/m^3$) would not exceed the California 1-hour H_2S standard (42 $\mu g/m^3$). This result is reasonable considering that these two projects are located approximately four miles from each other. However, both project's temporary emission sources, such as well testing and plant start-up, would create exceedances of the CAAQS, and so would also have cumulatively significant impacts. Also, as noted previously concentrations from normal operations would be well above odor thresholds outside the project fence line for periods shorter than an hour. Additionally, available H_2S ambient monitoring data is

[13] The maximum PM10 impacts occur at or very close to the fence line and drop quickly with distance from the fence line, and these impacts are below the PSD significant impact levels of 5 and 1 $\mu g/m^3$ for 24 hours and annual impacts, respectively.

limited and nearly a decade old, so the actual current H_2S background (24.6 µg/m^3) is uncertain.

Considering both the limitations of this analysis and the lack of recent ambient H_2S concentration data, staff is concerned that the BR123 project, alone or with the proposed future projects[14] could create cumulative adverse H_2S CAAQS impacts and associated H_2S odor impacts during normal operation where the CAAQS is within the range of the human odor threshold[15] for H_2S. Staff is recommending condition of certification **AQ-SC11** to address the potential for and if necessary mitigate the project's cumulative H_2S CAAQS impacts. In preparing this recommended condition staff recognizes that all ten of the existing operational geothermal projects in this geothermal resource area are owned by the BR123 project owner[16], so essentially the entire anthropogenic portion of the existing H_2S background would be caused by sources owned by the project owner. It is staff's position that with the implementation of this condition BR123 would not cause any new exceedances of the CAAQS H_2S standard and would mitigate its cumulative contribution to existing exceedances and to nuisance odor impacts.

COMPLIANCE WITH LORS

The ICAPCD issued a Preliminary Determination of Compliance (PDOC) for the amended BR123 project on May 11, 2010 (ICAPCD 2010a), a Final Determination of Compliance (FDOC) on July 9, 2010 (ICAPCD 2010b), and a revised FDOC on August 19, 2010 (ICAPCD 2010c). Compliance with all District Rules and Regulations was demonstrated to the District's satisfaction in the FDOC. The District's FDOC conditions are presented in the Conditions of Certification as AQ-1 through AQ-72. Staff completed a PDOC comment letter and communicated further NSR rule compliance issues to the District after receipt of the FDOC that were addressed to staff's satisfaction in the revised FDOC.

FEDERAL

The District is responsible for issuing the federal New Source Review (NSR) permit and has been delegated enforcement of the applicable New Source Performance Standard (Subpart IIII). This project will not require a PSD permit from U.S.EPA prior to initiating construction.

STATE

The project owner will demonstrate that the project will comply with Section 41700 of the California State Health and Safety Code, which restricts emissions that would cause

[14] There is the potential for a number of additional geothermal power plant projects within the SSKGRA, which has significant additional geothermal capacity. These additional projects, whether Energy Commission jurisdictional projects (50 MW or greater) or not, would have the potential to increase H_2S emissions significantly within the SSKGRA.

[15] The human odor threshold for H_2S ranges from 0.0005 ppm in the most sensitive individual to 0.3 ppm in the least sensitive individuals, while the 1-hour H2S CAAQS is 0.03 ppm.

[16] Where the term "owner" is defined as CE Obsidian Energy, LLC and all related parent companies and subsidiaries.

nuisance or injury, with the issuance of the District's FDOC and the Energy Commission's affirmative finding for the project.

The emergency generators and fire pump are also subject to the Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines. This measure limits the types of fuels allowed, establishes maximum emission rates, and establishes recordkeeping requirements. The proposed Tier 4 engine meets the emission limit requirements of this rule. This measure would also limit the engine's testing and maintenance operation to 20 hours per year for the emergency generator engines and 50 hours per year for the fire pump engines.

LOCAL

The District rules and regulations specify the emissions control and offset requirements for new sources such as the amended BR123 project. Best Available Control Technology would be implemented, and emission reduction credits (ERCs) are not required to offset the project's emissions by District rules and regulations based on the permitted stationary source emission levels for this project. Compliance with the District's new source requirements would ensure that the project would be consistent with the strategies and future emissions anticipated under the District's air quality attainment and maintenance plans.

The project owner provided an air quality permit application to the ICAPCD in November 2009 and the District issued a PDOC (ICAPCD 2010a) on May 11, 2010, an FDOC (ICAPCD 2010b) on July 9, 2010, and a revised FDOC on August 19, 2010 (ICAPCD 2010c). The FDOC states that the proposed project is expected to comply with all applicable District rules and regulations. The DOC evaluates whether and under what conditions the proposed project would comply with the District's applicable rules and regulations, as described below.

Regulation I – General Provisions

Rule 109 – Source Sampling

Rule 109 establishes the requirement to provide and maintain such facilities as are necessary for sampling and testing. The FDOC has conditions to ensure compliance with this regulation.

Rule 111 – Equipment Breakdown

Rule 111 requires that the ICAPCD be notified of any occurrence which constitutes a breakdown condition within prescribed timeframes. The FDOC has conditions to ensure compliance with this regulation.

Regulation II – Permits

Rule 201 – Permits Required

Rule 201 establishes the emission source requirements that must be met to obtain a Permit to Construct. Rule 203 prohibits use of any equipment or the use of which may emits air contaminants without obtaining a Permit to Operate. The project owner has initiated permitting/licensing to comply with this rule.

Rule 202 – Exemption

Rule 202 provides list of equipment types that do not require permits. Seven diesel fuel storage tanks piped exclusively to emergency engines, a propane tank, heating ventilation and air conditioning systems, a water heater, water treatment systems, and storage tanks for water treatment chemicals are found to be exempt under this rule and are not discussed further in the FDOC.

Rule 207 – New and Modified Stationary Source Review

This rule establishes the stationary source[17] requirements that must be met to obtain a Permit to Operate, including the requirement to comply with BACT, provide emission offsets for emission increase above specified thresholds; and provide a dispersion modeling analysis, an alternatives analysis, and a compliance certification (if applicable). In the FDOC, the District has determined that the proposed emission controls for the NCG (RTO/scrubber), cooling tower (ChemOx), emergency generator engine (Tier 4), and firewater pump engine (Tier 4) meet BACT requirements. The District did raise the required RTO destruction efficiency for VOC from 95 percent as proposed by the project owner to 98 percent.

The District determined that the amended project would have emissions below offset thresholds (137 lbs/day) for all regulated criteria pollutants, and found that an ambient air quality impact analysis was not required (although the one completed for the Energy Commission did pass all District impact thresholds). The project was also found not to require a compliance certification per District Rule 207.

Rule 208 – Permit to Operate

This rule provides the process by which a facility with a permit to construct may receive an approved permit to operate. The project owner has initiated permitting/licensing to comply with this rule.

Regulation IV – Prohibitions

Rule 400 – Fuel Burning Equipment

This rule limits discharge into the atmosphere from fuel burning equipment combustion contaminants exceeding in concentration at the point of discharge, 140 lbs/hr of nitrogen oxides, calculated as nitrogen dioxide (NO_2). In the FDOC, the District has determined that the applicable equipment's (emergency generator and fire pump engine) NOx emission concentration are less than 140 lbs/hr and so will be well below the limits established by this rule.

Rule 401 – Opacity of Emissions

Rule 401 limits visible emissions from emissions sources. This rule prohibits discharge of any emissions, other than uncombined water vapor, for more than three minutes in any hour. The FDOC did not directly analyze compliance with this rule but none of the project emission source exhausts are expected to have any opacity other than condensed water vapor.

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

Rule 403 – General Limitation on the Discharge of Air Contaminants

This rule limits discharge into the atmosphere from any single emission unit, combustion contaminants exceeding in concentration at the point of discharge of 0.2 grains per dry cubic foot of gas, calculated to 12 percent of carbon dioxide (CO_2) at standard conditions averaged over 25 consecutive minutes. The FDOC calculated the expected particulate emission concentrations from the various project emissions sources and determined that they are all expected to comply with this rule.

Rule 405 – Sulfur Compounds Emission Standards, Limitations and Prohibitions

This rule limits discharge of sulfur compounds into the atmosphere from equipment to specified amounts. Compliance is expected through the use of low sulfur diesel fuel and the inherent low sulfur content of propane.

Rule 407 – Nuisance

This rule restricts emissions that would cause nuisance or injury to people or property (identical to California Health and Safety Code 41700). The H_2S emissions during production well testing and initial commissioning would have the potential to cause nuisance or annoyance to the public in violation of this Rule 407. The FDOC did not explicitly address compliance with this regulation, but does include a general condition that requires that the project not create a public nuisance (**AQ-5**). Staff has provided additional review of the potential for nuisance odors and is recommending the addition of **AQ-SC8** (an existing condition) and **AQ-SC11** to reduce or mitigate public nuisance conditions should they occur in the project site area.

Rule 414 – Storage of Reactive Organic Compound Liquids

Rule 414 established control and inspection requirements applicable to storage tanks with a capacity equal to or greater than 1,500 gallons used to store ROC liquids with a true vapor pressure equal to or greater than 0.50 psia. The FDOC notes that compliance with this rule is expected.

Rule 424 – Architectural Coatings

This rule limits ROC emissions from architectural coatings. The FDOC notes that compliance with this rule is expected.

Regulation VIII – Fugitive Dust Rules

Rule 800 – General Requirements for Control of Fine Particulate Matter

Specifies the types of chemical stabilizing agents and dust suppressant materials that can (and cannot) be used to minimize fugitive dust from anthropogenic (man-made) sources. The rule also specifies test methods for determining compliance with visible dust emission (VDE) standards, stabilized surface conditions, soil moisture content, silt content for bulk materials, silt content for unpaved roads and unpaved vehicle/ equipment traffic areas, and threshold friction velocity (TFV). Records shall be maintained only for those days that a control measure was implemented, and kept for two years after the date of each entry. A fugitive dust management plan for unpaved roads is discussed in Rule 805. The FDOC includes conditions to assure compliance with all Regulation VIII rules. Compliance is expected.

Rule 801 – Construction and Earthmoving Activities

Requires fugitive dust emissions throughout construction activities (from pre-activity to active operations and during periods of inactivity) to comply with the conditions of a stabilized surface area and to not exceed an opacity limit of 20 percent, by means of water application, chemical dust suppressants, or constructing and maintaining wind barriers. A Dust Control Plan is also required and shall be submitted to the Air Pollution Control Office (APCO) at least 30 days prior to the start of any construction activities on any site that will include 10 acres or more of disturbed surface area for residential developments, 5 acres or more of disturbed surface area for non-residential development. The FDOC includes conditions to assure compliance with all Regulation VIII rules. Compliance is expected.

Rule 802 – Bulk Materials

Limits the fugitive dust emissions from the outdoor handling, storage and transport of bulk materials. Requires fugitive dust emissions to comply with the conditions of a stabilized unpaved road surface and to not exceed an opacity limit of 20 percent. It specifies that bulk materials be transported using wetting agents, allow appropriate freeboard space in the vehicles, or be covered. It also requires that stored materials be covered or stabilized. The FDOC includes conditions to assure compliance with all Regulation VIII rules. Compliance is expected.

Rule 803 – Carry-out and Track-out

Limits carry-out and track-out during construction, demolition, excavation, extraction, and other earthmoving activities (Rule 801), from bulk materials handling (Rule 802), and from paved and unpaved roads (Rule 805) where carry-out has occurred or may occur. Specifies acceptable (and unacceptable) methods for cleanup of carry-out and track-out. The FDOC includes conditions to assure compliance with all Regulation VIII rules. Compliance is expected.

Rule 804 – Open Areas

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

Rule 805 – Paved and Unpaved Roads

Specifies the width of paved shoulders on paved roads and guidelines for medians. Requires gravel, roadmix, paving, landscaping, watering, and/or the use of chemical dust suppressants on unpaved roadways to prevent exceeding an opacity limit of 20 percent. Exemptions to this rule include paved and unpaved driveways serving one single family residential dwelling and agricultural operation site defined in and subject to Rule 806, Conservation Management Practices. The FDOC includes conditions to assure compliance with all Regulation VIII rules. Compliance is expected.

Regulation XI – New Source Performance Standards

Rule 1101 – New Source Performance Standards (NSPS)

This rule incorporates the Federal NSPS (40 CFR 60) rules by reference. The proposed Tier 4 emergency engines and firewater pump comply with the emission limit requirements of the only NSPS (Subpart IIII) that applies to the proposed BR123 equipment.

CONCLUSIONS AND RECOMMENDATIONS

The requested changes in project design and construction would conform to applicable Federal, State, and ICAPCD air quality laws, ordinances, regulations, and standards, and the amended project would not cause significant air quality impacts, with the one exception noted below, provided that the following staff recommended and ICAPCD Conditions of Certification (COCs) are included. Due to the significant changes in the staff recommended and ICAPCD conditions only the recommended COCs for this amended project, which completely replace the existing license's COCs (CEC 2005b), are provided in this document.

Staff cannot demonstrate with certainty, considering that there is no recent H_2S concentration data available near the site, that the project would not cause or contribute to cumulative H_2S standard exceedances or odor events that would impact areas, including populated areas, surrounding the project site. Additionally, the amended project increases the permitted H_2S emissions substantially (increase is over 25 tons per year) and the project owner has withdrawn the proposal to provide H_2S offsets for this amended project. Therefore, staff is recommending a Condition of Certification (**AQ-SC11**) that requires the project owner to create cost effective H_2S emission reductions if exceedances of the CAAQS H_2S standard are observed from the ambient H_2S monitoring, that will be performed by the District after a monitor is obtained through the project owner (see Condition of Certification **AQ-72**), and BR123 contributes to those exceedances. These emission reductions would come from reducing emissions at BR123 or elsewhere within the SSKGRA, where cost effective. These emission reductions will be limited to the lowest of: 1) the H_2S emissions reduction that is determined to be cost effective; or 2) equivalent to the permitted annual H_2S emissions for the Black Rock 1, 2, and 3 Geothermal Power Project; or 3) sufficient to ensure ongoing attainment of the H_2S standard.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

STAFF CONDITIONS OF CERTIFICATION

Due to the significant changes in the staff recommended and ICAPCD conditions, only the recommended COCs for this amended project, which completely replace the existing license's COCs (CEC 2005b), are provided in this document.

Staff conditions **AQ-SC1** through **AQ-SC5** are based on current staff standards for mitigating construction emission impacts. Condition **AQ-SC6** will ensure that the license is amended as necessary to incorporate changes to the air quality permits. Condition **AQ-SC7** requires engines to meet model year EPA/ARB Tier emission standards for the year purchased. Conditions **AQ-SC8** and **AQ-SC11** are recommended to mitigate H_2S impacts. **AQ-SC9** and **AQ-SC10** are recommended for mitigation of NH_3 impacts.

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

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

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

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

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

a. The main access roads through the facility 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 (chemicals, replacement parts, etc.) will be paved or treated prior to taking initial deliveries.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

f. Construction equipment will employ electric motors when feasible.

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

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

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

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

AQ-SC6 The project owner shall provide the CPM copies of all District issued Authority-to-Construct (ATC) and Permit-to-Operate (PTO) documents for the facility.

The project owner shall submit to the CPM for review and approval any modification proposed by the project owner to any project federal air permit. The project owner shall submit to the CPM any modification to any federal air permit proposed by the District or U.S. Environmental Protection Agency (U.S. EPA), and any revised federal air permit issued by the District or U.S. EPA, for the project.

Verification: The project owner shall submit any ATC, PTO, and proposed federal air permit modifications to the CPM within 5 working days of 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 ATC/PTO documents and all federal air permits to the CPM within 15 days of receipt.

AQ-SC7 The project owner shall submit to the CPM and Air Pollution Control Officer (APCO) Quarterly Operations Reports that include Operations and emissions information as necessary to demonstrate compliance with all operating Conditions of Certification. The Quarterly Operations Report will specifically note or highlight incidents of noncompliance.

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

AQ-SC8 As a means to decrease maximum impacts below the California ambient hydrogen sulfide standard during well flow tests, the project owner shall limit the brine flow rate to 0.8 million pounds per hour during normal well flow testing for both the production wells and injection wells. Brine flow rate may be temporarily increased up to an average of 1.2 million pounds per hour to ascertain the production well behavior or reservoir response as necessary.

Verification: A summary of brine flow rates during normal well flow testing for both production wells and injection wells shall be included in each Monthly Compliance Report or Quarterly Operations Report, as appropriate, for all well flow testing.

AQ-SC9 The project owner shall provide through chemical monitoring and mass balance, or other means approved by the CPM, quarterly ammonia emission estimates for the BR123 plant.

Verification: The project owner/operator shall provide the CPM with a proposed ammonia emission estimation methodology within 30 days of the start of commercial operations and shall provide the BR123 ammonia emissions estimates in the Quarterly Operations Report.

AQ-SC10 The project owner shall provide an Ammonia Control Technology and Alternative Water Source Report to the CPM on advances in ammonia control technologies and availability of new alternative cooling water sources.

Verification: The Ammonia Control Technology and Alternative Water Source Report shall be submitted to the CPM in the Annual Compliance Report that is three years after the completion of the initial commissioning of the plant, and update it in the Annual Compliance Report every five years thereafter.

AQ-SC11 The project owner shall provide a Hydrogen Sulfide Ambient Air Quality Analysis, based on an approved Hydrogen Sulfide Ambient Air Quality Analysis Plan, in the second Quarterly Operations Report submitted after the completion of the first full 12 months of commercial operation. This analysis shall include a summary of the ambient hydrogen sulfide (H_2S) concentrations recorded at the local ambient H_2S monitor (see **AQ-72**), obtained from ICAPCD, and validated for use by ICAPCD, ARB, or otherwise as allowed in the approved Hydrogen Sulfide Ambient Air Quality Analysis Plan, that identifies all monitored exceedances of the California 1-hour H_2S ambient air quality standard, and an analysis of the distribution of exceedance magnitudes, meteorological conditions, and persistence of the CAAQS exceedances. If any exceedances are determined by the ICAPCD, other responsible regulatory agencies, or otherwise determined as allowed in the approved Hydrogen Sulfide Ambient Air Quality Analysis Plan then the Hydrogen Sulfide Ambient Air Quality Analysis shall also include:

a) An analysis of the ambient air quality standard exceedances, using dispersion modeling or other methods approved by the CPM in the Hydrogen Sulfide Ambient Air Quality Analysis Plan, which determines the amount of each exceedance that is attributable to the project.

b) If the project contributes to the monitored H_2S standard exceedances, then the project owner shall submit to the CPM a Hydrogen Sulfide Emission Reduction Plan, that will include an approach to reduce H_2S emissions at the project site, or elsewhere within the Salton Sea Known Geothermal Resource Area (SSKGRA), to reduce annual H_2S emissions to the lesser of: 1) the H_2S emissions reduction that is determined to be cost effective; or 2) equivalent to the permitted annual H_2S emissions for the Black Rock 1, 2, and 3 Geothermal Power Project; or 3) sufficient to ensure ongoing attainment of the H_2S standard. The project owner can apply H_2S emission reductions, which the project owner has created or funded, at other facilities within the SSKGRA that are accomplished as of the effective date of this license. The Hydrogen Sulfide Emission Reduction plan shall include a cost effectiveness analysis of technically achievable H_2S emission reduction options, including those that were selected for implementation and those that were discarded from consideration in the plan. In the event that no cost effective emission reduction options are found, or if the H_2S emission reductions implemented were less than the annual emissions of the project and exceedances of the CAAQS H_2S standard persist, then every three years after the initial Hydrogen Sulfide Emission Reduction Plan submittal the project owner shall submit a re-evaluation of the technically available H_2S emission reduction methods within the SSKGRA and their cost effectiveness in a revised Hydrogen Sulfide Emission Reduction Plan. The project owner shall implement the H_2S emission reduction methods found to be cost effective, as necessary to comply with the impact reduction requirements of this condition, within two years of that determination.

The Hydrogen Sulfide Ambient Air Quality Analysis Plan shall also identify the requested role of the ICAPCD or the ARB, with a letter from the agency confirming they are willing to take on that role, in regards to but not limited to: the validation of H_2S monitoring data; the determination of Hydrogen Sulfide ambient air standard exceedances; the review of modeling data; and the determination of the appropriate level of mitigation determined in the Hydrogen Sulfide Emission Reduction Plan.

Verification: The project owner shall submit the Hydrogen Sulfide Ambient Air Quality Analysis Plan to the CPM for approval at least 60 days prior to providing the Hydrogen Sulfide Ambient Air Quality Analysis with the second Quarterly Operations Report that occurs after the first full 12 months of commercial operation, and if necessary based on the requirements of this condition shall submit to the CPM the Hydrogen Sulfide Emission Reduction Plan within 60 days of approval of the Hydrogen Sulfide Ambient Air Quality Analysis. The hydrogen sulfide emission reductions, specified to be implemented in the Hydrogen Sulfide Emission Reduction Plan, shall be achieved within 2 years of submittal of the initial or revised Hydrogen Sulfide Emission Reduction Plan.

DISTRICT CONDITIONS

Due to the significant changes in the ICAPCD conditions only the recommended COCs for this amended project, which completely replace the existing license's COCs (CEC 2005b; ICAPCD 2010c), are provided in this document.

District Final Determination of Compliance Conditions (ICAPCD 2010c)

General Conditions

AQ-1 Operation of this equipment shall be 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 submit documentation and maintain records as required by the conditions of this license. These materials and any records shall be made available for inspection by representatives of the District, ARB, and the Energy Commission in accordance with the terms and conditions set forth in this license.

AQ-2 Operation of this equipment shall be in compliance with all applicable APCD Rules and Regulations.

Verification: The project owner shall maintain such records as required by the conditions set forth in this license and make the site available for inspection of these records and the equipment by representatives of the District, ARB, and the Energy Commission in accordance with the terms and conditions set forth in this license.

AQ-3 This Permit does not authorize the emissions of air contaminants in excess of those allowed by U.S.EPA (Title 40 of the Code of Federal Regulations), the State of California Division 26, Part 4, Chapter 3 of the Health and Safety Code, or the APCD (Rules and Regulations).

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

AQ-4 This Permit cannot be considered permission to violate applicable existing laws, ordinances, regulations, rules or statutes of other governmental agencies.

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

AQ-5 No air contaminant shall be released into the atmosphere which causes a public nuisance. (Rule 407)

Verification: The project owner shall maintain records of odor complaints; when these complaints occurred; and what was done to resolve the complaint. The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-6 The project owner shall not release or discharge into the atmosphere from any single source of emission, any air contaminant as dark or darker as designated as No. 1 on the Ringlemann Chart (20% opacity) for a period or periods aggregating more than three (3) minutes in any hour.

Verification: The project owner shall maintain records of opacity excursions; when these excursions occurred; and what was done to resolve the excursion. Within five (5) business days of receipt of a written request, the Project Owner shall make these records available to the District, ARB, and the Energy Commission. Notwithstanding the fore going, representatives of the District, ARB, and the Energy Commission shall have the right to inspect these records in accordance with the terms and conditions set forth in this license.

AQ-7 Disturbances of soil related to any construction, demolition, excavation, or other earthmoving activities shall comply with the requirements for fugitive dust control. (Rule 801)

Verification: The project owner shall submit information required by Conditions AQ-SC1 to AQ-SC5 during site construction and shall submit information regarding measures taken to comply with this condition during operation in the Quarterly Compliance Reports.

AQ-8 Any unpaved and paved road, and open areas subject to be disturbed by vehicles traffic shall comply with the requirements for fugitive dust control. (Rule 805)

Verification: The project owner shall submit information required by Conditions AQ-SC1 to AQ-SC5 during site construction and shall submit information regarding measures taken to comply with this condition during operation in the Quarterly Compliance Reports.

AQ-9 The project owner shall prevent or cleanup any carry-out or track-out. (Rule 803)

Verification: The project owner shall submit information required by Conditions AQ-SC1 to AQ-SC5 during site construction and shall submit information regarding measures taken to comply with this condition during operation in the Quarterly Compliance Reports.

Regenerative Thermal Oxidizers/Scrubber Units

AQ-10 Each RTO shall have a minimum Destruction Rate Efficiency of 98 percent or more for VOCs during all times of operation, except during commissioning, startups, and shutdown events.

Verification: The project owner shall include information necessary to demonstrate compliance with this condition, including summaries of the source test data required by condition **AQ-65** and operating parameter monitoring required by condition **AQ-68**, in the Annual Compliance Report.

AQ-11 Each Scrubber shall have a minimum removal efficiency of 97.5 percent or more for sulfur dioxide during all times of operation, except during commissioning, startups, and shutdown events.

Verification: The project owner shall include information necessary to demonstrate compliance with this condition, including summaries of the source test data required by condition **AQ-65** and operating parameter monitoring required by condition **AQ-68**, in the Annual Compliance Report.

AQ-12 Each Regenerative Thermal Oxidizer (RTO) shall be operated and properly maintained during normal operations; except during power plant startup/shutdowns.

Verification: The project owner shall maintain records of operation and maintenance, and records of when the maintenance was performed. Within five (5) business days of receipt of a written request, the Project Owner shall make these records available to the District, ARB, and the CPM.

AQ-13 For the duration of the commissioning period, the following emissions from the uncontrolled NCG stack and condensate line shall not be exceed for each Black Rock Unit:

a) VOC emissions 171.57 pounds per event;
b) Hydrogen sulfide emissions 4,476.40 pounds per event;
c) Sulfur dioxide emissions 88.63 pounds per event;
d) Nitrogen oxide emissions 30.69 pounds per event.

Verification: The project owner shall include information necessary to demonstrate compliance with this condition in the Monthly Compliance Report.

AQ-14 For normal RTO/Scrubber operations, the following emissions limits from the controlled NCG stack line shall not be exceeded in each Black Rock Unit:

a) VOC emissions 0.06 pounds per hour;
b) Hydrogen sulfide emissions 0.80 pounds per hour;
c) Sulfur dioxide emissions 1.79 pounds per hour;
d) Nitrogen oxide emissions 0.43 pounds per hour.

Verification: The project owner shall include information necessary to demonstrate compliance with this condition in the Quarterly Compliance Report.

AQ-15 For normal RTO/Scrubber operations, the following emissions limits from the controlled NCG stack line shall not be exceeded in each Black Rock Unit:

a) VOC emissions 1.44 pounds per day;
b) Hydrogen sulfide emissions 48.0 pounds per day;
c) Sulfur dioxide emissions 42.96 pounds per day;
d) Nitrogen oxide emissions 10.32 pounds per day.

Verification: The project owner shall include information necessary to demonstrate compliance with this condition in the Quarterly Compliance Report.

AQ-16 For each Black Rock Unit, the following emission limits from the condensate line shall not be exceeded:

a) Benzene emissions 0.01 pounds per hour and 0.24 pounds per day, measured at the condensate line before entering the cooling towers.

b) Hydrogen sulfide emissions 1.33 pounds per hour and 31.92 pounds per day, measured at the cooling tower shrouds.

Verification: The project owner shall include information necessary to demonstrate compliance with this condition, including summaries of the source test results from the tests conducted as required by conditions **AQ-66** and **AQ-69**, in the Annual Compliance Report.

AQ-17 During periods of operation without the abatement system (RTO/Scrubber system) for cold startups, the following emissions from the uncontrolled NCG stack and condensate line shall not be exceed for each Black Rock Unit:

a) VOC emissions 2.77 pounds per hour;
b) Hydrogen sulfide emissions 56.43 pounds per hour;
c) Sulfur dioxide emissions 0.27 pounds per hour;
d) Nitrogen oxide emissions 0.40 pounds per hour.

Verification: The project owner shall include information necessary to demonstrate compliance with this condition in the Quarterly Compliance Report.

AQ-18 During periods of operation without the abatement system (RTO/Scrubber system) for warm startups, the following emissions from the uncontrolled NCG stack and condensate line shall not be exceed for each Black Rock Unit:

a) VOC emissions 3.91 pounds per hour;
b) Hydrogen sulfide emissions 52.55 pounds per hour;
c) Sulfur dioxide emissions 1.12 pounds per hour;
d) Nitrogen oxide emissions 0.43 pounds per hour.

Verification: The project owner shall include information necessary to demonstrate compliance with this condition in the Quarterly Compliance Report.

AQ-19 During periods of operation without the abatement system (RTO/Scrubber system) for shutdowns, the following emissions from the uncontrolled NCG stack and condensate line shall not be exceed for each Black Rock Unit:

a) VOC emissions 1.27 pounds per hour;

b) Hydrogen sulfide emissions 33.31 pounds per hour.

<u>Verification</u>: The project owner shall include information necessary to demonstrate compliance with this condition in the Quarterly Compliance Report.

AQ-20 A log shall be maintained showing hours of operation and routine repairs for each RTO/Scrubber system at their respective Black Rock Unit. This log shall be made available for inspection by the ICAPCD.

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

Operation Conditions

AQ-21 Total yearly operations shall be limited to the following for each Black Rock Unit:

a) Up to 8,760 hours of normal operation,
b) up to 45 hours of cold start ups,
c) up to 16 hours of warm start ups, and
d) up to 48 hours of shut downs.

<u>Verification</u>: The project owner shall include information necessary to demonstrate compliance with this condition in the Annual Compliance Report.

AQ-22 The commissioning period for each Black Rock Unit shall be restricted to a total of 168 hours, with the following time limitations for each segment:

a) Up to 16 hours for the warm-up of the first production well,
b) up to 24 hours for the warm-up of the second and third production well,
c) up to 32 hours for the warm-up of production piping associated equipment,
d) up to 24 hours for steam blow activity to the rock muffler,
e) up to 24 hours to preheat the turbine and auxiliary loops,
f) up to 24 hours to carry out the turbine load test, and
g) up to 24 hours to carry out the turbine performance test.

<u>Verification</u>: The project owner shall include information necessary to demonstrate compliance with this condition in the Monthly Compliance Report.

AQ-23 Each cold startup event (the period beginning with production wells warmup and turbine and auxiliary loops preheated and lasting until the equipment has reached a continuous operating level and is generating emissions within "normal operating" levels) shall be restricted to a total of 45 hours in duration. Total cold startup events are limited to 3 events per year or 135 hours per year for the Black Rock Facility.

<u>Verification</u>: The project owner shall include information necessary to demonstrate compliance with this condition in the Quarterly Compliance Report.

AQ-24 Each warm startup event (the period beginning with the PGF control system detecting a problem and tripping the steam turbine offline and lasting until steam from the rock muffler is redirected to the turbine and the power generation cycle is reinitiated) shall be restricted to a total of 4 hours in duration. Total warm startup events are limited to 12 events per year and 48 hours per year for the Black Rock Facility.

Verification: The project owner shall include information necessary to demonstrate compliance with this Power Generating Facility (PGF) condition in the Quarterly Compliance Report.

AQ-25 Each shutdown event (the period beginning with the initiation of turbine shutdown sequence, a gradual reduction in brine flow, and emissions exceeding "normal operating" levels, lasting until brine flow is completely shutoff) shall be restricted to a total of 12 hours in duration. Total shutdown events are limited to 4 events and 48 hours per year for the Black Rock Facility.

Verification: The project owner shall include information necessary to demonstrate compliance with this condition in the Quarterly Compliance Report.

AQ-26 The Black Rock Facility shall not incur a total of more than one unit startup event per day.

Verification: The project owner shall include information necessary to demonstrate compliance with this condition in the Quarterly Compliance Report.

AQ-27 The project owner shall ensure that the emissions from each of the RTO/Scrubber stacks do not exceed the following limits during any calendar year, including emissions generated during gas turbine start-ups and shutdowns:

a) 1.88 tons of NOx, (as NO_2) per year;

b) 1.09 tons of CO per year;

c) 0.26 tons of VOC per year; and

d) 7.84 tons of SO_2 per year.

Verification: The project owner shall include information necessary to demonstrate compliance with this condition in the Annual Compliance Report.

AQ-28 Greenhouse gas emissions inventories shall be compiled and reported in accordance with applicable state and federal regulations.

Verification: The project owner shall submit to the CPM copies of any greenhouse gas inventories compiled for compliance with this condition as part of the Annual Compliance Report.

Cooling Tower

AQ-29 Each cooling tower's recirculating water total dissolved solids level shall not exceed 7,952 ppmw.

Verification: The project owner shall provide a summary of the weekly testing required in AQ-67 to demonstrate compliance with this condition in the Quarterly Compliance Report.

AQ-30 Cooling tower drift loss rate shall be limited to 0.0005%.

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

AQ-31 For each cooling tower under normal operations, the following emissions limits shall not be exceeded at each Black Rock Unit:

a) PM10 emissions 42.48 pounds per day;

b) Hydrogen Sulfide emissions 31.92 pounds per day.

Verification: The project owner shall include information necessary to demonstrate compliance with this condition in the Quarterly Compliance Report.

AQ-32 The ChemOx system at each Black Rock Unit shall have a minimum destruction rate efficiency of 95 percent for hydrogen sulfide emissions.

Verification: The project owner shall include information necessary to demonstrate compliance with this condition in the Quarterly Compliance Report.

AQ-33 An operation protocol for the ChemOx system of each Black Rock Unit shall be submitted to the APCD for approval prior to the issuance of a Permit to Operate (PTO).

Verification: The project owner shall submit the operation protocol for the ChemOx system as required by this condition to the District for approval and CPM for review.

Emergency Standby Combustion Units

AQ-34 Operation of the emergency generators other than for the purposes of maintenance and testing shall be limited to exclusively providing backup power, and in each instance, documented to the satisfaction of the APCD.

Verification: The project owner shall maintain an operation log for each engine to record engine operation and purpose of operation and shall make the log available for inspection by make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-35 Operation of the emergency fire water pumps other than for the purposes of maintenance and testing shall be limited to the pumping of water for fire suppression or protection, and in each instance, documented to the satisfaction of the APCD.

Verification: The project owner shall maintain an operation log for each engine to record engine operation and purpose of operation and shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-36 The engine of each emergency unit shall not discharge into the atmosphere any visible air contaminant other than uncombined water vapor, for a period or periods aggregating more than three minutes in any one hour, which is 20% opacity or greater.

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

AQ-37 Non-resettable hour meters, with a minimum display capability of 9,999 hours, shall be installed and maintained to proper working condition for each emergency unit.

Verification: At least 30 (thirty) days prior to the installation of the emergency engine, the project owner shall provide the District and the CPM the specification of the hour meters.

AQ-38 The diesel engine of each emergency unit shall be fueled only with one or a combination of the following:

a) CARB diesel fuel; or

b) an alternative diesel fuel, such as biodiesel or a biodiesel blend that does meet the definition of CARB diesel fuel; or

c) any alternative diesel fuel that meets the requirements of the Verification Procedure; or

d) CARB diesel fuel used with fuel additives that meets the requirements of the Verification Procedure.

Verification: The project owner shall submit records required by this condition that demonstrate compliance with the engine fuel requirements of this condition. The project owner shall make the site available for inspection of equipment and fuel purchase records by representatives of the District, ARB, and the Energy Commission.

AQ-39 Each emergency generator shall be restricted to operate a total of 20 (twenty) hours per year for maintenance and testing purposes.

Verification: The project owner shall submit records that demonstrate compliance with the engine use limitations of this condition in the Annual Compliance Report, including a photograph showing the annual reading of engine hours. The project owner shall make the site available for inspection of equipment by representatives of the District, ARB, and the Energy Commission.

AQ-40 Each emergency fire water pump shall be restricted to operate a total of 50 (fifty) hours per year for maintenance and testing purposes.

Verification: The project owner shall submit records that demonstrate compliance with the engine use limitations of this condition in the Annual Compliance Report, including a photograph showing the annual reading of engine hours. The project owner shall make the site available for inspection of equipment by representatives of the District, ARB, and the Energy Commission.

AQ-41 The diesel engine of each 1.5 MW emergency generator shall not emit more than 2.43 lbs/hr of NOx.

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 New Source Performance Standard (NSPS) and ARB Airborne Toxic Control Measures (ATCM) emission limit requirements at the time of engine purchase.

AQ-42 The diesel engine of each 1.0 MW emergency generator shall not emit more than 1.62 lbs/hr of NOx.

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

AQ-43 The diesel engine of each 1.5 MW emergency generator shall be source tested for compliance with the NOx emission limit stated in Condition **AQ-41** initially within the first 60 days of installation and every three (3) years thereafter, or any time as requested by the APCO. A testing protocol shall be submitted to the APCD for approval thirty (30) days prior to the source test being conducted.

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

AQ-44 The diesel engine of each 1.0 MW emergency generator shall be source tested for compliance with the NOx emission limit stated in Condition **AQ-42** initially within the first 60 days of installation and every three (3) years thereafter, or any time as requested by the APCO. A testing protocol shall be submitted to the APCD for approval thirty (30) days prior to the source test being conducted.

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

AQ-45 All testing of emergency generators for compliance determination shall be performed in accordance with U.S.EPA method 7, 7A, 7C, 7E, or any other EPA approved test method.

<u>Verification</u>: The test protocols required under **AQ-43** and **AQ-44** shall propose test method(s) that comply with this condition.

AQ-46 The engine of each unit shall comply with NSPS Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, at the time equipment is purchased.

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

AQ-47 The project owner shall retain all results of compliance and test reports for two (2) years from the date of each entry and made available to the APCD personnel upon request.

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

Breakdowns

AQ-48 The project owner shall notify the ICAPCD of any upset conditions, breakdown or scheduled maintenance which cause a violation of emission limitations prescribed by ICAPCD Rules and Regulations, or by State law. The ICAPCD shall be notified as soon as reasonably possible, but no later than two (2) hours after its detection by an operator. The completion of corrective measures or the shutdown of emitting equipment is required within 24 hours of occurrence of a breakdown condition.

Verification: The project owner shall provide equipment breakdown notification to the ICAPCD no later than two (2) hours after its detection and shall provide equipment breakdown records in the Annual Compliance Report.

AQ-49 If the breakdown condition will require more than twenty four (24) hours to correct, the project owner, in lieu of shutdown, shall submit a variance application to the Air Pollution Control Officer (APCO) requesting to commence the variance procedure set forth in the ICAPCD Hearing Board Procedures.

Verification: The project owner shall submit the variance application for the APCO in compliance with this condition, and shall provide variance request and acceptance records in the Annual Compliance Report.

AQ-50 The project owner shall submit a written report to the ICAPCD within ten (10) days after a break down occurrence has been corrected or an emergency event has occurred, and any impacts to operations thereof, have been resolved. This report shall include: a) a statement that the occurrence has been corrected, together with the date of correction and proof of compliance; b) the reason(s) or cause(s) of the occurrence or emergency; c) a description of the corrective measure undertaken; and d) the type of emission and estimated quantity of the emissions caused by the occurrence.

Verification: The project owner shall submit the written report to the ICAPCD within 10 days of a break down occurrence or an emergency event as required by this condition, and shall provide copies of these reports in the Annual Compliance Report.

AQ-51 In any enforcement proceeding, the project owner has the burden of proof for establishing that an emergency occurred.

Verification: None.

AQ-52 Potential emissions described within this permit, shall be utilized to calculate emissions caused by equipment breakdown, malfunction, or any occurrence which result in uncontrolled emissions in excess of permitted conditions.

Verification: None.

Recordkeeping/Reporting

AQ-53 The project owner shall submit written notification to the ICAPCD within 72 hours of the start of each segment of the commissioning period for each Black Rock Unit.

Verification: The project owner shall submit written notification to the ICAPCD and CPM within 72 hours of the start of each segment of the commissioning period for each Black Rock Unit.

AQ-54 At the end of each month, and not more than thirty (30) days thereafter, each Black Rock Unit shall submit a report to the ICAPCD which contains the following information:

a) Monthly emission report of hydrogen sulfide and benzene based on analysis conducted pursuant to the requirements of **AQ-66**. Emissions shall be reported in pounds per hour.

b) A report of days and hours of operation without RTO/Scrubber (uncontrolled) system.

Verification: As part of the Quarterly Compliance Report, the project owner shall include information demonstrating compliance with this condition.

AQ-55 At the end of each calendar quarter, and not more than thirty (30) days thereafter, each Black Rock Unit shall submit a report to the ICAPCD which contains the following information:

a) Quarterly emission report of hydrogen sulfide and benzene based on analysis conducted pursuant to the requirements of **AQ-66**. Emissions shall be reported in pounds per hour.

b) A report of days and hours of operation without RTO/Scrubber (uncontrolled) system.

Verification: As part of the Quarterly Compliance Report, the project owner shall include information demonstrating compliance with this condition.

AQ-56 A log shall be maintained at each Black Rock Unit indicating the monthly fuel consumption, hours of operation for maintenance and testing purposes, and in a separate section, the hours of operation for emergency situations for each emergency generator and fire water pump unit. This log shall be made available for inspection by the APCD.

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

AQ-57 The project owner shall submit to the APCD an annual report for each Black Rock Unit containing the monthly fuel consumption and hours operated per month for each emergency generator and fire water pump unit. This report shall reach the APCD by the end of February of each operating year.

<u>Verification:</u> As part of the Annual Compliance Report, the project owner shall include information demonstrating compliance with this condition.

AQ-58 The project owner shall maintain all records and reports at each Black Rock Unit for a minimum of five (5) years. These records shall include but are not limited to: cold startup events and warm startup events and duration; uncontrolled operating hours, emission rates, monitor excesses, breakdowns, etc.; source test and analytical records, emission calculation records, records of plant upsets and related incidents. The project owner shall make all records and reports available to ICAPCD staff upon request.

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

AQ-59 The project owner shall notify the ICAPCD of any violations of these permits conditions. Notification shall be submitted in a timely manner, in accordance with all applicable ICAPCD Rules and Regulations. Notwithstanding the notification and reporting requirements given in any District Rules and Regulations, the owner/operator shall submit written notification (facsimile is acceptable) to the ICAPCD within 96 hours of the identification of a violation of any permit condition.

<u>Verification</u>: The project owner shall provide the District and the CPM violation notification no later than 96 hours after its detection and shall provide records of violation in the Annual Compliance Report.

AQ-60 Records of cooling tower recirculating water total dissolved solids levels for each Black Rock Unit shall be kept up to date and available to the ICAPCD.

<u>Verification</u>: The project owner shall maintain records of weekly total dissolved solids levels required in AQ-67 and shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-61 The project owner shall furnish the ICAPCD written results of all source tests conducted within thirty (30) days of the test completion.

<u>Verification</u>: The project owner shall submit any source test results to the District and to the CPM within 30 days after test was conducted.

Monitoring, Testing, And Analysis

AQ-62 The ICAPCD may, at any time, monitor emissions from any source within each Black Rock Unit.

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

AQ-63 The ICAPCD may, at any time, but no more often than once per year, authorize third-party air emissions testing and/or air emissions inventory of each Black Rock Unit. The cost of the air emissions testing shall be borne by the project owner. The ICAPCD shall give advance notification to the project owner prior to any air emissions testing or air emissions inventory required.

Verification: The project owner shall make the site available for source testing by a District specified third party and shall make all requested records available to a District specified third party to complete an air emissions inventory. Copies of any such third party source tests reports or emission inventories shall be submitted to the CPM within 15 days of their receipt by the project owner or their representatives.

AQ-64 The project owner shall conduct the following analysis: First source test shall be conducted after the first full year of commercial operation, and every four years thereafter, as required under the Toxic Hot Spots Information and Assessment Act Emissions Inventory Criteria and Guidelines Report, Title 17, Section 93300.5. All analysis' results shall be available at the facility for inspection and include the following data:

a) Of turbine condenser condensate and cooling tower blow down for ammonia, arsenic, beryllium, cadmium, chromium, copper, hydrogen sulfide, lead, manganese, mercury, nickel, radon, selenium, and zinc.

b) Of the non-condensable gases vented for hydrogen sulfide, ammonia, benzene, arsenic, mercury, radon, toluene, and xylene.

Verification: The project owner shall notify the District and the CPM within 30 days before the execution of the source tests required in this condition and the test results shall be submitted to the District and to the CPM within 30 days after each test was conducted.

AQ-65 The project owner shall conduct a source test for the RTO and Scrubber Abatement Equipment at each Black Rock Unit. The source test shall be conducted within the first 60 days after commissioning of each Black Rock Unit and every year thereafter. The source testing shall use EPA methods or ICAPCD approved equivalent. Test protocol shall be submitted to the district for approval 30 days prior to source test being conducted.

a) The project owner shall estimate the hydrogen sulfide and benzene control efficiency by measuring their concentration in the non-condensable gas at the inlet and at the outlet of the RTO and scrubber system.

b) The project owner shall estimate the hydrogen sulfide and benzene mass flow emission rate in lb/hr vented from the RTO/scrubber system.

c) Project owner shall estimate the scrubber control efficiency for SO_2 by measuring the concentration in the exhaust gas at the outlet of the RTOs and at the outlet of the Scrubbers.

d) Project owner shall calculate a mass balance within the regulated pollutants controlled in the RTO/Scrubber system.

Verification: The project owner shall notify the District and the CPM within 30 days before the execution of the source test required in this condition. The first test shall be conducted within 60 days after initial commissioning and the test results shall be submitted to the District and to the CPM within 30 days after test was conducted.

AQ-66 The project owner shall conduct monthly analysis of benzene and hydrogen sulfide content in the condensate before it enters the ChemOx system, using EPA methods or equivalent.

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

AQ-67 The project owner shall conduct weekly testing of the cooling tower recirculating water total dissolved solids levels for each Black Rock Unit, with compliance of the required limitation, 7,952 ppmw, based on a thirty (30) calendar day average.

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

AQ-68 The project owner shall monitor each Black Rock Unit's controlled gas RTO/scrubber system as follows:

a) The RTO Unit Combustion Chamber operating temperature shall be continuously monitored and data logged every five (5) minutes.

b) The scrubber operation parameters of the scrubber water as re-circulation flow rate and pH shall be logged every five (5) minutes.

c) The project owner monitor on a weekly basis the hydrogen sulfide and benzene at the inlet and at the outlet of the RTO/scrubber system.

i. The project owner shall estimate the hydrogen sulfide and benzene mass flow emission rate in lb/hr and lb/day vented from the RTO/scrubber system. The NCG flow rate shall be determined by a volumetric flow-meter on the scrubber stack.

ii. The project owner shall calculate the RTO control efficiency by measuring hydrogen sulfide and benzene concentration in the non-condensable gas at the inlet of the RTO and the outlet of the RTO.

iii. The project owner shall estimate the scrubber control efficiency for sulfur dioxide by measuring ppmv sulfur dioxide concentration in the non-condensable gas at the outlet of the RTO (inlet to quench) and at the outlet of the scrubber.

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

AQ-69 The project owner shall conduct a source test of the cooling tower hydrogen sulfide emissions within the first 30 days after the commissioning period has ceased and every four years thereafter. The source test shall be conducted in the cooling tower shrouds at each Black Rock Unit. The source testing shall use EPA methods or ICAPCD approved equivalent (using for hydrogen sulfide ARB method 102 modified for Imperial County with NH_3 filter). Testing protocol shall be submitted to the district for approval 30 days prior to source testing being conducted. Annual testing shall be conducted as follows:

a) Total emissions of hydrogen sulfide from each cooling tower shall be estimated in accordance with EPA/ARB approved methods.

b) A 30-day advance notification of testing dates shall be provided to the APCD for scheduling.

Verification: The project owner shall notify the District and the CPM within 30 days before the execution of the source test required in this condition. The first test shall be conducted within 30 days after initial commissioning and the test results shall be submitted to the District and to the CPM within 30 days after test was conducted.

AQ-70 The project owner shall notify the APCD at least 30 days in advance of testing dates for scheduling purposes. All official tests shall be witnessed by an APCD official.

Verification: The project owner shall notify the District and the CPM within 30 working days before the execution of the source tests required by these conditions.

AQ-71 The project owner shall submit to the APCD, an approved H_2S monitoring program for each Black Rock Unit measuring the condensate H_2S off gassing.

Verification: The project owner shall submit the H_2S monitoring program demonstrating compliance with this condition to the APCD for approval and the CPM for review.

AQ-72 The project owner shall secure an H_2S monitor that meets ICAPCD specifications, to be installed, operated and maintained by the APCD at an APCD established monitoring station.

Verification: At least 30 (thirty) days prior to the procurement of the H_2S monitor, which shall be procured before the start of construction, the project owner shall provide the specification of the H_2S monitor and supporting equipment to the District for approval and the CPM for review.

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Appendix AIR-1 - Greenhouse Gas Emissions
Prepared by: William Walters, P.E.

SUMMARY OF CONCLUSIONS

The Black Rock 1, 2, and 3 Geothermal Power Project (BR123) is a geothermal project that would emit considerably less greenhouse gases (GHG) than the existing statewide average GHG emissions per unit of generation and considerably less than the GHG emissions from existing fossil fuel fired power plants providing generation to California, and thus would contribute to continued reduction of GHG emissions in the interconnected California and the western United States electricity systems.

While BR123 would emit some GHG emissions, the contribution of BR123 to the system build-out of renewable resources to meet the goals of the Renewable Portfolio Standard (RPS) in California would result in a net cumulative reduction of energy generation and GHG emissions from new and existing fossil-fired electricity resources. Electricity is produced by operation of inter-connected generation resources. Operation of one power plant, like BR123, affects all other power plants in the interconnected system. BR123 would be a "must-take[18] facility" and its operation would affect the overall electricity system operation and GHG emissions in several ways:

- BR123 would provide low-GHG, renewable generation.
- BR123 would facilitate to some degree the replacement high-GHG-emitting (e.g., out-of-state coal) electricity generation that must be phased out to meet the State's 2006 Emissions Performance Standard.
- BR123 could facilitate to some extent the replacement of generation provided by aging fossil-fired power plants that use once-through cooling.

These system impacts would result in a net reduction in GHG emissions across the electricity system providing energy and capacity to California. Thus, staff concludes that the proposed project would result in a cumulative overall reduction in GHG emissions from power plants, does not worsen current conditions, and would not result in impacts that are cumulatively significant.

Staff concludes that the short-term minor emissions of greenhouse gases during construction that are necessary to create this new low GHG-emitting power generating facility would be sufficiently reduced by "best practices" and would be more than offset by GHG emission reductions during operation. Thus, construction GHG emissions would be less than significant.

The BR123 Project, as a renewable energy generation facility, is determined by rule to comply with the Greenhouse Gas Emission Performance Standard requirements of SB 1368 (Chapter 11, Greenhouse Gases Emission Performance Standard, Article 1, Section 2903 [b][1]).

[18] This refers to the fact that the contract between the owner of this geothermal power facility and the utility will require that the utility take all generation from this facility with little or no provisions for the utility to direct turn down of generation from the facility.

The California Air Resources Board (ARB) has promulgated regulations for mandatory GHG emission reporting to comply with the California Global Warming Solutions Act of 2006 (AB 32 Núñez, Statutes of 2006. Chapter 488, Health and Safety Code sections 38500 et seq.) (ARB 2008a). The BR123 project, which solely generates electricity from a geothermal brine energy source, is exempt from the mandatory GHG emission reporting requirements for electricity generating facilities [CCR Title 17 §95101(c)(1)]. However, the proposed project may be subject to future reporting requirements and GHG reductions or trading requirements as additional state or federal GHG regulations are developed and implemented.

INTRODUCTION

GHG emissions are not criteria pollutants, but they are discussed in the context of cumulative impacts. However, on April 2, 2007, the U.S. Supreme Court found that GHGs are pollutants that must be covered by the federal Clean Air Act. In response, on September 30, 2009, the U.S. Environmental Protection Agency (U.S. EPA) proposed to apply Prevention of Significant Deterioration (PSD) requirements to facilities whose carbon dioxide-equivalent emissions exceed 25,000 tons per year (U.S.EPA 2009). On May 13, 2010, U.S. EPA announced a final rule “tailoring” GHG emissions to PSD requirements (U.S.EPA 2010) and raised the emissions threshold for rule applicability to 100,000 tons per year of carbon dioxide equivalent emissions.

The state has demonstrated a clear willingness to address global climate change through research, adaptation and inventory reductions. In that context, staff evaluates the GHG emissions from the proposed project, presents information on GHG emissions related to electricity generation, and describes the applicable GHG standards and requirements.

Generation of electricity can produce greenhouse gases 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). For geothermal energy generation projects the stationary source GHG emissions are much lower than fossil fuel fired power plants, but the associated maintenance vehicle emissions are higher. Other sources of GHG emissions include 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 carbon-based fuels; other sources of GHG emissions are small and also are more likely to be easily controlled or reused or recycled, but are nevertheless documented here as some of the compounds have very high 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 (CO2E) 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 proposed 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 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.
California Code of Regulations, tit. 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 AND ELECTRICITY PRODUCTION

There is general scientific consensus that climate change is occurring and that human activity contributes in some measure (perhaps substantially) 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 global 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 California Energy Commission (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 GHG or global climate change[19] 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

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

emissions to statewide GHG emissions levels in 1990, with such reductions to be achieved by 2020.[20] 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 major 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 (ARB 2006). The regulations must be effective by January 1, 2011 and mandatory compliance commences on January 1, 2012. The mandatory reporting requirements are effective for electric generating facilities with a nameplate capacity equal or greater than 1 megawatt (MW) capacity if their emissions exceed 2,500 metric tonnes per year. The due date for initial reports by existing facilities was June 1, 2009.

Examples of strategies that the state might pursue for managing GHG emissions in California, in addition to those recommended by the Energy Commission and the Public Utilities Commission, 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 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), land use planning and alternatives to petroleum-based fuels are slated to provide substantial reductions by 2020 (CalEPA 2006). The scoping plan includes a requirement for 33% of California's electrical energy to be provided from renewable sources (such as BR123) by 2020 (implementing California's 33% RPS goal), aggressive energy efficiency targets, and a cap-and-trade system that includes the electricity sector (ARB 2008b).

It is likely that GHG reductions mandated by ARB will not be uniform across emitting sectors, in that reductions will be based on cost-effectiveness (i.e., the greatest effect for the least cost). For example, the ARB proposes a 40 percent reduction in GHG from the electricity sector, even though that sector currently only produces about 25 percent 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.

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

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

percent renewable portfolio standard. The Energy Commission's *2009 Integrated Energy Policy Report* continues to emphasize the importance of meeting greenhouse gas emissions reduction goals along with other important statewide issues such as backing out use of once-through cooling in coastal California power plants (CEC 2009d).

SB 1368[21], enacted in 2006, and regulations adopted by the Energy Commission and the Public Utilities Commission pursuant to the bill, prohibits California utilities from entering into long-term commitments with any base load facilities that exceed the Emission Performance Standard of 0.500 metric tonnes CO_2 per megawatt-hour[22] (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.[23] If a project, instate or out of state, plans to sell base load electricity to a California utility, that utility will have to demonstrate that the project meets the EPS. *Base load* units are defined as units that operate at a capacity factor higher than 60 percent. As a renewable electricity generating facility, BR123 is determined by rule to be compliant with the SB 1368 EPS.

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

ELECTRICITY PROJECT GREENHOUSE GAS EMISSIONS

Electricity use can be as simple as turning on a switch to operate a light or fan. The system to deliver adequate and reliable electricity supply is complex and variable. But it operates as an integrated whole to meet demand, such that the dispatch of a new source of generation generally curtails or displaces one or more less efficient or less competitive existing sources. Within the system, generation resources provide electricity, or energy, generating capacity, and ancillary services to stabilize the system and facilitate electricity delivery, or movement, over the grid. *Capacity* is the instantaneous output of a resource, in megawatts. *Energy* is the capacity output over a unit of time, for example an hour or year, generally reported as megawatt-hours or gigawatt-hours (GWh). Ancillary services[24] include regulation, spinning reserve, non-spinning reserve, voltage support, and black start capability. Individual generation resources can be built and operated to provide only one specific service. Alternatively, a resource may be able to provide one or all of these services, depending on its design and constantly changing system needs and operations.

[21] Public Utilities Code § 8340 et seq.

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

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

[24] See page CEC 2009b, p. 95.

California is actively pursuing policies to reduce GHG emissions that include adding non-GHG emitting renewable generation resources to the system mix. The generation of electricity using fossil fuels, even in a back-up generator at a geothermal power plant, produces air emissions known as greenhouse gases in addition to the criteria air pollutants that have been traditionally regulated under the federal and state Clean Air Acts. Greenhouse gas emissions contribute to the warming of the earth's atmosphere, leading to climate change.

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 would last approximately 53 months. Prior to commercial operation each power block will also require an initial commissioning period, which as a one-time pre-operation event has been added to the construction emissions. The GHG emissions from initial commissioning are from flow back, production well testing, and injection and plant well testing operations, where the primary GHG emissions are CO_2 that is directly released from the brine during these activities. The greenhouse gas emissions estimate for the entire construction and initial commissioning period, provided by the project owner is below in **Greenhouse Gas Table 2**.

Greenhouse Gas Table 2
BR123 Construction and Initial Commissioning Greenhouse Gas Emissions

Construction Element	CO_2 Equivalent (MTCO2E) [a,b]
Earthwork Construction[b]	2,338
Power Block Construction[b]	12,572
Well Construction[b]	8,174
Initial Commissioning	2,183
Construction and Initial Commissioning Total	25,267

Sources: CE Obsidian/AECOM 2009, Appendix E Table 2.19; CE Obsidian/CH2MHILL 2009a, DR #24
a - One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms
b - The vast majority of the CO2E emissions from these sources, over 99 percent, are CO_2 from construction combustion sources.

PROJECT OPERATIONS

Operations GHG emissions are shown in **Greenhouse Gas Table 3**. Operation of the BR123 would cause GHG emissions from a number of direct and indirect sources. The normal operating direct emission sources include the non-condensable gas (NCG) streams, including the RTO burners and the startup and shutdown emissions from flow to the rock muffler. The indirect sources include the emergency generators and fire pumps, operations and maintenance vehicles, delivery and employee vehicles, and fugitive leaks from electrical equipment. Most of GHG emissions would be emitted from the NCG, which is known to contain CO_2 and CH_4. The RTO will not control CO_2 emissions, but will control the CH_4 emissions with 99.9 percent control efficiency.

Greenhouse Gas Table 3
BR123 Project Operation Greenhouse Gas Emissions

	Annual CO_2-Equivalent (MTCO2E) [a]
Normal Operations[b]	165,716
Emergency Generators[b]	105
Fire Pumps[b]	5
Well Drilling[b]	1,407
O&M Equipment[b]	51
Delivery Vehicles[b]	125
Employee Vehicles[b]	533
Equipment Leakage (SF_6) [e]	18
Total Project GHG Emissions – MTCO2E[c]	**167,960**
Facility MWh per year[d]	1,392,840
Facility GHG Emission Rate (MTCO2E/MWh)	0.1206

Sources: CE Obsidian/AECOM 2009, Appendix E Table 2.19; CE Obsidian/CH2MHILL 2009a, DRs #4 and 25.
a - One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms
b - The vast majority of the CO2E emissions, over 99 percent, are CO_2 from these sources.
c – The GHG emission basis is conservative as it includes both full-time (8,760 hours/year) operating emissions along with startup and shutdown emissions.
d – Based on 8,760 hours per year with net generation of 159 MW per hour, which is the same basis that was used for the emissions calculations.
e – Project owner estimated a total inventory of 34 pounds of SF_6 and staff is assuming a conservative leakage rate of 0.5% per year with the GHG CO_2 equivalency of 23,900 for SF_6.

The proposed project is estimated to emit, directly from primary and secondary emission sources on an annual basis, nearly 168,000 metric tonnes of CO_2-equivalent GHG emissions per year. BR123, as a renewable energy generation facility, is determined by rule to comply with the Greenhouse Gas Emission Performance Standard requirements of SB 1368 (Chapter 11, Greenhouse Gases Emission Performance Standard, Article 1, Section 2903 [b][1]). Regardless, BR123 has an estimated GHG emission rate of 0.1206 MTCO2E/MWh, well below the Greenhouse Gas Emission Performance Standard of 0.500 $MTCO_2$/MWh.

Geothermal Project Energy Payback Time

The beneficial energy and greenhouse gas impacts of renewable energy projects can also be measured by the *energy payback time*[25]. **Greenhouse Gas Tables 2** and **3** provide an estimate of the onsite construction and operation emissions, employee transportation emissions, and the final segment of offsite materials and consumables transportation. However, there are additional direct transportation and indirect manufacturing GHG emissions associated with the construction and operation of the proposed project, which are all considered in the determination of the energy payback time. A document sponsored by Greenpeace estimates that the energy payback time for concentrating solar power plants, which have a much smaller capacity factor than BR123 and significant construction and materials fabrication requirements, to be on the order of 5 months (Greenpeace 2005, Page 9). Staff would assume that the energy

[25] The energy payback time is the time required to produce an amount of energy as great as what was consumed during production, which in the context of a geothermal power plant includes all of the energy required during construction and operation.

payback time for this type of geothermal project would be a similarly short period of time, and the project life for BR123 is on the order of 30 years. Therefore, the proposed project's GHG emissions reduction potential from energy displacement would be substantial[26].

CLOSURE AND DECOMMISSIONING

Closure and decommissioning, as a one-time limited duration event, would have emissions that are similar in type and magnitude, but likely lower than, the construction emissions as discussed above.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assesses four kinds of impacts: construction, operation, closure and decommissioning, and cumulative effects. As the name implies, construction impacts result from the emissions occurring during the construction of the proposed project. The operation impacts result from the emissions of the proposed project during operation. Cumulative impacts analysis assesses the impacts that result from the proposed project's incremental effect viewed over time. The impact of GHG emissions caused by this geothermal facility is characterized by considering how the power plant would affect the overall electricity system. The integrated electricity system depends on non-fossil and fossil-fueled generation resources to provide energy and satisfy local capacity needs. As directed by the Energy Commission's adopted order initiating an informational (OII) proceeding (08-GHG OII-1) (CEC 2009a), staff is refining and implementing the concept of a "blueprint" that describes the long-term roles (i.e., retirements and displacement) of fossil-fueled power plants in California's electricity system as we move to a high-renewable, low-GHG electricity system, which will include projects like BR123.

PROPOSED PROJECT

Construction Impacts

Staff concludes that the GHG emission increases from construction activities would not be significant for several reasons. First, the period of construction would be short-term and the emissions intermittent during that period, not ongoing during the life of the proposed project. Second, best practices control measures that staff recommends, such as limiting idling times and requiring, as appropriate, equipment that meets the latest emissions standards would further minimize greenhouse gas emissions since the use of newer equipment would increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of the ARB regulations to reduce GHG from construction vehicles and equipment. And lastly, these temporary GHG emissions are necessary to create this renewable energy source that would provide power with a very low GHG emissions

[26] The GHG displacement for the project would be similar to, but not exactly the same as, the amount of energy produced after energy payback is achieved multiplied by the average GHG emissions per unit of energy displaced. The average GHG emissions for the displaced energy over the project life is not known but currently fossil fuel fired power plants have GHG emissions that range from 0.35 MT/MWh CO2E for the most efficient combined cycle gas turbine power plants to over 1.0 MT/MWh CO2E for coal fired power plants.

profile, and the construction emissions would be more than offset by the reduction in fossil fuel fired generation that would be enabled by this proposed project. If the proposed project's construction and initial commissioning emissions were distributed over the estimated 30 year life of the proposed project they would only increase the project life time annual facility GHG emissions rate by 0.0006 MT CO2E per MWh.

Direct/Indirect Operation Impacts and Mitigation

The proposed BR123 promotes the state's efforts to move towards a high-renewable, low-GHG electricity system, and, therefore, reduces both the amount of natural gas used by electricity generation and greenhouse gas emissions.

Net GHG emissions for the integrated electric system will decline when new renewable power plants are added to: 1) move renewable generation towards the 33 percent target; 2) improve the overall efficiency, or GHG emission rate, of the electric system; or 3) serve load growth or capacity needs more efficiently, or with fewer GHG emissions.

The Role of BR123 in Renewables Goals/Load Growth

As California moves towards an increased reliance on renewable energy by implementing the Renewables Portfolio Standard (RPS), non-renewable energy resources will be displaced. These reductions in non-renewable energy, shown in **Greenhouse Gas Table 4**, are targeted to be as much as 36,500 GWh. These assumptions are conservative in that the forecasted growth in electricity retail sales assumes that the impacts of planned increases in expenditures on (uncommitted) energy efficiency are already embodied in the current retail sales forecast[27]. Energy Commission staff estimates that as much as 18,000 GWh of additional savings due to uncommitted energy efficiency programs may be forthcoming.[28] This would reduce non-renewable energy needs by a further 12,000 GWh given a 33 percent RPS.

[27] Energy efficiency savings are already represented in the current Energy Commission demand forecast adopted December 2009 (CEC 2009c).

[28] See *Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast* (CEC-200-2010-001-D, January, 2010), page 2. Table 1 indicates that additional conservation for the three investor-owned utilities may be as high as 14,374 GWh. Increasing this value by 25 percent to account for the state's publicly-owned utilities yields a total reduction of 17,967 GWh.

Greenhouse Gas Table 4
Estimated Changes in Non-Renewable Energy Potentially Needed to Meet California Loads, 2008-2020

California Electricity Supply	**Annual GWh**	
Statewide Retail Sales, 2008, actual [a]	264,794	
Statewide Retail Sales, 2020, forecast [a]	289,697	
Growth in Retail Sales, 2008-20	24,903	
Growth in Net Energy for Load [b]	29,840	
California Renewable Electricity	**GWh @ 20% RPS**	**GWh @ 33% RPS**
Renewable Energy Requirements, 2020 [c]	57,939	95,600
Current Renewable Energy, 2008	29,174	
Change in Renewable Energy-2008 to 2020	28,765	66,426
Resulting Change in Non-Renewable Energy	176	(36,586)

Source: Energy Commission staff 2010.
Notes:
a. 2009 IEPR Demand Forecast, Form 1.1c. Excludes pumping loads for entities that do not have an RPS.
b. 2009 IEPR Demand Forecast, Form 1.5a.
c. RPS requirements are a percentage of retail sales.

The Role of BR123 in Retirements/Replacements

BR123 would be capable of annually providing 1,393 GWh of renewable generation energy to replace resources that are or will likely be precluded from serving California loads. State policies, including GHG goals, are discouraging or prohibiting new contracts and new investments in high GHG-emitting facilities such as coal-fired generation, generation that relies on water for once-through cooling, and aging power plants (CEC 2007). Some of the existing plants that are likely to require substantial capital investments to continue operation in light of these policies may be unlikely to undertake the investments and will retire or be replaced.

Replacement of High GHG-Emitting Generation

High GHG-emitting resources, such as coal, are effectively prohibited from entering into new long-term contracts for California electricity deliveries as a result of the Emissions Performance Standard adopted in 2007 pursuant to SB 1368. Between now and 2020, more than 18,000 GWh of energy procured by California utilities under these contracts will have to reduce GHG emissions or be replaced; these contracts are presented in **Greenhouse Gas Table 5**.

Greenhouse Gas Table 5
Expiring Long-term Contracts with Coal-fired Generation 2009 – 2020

Utility	Facility [a]	Contract Expiration	Annual GWh Delivered to CA
PG&E, SCE	Misc In-state Qual.Facilities [a]	2009-2019	4,086
LADWP	Intermountain	2009-2013	3,163 [b]
City of Riverside	Bonanza, Hunter	2010	385
Department of Water Resources	Reid Gardner	2013 [c]	1,211
SDG&E	Boardman	2013	555
SCE	Four Corners	2016	4,920
Turlock Irrigation District	Boardman	2018	370
LADWP	Navajo	2019	3,832
TOTAL			18,522

Source: Energy Commission staff based on Quarterly Fuel and Energy Report (QFER) filings.
Notes:
a. All facilities are located out-of-state except for the Miscellaneous In-state Qualifying Facilities.
b. Estimated annual reduction in energy provided to LADWP by Utah utilities from their entitlement by 2013.
c. Contract not subject to Emission Performance Standard, but the Department of Water Resources has stated its intention not to renew or extend.

This represents almost half of the energy associated with California utility contracts with coal-fired resources that will expire by 2030. If the State enacts a carbon adder[29], all the coal contracts (including those in **Greenhouse Gas Table 5**, which expire by 2020 and, other contracts that expire beyond 2020 and are not shown in the table) may be retired at an accelerated rate as coal-fired energy becomes uncompetitive due to the carbon adder or the capital needed to capture and sequester the carbon emissions. Also shown are the approximate 500 MW of in-state coal and petroleum coke-fired capacity that may be unlikely to contract with California utilities for baseload energy due to the SB1368 Emission Performance Standard. As these contracts expire, new and existing generation resources will replace the lost energy and capacity. Some will come from renewable generation such as this proposed project; some will come from new and existing natural gas fired generation. All of these new facilities will have substantially lower GHG emissions rates than coal and petroleum coke-fired facilities which typically average about 1.0 $MTCO_2$/MWh without carbon capture and sequestration. Thus, new renewable facilities will result in a net reduction in GHG emissions from the California electricity sector.

Retirement of Generation Using Once-Through Cooling

The State Water Resource Control Board (SWRCB) has proposed major changes to once-through cooling (OTC) units, shown in **Greenhouse Gas Table 6**, which would likely require extensive capital to retrofit, or retirement, or substantial curtailment of dozens of generating units. In 2008, these units collectively produced almost 58,000 GWh. While the more recently built OTC facilities may well install dry or wet cooling towers and continue to operate, the aging OTC plants are not likely to be retrofit to use dry or wet cooling towers without the power generation also being retrofit or replaced to

[29] A carbon adder or carbon tax is a specific value added to the cost of a project for per ton of associated carbon or carbon dioxide emissions. Because it is based on, but not limited to, actual operations and emission and can be trued up at year end, it is considered a simple mechanism to assign environmental costs to a project.

use a more efficient and lower GHG emitting combined cycle gas turbine technology. Most of these existing OTC 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.

Any additional costs associated with complying with the SWRCB regulation would be amortized over a limited revenue stream today and into the foreseeable future. Their energy and much of their dispatchable, load-following capability will have to be replaced. These units constitute over 15,000 MW of merchant capacity and 17,800 GWh of merchant energy. Of this, much but not all of the capacity and energy are in local reliability areas, requiring a large share of replacement capacity – absent transmission upgrades – to locations in the same local reliability area. **Greenhouse Gas Table 6** provides a summary of the utility and merchant energy supplies affected by the OTC regulations.

New renewable generation resources will emit substantially less GHG emissions on average than other energy generation sources. Existing aging and OTC natural gas facility generation typically averages 0.6 to 0.7 $MTCO_2$/MWh, which is much less efficient, higher GHG emitting, than a renewable energy project like BR123. A project like BR123 located far from the coastal load pockets like the Los Angeles Local Reliability Area (LRA), would more likely provide energy support to facilitate the retirement of some aging and/or OTC power plants, but would not likely provide any local capacity support at or near the coastal OTC units. Regardless, due to its low greenhouse gas emissions, BR123 would serve to reduce GHG emissions from the electricity sector.

Closure and Decommissioning

Eventually the facility would close, either at the end of its useful life or due to some unexpected situation such as a natural disaster or catastrophic facility breakdown. When the facility closes, all sources of air emissions would cease to operate and thus impacts associated with those greenhouse gas emissions would no longer occur. The only other expected, albeit temporary, GHG emissions would be equipment exhaust (off-road and on-road) from dismantling activities. These activities would be of a much shorter duration than construction of the proposed project. Equipment used to dismantle the facility are assumed to have lower comparative GHG emissions due to technology advancement, and would be required to be controlled in a manner at least equivalent to that required during construction. It is assumed that the beneficial GHG impacts of this facility, displacement of fossil fuel fired generation, would be replaced by the construction of newer more efficiency renewable energy or other low GHG generating technology facilities. Also, the recycling of the facility components (steel, concrete, etc.) could indirectly reduce GHG emissions from decommissioning activities. Therefore, while there would be temporary adverse greenhouse gas impacts during decommissioning they are determined to be less than significant.

Greenhouse Gas Table 6
Aging and Once-Through Cooling Units: 2008 Capacity and Energy Output [a]

Plant, Unit Name	Owner	Local Reliability Area	Aging Plant?	Capacity (MW)	2008 Energy Output (GWh)	GHG Emission Rate ($MTCO_2$/MWh)
Diablo Canyon 1, 2	Utility	None	No	2,232	17,091	Nuclear
San Onofre 2, 3	Utility	L.A. Basin	No	2,246	15,392	Nuclear
Broadway 3 [b]	Utility	L.A. Basin	Yes	75	90	0.648
El Centro 3, 4 [b]	Utility	None	Yes	132	238	0.814
Grayson 3-5 [b]	Utility	LADWP	Yes	108	150	0.799
Grayson CC [b]	Utility	LADWP	Yes	130	27	0.896
Harbor CC	Utility	LADWP	No	227	203	0.509
Haynes 1, 2, 5, 6	Utility	LADWP	Yes	1,046	1,529	0.578
Haynes CC	Utility	LADWP	No	560	3,423	0.376
Humboldt Bay 1, 2 [a]	Utility	Humboldt	Yes	107	507	0.683
Olive 1, 2 [b]	Utility	LADWP	Yes	110	11	1.008
Scattergood 1-3	Utility	LADWP	Yes	803	1,327	0.618
Utility-Owned [c]				7,776	39,988	0.693
Alamitos 1-6	Merchant	L.A. Basin	Yes	1,970	2,533	0.661
Contra Costa 6, 7	Merchant	S.F. Bay	Yes	680	160	0.615
Coolwater 1-4 [b]	Merchant	None	Yes	727	576	0.633
El Segundo 3, 4	Merchant	L.A. Basin	Yes	670	508	0.576
Encina 1-5	Merchant	San Diego	Yes	951	997	0.674
Etiwanda 3, 4 [b]	Merchant	L.A. Basin	Yes	666	848	0.631
Huntington Beach 1, 2	Merchant	L.A. Basin	Yes	430	916	0.591
Huntington Beach 3, 4	Merchant	L.A. Basin	No	450	620	0.563
Mandalay 1, 2	Merchant	Ventura	Yes	436	597	0.528
Morro Bay 3, 4	Merchant	None	Yes	600	83	0.524
Moss Landing 6, 7	Merchant	None	Yes	1,404	1,375	0.661
Moss Landing 1, 2	Merchant	None	No	1,080	5,791	0.378
Ormond Beach 1, 2	Merchant	Ventura	Yes	1,612	783	0.573
Pittsburg 5-7	Merchant	S.F. Bay	Yes	1,332	180	0.673
Potrero 3	Merchant	S.F. Bay	Yes	207	530	0.587
Redondo Beach 5-8	Merchant	L.A. Basin	Yes	1,343	317	0.810
South Bay 1-4	Merchant	San Diego	Yes	696	1,015	0.611
Merchant-Owned [c]				15,254	17,828	0.605
Total In-State OTC				23,030	57,817	

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

a. OTC Humboldt Bay Units 1 and 2 are included in this list. They must retire in 2010 when the new Humboldt Bay Generating Station (not ocean-cooled), currently under construction, enters commercial operation.

b. Units are aging but are not OTC.

c. The GHG Emission Rates presented here are non-weighted facility averages that do not include the two nuclear facilities.

CUMULATIVE IMPACTS

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

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

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

BR123, as a renewable energy generation project, is exempt from the mandatory GHG emission reporting requirements for electricity generating facilities as currently required by the California Air Resources Board (ARB) for compliance with the California Global Warming Solutions Act of 2006. (AB 32 Núñez, Statutes of 2006, Chapter 488, Health and Safety Code sections 38500 et seq.) (ARB 2008a)

BR123, as a renewable energy generation facility, is determined by rule to comply with the Greenhouse Gas Emission Performance Standard requirements of SB 1368 (Chapter 11, Greenhouse Gases Emission Performance Standard, Article 1, Section 2903 [b][1]).

Since BR123 would have emissions that are above 25,000 MT/year of CO2E, the proposed project would be subject to federal mandatory reporting of greenhouse gases. Additionally, the proposed project would also be subject to the federal air quality permitting requirements of the new PSD and Title V Tailoring Rule that has a CO2E emissions trigger of 100,000 tons per year.

NOTEWORTHY PUBLIC BENEFITS

Greenhouse gas related noteworthy public benefits include the construction of renewable and low-GHG emitting generation technologies and the potential for successful integration into the California and greater WECC electricity systems. Additionally, the BR123 project would contribute to meeting the state's AB32 goals.

CONCLUSIONS

The Black Rock 1, 2, and 3 Geothermal Power Project would emit considerably less greenhouse gases (GHG) than existing power plants and most other generation technologies, and thus would contribute to continued improvement of the overall western United States, and specifically California, electricity system GHG emission rate average. The proposed project would lead to a net reduction in GHG emissions across the electricity system that provides energy and capacity to California. Thus, staff concludes that the proposed project's operation would result in a cumulative overall reduction in GHG emissions from the state's power plants that would create a beneficial effect, would not worsen current conditions, and would thus not result in impacts that are cumulatively significant.

Staff concludes that the GHG emission increases typical from construction and decommissioning activities would not be significant for several reasons. First, the periods of construction and decommissioning would be short-term and not ongoing during the life of the proposed project. Second, the best practices control measures that staff recommends, such as limiting idling times and requiring, as appropriate, equipment that meets the latest emissions standards, would further minimize greenhouse gas emissions since the use of newer equipment would increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of the ARB regulations to reduce GHG from construction vehicles and equipment. Finally, the construction and decommissioning emissions are miniscule when compared to the reduction in fossil-fuel power plant greenhouse gas emissions during project operation. For all these reasons, staff would conclude that the short-term emission of greenhouse gases during construction would be sufficiently reduced and would be offset during proposed project operations and would, therefore, not be significant.

The Black Rock 1, 2, and 3 Geothermal Power Plant, as a renewable energy generation facility, is determined by rule to comply with the Greenhouse Gas Emission Performance Standard requirements of SB 1368 (Chapter 11, Greenhouse Gases Emission Performance Standard, Article 1, Section 2903 [b][1]).

MITIGATION MEASURES/PROPOSED CONDITIONS OF CERTIFICATION

No Conditions of Certification related to project greenhouse gas emissions are proposed because none are needed beyond those already required in the Air Quality Section. The project owner would have to comply with any future applicable GHG regulations formulated by the ARB or the U.S.EPA, such as GHG reporting or emissions cap and trade markets. The project will have to report GHG emissions under federal reporting requirements and obtain a PSD/Title V permit for GHG emissions based on currently approved regulations. However, the recommended staff and District conditions in the Air Quality section already require that the project owner provide the Energy Commission with copies of required GHG emission estimates (**AQ-28**) and federal air quality permit applications and permits (**AQ-SC6**).

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ACRONYMS

AAQS	Ambient Air Quality Standard
AERMOD	ARMS/EPA Regulatory Model
AFC	Application for Certification
APCD	Air Pollution Control District (ICAPCD)
APCO	Air Pollution Control Officer
AQCMM	Air Quality Construction Mitigation Manager
AQCMP	Air Quality Construction Mitigation Plan
AQMP	Air Quality Management Plan
ARB	California Air Resources Board
ARM	Ambient Ratio Method
ATC	Authority to Construct
ATCM	Airborne Toxic Control Measures
BACM	Best Available Control Measures
BACT	Best Available Control Technology
BR123	Black Rock 1, 2, and 3 Geothermal Power Project
CalEPA	California Energy Commission
CCR	California Code of Regulation
CEC	California Energy Commission (or Energy Commission)
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CH_4	Methane
ChemOx	Chemical Oxidation Process
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO2E	Carbon Dioxide Equivalent
COC	Conditions of Certification
CPM	(CEC) Compliance Project Manager
CPUC	California Public Utilities Commission
CTG	Control Techniques Guideline
DOC	Determination of Compliance
EIR	Environmental Impact Report
EPS	Emission Performance Standard
FDOC	Final Determination Of Compliance
GCC	Global Climate Change
GHG	Greenhouse Gas
GPM	Gallon per minute
GWh	Gigawatt-hour
HFCs	Hydrofluorocarbons
H_2S	Hydrogen Sulfide
hp	Horsepower
HSC	Health and Safety Code

ICAPCD	Imperial County Air Pollution Control District
IDLH	Immediately Dangerous to Life and Health
IEPR	Integrated Energy Policy Report
ISCST3	Industrial Source Complex Short Term, version 3
kW	Kilowatts (1,000 watts)
lbs	Pounds
LADWP	Los Angeles Department of Water and Power
LORS	Laws, Ordinances, Regulations and Standards
LRA	Local Reliability Area
µg	Microgram
$\mu g/m^3$	Microgram per cubic meter
mg/m^3	Milligrams per cubic meter
MT	Metric tonnes
MW	Megawatts (1,000,000 Watts)
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standard
NCG	Non Condensable Gas
NH_3	Ammonia
N_2O	Nitrous Oxide
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen or Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O_2	Oxygen
O_3	Ozone
OB-3	Obsidian Butte
OII	Order Initiating an Informational
OLM	Ozone Limiting Method
O&M	Operation and Maintenance
OTC	Once Through Cooling
PDOC	Preliminary Determination Of Compliance
PFC	Perfluorocarbons
PGF	Power Generating Facility
PM	Particulate Matter
PM10	Particulate Matter less than 10 microns in diameter
PM2.5	Particulate Matter less than 2.5 microns in diameter
ppm	Parts Per Million
ppmv	Parts Per Million by Volume
ppmvd	Parts Per Million by Volume, Dry
PSD	Prevention of Significant Deterioration
psia	Pound per square inch absolute
PTO	Permit to Operate

PTU	Production Test Unit
QFER	Quarterly Fuel and Energy Report
RACM	Reasonably Available Control Measures
RACT	Reasonably Available Control Technology
ROC	Reactive Organic Compounds
RPF	Resource Production Facility
RPS	Renewable Portfolio Standard
RTO	Regenerative Thermal Oxidizer
RTP	Regional Transportation Plan
SAM	Sulfur Acid Mist
SB	Senate Bill
SCAG	Southern California Association of Government
SF_6	Sulfur hexafluoride
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_4	Sulfate
SOx	Oxides of Sulfur
SSAB	Salton Sea Air Basin
SSKGRA	Salton Sea Known Geothermal Resource Area
SSU6	Salton Sea Unit 6
STG	Steam Turbine Generator
SWPPP	Storm Water Pollution Prevention Plan
SWRCB	State Water Resource Control Board
TDS	Total Dissolved Solid
TFV	Thresholds Friction Velocity
tpy	Tons per year
U.S.EPA	United States Environmental Protection Agency
VDE	Visible Dust Emission
VOC	Volatile Organic Compounds
WECC	Western Electricity Coordinating Council

BIOLOGICAL RESOURCES

Testimony of Misa Milliron and Rick York

INTRODUCTION

This analysis addresses project changes that would potentially affect biological resources in the project area. This analysis examines only those aspects of the Black Rock 1, 2, and 3 Geothermal Power Project (BR123) that would change because of the proposed amendment seeking to relocate production well facilities and expand the power plant site by an additional 80 acres, and that affect staff's testimony for Biological Resources as contained in the Commission Decision dated December 19, 2003 (CEC 2003a). No new biological resource impacts would occur as a result of the amended project. Previously analyzed impacts would change in their physical location or magnitude.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS) COMPLIANCE

There are no new or changed biological resource laws, ordinances, regulations, and standards (LORS) that would be applicable to the amended project as proposed.

ANALYSIS

This analysis is based, in part, on information provided in the Salton Sea Geothermal Unit #6 Power Project Petition for License Amendment (CE Obsidian/AECOM 2009a), the original siting case documents (Docket No. 02-AFC-02), and discussions with the applicant and consultants, U.S. Fish and Wildlife Service (USFWS), and the California Department of Fish and Game (CDFG).

SETTING

In support of the proposed amendment, the applicant's consultants completed biological resource surveys of the proposed project area on the following dates: September 23, 2008, October 7 through 9, 2008, November 7 through 9, 2008, December 24, 2008, and August 24 through August 27, 2009. The habitats/cover types present within the amended project footprint include roadway/agricultural ditch, developed areas, agricultural lands, and tamarisk scrub. Other habitats found within the one-mile survey buffer around the amended project footprint include desert sink scrub, freshwater wetland, open water of the Salton Sea, salt pan, and barren land.

<u>Special-Status Species</u>

Consultants to the applicant conducted reconnaissance-level wildlife and floristic surveys of the project site and a habitat suitability assessment for special-status species within a one-mile radius of the amended project footprint. California Natural Diversity Database (CNDDB) (CDFG 2009a) and California Native Plant Society's Online Inventory (CNPS 2009) searches were also conducted. **BIOLOGICAL RESOURCES Table 1** identifies special-status species that have the potential to be present within the vicinity of the project area.

BIOLOGICAL RESOURCES Table 1
Special-Status Species Identified as Potentially Occurring in the Vicinity of the Amended Project Site

Common Name	Scientific Name	Status*
Plants		
Abrams' spurge	*Chamaesyce abramsiana*	CNPS 2.2
Birds		
burrowing owl	*Athene cunicularia hypugaea*	CSC
mountain plover	*Charadrius montanus*	CSC
black tern	*Chlidonias niger*	CSC
Northern harrier	*Circus cyaneus*	CSC
yellow warbler	*Dendroica petechia brewsteri*	CSC
southwestern willow flycatcher	*Empidonax traillii* extimus	FE,CE
gull-billed tern	*Gelochelidon nilotica*	CSC
Caspian tern	*Hydroprogne caspia*	--
yellow-breasted chat	*Icteria virens*	CSC
least bittern	*Ixobrychus exilis*	CSC
loggerhead shrike	*Lanius ludovicianus*	CSC
California gull	*Larus californicus*	WL
California black rail	*Laterallus jamaicensis coturniculus*	CT, FP
California brown pelican	*Pelecanus occidentalis californicus*	FE, CE, FP
white-faced ibis	*Plegadis chihi*	WL
black-tailed gnatcatcher	*Polioptila melanura*	--
Yuma clapper rail	*Rallus longirostris yumanensis*	FE, CT, FP
black skimmer	*Rynchops niger*	CSC
Crissal thrasher	*Toxostoma crissale*	CSC
Le Conte's thrasher	*Toxostoma lecontei*	CSC
least Bell's vireo	*Vireo bellii pusillus*	FE, CE
Fish		
Desert pupfish	*Cyprinodon macularius*	FE, CE
razorback sucker	*Xyrauchen texanus*	FE, CE, FP
Amphibians and Reptiles		
Colorado River toad	*Incilius alvarius*	CSC
lowland (=Yavapai, San Sebastian & San Felipe) leopard frog	*Lithobates yavapaiensis*	CSC
flat-tailed horned lizard	*Phyrynosoma mcallii*	CSC
Mammals		
California mastiff bat	*Eumops perotis californicus*	CSC
California leaf-nosed bat)	*Macrotus californicus*	CSC
Townsend's big-eared bat	*Plecotus townsendii*	CSC
American badger	*Taxidea taxus*	CSC

* Status legend:
CNPS 2.2 = plants rare, threatened, or endangered in California, but more common elsewhere; fairly threatened.
FE = federally endangered
CE = state endangered
CT = state threatened
CSC = state species of special concern
FP = state fully protected animal
WL = CDFG Watch List
-- = no status listed in CNDDB (species for which dashes are shown for both federal and state status are included by CNDDB because of declining trends)
Sources: CDFG 2009a, CNPS 2009.

The applicant's surveys reported that suitable habitat for most special-status species with potential to occur onsite is lacking. Special-status plant species are not expected to occur in the project area. The CNDDB and CNPS database searches identified only one plant species, Abrams' spurge, known to occur in the general vicinity. However, the nearest occurrence is approximately 7 miles to the northeast of the project. This species was determined to have no potential to occur on site due to the site's level of disturbance and the resulting lack of suitable habitat (Mojavean desert scrub or Sonoran desert scrub) and environmental conditions to support it.

Special-status wildlife species were not observed in the project footprint during biological surveys for the amended project. However, one burrowing owl and suitable habitat for burrowing owl, Yuma clapper rail, and mountain plover were documented adjacent to the project. One potential burrowing owl burrow was located within 500 feet of the proposed power plant site boundary, and one burrow with recent sign was located near injection well pad OB-1. The burrowing owl individual was observed within 500 feet of injection pipeline OB-1. Although no Yuma clapper rails were observed during 2008 surveys, suitable habitat consisting of freshwater wetland occurs adjacent to the northwest corner of the power plant site. The northwest corner of the power plant site is also mapped by the CNDDB as a mountain plover occurrence, which extends along the shore of the Salton Sea, which is approximately 500 feet northwest of the amended project at its closest point. Agricultural land on the proposed project site and vicinity provides foraging habitat for overwintering migratory birds (including birds of prey) and waterfowl.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

IMPACTS

The amended project would require a larger acreage but result in reduced impacts to biological resources compared to the original project. First, the impact to the Yuma clapper rail habitat located near McKendry Road, 0.18 acre of federally jurisdictional wetland, 0.3 acre of state jurisdictional wetland, and well pads near the Sonny Bono Salton Sea National Wildlife Refuge would no longer occur due to the relocation of all production wells and associated pipelines to the power plant site and the elimination of changes to McKendry Road. Secondly, construction of the amended project would result in reduced noise and vibration impacts to Yuma clapper rail during the breeding season due to the relocation of well facilities and because pile-driving activities would occur further from the northwestern corner of the power plant site. However, construction noise from pile driving in the northwest corner of the power plant site could exceed the U.S. Fish and Wildlife Service (USFWS) significance threshold of 60dBA Leq during the breeding season. Finally, burrowing owl burrows were located outside the project footprint, and based on more recent survey results, impacts to this species are not expected to differ significantly from the original project.

MITIGATION

During the licensing of the original project, the applicant received a federal Biological Opinion from the USFWS to mitigate the original project's possible effects to Yuma clapper rail and its habitat. The Biological Opinion was issued in 2004, and remains in force (CE Obsidian, LLC 2009b). The original project required a state Incidental Take Permit in Biological Resources Condition of Certification **BIO-7**; however CDFG has since determined that the amended project does not need this permit (CDFG 2009b). CDFG does not issue Incidental Take Permits for the Yuma clapper rail due to its "Fully Protected" status, and the project's indirect impacts would not constitute take, therefore this permit is not needed and staff proposes the elimination of Condition of Certification **BIO-7**. In addition, Condition of Certification **BIO-16** calls for a Noise and Vibration Assessment and Abatement Plan, which would contain measures to reduce/mitigate construction noise and vibration impacts to Yuma clapper rail (during the breeding season) and other sensitive wildlife. New noise measurement locations would have to be determined based on the recommendations of USFWS due to the relocation of facilities farther from sensitive species habitat.

The applicant was required to secure a conservation easement related to the restoration and creation of wetland habitat due to the previous project's fill of wetlands along McKendry Road. The amended project will no longer impact this wetland habitat; therefore, staff recommends elimination of Condition of Certification **BIO-24**. The applicant has indicated plans to implement a voluntary wetland creation program (CE Obsidian/AECOM 2009a). As a bank for future potential impacts for other projects and in accordance with the project's original Section 404 permit from the U.S. Army Corps of Engineers, the applicant proposes to construct approximately 4.5 acres of jurisdictional wetlands on the south side of the Alamo River, approximately 1 mile from the amended project site (CE Obsidian/CH2MHill 2009c, CE Obsidian 2010). The applicant already owns this land and is proposing to mitigate the amended project's 0.072 acre of permanent impacts within the 4.5 acres of created wetland (CE Obsidian 2010). CDFG (2009) stated that this wetland creation could serve to compensate for the project's streambed permanent impacts (0.072 acre) provided the program is indeed implemented rather than voluntary and the land is conserved in perpetuity.

To assess potential impacts to burrowing owl, surveys were required in Condition of Certification **BIO-19** as well as habitat compensation for impacted burrowing owl pairs. Staff is recommending deletion of **BIO-19** because the applicant completed surveys during the 2009 breeding season, and staff has consolidated the compensation requirements for burrowing owl into a single condition (**BIO-25**). The results of these surveys enable compensation acreage to be estimated. A total of 14 burrowing owl territories were documented (CE Obsidian/AECOM 2009d). CDFG (2010) noted that a significant number of owls were located within the 500-foot buffer of the amended project site and the injection wells and recommends that the seven occupied burrows around the amended project site be compensated for using the California Burrowing Owl Consortium Guidelines (1993) of 6.5 acres each (45.5 acres total). The eight occupied owl burrows that were found along the pipeline, injection wells, or the borrow site are not included in this calculation because the amount of foraging habitat loss was considered minimal. In addition, two replacement burrows would need to be enhanced or constructed to mitigate for the loss of one burrow that overlaps with the power plant site footprint. Staff has revised **BIO-25** because the acreages are no longer accurate with respect to the amended BR123 project.

Although the amended project does not create any new impacts to drainages or washes, the original Streambed Alteration Agreement (Fish and Game Code Section

1603 permit) that the applicant obtained from CDFG for impacts along the L-line interconnection expired on June 1, 2007. The applicant submitted a new application for a Streambed Alteration Agreement to CDFG in early November 2009. Since the project's original licensing, there has also been a change to an in-lieu permitting process for state Streambed Alteration Agreements for projects under the Energy Commission's jurisdiction. The Energy Commission has a one-stop permitting process for all thermal power plants rated 50 MW or more under the Warren-Alquist Act (Pub. Resources Code § 25500 et seq.). Under the act, the Energy Commission's certificate is "in lieu of" other state, local, and regional permits (*ibid*.). Accordingly, Commission staff has coordinated joint environmental review with CDFG and incorporated all required terms and conditions that might otherwise be included in CDFG's Streambed Alteration Agreement into the Energy Commission's amendment process. The revised Condition of Certification **BIO-8** (Streambed Alteration Agreement) satisfies the following state LORS and take the place of terms and conditions that, but for the Commission's exclusive authority, would have been included in the following state permit.

Streambed Alteration Agreement: California Fish and Game Code §§ 1600-1608

Pursuant to these sections, CDFG typically regulates all changes to the natural flow, bed, or bank of any river, stream, or lake that supports fish or wildlife resources. As previously analyzed in the original licensing of the project, construction would result in permanent impacts to state-jurisdictional waters located along the transmission line corridors. Staff has reviewed information supplied by the applicant (CDFG 2002) and has coordinated with CDFG to revise Condition of Certification **BIO-8**. Implementation of this revised condition would minimize and offset temporary and permanent impacts to state waters and would assure compliance with CDFG codes that provide protection to state waters.

For the proposed amendment, specific items related to Biological Resources Conditions of Certification are modified to be consistent with the changes that would result from adoption of the proposed amendment.

CONCLUSIONS AND RECOMMENDATIONS

There would be no unmitigated impacts to biological resources because of the proposed project changes to amend the license for the BR123. The project would conform to all applicable laws, ordinances, regulations, and standards (LORS) for biological resources. The new project changes, as proposed, would not have a significant effect on sensitive species or their habitat near the project providing that the proposed Biological Resources conditions of certification below are adopted. Staff recommends elimination of three Biological Resources conditions of certification and changes to eight other conditions of certification originally contained in the Commission Decision. The conditions of certification have been updated to reflect the proposed project changes and remain relevant to the proposed amendment.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

Staff has proposed modifications to the Biological Resources conditions of certification as shown below. (**Note:** Deleted text is in ~~strikethrough~~, new text is **bold and underlined)**.

BIOLOGICAL RESOURCES MITIGATION IMPLEMENTATION AND MONITORING PLAN (BRMIMP)

BIO-5 The project owner shall submit two copies of the proposed Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP) to the CPM for review and approval, and to California Department of Fish and Game (CDFG) and U.S. Fish and Wildlife Service (USFWS) for review and comment, and shall implement the measures identified in the approved BRMIMP.

The final BRMIMP shall identify:

1. All biological resources mitigation, monitoring, and compliance measures proposed and agreed to by the project owner;
2. All biological resources Conditions of Certification identified in the Commission's Final Decision;
3. All biological resource mitigation, monitoring and compliance measures required in federal agency terms and conditions, such as those provided in the USFWS Biological Opinion and Bureau of Land Management (BLM) Right-of-Way permit;
4. All biological resources mitigation, monitoring, and compliance measures required in other state agency terms and conditions, such as those provided in the ~~CDFG Incidental Take Permit and Streambed Alteration Agreement and~~ Regional Water Quality Control Board permits;
5. All biological resources mitigation, monitoring**,** and compliance measures required in local agency permits, such as site grading and landscaping requirements;
6. All sensitive biological resources to be impacted, avoided, or mitigated by project construction, operation**,** and closure;
7. All required mitigation measures for each sensitive biological resource;
8. Required habitat compensation strategy, including provisions for acquisition, enhancement, and management for any temporary and permanent loss of sensitive biological resources;
9. **A** detailed description of measures that shall be taken to avoid or mitigate temporary disturbances from construction activities;
10. All locations on a map, at an approved scale, of sensitive biological resource areas subject to disturbance and areas requiring temporary protection and avoidance during construction;
11. **Pre- and post-construction photographic or other documentation of areas to be disturbed during project construction activities. One set shall document conditions prior to any site or related facilities mobilization disturbance, and one set shall document conditions subsequent to completion of project construction. Documentation can**

be accomplished through aerial photography, GPS/GIS surveys, or other form of documentation agreed to by the CPM. Documentation shall include planned timing of the aerial photography, GPS/GIS surveys or other form of documentation, and a description of why times were chosen.~~Aerial photographs, at an approved scale, of all areas to be disturbed during project construction activities - one set prior to any site or related facilities mobilization disturbance and one set subsequent to completion of project construction. Include planned timing of aerial photography and a description of why times were chosen;~~

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

Verification: The project owner shall provide the specified document at least 60 days prior to start of any site (or related facilities) mobilization.

The CPM, in consultation with the CDFG, the USFWS and any other appropriate agencies, will determine the BRMIMP's acceptability within 45 days of receipt.

The project owner shall notify the CPM no less than five working days before implementing any modifications to the approved BRMIMP to obtain CPM approval.

Any changes to the approved BRMIMP must also be approved by the CPM in consultation with CDFG, the USFWS and appropriate agencies to ensure no conflicts exist.

Within 30 days after completion of project construction, the project owner shall provide to the CPM, for review and approval, a written report identifying which items of the BRMIMP have been completed, a summary of all modifications to mitigation measures made during the project's site mobilization, ground disturbance, grading, and construction phases, and which mitigation and monitoring items are still outstanding.

~~INCIDENTAL TAKE PERMIT~~

~~**BIO-7** The project owner shall acquire an Incidental Take Permit from the California Department of Fish and Game (CDFG) (per Section 2081(b) of the Fish and Game Code; California~~ Endangered ~~Species Act) if required and incorporate the terms and conditions into the project's BRMIMP.~~

~~**Verification:** At least 30 days prior to the start of any site or related facilities mobilization activities, the project owner shall submit to the CPM a copy of the CDFG Incidental Take Permit (if required).~~

STREAMBED ALTERATION AGREEMENT

~~**BIO-8**~~ ~~The project owner shall acquire a Streambed Alteration Agreement from the CDFG (per Section 1600 of the Fish and Game Code) if required, and incorporate the biological resource related terms and conditions into the project's BRMIMP.~~

~~**Verification:**~~ ~~At least 30 days prior to the start of any site or related facilities mobilization activities, the project owner shall submit to the CPM a copy of the CDFG Streambed Alteration Agreement (if required).~~

BIO-8 **The project owner shall implement Best Management Practices and other measures described below to protect jurisdictional waters of the state occurring along the linear alignments. The project owner shall implement the following measures to compensate for and minimize impacts to waters of the state:**

1. **As mitigation for 0.072 acre of permanent impact to waters of the state, the project owner shall mitigate at a ratio of 1:1.The project owner proposes to construct approximately 4.5 acres of jurisdictional wetlands on the south side of the Alamo River, approximately 1 mile from the amended project site on land owned by the applicant. Therefore, 0.072 acre of this 4.5-acre wetland creation shall be set aside for the project's streambed impacts with the wetlands and land managed and protected in perpetuity.**

2. **As mitigation for 0.508 acre of temporary impact to waters of the state, the project owner shall recontour and restore the areas to functioning streambed and bank following construction.**

3. **Best Management Practices: The applicant shall comply with the following conditions:**

   a. **Prior to any activities that cross or have the potential to impact any jurisdictional drainage, the owner shall provide a detailed map to the CDFG and CPM in a GIS format that identifies all potential crossings of jurisdictional habitats including bridges and culverts. The maps shall identify the type of crossing proposed by the owner such as bridges, culverts, or other mechanism and the best management practices that would be employed.**

   b. **Precautions to minimize turbidity/siltation shall be taken into account during project planning and shall be installed prior to construction. Precautions may also include placement of silt fencing, straw bales, or sand bags, so that silt or other deleterious materials are not allowed to pass to downstream reaches. The method used to prevent siltation shall be monitored and cleaned/repaired weekly.**

c. <u>The project owner shall not operate vehicles or equipment in ponded or flowing water except as described in this condition. Diversion of any stream is not authorized.</u>

d. <u>Dewatering of streams or other waterways is not authorized in this condition.</u>

e. <u>At the completion of construction, all temporary bridges, culverts, or other structures shall be removed unless authorized by the CDFG and CPM.</u>

f. <u>When any activity requires moving of equipment across a flowing stream, such operations shall be conducted without substantially increasing stream turbidity. The project owner shall bridge by the use of railroad flat cars or other bridging material all ponded or flowing streams if vehicles travel where high flow levels occur.</u>

g. <u>Where drainages support sheet flow in direct response to rainfall for periods of less than 48 hours construction of bridges is not required. Vehicle use in these areas shall not result in silt/mud/turbid water from reaching downstream areas.</u>

h. <u>Vehicles driven across ephemeral drainages when water is present shall be completely clean of petroleum residue and water levels shall be below the vehicles axles.</u>

i. <u>Any equipment or vehicles driven and/or operated within or adjacent to the stream/lake shall be checked and maintained daily, to prevent leaks of materials that if introduced to water could be deleterious to aquatic life.</u>

j. <u>Installation of bridges, culverts, or other structures shall be such that water flow (velocity and low flow channel width) is not impaired. Bottoms of temporary culverts shall be placed at or below stream channel grade. A biological monitor shall be present during the installation of all bridges, culverts, and BMPs.</u>

k. <u>Installation of bridges or culverts shall be done in a manner that shall prevent pollution and/or siltation and which shall provide flows to downstream reaches. Flows to downstream reaches shall be provided during all times.</u>

l. <u>The project owner shall not allow water containing mud, silt, or other pollutants from grading, aggregate washing, or other activities to enter a lake or flowing stream or be placed in locations that may be subjected to high storm flows.</u>

m. <u>If turbidity/siltation levels resulting from project related activities constitute a threat to aquatic life, activities associated with the turbidity/siltation shall be halted until effective CPM-approved control devices are installed, or abatement procedures are initiated.</u>

n. <u>The project owner shall comply with all litter and pollution laws. All contractors, subcontractors, and employees shall also obey these</u>

laws, and it shall be the responsibility of the project owner to ensure compliance.

o. **If a stream's low flow channel, bed or banks/lake bed or banks have been altered, these shall be returned as nearly as possible to their original configuration and width, without creating future erosion problems. The gradient of the streambed shall be returned to pre-project grade unless such operation is part of a restoration project, in which case, the change in grade must be approved by the Department prior to project commencement.**

p. **No debris, soil, silt, sand, bark, slash, sawdust, rubbish, construction waste, cement or concrete or washings thereof, asphalt, paint, oil or other petroleum products or any other substances which could be hazardous to aquatic life, or other organic or earthen material from any logging, construction, or other associated project related activity shall be allowed to contaminate the soil and/or enter into or placed where it may be washed by rainfall or runoff into waters of the State. Any of these materials, placed within or where they may enter a stream or lake, by the owner or any party working under contract, or with the permission of the owner, shall be removed immediately.**

q. **When operations are completed, any excess materials or debris shall be removed from the work area. No rubbish shall be deposited within 150 feet of the high water mark of any stream or lake.**

r. **Stationary equipment such as motors, pumps, generators, and welders, located within or adjacent to the stream/lake shall be positioned over drip pans. Stationary heavy equipment shall have suitable containment to handle a catastrophic spill/leak. Clean up equipment such as extra boom, absorbent pads or skimmers shall be on site prior to the start of dredging.**

s. **No equipment maintenance shall be done within or near any stream channel where petroleum products or other pollutants from the equipment may enter these areas under any flow.**

t. **The cleanup of all spills shall begin immediately. The CDFG and CPM shall be notified immediately by the owner of any spills and shall be consulted regarding clean-up procedures.**

u. **Spoil sites shall not be located within any watercourse where spoil could be washed back into a stream, or where it will cover aquatic or desert riparian vegetation. Any materials placed in seasonally dry portions of a stream that could be washed downstream or that could be deleterious to aquatic life shall be removed from the project site prior to inundation by high flows.**

v. **Structures and associated materials, including construction debris, that are not designed to withstand high seasonal flows shall be removed to areas above the high water mark before such flows occur.**

w. All disturbed portions of any watercourse will be restored to as near original condition as possible, except as otherwise indicated in the submitted application or as directed by the Department.

x. Fill length, width, and height dimensions shall not exceed those of the original installation or the original naturally occurring topography, contour, and elevation; fill shall be limited to the minimal amount necessary to accomplish the agreed activities; fill construction materials other than on-site alluvium, shall consist of clean uncontaminated soil, silt-free gravel, and/or river rock; except as described in the submitted application or as otherwise specified in this agreement.

y. In all areas, native vegetation outside the construction area will be protected from construction activities through clear flagging and/or signing, and by enforcement of the construction area limits. These specimens will be avoided wherever possible.

4. Non-native Vegetation Removal. The owner shall remove any non-native vegetation from any drainage that requires the placement of a bridge, culvert, or other structure. Removal shall be done as needed during the construction of the linear features that directly impact waters of the state. The removal of riparian vegetation is not authorized under this condition. Should the removal of riparian vegetation become necessary, temporary impacts will be mitigated at a ratio of 2:1 and permanent impacts will be mitigated at a ratio of 5:1.

5. Reporting of Special-Status Species: If any special-status species are observed on or in proximity to the project site, or during project surveys, the project owner shall submit California Natural Diversity Data Base (CNDDB) forms and maps to the CNDDB within thirty (30) working days of the sightings and provide the regional CDFG office with copies of the CNDDB forms and survey maps. The CNDDB form is available online at: www.dfg.ca.gov/whdab/pdfs/natspec.pdf. This information shall be mailed within five days to: California Department of Fish and Game, Natural Diversity Data Base, 1807 13th Street, Suite 202, Sacramento, CA 95814, (916) 324-3812. A copy of this information shall also be mailed within five days to the CDFG regional office and the CPM.

6. Notification: The project owner shall notify the CPM and CDFG, in writing, at least five days prior to initiation of project activities in jurisdictional areas and at least five days prior to completion of project activities in jurisdictional areas. The project owner shall notify the CPM and CDFG of any change of conditions to the project, the jurisdictional impacts, or the mitigation efforts, if the conditions at the site of the proposed project change in a manner which changes risk to biological resources that may be substantially adversely affected by the proposed project. The notifying report shall be provided to the CPM and CDFG no later than seven working days after the change of conditions is

identified. As used here, change of condition refers to the process, procedures, and methods of operation of a project; the biological and physical characteristics of a project area; or the laws or regulations pertinent to the project, as described below. A copy of the notifying change of conditions report shall be included in the annual reports.

a. Biological Conditions: a change in biological conditions includes, but is not limited to, the following: 1) the presence of biological resources within or adjacent to the project area, whether native or non-native, not previously known to occur in the area; or 2) the presence of biological resources within or adjacent to the project area, whether native or non-native, the status of which has changed to endangered, rare, or threatened, as defined in section 15380 of Title 14 of the California Code of Regulations.

b. Physical Conditions: a change in physical conditions includes, but is not limited to, the following: 1) a change in the morphology of a river, stream, or lake, such as the lowering of a bed or scouring of a bank, or changes in stream form and configuration caused by storm events; 2) the movement of a river or stream channel to a different location; 3) a reduction of or other change in vegetation on the bed, channel, or bank of a drainage, or 4) changes to the hydrologic regime such as fluctuations in the timing or volume of water flows in a river or stream (excluding volume or timing flows due to storm events).

c. Legal Conditions: a change in legal conditions includes, but is not limited to, a change in Regulations, Statutory Law, a Judicial or Court decision, or the listing of a species, the status of which has changed to endangered, rare, or threatened, as defined in section 15380 of Title 14 of the California Code of Regulations.

7. Code of Regulations: The project owner shall provide a copy of the Energy Commission Decision to all contractors, subcontractors, and the applicant's project supervisors. Copies shall be readily available at work sites at all times during periods of active work and must be presented to any CDFG personnel or personnel from another agency upon demand. The CPM reserves the right to issue a stop work order or allow CDFG to issue a stop work order after giving notice to the project owner and the CPM, if the CPM, in consultation with CDFG, determines that the project owner has breached any of the terms or conditions or for other reasons, including but not limited to the following:

   a. The information provided by the applicant regarding streambed conditions is incomplete or inaccurate;

   b. New information becomes available that was not known to it in preparing the terms and conditions;

   c. The project or project activities as described in the Amendment Staff Analysis have changed; or

d. **The conditions affecting biological resources changed or the CPM, in consultation with CDFG, determines that project activities will result in a substantial adverse effect on the environment.**

Verification: No fewer than 90 days before the start of construction of project features that directly impact waters of the state associated with the linear features, the project owner shall provide the CPM with a management plan for review and approval, in consultation with CDFG, for the compensation lands and created wetlands.

No fewer than 30 days prior to the start of work potentially affecting waters of the state, the project owner shall provide written verification (i.e., through incorporation into the BRMIMP) to the CPM that the above best management practices and measures will be implemented and provide a discussion of work in waters of the state in Compliance Reports every six months for the duration of the project (or until construction of the L-transmission line is completed).

CONSTRUCTION MITIGATION MANAGEMENT TO AVOID HARASSMENT OR HARM

BIO-13 The project owner shall manage their construction site, and related facilities, in a manner to avoid or minimize~~s~~ impacts to the local biological resources.

Typical measures are:

1. Install a temporarily fence and provide wildlife escape ramps for construction areas that contain steep walled holes or trenches if outside of an approved, permanent exclusionary fence. The temporary fence shall be constructed of materials that are approved by USFWS and CDFG. The ramps shall be located at not greater than 1,000-foot intervals and shall be sloped less than 45 degrees. All animals discovered in trenches shall be allowed to escape voluntarily (by escape ramps or temporary structures), without harassment, before construction activities resume, or be removed from the trench or hole by a qualified biologist and allowed to escape unimpeded;

2. Make certain all food-related trash is disposed of in closed containers and removed at least once a week;

3. Prohibit feeding of wildlife by staff or contractors;

4. Prohibit non-security related firearms or weapons from being brought to the site;

5. Prohibit pets from being brought to the site;

6. Minimize use of rodenticides and herbicides in the project area;

7. Advise all employees, contractors, and visitors of the need to adhere to speed limits and to avoid any animals, including burrowing owls, which may be encountered on or crossing the roads to and from the project site. The maximum speed on unpaved roads or on paved roads within 300 feet

of occupied sensitive species habitat (such as on McKendry Road west of Boyle road and Lack Road between Kuns and Lindsey Roads) shall be restricted 15 miles per hour or lower during construction;

8. Inspect all construction pipes, culverts, or similar structures with a diameter of four inches or greater for sensitive species (such as burrowing owls) prior to movement of pipe or pipe burial. Cap all pipes with a diameter of four inches or greater if they are to be left in trenches overnight or in storage areas outside of the construction laydown area;

~~9. For the section of pipeline between production well OB3 and the power plant site, empty~~ the ~~concrete-lined pipe at the power plant site. For all remaining sections,~~ empty ~~concrete lined pipe into designed evaporation and percolation ponds;~~

9~~10~~. Report all inadvertent deaths of sensitive species to the appropriate project representative. Injured animals shall be reported to USFWS and CDFG and the project owner shall follow instructions that are provided by USFWS and CDFG. All incidences of wildlife injury or mortality resulting from project-related vehicle traffic on roads used to access the project shall be reported in the MCR;

10~~11~~. Implement standard mitigation measures for the flat-tailed horned lizard detailed in the *Flat*-tailed *Horned Lizard Rangewide Management Strategy-Appendix 3* for work in flat-tailed horned lizard habitat;

11~~12~~. Confine construction activities to the plant, well pad, or pipeline side of any existing or constructed barriers (such as roads or levees) to reduce the potential disruption associated with human presence within occupied sensitive species habitat;

12~~13~~. Transmission line construction within 1 mile of the intersection of Lack and Lindsey Roads shall not be conducted at night or when wind speeds exceed 15 miles per hour**; and,**

13~~14~~. **Implement standard mitigation measures for burrowing owl detailed in CDFG's 1995 Staff Report on Burrowing Owl Mitigation.**

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

PRE-CONSTRUCTION MONITORING TO AVOID HARASSMENT OR HARM

BIO-14 The project owner shall provide a baseline survey proposal in the BRMIMP. The CPM, in consultation with the CDFG, Refuge, the USFWS and any other appropriate agencies, will determine the acceptability of the baseline survey protocol(s), the survey area(s) and the Designated Biologist's prescription(s) for potential impacts.

Surveys of burrowing owl habitat shall be conducted for any areas subject to disturbance from construction within the 30 days prior to commencing ground-disturbing activities to identify for impact avoidance and

<u>minimization any additional territories that may have established since previous surveys. If ground-disturbing activities are delayed for more than 30 days after the pre-construction survey, the site shall be re-surveyed.</u>

Prior to mobilization, the project owner shall conduct baseline surveys for special status species at a level that establishes the occurrence and abundance of species. In addition, mapping of suitable habitat types will be completed for any special status species that potentially occur, but are not present at the time of the baseline survey. Mapping of suitable habitat types will also be completed for any species that cannot be surveyed for because of protocol restrictions. The baseline surveys shall cover appropriate habitats within one-mile of the plant site and within 1,000 feet of all linear facilities, unless other areas are deemed more appropriate. Protocol level surveys for Yuma clapper rails shall be conducted by qualified individuals at Union Pond, McKendry Pond, and the adjacent parts of the Vail 5 drain prior to the start of any construction within 0.5 mile of these sites.

The Designated Biologist shall make recommendations to the project owner to avoid or minimize impacts to the special status species based on completed baseline surveys and any protocol level surveys.

<u>Verification</u>: <u>The results of the baseline surveys must be submitted to the CPM, USFWS, CDFG, and Refuge no later than 30 days prior to the start of mobilization. Results of pre-construction burrowing owl surveys shall be submitted to the CPM, USFWS, CDFG, and Refuge prior to the commencement of ground-disturbing activities. The protocol survey results shall be submitted to the CPM, USFWS, CDFG, and Refuge no more than 10 days after completion and at least 20 days prior to mobilization.</u>

The baseline survey proposal shall include a list of target species and the survey techniques to be used. The list of target species must, at a minimum, include California brown pelicans, mountain plover, burrowing owl, Yuma clapper rail, California black rail, and flat-tailed horned lizard. In addition, a proposal for mapping suitable habitats shall, at a minimum, include Yuma clapper rail and mountain plover habitat. The baseline survey proposal shall establish indices (e.g., propensity for flight) for comparison with other monitoring efforts. The baseline survey proposal shall include the survey locations and their distance from the site or linear facilities. The baseline survey proposal shall identify actions that can be taken to avoid or minimize impacts to the special status species (such as restricting construction to certain months or marking sensitive areas).

The project owner shall provide copies of agency-approved survey protocols in the BRMIMP. At a minimum, the project owner shall include a copy of the agency-approved survey protocol for California black rail and Yuma clapper rail in the event that the baseline surveys show these species are mating or nesting within 1,000 feet of the proposed project. The BRMIMP shall identify at least two southern California or western Arizona biologists that hold a USFWS permit for surveying these species and include their contact information.

~~Results of the baseline surveys must be submitted to the CPM, USFWS, CDFG, and Refuge no later than 30 days prior to the start of mobilization. The protocol survey~~

~~results shall be submitted to the CPM, USFWS, CDFG and Refuge no more than 10 days after completion and at least 20 days prior to mobilization.~~

NOISE AND VIBRATION MANAGEMENT TO AVOID HARASSMENT OR HARM

BIO-16 The project owner shall prepare a detailed Noise and Vibration Assessment and Abatement Plan based on the final design of the facility to determine the most practicable measures to reduce/mitigate construction noise and vibration impacts. At a minimum, the Noise and Vibration Assessment and Abatement Plan shall address measures to:

1. Reduce site grading and clearing, pile-driving, and steam-blow noise levels using measures that have the maximum sound attenuation effect practicable (e.g., beyond 78 dBA L_{eq5}) at the occupied habitat areas during the Yuma clapper rail mating and nesting season (February 15 to August 31);
2. Ensure overall noise levels at the power plant site during the mating season of Yuma clapper rails (February 15 to August 31), will not exceed the threshold of 60 dBA Leq hourly at occupied habitat areas for one-half hour before and one hour after sunrise and one hour before and one-half hour after sunset; and
3. Ensure site grading and clearing and pile-driving vibrations levels are equal or less than 72 VdB at the northern and western boundaries of the power plant site during the Yuma clapper rail nesting season (June 1 to August 31). The project owner will conduct noise monitoring at the edge of project boundaries facing occupied listed species breeding habitat to verify compliance with any applicable noise restrictions. Other noise and vibration avoidance measures can be considered for approval by the CPM in consultation with involved agencies.

<u>**Verification**</u>**:** <u>**The Noise and Vibration Assessment and Abatement Plan shall be submitted to the CPM, CDFG, Refuge and USFWS 60 days prior to the start of any site (or related facilities) mobilization. The CPM, in consultation with the CDFG, Refuge, USFWS, and any other appropriate agencies, will determine the Noise and Vibration Assessment and Abatement Plan's acceptability within 45 days of receipt.**</u> The project owner shall submit two copies of the Noise and Vibration Assessment and Abatement Plan to the CPM for review and approval and one copy to the CDFG, Refuge, and USFWS for review and comment ~~60 days prior to start of any site (or related facilities) mobilization~~. The Noise and Vibration Assessment and Abatement Plan shall identify all noise and vibration sources by construction phase, the location of all biologically related sensitive receptors, and the noise and vibration levels expected after the implementation of mitigation. ~~The CPM, in consultation with the CDFG, Refuge, USFWS, and any other appropriate agencies, will determine the Noise and Vibration Assessment and Abatement Plan's acceptability within 45 days of receipt.~~ The project owner shall, at a minimum, appoint a person(s) to collect weekly noise measurements ~~at the original Noise Measurement Locations ML2, ML3 and ML4~~ for a 1-hour period. <u>**The noise measurement locations shall be mapped and proposed by the project owner in the Noise and Vibration Assessment and Abatement Plan according to the recommendations of the USFWS.**</u> The results shall be utilized as follows:

- If noise measurement is outside of Yuma clapper rail mating and nesting season (September 1 to February 14) and exceeds 60 dBA Leq at the edge or within occupied habitat, it shall be highlighted in the data table for the MCR and the reasons for the noise level (if known) described.
- If a noise measurement is within Yuma clapper rail mating and nesting season (February 15 to August 31) and exceeds 60 dBA Leq hourly at the edge or within occupied habitat, then pieces of construction equipment shall be stopped, moved, or quieted such that resultant noise levels are less than 60 dBA. Construction work need only be stopped or quieted for one-half hour before and 1 hour after sunrise and 1 hour before and one-half hour after sunset. If 24-hour construction is required, every person on the agency call list shall be notified as to the expected noise level, the equipment in use, and the remedial actions that are recommended (if any). The remedial action(s) should be implemented after approval by agency staff.

The noise measurements and any remedial actions taken shall be described in the MCR.

RE-VEGETATION FOR CONSTRUCTION IMPACTS

BIO-18 The project owner shall contour all temporary disturbance areas and allow them to re-vegetate with pre-disturbance species. Invasive exotic species (as defined by the U.S. Department of Agriculture **and/or California Invasive Plant Council [Cal-IPC]**) shall be precluded from establishing themselves in the temporary disturbance areas through implementation of a three-year post-construction weed removal program. Every three years for a period of nine years following construction, the project owner shall evaluate the need for control of exotic species in areas disturbed by construction of the power plant and its associated facilities.

Verification: The project owner shall provide a brief report of temporary disturbance conditions at the end of the project construction in the BRMIMP Closure Report. Annual reporting of weed **abatement** shall be provided to the CPM in the annual reporting for nine years post-construction, or until such time as the CPM determines it is no longer needed.

~~SURVEY AND PROVIDE HABITAT COMPENSATION FOR BURROWING OWLS~~

~~**BIO-19** The project owner shall survey for burrowing owl activities on the 80-acre parcel and along the transmission lines prior to site mobilization to assess owl presence. The project owner shall evaluate the potential impact to each burrowing owl occurrence using impact criteria reviewed by the CDFG and USFWS and approved by the CPM. The impact criteria will be based on type of activity, length of activity, distance maintained from~~ the ~~burrowing owl(s), and time of year. For impact determinations which require monitoring of burrowing owls, a credentialed biologist approved by the CPM must do the monitoring.~~

~~The project owner shall protect at least 6.5 acres of suitable land for each impacted pair of owls or~~ impacted ~~unpaired resident bird (as determined by the CPM-approved impact criteria). For each occupied burrowing owl burrow that must be destroyed, existing unsuitable burrows on the protected lands shall be enhanced (e.g., cleared of debris or enlarged) or new burrows installed at a~~

~~ratio of 2:1. If habitat is made unsuitable (e.g., the evicted owls leave the area), 6.5 acres of habitat per pair would be provided. For example, if pre-construction surveys find 17 occupied owl burrows within the project's footprint, and monitoring determined 17 burrowing owl pairs left the area, the project owner must create 34 new or improve 34 existing burrows and provide 110.5 acres of protected land. The actual requirement will be determined after the CPM reviews the burrowing owl pre-construction surveys and monitoring. Avoidance is preferred over mitigation of impacts.~~

Verification: ~~At least 60 days prior to site mobilization, the project owner shall provide to the CPM for review and approval, and to the USFWS and CDFG for review and comment, the impact criteria that will be used to evaluate construction, maintenance, and operational impacts to burrowing owls. The project owner must submit to the CPM for approval the resume of any biologist (s) that will perform the burrowing owl monitoring at least one week prior to their assignment to start monitoring. If burrowing owl monitoring is needed, then a summary report completed by the Designated Biologist and all original data sheets shall be included in the MCR. At least 15 days prior to site mobilization, the project owner shall provide the CPM, USFWS, Refuge, and CDFG with the burrowing owl survey results. Burrowing owl surveys are valid only for 30 days.~~

~~Based on the number of burrowing owls identified as potentially impacted, the project owner shall identify the amount of land it intends to protect 15 days prior to construction. The project owner shall fund the acquisition and long-term management of the compensation lands in a form acceptable to the CEC and CDFG (e.g., provide a letter of credit or establish an escrow account) 15 days prior to construction. The project owner shall propose land for purchase or protection with a description of habitat types and propose a management and monitoring plan 90 days prior to commercial operation. The land protection proposal and management fund(s) shall be approved by the CPM and reviewed by CDFG.~~

~~The project owner shall rectify any under-funded amounts in the acquisition and long-term management account(s) at least 60 days prior to commercial operation. At least 30 days prior the start of commercial operation, the project owner shall submit to the CPM two copies of the relevant legal paperwork that protects lands in perpetuity (e.g., a conservation easement as filed with the Imperial County Recorder), a final land management and monitoring plan, and documents which discuss the types of habitat protected on the parcel. If a private mitigation bank is used, the project owner shall provide a letter to the CPM from the approved land management organization stating the amount of funds received, the amount of acres purchased and their location, and the amount of funds dedicated to long term monitoring or management at least 60 days prior to commercial operation. If fund remain after performance of all habitat compensation obligations, the monies in the letter of credit or escrow account will be returned to the project owner with written approval of the CPM. All mitigation measures and their implementation methods shall be included in the BRMIMP.~~

~~CONSERVATION EASEMENT FOR WETLAND~~

~~BIO-24~~ ~~The project owner shall submit copies of the fee title and/or conservation easement relating to the restoration and creation of wetland habitat prior to the start of the first Yuma clapper rail breeding season that follows the initiation of~~

~~fill operations along McKendry Road. The project owner shall provide an endowment to fund management of the~~ land ~~to achieve the targeted functions and values described in the U.S. Army Corps of Engineers permit.~~

~~Verification~~: ~~Within 30 days before the start of commercial operation, the project owner shall submit to the CPM two copies of the conservation easement, as recorded with the Imperial County Recorder and any related documents that discuss the types of habitat restored or created on the parcel.~~

PROVIDE HABITAT COMPENSATION FOR PERMANENT IMPACTS TO BURROWING OWLS AND THEIR HABITAT

BIO-25 Permanent **impacts to burrowing owls and** foraging habitat ~~which is permanently destroyed~~ shall be ~~replaced~~ **compensated** ~~at 0.5:1 (mitigation:impacts).~~through **acquisition or easement. The acquired compensation lands shall be** ~~and~~ managed for the protection of burrowing owls. ~~Based on these ratios,~~ **T**he project owner must protect and manage ~~42.65~~ 50.4 acres of land for burrowing owls **(45.5 acres for the power plant site, 2.25 acres for off-site injection wells, and** ~~40 acres for the power plant site and~~ 2.65 acres for the transmission line pads). ~~The mitigation amount can be reduced if mitigation land for the same burrowing owls is also being provided under Condition of Certification BIO-19.~~ **For each occupied burrowing owl burrow that must be destroyed, existing unsuitable burrows on the protected lands shall be enhanced (e.g., cleared of debris or enlarged) or new burrows installed at a ratio of 2:1. Based on the 2009 survey results, the applicant must enhance or install at least 2 new burrows.**

Verification: ~~At least 15 days prior to site mobilization, the project owner shall provide the CPM, USFWS, Refuge, and CDFG with the burrowing owl survey results. If burrowing owls are present where a permanent facility will be placed or within 300 feet of a permanent facility, the project owner shall identify the amount of land they intend to protect 15 days prior to construction.~~ **At least 15 days prior to construction, the** project owner shall fund the acquisition **(or placement of the project owner's previously owned land under conservation easement)** and long-term **management** of the compensation lands ~~in a form acceptable~~ **under conditions acceptable** to the CEC and CDFG (e.g., provide a letter of credit or establish an escrow account**, ensure a specified crop type on agricultural lands**) ~~15 days prior to construction~~. **At least 90 days prior to commercial operation, the project owner shall propose land for purchase or protection with a description of habitat types and propose a management and monitoring plan**. The land protection proposal and management fund(s) shall be approved by the CPM and reviewed by CDFG. ~~The project owner shall propose land for purchase or protection with a description of habitat types and propose a management plan at least 90 days prior to commercial operation.~~

The project owner shall rectify any underfunded amounts in the acquisition and long-term management account(s) at least 60 days prior to commercial operation. At least 30 days prior to commercial operation, the project owner shall submit to the CPM two copies of the relevant legal paperwork that protects lands in perpetuity (e.g., a conservation easement as filed with the Imperial County Recorder), a final management and monitoring plan, and documents which discuss the types of habitat protected on the parcel. If a private mitigation bank is used, the project owner shall provide a letter to the CPM from the approved land management organization stating the amount of funds received, the amount of acres purchased and their location, and the amount of funds dedicated to long term monitoring or management 60 days prior to commercial operation. If funds remain after performance of all habitat compensation obligations, the monies in the letter of credit or escrow account will be returned to the project owner with written approval of the CPM.

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

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California Department of Fish and Game (CDFG). 2002. Agreement Regarding Proposed Activities Subject to California Fish and Game Code Section 1603. Notification No. 6-2002-279-R6. 10-31-2002. Agreement between the Department of Fish and Game, Eastern Sierra and Inland Deserts Region and CE Obsidian Energy LLC.

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CE Obsidian, LLC (CE Obsidian/CH2MHILL). 2009d. Burrowing Owl Survey Report. Black Rock 1, 2 and 3 Geothermal Power Project. Dated December 2009.

CE Obsidian, LLC. 2010. E-mail communications with Michael Fawdry and Doug Hackley regarding Section 404 permit requirements for the BR123 project on February 28, 2010 and March 1, 2010.

U.S. Fish and Wildlife Service (USFWS). 2009. E-mail communication with Christian Shoneman, Project Leader, Sonny Bono Salton Sea National Wildlife Refuge Complex, re: potential biological concerns related to the BR123 project amendment on May 12, 2009.

CULTURAL RESOURCES
Testimony of Dorothy Torres

INTRODUCTION

CE Obsidian Energy, LLC, is proposing a major amendment to the 215-megawatt (MW) project previously certified as “Salton Sea Unit 6” (SSU6). The amended project would be named the Black Rock 1, 2, and 3 Geothermal Power Plant (BR123), and would consist of three power plants producing approximately 53 MW each. BR123 would be built in the Salton Sea Known Geothermal Resource Area (KGRA), which has been zoned by Imperial County for geothermal development.

BR123 would include the original 80-acre SSU6 project site and an additional 80 acres adjacent to the south of the original project, plus additional lands for the off-site injection wells, pipelines, project transmission lines (previously licensed under the SSU6 Amendment), and two borrow sites (one of the borrow sites was previously licensed under the SSU6 Amendment). The project would be located adjacent to the Salton Sea, just east of Obsidian Butte and 0.6 mile from the Salton Sea Sonny Bono National Wildlife Refuge (CE Obsidian 2009, p. 2-3–2-7).

PROJECT DESCRIPTION

BR123 would consist of three production well pads with three wells each located at the northern, western, and southern perimeters of the site. The project also includes three injection well pads with three injection wells each, located off the project site to the east, southeast, and south of the project site. The previously proposed 80 acres used for the project would be doubled to 160 acres. A total of 18 production and injection wells utilizing six well pads would be built. In addition, two plant injection wells and two aerated brine injection wells would be drilled to inject cooling tower blow down and aerated brine (CE Obsidian 2009, p. 2-2).

Three brine ponds would be constructed on the project site. Each pond would be 620 feet by 42 feet by 4 feet deep. Containment areas would be constructed around each brine pond for pipes and de-scaling activities (CE Obsidian 2009, pp. 2-32–2-33). The brine ponds would be permitted by the Regional Water Quality Control Board (RWQCB) (CE Obsidian 2009, p. 2-32). The amended project would obtain water from an Imperial Irrigation District (IID) canal, Vail Lateral 4-A.

The amended project would use a borrow site located immediately southeast of the plant site to obtain soil to construct a berm around the entire perimeter of the 160-acre project site, as protection against flooding. An additional borrow site located adjacent to the Leathers geothermal plant, approximately two miles northeast of the project, would also be used (CE Obsidian 2009, p. 2-37). The project would utilize approximately 361,840 cubic yards of soil from the borrow locations. Perimeter roads would be located on top of the berm.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

There are no new or changed LORS pertaining to cultural resources that are applicable to BR123.

CULTURAL RESOURCES ANALYSIS

ORIGINAL PROJECT FINDINGS

For the original SSU6 project, the Final Staff Assessment (FSA) discussed six archaeological sites that were identified during previous cultural surveys that could not be relocated during surveys for the original permit. The FSA also recognized additional known cultural resources, stating that there were "…28 archaeological sites, features, objects, buildings, or structures known to be located in the vicinity of the project" (CEC 2003a p. 4.3-23). These cultural resources included 15 historic-era buildings or structures and 13 archaeological sites, some containing human remains. However, many of the cultural resources identified during permitting of the SSU6 project were located near the transmission line route. The transmission line route has already been permitted as part of the SSU6 project, and is not a subject of this amendment.

The original FSA also recommended that "…Obsidian Butte meets the eligibility requirements for the California Register under criteria 4. Obsidian Butte is potentially eligible to the inventory of sacred places. It also retains sufficient integrity to provide important information about prehistory and to function as a Traditional Cultural Place, and will be treated as also eligible for the California Register of Historical Resources (CRHR) under criterion 1 for the purposes of this analysis" (CEC 2003a, p. 4.3-21). The FSA also concluded that there would be a change in the integrity of setting, feeling, and association of Obsidian Butte, diminishing the integrity of the resource, but that the change was not expected to materially impair Obsidian Butte's eligibility to the CRHR under criterion 1 (CEC 2003a, p. 4.3-22). In addition, the original FSA concluded that there were no cumulative impacts (CEC 2003a, p. 4.3-23).

Cultural resources Conditions of Certification, **CUL-1** through **CUL-11** are thoroughly discussed in the FSA prepared for the SSU6 project. **CUL-1** through **CUL-9** provided for the identification, assessment, and appropriate treatment of CRHR-eligible archaeological resources that might be discovered during construction. **CUL-10** required an ethnographic study to determine the traditional use and the cultural importance of Obsidian Butte by and to Native American groups. **CUL-11** provided a guide for mitigation for the lithic scatter located on Obsidian Butte that would have been impacted by the construction of a production well pad.

The previous project, SSU6, had planned to locate a production well, pipeline, and access road on Obsidian Butte. The amended project, BR123, moves all production wells onto the 180-acre project site, and no injection wells are proposed in the Wildlife Refuge or on Obsidian Butte (CE Obsidian 2009, p. 2-2).

AMENDED PROJECT INVESTIGATIONS

Records Search

In the preparation of the Petition to Amend the SSU6 license, consultants to the project owner conducted a records search at the Imperial Valley College Desert Museum. The search addressed a study area that extended 1.0 mile beyond the project facilities and 0.25 mile to either side of the linear facilities (CE Obsidian 2009, p. 5.4-15). The records search included a search of the Native American Heritage Commission's (NAHC) Sacred Land Files that indicated cultural resources were present in the project area (CE Obsidian 2009, p. 24). The records search revealed that no previous surveys had been conducted in the area of the injection well pads and pipelines that would be located south and east of the plant site.

A historic records search included a review of historic USGS topographical maps and historic site inventories conducted for previous studies in the vicinity of the project. The Pioneer Museum in Imperial, California, was also contacted; however, no response was received from the museum.

In response to staff's data request, additional information sources were selected and reviewed based on the information that the sources might provide regarding Obsidian Butte (CE Obsidian 2009a, p. 8).

Field Surveys

Since the proposed amendment has expanded the location of the proposed project, additional areas were surveyed by cultural resources consultants to the applicant. Buffer areas and some linear facilities changed, necessitating additional surveys. Consultants to the project owner surveyed the buffer for the plant site, injector well pads, pipelines, and borrow area by pedestrian archaeological reconnaissance between November 4, 2008, and November 6, 2008. The built-environment survey area extended 0.5 mile beyond the amended project components (CE Obsidian 2009, p. 29).

Ground visibility for the archaeological survey was good to excellent, revealing that the area was level, had been graded and cultivated, and was heavily disturbed. The survey identified and recorded Vail Canal Lateral 3-A, 4, and 4-A (CE Obsidian 2009, p. 31). The survey of the plant buffer area identified pieces of unmodified obsidian in the northwest corner of the buffer area and along a 2,400-foot segment of Vail Lateral 4-A, which parallels the eastern side (boundary) of the plant site.

Native American Consultation

In support of the BR123 amendment, the project owner's cultural resources consultant contacted the NAHC on September 8, 2008, to request a search of the Sacred Lands File. The NAHC responded that there were cultural resources located within the search area (CE Obsidian 2009, p. 5.4-14). The NAHC also provided an updated list of Native American Individuals and groups who had requested to be informed regarding construction development in Imperial County. Those Native American individuals and groups were contacted by the consultant to the project owner on September 23, 2008. Telephone calls were made to the listed Native Americans on December 10, 2008 (CE Obsidian 2009, p. 25). Only Carmen Lucas with the Kwaaymii Laguna Band of Mission

Indians and Bridget Nash-Chrabascz, Tribal Historic Preservation Officer to the Quechan Indian Nation, responded with expressions of concern. Preston Arrow-Weed, Quechan Kumeyaay Tribal Elder, responded that the Quechan Indian Nation should be contacted and that he need not be contacted again (CE Obsidian 2009a, p. 8).

As a result of staff's Data Requests for additional information on Native American concerns regarding Obsidian Butte, in 2009 persons on the 2008 list of Native Americans were contacted again by LSA, an additional consultant to the project owner. Contacts included Carmen Lucas, Bridget Nash-Chrabascz, and Bernice Paipa, tribal member of the Santa Ysabel Band of Kumeyaay Indians and Cultural Representative with the Kumeyaay Culture and Repatriation Committee. All responded that Obsidian Butte was either sacred or important to their particular group. Michael Garcia, of the Ewiiaapaayp Band of Kumeyaay Indians said that he would consult with elders and respond at a later date.

Cultural Resources Identified by Investigations Conducted in Support of SSU6 and BR123

Obsidian Butte

As addressed in the FSA completed for SSU6, Obsidian Butte is a known source of obsidian used by Native Americans to make flaked stone tools during the latter part of the Late Prehistoric period. Two small areas around the base of Obsidian Butte have been recorded as archaeological sites (CA-IMP-452 and CA-IMP-6683).

Obsidian Butte, as a whole, has not been recorded (CEC 2003a, p. 4.3-10). At the proposed plant site, the level of elevation ranges from 230 feet bmsl (below mean sea level) to approximately 220 feet bmsl at the highest point. The terrain is generally flat and "the volcanic glass dome of obsidian butte rises approximately 100 feet above the surrounding farm land" (CE Obsidian 2009, p. 5.5-5). "Materials suitable for prehistoric stone tool manufacture were quarried, from the obsidian, rhyolite, and silicified sediment (Wonderstone) deposits at Obsidian Butte…" (CE Obsidian 2009, p. 5.4-7). The area surrounding Obsidian Butte is composed of about 40 acres of rhyolite flow with chunks of rhyolitic obsidian covered by a weathered light gray pumice mantle. Soon after Obsidian Butte formed by volcanic activity, it was covered by the water of Lake Cahuilla, as indicated by rounded pumice clasts and seven wave cut benches on the east slope of the dome. In the past, Lake Cahuilla extended much farther than the boundaries of the present-day Salton Sea. It appears that over the course of "the last approximately 1,300 years the Colorado River has filled the Salton Sink at least four times and that, at each time, the level of Lake Cahuilla…" (CE Obsidian 2009a, p. cult-15) appears to have reached the top of the sill that separated Lake Cahuilla from the Gulf of California. During these times, the project vicinity would have been under approximately 315 feet of water. Native Americans could only access obsidian when Lake Cahuilla was low (CEC 2003a, p. 4.3-10).

In February, 2002, the consultant to the project owner sent letters to Native American individuals and groups listed by the NAHC in preparation of the SSU6 Application for Certification. The Native American individuals and groups had requested that they be informed regarding construction development in Imperial County. Telephone calls were

made to the same people in February and March 2003. As a result of those calls, two Native Americans stated that Obsidian Butte was important to Native Americans.
During the permitting process for the SSU6 project, staff also spoke with numerous Native Americans regarding the proposed project. As a result of those conversations, many Native Americans asserted that Obsidian Butte was important to the Native American community (CEC 2003, p. 4.3-20). In the FSA completed for SSU6, staff concluded that Obsidian Butte, due to presence of archaeological sites, met the requirements of the CRHR under criterion 4, the ability to yield important information. In addition to a recommendation of eligibility under criterion 4, staff recommended that Obsidian Butte retained sufficient integrity to function as a traditional cultural place, and so Obsidian Butte, for the purpose of staff's analysis, would be treated as a traditional cultural place (CEC 2003, p. 4.3-21), eligible to the CRHR under criterion 1: "is associated with events that have made a significant contribution to the broad patterns of California's history and cultural heritage" (OHP 1999, p. 15).

Historic Canals and Drainages Identified During Surveys for this Amendment

Cultural resources surveys for the original project did not identify canals and drainages within the boundaries of the original SSU6 project. The survey conducted for the amended BR123 project identified the Vail Canal Laterals 3-A, 4, and 4-A that appeared to be greater than 50 years old within the project amendment boundaries. The Vail Canal Laterals, 3-A, 4, and 4-A appear to have been associated with historic canal expansion in the Imperial Valley between 1920 and 1930.

The California Irrigation Company began construction of canals in 1891 to transport water from the Colorado River to the Salton Sink. The company went out of business after a series of mishaps that included the overflow of the Colorado River and the current formation of the Salton Sea (CE Obsidian 2009, p. 5.4-13). IID was formed in 1911, filling the service gap left by the defunct California Irrigation Company. After 1929, IID expanded the canals with lateral drain systems. Many of the canals and lateral drain systems were constructed of dirt, or lined with tile, and provided irrigation outlets to farms. Regional agriculture still relies on many of the canals and drainage ditches that were already in place before the Second World War.

The Vail Canal, a major canal in the vicinity of the project was constructed in 1910 by the Vail family. It is situated just south of the Salton Sea, on land owned by the Vail family, and runs between the Alamo River and the New River. The Vail Laterals in the project vicinity are also located between the Alamo River and New River. The consultant to the project owner stated that the Vail Canal Laterals (Vail Laterals) may have been part of IID's expansion and would date from the drainage expansion period of 1920s and 1930s. The consultant to the project owner noted that it is likely that modern concrete linings were added to the drainages sometime between 1949 and the present (CE Obsidian 2009, p. 35).

Vail Lateral 3-A

Vail lateral 3-A is "an open, concrete lined trapezoidal shaped channel with flowing water. Canal walls are poured slab concrete with a smooth finish" (CE Obsidian 2009, Department of Parks and Recreation (DPR) Primary Record Form). The width at the top of the canal is 10 feet 3 inches, at the bottom it is approximately 2 feet, and the canal's depth is approximately 4 feet. A segment of the canal is labeled 1949, and includes two sluice gates. One sluice gate is stamped "Vail 3-A," and divides the canal into two segments that correspond with an intersecting road. The second sluice gate is labeled "367," and leads to another unnamed canal that runs east-west. Water was present in the canal at the time of recordation (CE Obsidian 2009, p. 32).The presence of a concrete lining that was not a feature of the early canal laterals leads staff to recommend that Vail Lateral 3-A would not be eligible to the CRHR.

Vail Lateral 4

In the project area, Vail Lateral 4 is an open, smooth, concrete-lined, trapezoidal-shaped channel with flowing water, composed of three segments. The first segment (Segment 1), has a contractor's stamp that indicates, "MERRILL 1993", is 2,254 feet long and is situated between Gentry Road and Kuns Road. It has two sluice gates, and the first, "Vail 4," divides the canal into sections that correspond with intersecting roads. Segment 1 is 14 feet, four inches wide, with a bottom width of approximately 2 feet and a depth of approximately 4 feet. The additional sluice gate is labeled "415" and leads to an east-west-trending unnamed irrigation canal. Small sluice valves are present in the wall of the segment to allow drainage to agricultural fields (CE Obsidian 2009, DPR Primary Record Form).

Segment 2 is 200 feet long and contains water. The southernmost portion of this canal segment is 0.25 mile south of the intersection of Gentry Road and McNerny Road at an unnamed dirt road. It is 11 feet, 4 inches wide, approximately 2 feet wide at the bottom and approximately 4 feet deep. There is also a stamped contractor's mark that says "Ryerson 1992" (CE Obsidian 2009, DPR Primary Record Form).

Segment 3 is 150 feet long and its southern point is 60 feet north of McNerny Road. It has a contractor's stamp that says "Ryerson 1992." The recorders note that "McNerny Road is incorrectly labeled with a sign that says McKendry Road" (CE Obsidian 2009, DPR Primary Record Form). Two sluice gates are present; one sluice gate labeled "Vail 4" divides the segment into sections that correspond with an intersecting road. The second sluice gate is labeled "419," and is the entrance to an east-west running unnamed canal. The portion of the segment north of McNerny Road, includes the sluice gate labeled "419," is 13 feet, 9 inches wide, and is 49 feet long with water present (CE Obsidian 2009, DPR Primary Record Form). The remainder of the segment is 9 feet, 7 inches in width at the top, approximately 2 feet at the bottom and approximately 4 feet deep. Sluice valves in the north wall of the segment allow water access to agricultural fields. The presence of the contractor's mark indicating that modifications were made to Vail Lateral 4 in 1992 leads staff to recommend that Vail Lateral 4 would not be eligible to the CRHR.

Vail Lateral 4-A

This recorded canal segment extends 1.4 miles in the project area and parallels Boyle Road. It is an open, trapezoidal-shaped canal with flowing water. The top width of the canal is 10 feet 3 inches; the bottom width is approximately 2 feet, with a depth of approximately 4 feet. It has a contractor's stamp "Granite Construction 2003" and includes 9 sluice gates. Four of the sluice gates are labeled "Vail 4-A" and correspond with intersecting roads. The other five sluice gates are labeled "455," "457," "459," "460," and “461-A,” and lead into east-west-running, unnamed irrigation canals to the west. The unnamed canals have sluice valves in the side of the canal to provide water to agricultural fields (CE Obsidian 2009, DPR Record Form).

In January, 2010, staff asked the project owner questions regarding the Vail Canal and Vail Laterals, Vail 3-A, Vail 4 and Vail 4-A. The information provided stated that the Vail Canal was visible on the Map of Imperial Valley Settlements dated July, 1913, and Vail Laterals 3-A, 4, and 4-A were apparent on the IID Plat Book Map dated November, 1924. This indicates that Vail Laterals 3, 4, and 4A were built prior to 1924, and that it is very likely that that they were built during the drainage expansion that occurred between 1920 and 1930 (Salamy 2010). The consultant to the applicant recommended Vail Laterals 3-A, 4, and 4-A as potentially eligible to the CRHR based on their “associations with agricultural development of the region” (CE Obsidian 2009, p. 5.4-22). However, the information that the Vail 3-A, Vail 4, and Vail 4-A laterals, originally unlined dirt, are now concrete-lined indicates an important change in a character-defining feature of these canals, resulting in a loss of their integrity of materials. Based on this loss, staff recommends that, while these canals may be potentially eligible for listing on the CRHR, their loss of integrity due to the addition of concrete lining significantly impairs their ability to convey historical significance, and so additional impacts to them would not be significant.

IMPACTS

For an amendment, staff is charged with assessing impacts to cultural resources that are due to modifications of a previously certified project. To assess potential impacts to cultural resources from an amended project, staff must consider whether the amended project modifications would cause additional or more severe impacts to identified, or undiscovered cultural resources than impacts identified in the Energy Commission Final Decision for the previously approved project.

PREHISTORIC ERA RESOURCES

Since transmission line routes are not part of this amendment, previously identified archaeological sites along these routes, and the potential to encounter additional archaeological sites on these routes, will not be discussed in the analysis for this amendment.

The cultural resources section of the SSU6 FSA identified an archaeological site and lithic scatter, located on Obsidian Butte, which would be adversely affected by construction of a pipeline, access road, and Well Pad OB-3. Staff recommended that the archaeological site and lithic scatter were eligible to the CRHR and that construction of the pipeline and Well Pad OB-3 would constitute a significant impact to a significant cultural resource. Since amended project BR123 would not construct Well Pad OB-3 or the associated access road and brine pipeline, there would not be an impact to Obsidian Butte and the archaeological sites that were recommended eligible to the CRHR.

Historic-Era Resources

New cultural resources surveys conducted for BR123 identified historic canals and drainages within or adjacent to project boundaries that had not been identified within the boundaries of the SSU6 project. The Vail Canal Laterals 3-A, 4, and 4-A were confirmed to be more than 50 years of age and recommended as potentially eligible for the CRHR. However, improvements to these canals have resulted in a loss of integrity sufficient to impair their ability to convey historical significance. Staff, therefore, recommends that the Vail Canal Laterals 3-A, 4, and 4-A are not eligible for listing on the CRHR. Since, under CEQA, staff need only consider potential impacts to resources eligible or recommended eligible for listing on the CRHR, impacts to the Vail Canal Laterals 3-A, 4, and 4-A will not be analyzed.

Ethnographic Resources

The original FSA found Obsidian Butte eligible to the CRHR under criterion 1, which states that a potential cultural resource might be considered eligible to the CRHR if it is associated with events that have made a significant contribution to the broad patterns of California's history and cultural heritage. The FSA assessed Obsidian Butte's eligibility to the CRHR under criterion 1, as follows, "Obsidian Butte is potentially eligible to the inventory of sacred places. It also retains sufficient integrity to provide important information about prehistory and to function as a Traditional Cultural Place [an ethnographic resource], and will be treated as also eligible for the CRHR under criterion 1 for the purposes of this analysis" (CEC 2003a, p. 4.3-21). The FSA also concluded that "Obsidian Butte would be impacted by diminishing aspects of integrity (setting, feeling, and association) under criterion 1" (CEC 2003a, p. 4.3-21), but also concluded that construction of SSU6 would not materially impair Obsidian Butte's eligibility to the CRHR under criterion 1 (CEC2003a, p. 60).

For the BR123 amendment, staff is tasked with determining whether there would be additional impacts to Obsidian Butte as an ethnographic resource, eligible to the CRHR under criterion 1, caused by modifications to the previously certified SSU6, and, if so, would they be significant. For BR123, Well Pad OB3 and its two associated wells would be moved from Obsidian Butte and placed within the boundaries of the project, the associated above-ground brine pipeline would no longer be placed on Obsidian Butte, and McKendry Road would not be widened (CE Obsidian 2009, p. 2-3). Thus the amended project would result in a less significant physical impact on Obsidian Butte than the original project.

However, a comparison between the heights of project components indicates that three stacks reaching 99 feet would be built for BR123 as opposed to two for SSU6. Cooling towers would decrease from 55 feet to 53 feet, but there would be three cooling tower plumes rather than two as proposed for the SSU6 facility. The associated plumes for the BR123 amendment would also be visible 11 percent of the time as opposed to being visible 1 percent of the time for the SSU6 project. The BR123 Staff Assessment Visual Section asserted that the plume dimensions would be comparable to existing geothermal facilities and would not stand out in the visual setting.

In conclusion, the BR123 amendment would remove a well pad and associated pipeline from Obsidian Butte, but some of the taller project components would be slightly more numerous. Therefore, the impact would not exceed that of the SSU6 project.

For BR123, staff concludes that there are no additional significant impacts from BR123. Staff also concludes that the only significant impacts identified in the Commission Final Decision (the construction of well pad OB3, associated pipeline, and access road) would not occur because the BR123 amendment has removed them from the project. Therefore, the significant impacts to Obsidian Butte that would have resulted from the original project would be avoided under the amended project.
Although it is not likely that the amended project would impact any previously undiscovered archaeological sites, a potential still exists that archaeological material left in the area by prehistoric uses of Obsidian Butte, including hearths, campsite remnants, and evidence of fish and flora processing, might be discovered during construction. Those impacts that could occur during construction-related excavations, potentially affecting unknown buried archaeological resources, are the only impacts to cultural resources from the construction proposed in the amendment. The existing cultural resources Conditions of Certification **CUL-1** through **CUL-9** would mitigate to below the level of significance impacts to resources discovered during construction.

CUMULATIVE IMPACTS

A cumulative impact under CEQA refers to a proposed project's incremental effects considered over time and together with those of other, nearby, past, present, and reasonably foreseeable future projects whose impacts may compound or increase the incremental effect of the proposed project. Cumulative impacts to archaeological cultural resources in the vicinity of the BR123 project site could occur if any other existing or proposed projects, in conjunction with the proposed BR123 modifications, had or would have impacts on archaeological resources that, considered together, would be significant.

The original FSA concluded that SSU6 would have no cumulative impacts (CEC 2003a, p. 4.3-23). Staff has determined that the amended BR123 would not impact any known CRHR-eligible built-environment resources and that the project would, in fact, avoid known archaeological resources that SSU6 would have impacted. Since the BR123 project impacts to any CRHR-eligible archaeological resources discovered during construction would be mitigated to a less-than-significant level by the project’s compliance with existing Conditions of Certification **CUL-1** through **CUL-9**, and since similar protocols can be applied by other projects in the area, staff does not expect any incremental BR123 project effects on archaeological resources to be cumulatively considerable when viewed in conjunction with other projects.

CONCLUSIONS AND RECOMMENDATIONS

The amended BR123 project would comply with all applicable LORS. Staff determined that the amended BR123 project would avoid previously identified significant impacts to CRHR-eligible cultural resources and would not impact any additional CRHR-eligible resources.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

The applicant requested that **CUL-10** be deleted because the amended project would not locate a well pad on Obsidian Butte and consequently would not impact the previously identified CRHR-eligible cultural resources. Staff recommends deleting both **CUL-10** and **CUL-11** since the amended project would not impact any Obsidian Butte cultural resources. Existing cultural resources Conditions of Certification **CUL-1** through **CUL-9** would ensure that impacts to newly discovered cultural resources would be mitigated to below the level of significance. With the continued applicability of Conditions of Certification **CUL-1** through **CUL-9**, staff concludes that construction and operation of BR123 would not cause a significant direct, indirect, or cumulative impact to cultural resources.

Changes to the cultural resources conditions of certification are shown below, with deleted text shown as ~~strikethrough~~.

~~**CUL-10**~~ ~~The project owner shall ensure that a cultural anthropologist meeting the Secretary of Interior's Standards prepares a study of the ethnographic area that contains the Salton Sea Unit 6 Project for review and approval by the CPM. After permitting, the project owner shall provide a Scope of Work (SOW) to the CPM identifying aspects of the ethnographic study for review and approval. The SOW may identify additional individuals or groups that shall be included in the consultation. The scope of the study will focus on the area of the project with an emphasis on Obsidian Butte. Consultation shall be with the Cahuilla, FortMohave, and Quechan Tribes and other interested groups as identified through the consultation with the Native American Heritage Commission. The report shall also provide a cultural background documenting the importance of Obsidian Butte, a record of the resource including boundaries, and recommendations for eligibility for the CRHR and management of the resource, if applicable. Following the start of commercial operation of the power plant, the project owner shall provide a draft copy of the ethnographic study to the CPM for review and approval. The draft will be considered final upon CPM approval. Copies of the final ethnographic study shall be submitted to the CPM and other institutions agreed to by the involved Native American groups.~~

~~**Verification:**~~ ~~No later than 30 days after the start of ground disturbance, a copy of the SOW of the ethnographic study shall be submitted to the CPM for review and approval. Within six months following the start of commercial operation of the power plant, the project owner shall provide a copy of the ethnographic study of the project area (with request for confidentiality, if needed), along with any associated maps, to the CPM for review and approval.~~

~~**CUL-11**~~ ~~Prior to ground disturbing activities in the area of the Obsidian Butte Lithic Scatter, a protective fence shall be erected between the Obsidian Butte Lithic Scatter and the construction area. The fenced area shall be designated as a "Do no enter" area. The fence shall be constructed a minimum of 25 feet outside the recorded boundary of the Obsidian Butte Lithic Scatter. During the periods of ground disturbance and construction in this area, the CRS or CRM~~

~~shall inspect the area to ensure that the fence is maintained in good condition and that no ground disturbing activities occur within the area designated as "Do not enter." If the Obsidian Butte Lithic Scatter cannot be avoided, prior to any ground disturbing activities within the recorded boundaries of the Obsidian Butte Lithic Scatter, the project owner shall ensure that details of the proposed data recovery program are included in the CRMMP or as an addendum to the CRMMP and provided to the Imperial County Planning Department for review and approval and a copy shall be provided to the CPM. The data recovery program shall be implemented and completed prior to ground disturbing activities in the recorded area of the Obsidian Butte Lithic Scatter. The data recovery program shall include surface collection, testing for subsurface deposits, and systematic excavation and collection of samples of subsurface deposits sufficient to recover the information values contained in the site.~~

~~**Verification**~~ ~~If the lithic scatter cannot be avoided by fencing pursuant to this condition, at least thirty days prior to ground disturbing activities in the area of the Obsidian Butte Lithic Scatter, the CRMMP or an addendum to the CRMMP with details of the proposed data recovery program shall be provided to the Imperial County Planning Department for review and approval and a copy shall be provided to the CPM.~~

REFERENCES

CEC 2003—California Energy Commission. Decision for the Salton Sea Geothermal Unit 6 (now Black Rock 123) Power Plant Application for Certification, Docket No. 02-AFC-2, Imperial County, published on December 19, 2003.

CEC 2003a—California Energy Commission. Staff Assessment for Salton Sea Geothermal Unit 6 (now Black Rock 123) Power Plant Application for Certification (02-AFC-2). Imperial County, California. Published August 5, 2003.

CE Obsidian 2002—CE Obsidian Energy, LLC. Application for Certification: Salton Sea Unit 6 Project, Volume 1. July, 2002.

CE Obsidian 2009—CE Obsidian Energy, LLC (CE Obsidian/AECOM). Salton Sea Geothermal Unit 6 (now Black Rock 123) Power Plant, Petition for License Amendment, to Modify Project to Allow Construction of Three 53 MW Units, Totaling 159 MW. Submitted to the California Energy Commission, March 10, 2009.

CE Obsidian 2009a—CE Obsidian Energy, LLC (CE Obsidian/CH2MHill). CalEnergy Black Rock 1-3 Data Responses 1-64. Submitted to the California Energy Commission, November, 2009.

OHP 1999—California Office of Historic Preservation, *State Law & Historic Preservation, Statutes, Regulations & Administrative Policies Regarding the Preservation & Protection of Cultural & Historical Resources*, Technical Assistance Series Bulletin 10 (current as of 1999).

Salamy 2010—Jerry Salamy, CH2MHill. Email Communication with Dale Rundquist of the Energy Commission, regarding Vail Laterals, February 2, 2010.

LAND USE

Testimony of Jeanine Hinde

INTRODUCTION

The Salton Sea Unit 6 Geothermal Power Project (SSU6) was certified by the California Energy Commission (Energy Commission) in December 2003 as a 185-MW geothermal power plant (Energy Commission 2003a). The application for certification for SSU6 included an assessment of the project's consistency with applicable laws, ordinances, regulations, and standards (LORS) pertaining to land use and agricultural resources (CE Obsidian Energy 2002). In 2003, Energy Commission staff assessed compatibility of SSU6 with existing and planned land uses. Conditions of certification were proposed to address impacts relating to the conversion and loss of productive agricultural land, ensure conformity of SSU6 with the Imperial County Land Use Ordinance, and address anticipated transmission line right-of-way issues (Energy Commission 2003b).

The project applicant subsequently proposed to increase generation from 185 MW to 215 MW, and in May 2005, the Energy Commission approved a petition to modify the SSU6 project and amend the related conditions of certification (Energy Commission 2005a). Proposed modifications to SSU6 included adding approximately 20 acres to the project site, which required moderate changes to the conditions of certification relating to land use (Energy Commission 2005b).

In March 2009, the SSU6 project owner filed a petition with the Energy Commission requesting to amend its license to allow for the construction of three smaller geothermal plants that would be co-located on the same site as the original SSU6 project, and the name of the project was changed on August 3, 2009, to the Black Rock 1, 2, and 3 Geothermal Power Project (BR123). The three plants associated with BR123 would be constructed on the same 80-acre site that was previously analyzed for SSU6 plus a contiguous 80-acre site south of the original site for a total of 160 acres. The entire 160-acre site is located on a parcel that is owned by Imperial Magma, an affiliated company of the project applicant. Compared to the project that was certified in December 2003, many of the facilities for BR123 would be consolidated within the expanded main plant site. A 34-acre borrow site would be established near the BR123 plant site (referred to in this staff assessment as Borrow Area 1). Soils imported from Borrow Area 1 would be used to construct several project features at the main plant site.

This analysis addresses whether BR123 would cause additional impacts relating to land use planning and agricultural resources compared to the licensed SSU6 project.

APPLICABLE LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

This section discusses LORS pertaining to land use and agricultural resources that are new or that have changed since SSU6 was certified in 2003, or that have become applicable due to the differences between the SSU6 and BR123 projects.

FEDERAL

No changes to federal LORS pertaining to land use planning or agricultural resources have been identified since SSU6 was certified in 2003.

STATE

Williamson Act

Portions of the BR123 project are under the jurisdiction of the California Land Conservation Act of 1965, commonly known as the Williamson Act, which enables local governments to enter into contracts with private landowners to restrict specific parcels of land to agricultural or related open space use. In return, landowners receive property tax assessments that are based on farming and open space uses instead of full market value (California Department of Conservation 2007a).

The Williamson Act empowers local governments to establish "agricultural preserves" consisting of lands devoted to agricultural and other compatible uses (Gov. Code § 51230). When such preserves are established, the locality may offer to owners of included agricultural land the opportunity to enter into annually renewable contracts that restrict the land to agricultural use for at least 10 years (i.e., the contract continues to run for 10 years following the first date upon which the contract is not renewed). In return, the landowner is guaranteed a relatively stable tax base, founded on the value of the land for agricultural/open space use only and unaffected by its development potential (Gov. Code §§ 51240, 51243, 51244).

Regulations governing land uses in agricultural preserves identify construction and maintenance of various utilities as compatible uses while allowing local municipalities to impose additional limiting conditions (Gov. Code § 51238):

> *(a) (1) Notwithstanding any determination of compatible uses by the county or city pursuant to this article, unless the board or council after notice and hearing makes a finding to the contrary, the erection, construction, alteration, or maintenance of gas, electric, water, communication, or agricultural laborer housing facilities are hereby determined to be compatible uses within any agricultural preserve.*
>
> *(2) No land occupied by gas, electric, water, communication, or agricultural laborer housing facilities shall be excluded from an agricultural preserve by reason of that use.*

The regulations establish principles of compatibility for uses that are approved on contracted lands (Gov. Code § 51238.1):

> *(a) Uses approved on contracted lands shall be consistent with all of the following principles of compatibility:*
>
> *(1) The use will not significantly compromise the long-term productive agricultural capability of the subject contracted parcel or parcels or on other contracted lands in agricultural preserves.*
>
> *(2) The use will not significantly displace or impair current or reasonably foreseeable agricultural operations on the subject contracted parcel or parcels*

or on other contracted lands in agricultural preserves. Uses that significantly displace agricultural operations on the subject contracted parcel or parcels may be deemed compatible if they relate directly to the production of commercial agricultural products on the subject contracted parcel or parcels or neighboring lands, including activities such as harvesting, processing, or shipping.

(3) The use will not result in the significant removal of adjacent contracted land from agricultural or open-space use.

Surface Mining and Reclamation Act

Because of its use for obtaining fill material for plant construction, Borrow Area 1 is subject to the Surface Mining and Reclamation Act of 1975 (SMARA), which requires the State Mining and Geology Board (SMGB) to adopt state policy for the reclamation of mined lands and the conservation of mineral resources. SMARA provides a comprehensive surface mining and reclamation policy for the regulation of surface mining operations to ensure that adverse environmental impacts are minimized and mined lands are reclaimed to a usable condition. SMARA also encourages the production, conservation, and protection of the state's mineral resources (Pub. Resources Code §§ 2710–2796, California Department of Conservation 2007b).

SMARA requirements apply to any entity engaged in surface mining operations in California that disturb more than 1 acre or remove more than 1,000 cubic yards of material. Activities that are subject to SMARA include, but are not limited to: prospecting and exploratory activities, dredging and quarrying, streambed skimming, borrow pitting, and the stockpiling of mined materials (Imperial County Planning & Development Services 2010). Borrow pits are defined as: "Excavations created by the surface mining of rock, unconsolidated geologic deposits or soil to provide material (borrow) for fill elsewhere." (14 Cal. Code Regs. § 3501)

SMARA allows for a one-time exemption for certain surface mining operations, subject to approval by SMGB. SMARA addresses conditions under which an exemption may be granted, including "Any other surface mining operations that the board, as defined by Section 2001, determines to be of an infrequent nature and which involve only minor surface disturbances." (Pub. Resources Code § 2714[f])

SMARA regulations establish state policy for the reclamation of mined lands, including performance standards for reclamation of prime and other agricultural land (14 Cal. Code Regs. §§ 3707 and 3708).

LOCAL

Imperial County Municipal Code – Surface Mining and Reclamation

Imperial County (County) has a regulatory program for activities in the County that are subject to the requirements of SMARA, which is implemented through the County's Municipal Code. The Surface Mining and Reclamation Ordinance (Title 9, Division 20) regulates surface mining operations, in accordance with SMARA. The purpose and intent of the ordinance is to ensure the continued availability of important mineral resources while regulating mining operations to ensure that:

A. Adverse environmental effects are prevented or minimized and that mined lands are reclaimed to a usable condition which is readily adaptable for alternative land uses.

B. The production and conservation of minerals are encouraged, while giving consideration to values relating to recreation, watershed, wildlife, range and forage, and aesthetic enjoyment.

C. Residual hazards to the public health and safety are eliminated.

The ordinance requires that "no person shall conduct surface mining operations unless a permit, reclamation plan, and financial assurances for reclamation have first been approved by the county." (Imperial County Municipal Code Title 9, Division 20, § 92001.03) The provisions of Division 20 apply to all lands within the County, both public and private. Compliance with Division 20 requires submittal of an application for a site approval(s) or a reclamation plan approval for a surface mining or land reclamation project on forms provided by the planning department. Reclamation plan applications are required, at a minimum, to address each of the elements required by SMARA (Pub. Resources Code §§ 2772 and 2773; Imperial County Municipal Code Title 9, Division 20, § 92001.00)

The process of reclamation includes maintaining water and air quality, and minimizing flooding, erosion and damage to wildlife and aquatic habitats caused by surface mining. The final step in this process is often topsoil replacement and revegetation with suitable plant species (Imperial County Planning & Development Services 2010).

Imperial County General Plan – Conservation and Open Space Element

The Conservation and Open Space Element of the County's General Plan addresses preservation of mineral resources and protection of other environmental resources from the adverse effects of mining activities. The following goal and related objectives from the Conservation and Open Space Element are applicable to the amended project (Imperial County Planning & Development Services 1993):

Goal 5. *The County will identify and protect mineral resources for extraction and minimize the effect of mining on surrounding land uses and other environmental resources.*

Objective 5.1. *Encourage the sound extraction of mineral and quarry/aggregate resources while protecting the natural desert environment.*

Objective 5.3. *Require that mineral extraction and reclamation operations be performed in a way that is compatible with surrounding land uses and minimize adverse effects on the environment.*

Objective 5.4. *Safeguard the use and full development of all mineral deposits.*

Objective 5.5. *Regulate the development adjacent to or near all mineral deposits and geothermal operations due to the potential for land subsidence.*

SETTING

SITE AND VICINITY DESCRIPTION

Proposed facilities for the BR123 amended project are located approximately 1,000 feet southeast of the Salton Sea in an unincorporated area of Imperial County (CE Obsidian Energy 2009a). The project area is in the northern portion of the Imperial Valley, a large, irrigated agricultural region that is surrounded by desert. The area is mostly used for agricultural operations and geothermal power production. Crops grown in the area include lettuce, asparagus, carrots, onions, alfalfa, sugarcane, and sweet beets (CE Obsidian Energy 2009b).

The project site is located approximately 6 miles northwest of the town of Calipatria and approximately 7½ miles southwest of the town of Niland. A total of 10 existing geothermal power plants that are owned by affiliates of the project applicant are located within a 2-mile radius of the BR123 site (CE Obsidian Energy 2009a) (Integrated Engineers & Contractors 2009). These geothermal projects are located in the Salton Sea Known Geothermal Resource Area (KGRA).

The main plant site would be located on a 160-acre parcel that is bounded by McKendry Road to the north, Severe Road to the west, Grubbel and Peterson Roads to the south, and Boyle Road to the east (CE Obsidian Energy 2009a). Most of the proposed plant site is irrigated agricultural land (CE Obsidian Energy 2009b). Fallow land and the Vulcan and Hoch Power Plants border the east side of the plant site. Beyond the site to the west are wetlands and open space near the Salton Sea. A portion of the Salton Sea National Wildlife Refuge lies north of the plant site. Agricultural land lies south of the plant site. An automotive parts manufacturing facility is located in the agricultural area south of the proposed plant site (CE Obsidian Energy 2009a). Existing land uses in the project area are shown in **LAND USE Figure 1**.

Other property east of the BR123 project site is occupied by CalEnergy's (under Imperial Magma) administration buildings, warehousing facilities, and a waste disposal staging site (CE Obsidian Energy 2009b).

DESIGNATED LAND USES AND ZONING

BR123 would be located in an area that is under the jurisdiction of Imperial County. The Imperial County General Plan was adopted by the Board of Supervisors in November 1993. As shown below in **LAND USE Table 1**, land use designations for the area where project facilities would be located include Agriculture and Industry (Imperial County Planning & Development Services 2008). The County's General Plan defines these land use designations:

- **Agriculture.** This land use designation is intended to preserve lands for agricultural production and related industries, ranging from light to heavy agriculture. Where this designation is applied, agriculture shall be promoted as the principal and dominant use to which all other uses shall be subordinate. Geothermal plants may be permitted with a conditional use permit (CUP) subject to zoning and environmental review.

- **Industry.** This land use designation applies to heavy manufacturing land uses located in areas with the necessary supporting infrastructure and located away from conflicting existing or planned land uses. Generally, these lands are not suitable for agricultural use and are located adjacent to major transportation systems.

The Geothermal/Alternative Energy and Transmission Element of the County's General Plan provides a framework for the review and approval of geothermal projects in the County. The County supports and encourages the development of geothermal resources in a manner compatible with the protection of agricultural and environmental resources (Imperial County Planning & Development Services 2006).

The County of Imperial has adopted a zoning ordinance to divide designated land uses into classes of use zones and sub-zones to regulate land uses and protect the public health, safety, and welfare. Most of the area where BR123 project facilities would be located is zoned Heavy Agriculture (A-3). Lot sizes in the A-3 zone are typically 40 acres or larger. The A-3 zone is intended to prevent the encroachment of incompatible uses onto and within agricultural lands and to prohibit the premature conversion of such lands to nonagricultural uses. Land uses in the A-3 zone are limited primarily to uses and activities that are related to and compatible with agricultural uses (Imperial County Municipal Code Title 9, Division 5, § 90509).

One of the injection well pads, INJ OB-2, would be located in an area that is zoned Medium Industrial (M-2), which designates areas for wholesale commercial, storage, trucking, assembly type manufacturing, general manufacturing, research and development, medium intensity fabrication and other similar medium intensity processing facilities (Imperial County Municipal Code Title 9, Division 5, § 90516).

The County regulates the use of land for geothermal purposes through zoning and local land use permits. Regulations for geothermal projects are contained in the County's Land Use Ordinance (Imperial County Municipal Code, Title 9, Division 17). To facilitate and manage geothermal resources, the County has established an overlay zone designation of "G," the Geothermal Overlay Zone (GOZ), to indicate that geothermal production is conditionally permitted through a CUP in that general zone (CE Obsidian Energy 2009a). All of the proposed BR123 project area is located within an existing GOZ established by the County.

Geothermal facilities and projects are permitted in the A-3-G zone, subject to first securing a CUP (Imperial County Municipal Code, Title 9, Division 5, § 90509.02). For geothermal projects, CUPs are also referred to as "geothermal permits" (CE Obsidian Energy 2009a).

LAND USE Table 1 Land Use Designations and Zoning Categories			
Project Component	**Jurisdiction**	**General Plan Land Use Designation**	**Zoning Category**
BR123 Plant Site, Including Three Production Well Pads and Associated Pipelines	County of Imperial	Agriculture	Heavy Agriculture, Geothermal Overlay (A-3-G)
Brine Injection Well Pads – INJ OB-1, INJ OB-2, and INJ OB-3	County of Imperial	Agriculture	Heavy Agriculture, Geothermal Overlay (A-3-G) Medium Industrial, Geothermal Overlay (M-2-G)
Aboveground Pipelines Connecting to Brine Injection Wells	County of Imperial	Agriculture, Industry	Heavy Agriculture, Geothermal Overlay (A-3-G) Medium Industrial, Geothermal Overlay (M-2-G)
Borrow Site	County of Imperial	Agriculture, Industry	Heavy Agriculture, Geothermal Overlay (A-3-G)
Source: CE Obsidian Energy 2009a			

IMPACT ANALYSIS

THRESHOLDS OF SIGNIFICANCE

Based on Appendix G of the California Environmental Quality Act Guidelines (State CEQA Guidelines), an impact to land use or agricultural resources is considered significant if the project would:

- physically divide an established community;
- conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project adopted for the purpose of avoiding or mitigating an environmental effect;
- conflict with any applicable habitat conservation plan or natural community conservation plan;
- convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance, as shown on the maps prepared pursuant to the Farmland Mapping and Monitoring Program of the California Resources Agency, to nonagricultural use;
- conflict with existing zoning for agricultural use, or a Williamson Act contract; or
- involve other changes in the existing environment which, due to their location or nature, could result in conversion of farmland to nonagricultural use.

The amended project would be located in a rural area that primarily consists of a mixture of agricultural and industrial uses, including geothermal power production. The project would not physically divide an established community. No habitat conservation or natural community conservation plans are in effect that would apply to the project area, and the project would not conflict with any such plans. Because the amended project would have no impact related to these thresholds, they are not discussed further in this section.

EFFECTS OF THE AMENDED PROJECT ON LAND USE

OVERVIEW OF THE AMENDED PROJECT

The three geothermal power plants associated with BR123 would be located near the center of the BR123 plant site. Areas for construction laydown and parking that were previously planned for location offsite are proposed for location within the main plant site. A total of nine new production wells would be located on three well pads within the north, west, and south perimeters of the site.

The amended project would require construction of nine brine injection wells that are proposed for location on three approximately 4.7-acre well pads outside of the BR123 plant site; each of these well pads (INJ OB-1, INJ OB-2, and INJ OB-3) would be approximately 8,000 to 10,000 feet from the main plant site. The three injection well pads are proposed for location along paved and unpaved rural roadways and are mostly surrounded by agricultural land. The automotive parts manufacturing facility discussed above is located on property near the area proposed for INJ OB-2. Areas proposed for the main plant site and well pads INJ OB-1 and INJ OB-3 are in agricultural production (CE Obsidian Energy 2009a).

Brine would be pumped from the BR123 plant site to the offsite injection wells through three aboveground injection pipelines. The 30-inch injection pipelines would be constructed out of a highly corrosive-resistant alloy material and welded in the field during assembly. The injection pipelines generally parallel existing rural roadways. A portion of the pipeline to INJ OB-3 crosses an open area between an agricultural field and an area occupied by CalEnergy facilities and buildings (CE Obsidian Energy 2009b).

The proposed 34-acre Borrow Area 1 would be located southeast of the BR123 plant site along the south side of Peterson Road (CE Obsidian Energy 2009a). The borrow site is bordered on the north by the Vulcan and Hoch Power Plants (CE Obsidian Energy 2009b). Construction of the modified BR123 project would require a total of approximately 361,840 cubic yards (cu. yd.) of borrow material for construction of the perimeter berm, the buildings/power block area and on-site roads, the well pads and construction laydown area, and the brine ponds and mud sumps. A portion of injection pipeline INJ OB-2 would cross the proposed borrow site.

EFFECTS ON AGRICULTURAL LANDS

The California Department of Conservation (DOC) Division of Land Resource Protection works with landowners, local governments, and researchers to conserve the state’s farmland and open space, and it maintains a statewide inventory of farmlands. These lands are mapped as part of the Farmland Mapping and Monitoring Program (FMMP), based on a classification system that combines technical soil ratings and current land use. Lands are divided and mapped into the following farmland categories (often referred to as Important Farmland categories) and other categories based on their suitability for agricultural use:

- **Prime Farmland.** Farmland with the best combination of physical and chemical features able to sustain long term agricultural production. This land has the soil quality, growing season, and moisture supply needed to produce sustained high yields.
- **Farmland of Statewide Importance.** Farmland similar to Prime Farmland but with minor shortcomings, such as greater slopes or less ability to store soil moisture.
- **Unique Farmland.** Farmland of lesser quality soils used for the production of the state's leading agricultural crops. This land is usually irrigated, but may include nonirrigated orchards or vineyards as found in some climatic zones in California.
- **Farmland of Local Importance.** Land of importance to the local agricultural economy as determined by each county's board of supervisors and a local advisory committee.
- **Grazing Land.** Land on which the existing vegetation is suited to the grazing of livestock.
- **Urban and Built-up Land.** Land occupied by structures with a building density of at least 1 unit to 1.5 acres, or approximately six structures to a 10-acre parcel.
- **Other Land.** Land not included in any other mapping category. Common examples include low-density rural developments; brush, timber, wetland, and riparian areas not suitable for livestock grazing; confined livestock, poultry or aquaculture facilities; strip mines, borrow pits; and water bodies smaller than 40 acres.
- **Water.** Perennial water bodies with an extent of at least 40 acres.

As of 2006, approximately 543,140 acres of Important Farmland were in Imperial County, classified by the DOC as 196,180 acres of Prime Farmland, 311,650 acres of Farmland of Statewide Importance, 2,280 acres of Unique Farmland, and 33,040 acres of Farmland of Local Importance (DOC 2007c).

As shown in **LAND USE Table 2**, the amended project would convert a total of approximately 190 acres of Important Farmland to nonagricultural uses. This total acreage includes 116 acres of Important Farmland that would have been converted from construction of the original SSU6 project (Energy Commission 2005b). Changes to the configuration of BR123 project facilities have added approximately 74 acres of Important Farmland to the total acreage that would be converted by the project. Based on Appendix G of the State CEQA Guidelines, Energy Commission staff considers the conversion of Important Farmland to be a significant impact of the amended project. Energy Commission staff proposes modifying the existing Condition of Certification **LAND-6** to require compensation for the total 190 acres of Important Farmland that would be converted by the BR123 project. **LAND-6** requires the project applicant, in coordination with the County, to: 1) contribute funds to Imperial County for a 1:1

purchase of Prime Farmland for permanent farming use and/or easement purchases, 2) establish a local agricultural land trust, or 3) contribute funds to a statewide agricultural land trust (Energy Commission 2003b). Based on conclusions reached by Energy Commission staff in 2003 for the assessment of project impacts to Important Farmland, implementation of Condition of Certification **LAND-6** would reduce the impact to a less-than-significant level. See the discussion below under "Proposed Modifications to the Conditions of Certification."

LAND USE Table 2
Effects of the Amended Project on Agricultural Resources

Project Component	Prime Farmland (acres)	Farmland of Statewide Importance (acres)	Williamson Act Contracted Lands (acres)
BR123 Plant Site	40.2	100.1	0.0
Brine Injection Well Pads	14.1	0.0	9.4
Right-of-Way (ROW) for Aboveground Pipelines Connecting to Brine Injection Wells [1]	27.1	8.2	11.1
Totals	81.4	108.3	20.5

[1] Assumes a 100-foot right-of-way (ROW) plus 10 percent for expansions joints for a total ROW of 100 feet.
Source: CE Obsidian Energy 2009a

Portions of injection well pads INJ OB-1 and INJ OB-2 and their associated pipelines would be located on parcels currently under Williamson Act contracts (Assessor's Parcel Number [APN] 020-110-029, Preserve 2 Contract 2000-005; APN 020-110-031, Preserve 2 Contract 2000-002) (CE Obsidian Energy 2009a). The two affected parcels contain a total of approximately 398 acres that are subject to Williamson Act contracts. Construction of the amended project would remove 20.5 acres of these Williamson Act contracted lands from agricultural use (**LAND USE Table 2**).

The County has found geothermal uses to be compatible with agricultural uses provided that geothermal wells and pipelines are designed and constructed in a way that ensures continuance of viable agricultural operations on affected agricultural fields (Minnick, pers. comm., 2006). The County allows construction of geothermal wells and pipelines on lands held under Williamson Act contracts provided that viable agricultural operations can continue on at least 80 percent of the historical agricultural field (e.g., an 80-acre [gross] parcel, with a historical field footprint of 70 acres, could be reduced in size to a 56-acre field footprint). For agricultural operations that are greater than 10 acres, the County considers geothermal wells and pipelines to be compatible with its Williamson Act Program (Minnick, pers. comm., 2006).

Of the total 20.5 acres of Williamson Act lands that would be removed from agricultural production by the amended project, approximately 15.0 acres are associated with injection well pad INJ OB-1 and its injection pipeline. These project facilities would be located on an approximately 320-acre parcel (APN 020-110-031) that is subject to a Williamson Act contract. Based on the County's calculations in the example above, the field could be reduced in size by as much as 64 acres and continue to support a viable agricultural operation.

Of the total 20.5 acres of Williamson Act lands impacted by the amended project, approximately 6.0 acres are associated with injection well pad INJ OB-2 and a small segment of its injection pipeline. These project facilities would be located on an approximately 78-acre parcel (APN 020-110-031) that is subject to a Williamson Act contract. The 78-acre field could be reduced in size by as much as 16 acres and continue to support a viable agricultural operation. Impacts to agricultural operations on these parcels have also been minimized by locating the well pads and pipelines along the property boundaries and as close to the BR123 plant site as possible. Based on the County's General Plan and additional County guidelines, the geothermal wells and pipelines for BR123 are considered compatible with the County's Williamson Act program.

As discussed above, the Williamson Act addresses principles of compatibility for uses that are approved on contracted lands. Approved uses may not compromise long-term productivity or displace or impair current or reasonably foreseeable agricultural operations (Gov. Code § 51238.1). Based on the fact that the proposed geothermal wells and pipelines would not violate the principles of compatibility for uses on contracted lands, Energy Commission staff considers the BR123 amended project to be consistent with Williamson Act objectives. See Land Use Table 3, below.

EFFECTS RELATED TO THE PROPOSED BORROW SITE

The project applicant is proposing to obtain imported soil from a new borrow site for construction of various project features at the BR123 site (CE Obsidian Energy 2009a). The proposed 34-acre Borrow Area 1 is located immediately southeast of the main plant site. Approximately one-half of the proposed borrow site is classified by DOC as Prime Farmland. The eastern half is classified by DOC as Urban and Built-up Land. The project applicant is proposing to stockpile topsoil that would be removed from the main plant site. Following extraction of borrow material from the borrow site, it would be backfilled with the stockpiled topsoil from the main plant site. The borrow site would be returned to conditions approximating those currently present (CE Obsidian Energy 2009a).

Borrow site work would not result in a permanent conversion of agricultural lands to nonagricultural uses. Impacts to agricultural resources and uses at the proposed borrow site would be temporary, and no significant long-term impact to agricultural resources would occur relating to borrow site activities.

As discussed above, SMARA requirements apply to any entity engaged in surface mining operations in California that disturb more than 1 acre or remove more than 1,000 cubic yards of material. Borrow pitting is an activity that is subject to SMARA. Imperial County's regulatory program relating to activities in the County that are subject to SMARA is implemented through its Municipal Code. The borrow site work for the BR123 project would be subject to the County's surface mining and reclamation ordinance (Valenzuela, pers. comm., 2010).

SMARA allows for a one-time exemption for certain surface mining operations, subject to approval by SMGB. The Energy Commission requested a determination from SMGB on whether the new borrow site would be eligible for such an exemption from SMARA. The request was based on statutory provisions pertaining to activities that are infrequent and involve only minor surface disturbances (Pub. Resources Code § 2714[f]). SMGB considered the request at its regularly scheduled Board meeting, and on May 13, 2010, the one-time exemption was granted on the condition that all topsoil from the borrow site be salvaged and replaced as part of reclaiming the site to agricultural use (SMGB 2010). Verification of satisfactory reclamation of the site by SMGB staff is also required.

Condition of Certification **LAND-9** is proposed to address the temporary construction-related impact to Prime Farmland at the borrow site. It includes performance standards that are consistent with state policy for reclamation of prime and other agricultural land (14 Cal. Code Regs. §§ 3707 and 3708). See the discussion below under "Proposed Modifications to the Conditions of Certification." Refer also to <u>Condition of Certification **SOIL & WATER-16** in the Soil & Water Resources section of this staff assessment, which addresses preparation and implementation of a detailed plan for reclaiming areas disturbed at Borrow Area 1.</u>

The project applicant is also proposing to use an existing borrow site that is located approximately 2 miles northeast of the BR123 site on property that is owned by an affiliated company of the project applicant. This borrow site has been used for ongoing construction work at existing geothermal facilities. All necessary approvals for use of the existing borrow site have been obtained (Hackley, pers. comm., 2010).

With implementation of Condition of Certification **LAND-9**, Energy Commission staff considers the BR123 amended project to be consistent with SMARA and the County's ordinance addressing surface mining activities. See **LAND USE Table 3**, below.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

In 2003, Energy Commission staff identified LORS relating to land use planning and agricultural resources that were applicable to the original project (Energy Commission 2003b). These LORS continue to apply to BR123. The proposed design changes for the amended project are being planned and would be implemented to comply with the Imperial County Land Use Code and the Imperial County General Plan, including the Land Use Element, the Agricultural Element, the Conservation and Open Space Element, and the Geothermal/Alternative Energy and Transmission Element. The BR123 project sites and facilities would be located in an existing GOZ where geothermal production is conditionally permitted; therefore, the amended project is considered consistent with County zoning.

Review of the amended project description contained in the 2009 amendment petition (CE Obsidian Energy 2009a) resulted in identification of additional LORS relating to land use and agricultural resources that are applicable to BR123. **LAND USE Table 3** provides an assessment of consistency of the amended project with the additional LORS.

LAND USE Table 3 Consistency of the Amended Project with LORS for Land Use and Agricultural Resources		
LORS	**Consistency Determination**	**Basis for Consistency**
State		
California Land Conservation Act of 1965 (Williamson Act) (Gov. Code commencing with § 51200)	Consistent	The Williamson Act addresses uses that are considered compatible in areas that are identified as agricultural preserves and on contracted lands. Construction and maintenance of various utilities are identified as compatible uses in areas identified as agricultural preserves (Gov. Code § 51238). The amended project would supply geothermal electric power, which is considered a compatible use. The Williamson Act establishes principles of compatibility on contracted lands. Approved uses may not compromise long-term productivity or displace or impair current or reasonably foreseeable agricultural operations (Gov. Code § 51238.1). The Imperial County Planning & Development Department considers geothermal wells and pipelines to be compatible with the County's Williamson Act program provided that individual parcels still allow for a viable agricultural operation on at least 80 percent of the historical agricultural field, and the agricultural operation is greater than 10 acres. The amended project is being planned and designed to minimize impacts on Williamson Act contracted lands, in accordance with Imperial County's standards for geothermal facilities on such lands; therefore, the amended project is considered consistent with Williamson Act objectives and principles of compatibility.
Surface Mining and Reclamation Act (Pub. Resources Code §§ 2710–2796)	Consistent, with implementation of **LAND-9** (see below)	Borrow pitting is an activity that is subject to SMARA. SMARA addresses conditions under which an activity may be exempted from the requirements of SMARA (Pub. Resources Code § 2714[f]). On May 13, 2010, the State Mining and Geology Board (SMGB) granted a one-time exemption for borrow pitting activities at the 34-acre borrow site for the project (SMGB 2010). The SMGB decision includes a requirement that the borrow site be returned to agricultural use as soon as extraction of borrow material is completed.
Local		
Imperial County Municipal Code, Title 9 Land Use Code, Division 20 Surface Mining and Reclamation, § 92001	Consistent, with implementation of **LAND-9** (see below)	Activities at the borrow site would be subject to the requirements of the Imperial County Surface Mining and Reclamation Ordinance, which regulates surface mining operations, in accordance with SMARA. Compliance with SMGB conditions for returning the borrow site to agricultural use would constitute compliance with the Imperial County ordinance.

LAND USE Table 3 Consistency of the Amended Project with LORS for Land Use and Agricultural Resources		
LORS	**Consistency Determination**	**Basis for Consistency**
Imperial County General Plan – Conservation and Open Space Element, Goal 5 addressing mineral resources (Imperial County Planning & Development Services 1993)	Consistent, with implementation of **CIVIL-1**; **LAND-9**; and **SOIL & WATER-1**, **-2**, and **-3**.	Energy Commission staff has evaluated the amended petition for BR123 to determine whether it would cause direct or indirect changes to the environment, pursuant to CEQA and the State CEQA Guidelines. Potential impacts relating to borrow site activities are evaluated for the full range of environmental resource sections addressed in this proposed amendment. Potential adverse effects on the environment would be minimized through compliance with all applicable permitting requirements relating to the control of soil erosion and waste discharges and protection of surface and groundwater quality. Irrigation of the Imperial Valley has altered the natural desert environment. Impacts to agricultural land uses and habitat values present at the project site would be minimized through implementation of a reclamation plan for Borrow Area 1 (see Conditions of Certification **SOIL & WATER-1** and **LAND-9**). (Refer to the Facility Design, Soil and Water Resources, and Biological Resources sections of this staff assessment for further details on mitigation requirements.) Compliance with Goal 5 would be achieved with implementation of Conditions of Certification **CIVIL-1**; and **SOIL & WATER-1**, **-2**, and **-16**. The County of Imperial bears responsibility for controlling land uses in parts of the County identified as important for geothermal development and mineral resource extraction.

CUMULATIVE IMPACTS

Approximately 20 percent of the land within the County is irrigated for agricultural purposes, most notably the central area known as Imperial Valley, which covers approximately 512,160 acres and extends southward for approximately 50 miles from the southern end of the Salton Sea into Mexico (Imperial County Planning & Development Services 1996). The BR123 site is located in the northern portion of the Imperial Valley.

LAND USE Table 4 shows the most recent data compiled by the FMMP on land use conversions involving Important Farmland in Imperial County. Data are available through 2006. These data generally represent a continuing decline in total acreage of Important Farmland in the County. Future agricultural production in the County has been affected by land use conversions to urban and other uses (Imperial County Planning & Development Services 1996).

LAND USE Table 4 Land Use Conversions in Imperial County Involving Important Farmland	
Year	**Imperial County**
	Total Acreage of Important Farmland Inventoried
1996	555,592
1998	554,889
2000	554,964
2002	550,161
2004	545,612
2006	543,140
	Total Losses and Gains of Important Farmland (acres)
1996–1998	-5,036 + 4,333 = 703 net loss
1998–2000	-2,229 + 2,303 = 74 net gain
2000–2002	-6,706 + 5,622 = 1,084 net loss
2002–2004	-13,609 + 9,058 = 4,551 net loss
2004–2006	-5,237 + 2,765 = 2,472 net loss
	Important Farmland Converted to Urban and Built-up Land (acres)
1996–1998	422
1998–2000	302
2000–2002	1,014
2002–2004	1,985
2004–2006	849

* Notes: Important Farmland includes Prime Farmland, Farmland of Statewide Importance, Unique Farmland, and Farmland of Local Importance.
The net gain for 1998–2000 partially relates to an urban line correction that resulted in a conversion from Urban and Built-up Land.
Source: Data compiled by Energy Commission staff based on online reports prepared by DOC through 2007 (DOC 2007c).

The County anticipates significant population growth through approximately 2020, in part because the local economy is becoming more diversified and less reliant on the economic cycles of agriculture (Imperial County Planning & Development Services 2008). In addition to economic diversification, the County has identified a number of other factors that may accelerate population growth in the future, including growth in the geothermal industry.

With few exceptions, virtually all land surrounding cities and unincorporated communities is classified as Important Farmland (Imperial County Planning & Development Services 1996). Most land that surrounds existing urban uses in the County is classified by DOC as Prime Farmland or Farmland of Statewide Importance. Net losses of existing Important Farmland are anticipated as development of new urban and industrial uses are approved in the County. Urban encroachment resulting in conversion of Important Farmland is occurring in several areas, particularly in the vicinities of El Centro, Imperial, and Calexico in the southern portion of the Imperial Valley.

An analysis of the cumulative impacts of implementing the amended BR123 project must be taken together with other past, present, and probable future projects producing related impacts, as required by the State CEQA Guidelines (14 Cal. Code Regs. § 15130). A list of projects in the vicinity of the BR123 project area has been identified to include in the cumulative analysis for the project; these projects would result in the conversion of additional acreages of Important Farmland to nonagricultural uses:

- **Hudson Ranch Geothermal Development Project (commonly referred to as the CHAR project), in the Salton Sea KGRA.** The Hudson Ranch I Geothermal Development Project is a 49.9-MW geothermal power generating facility under development within the Salton Sea KGRA. The project is being implemented by a subsidiary of CHAR, LLC on property that is owned by Magma Power Company. It is located approximately 3.4 miles northeast of the BR123 project site in an unincorporated area of the County southwest of the city of Niland. A CUP for the CHAR project is in place. The project is planned to be operational in 2010.

- **Ormat Geothermal Projects, in the Brawley KGRA.**

    - **North Brawley Geothermal Project.** Construction is nearing completion on the North Brawley Geothermal Project, which will be operated by Ormat. The North Brawley project is located approximately 11.2 miles southeast of the BR123 plant site, in an unincorporated area of the County north of Brawley. The project is a 49.9-MW binary power plant, including 20–26 production wells and 14–20 injection wells (CE Obsidian Energy 2009a, Integrated Engineers & Contractors 2009).
    - **East Brawley Geothermal Project.** Ormat also plans to develop a 49.9-MW geothermal power plant in its East Brawley field, located east of the North Brawley field (CE Obsidian Energy 2009a). The proposed East Brawley project would be located near the intersection of Ward Road and Best Road, approximately 11.8 miles southeast of the BR123 plant site. The East Brawley plant would be constructed nearly identically to the North Brawley plant (Integrated Engineers & Contractors 2009).

- **Ram East Brawley, in the Brawley KGRA.** The Ram East Brawley project is being developed by Ram Power, Inc. The project site is located a few miles east of Brawley near the Imperial Irrigation District East Highline Canal. This 50-MW plant is expected to be operational in 2012 with other identical units to follow (Integrated Engineers & Contractors 2009).

- **Blackrock 4, 5, and 6, in the Salton Sea KGRA.** This project is being proposed by CalEnergy (Integrated Engineers & Contractors 2009), and although details are unknown, it is anticipated that construction and operation would be similar to BR123.

Historical FMMP data show a consistent decline in availability of Important Farmland in Imperial County that is primarily the result of conversions to urban uses. Between 1996 and 2006, conversions of Important Farmland to Urban and Built-up Land resulted in losses of approximately 1,070 acres of Prime Farmland, 2,400 acres of Farmland of Statewide Importance, 30 acres of Unique Farmland, and 1,070 acres of Farmland of Local Importance (DOC 2007c). The total acreage of Important Farmland converted over this 10-year period represents approximately 1.0 percent of the average total Important Farmland inventoried during those years. Although data are not yet available, additional conversions of Important Farmland have occurred since 2006.

The effectiveness of mitigation measures designed to offset the impacts of farmland conversion from other approved projects in the Imperial Valley is not known. Given the losses of Important Farmland from 1996 through 2006, coupled with additional acreage lost between 2006 and the present, and additional acres that could be lost through future implementation of development projects in the Imperial Valley, Energy Commission staff considers the overall loss to be a significant adverse cumulative effect.

Although the BR123 project would result in conversion of approximately 190 acres of Important Farmland to nonagricultural uses, Condition of Certification **LAND-6** requires a mitigation fee payment to compensate for this loss at a 1:1 ratio. With implementation of Condition of Certification **LAND-6**, Energy Commission staff concludes that the amended BR123 project would not contribute considerably to the significant future cumulative condition relating to the loss of Important Farmland.

CONCLUSIONS AND RECOMMENDATIONS

Energy Commission staff has reviewed the amendment petition (CE Obsidian Energy 2009a) and evaluated whether BR123 would cause additional impacts relating to land use planning and agricultural resources that were not previously identified in the process to certify the original project in 2003.

Staff recommends changes to the conditions of certification that were last amended in 2005 (Energy Commission 2005b). With implementation of these recommended changes (described below), BR123 would comply with all applicable LORS. Approval of the amendment would not cause any new significant impacts relating to land use planning and agricultural resources, pursuant to CEQA (Pub. Resources Code § 21000 et seq.) and the State CEQA Guidelines (14 Cal. Code Regs. § 15000 et seq.).

PROPOSED MODIFICATIONS TO THE CONDITIONS OF CERTIFICATION

In 2003, Energy Commission staff proposed conditions of certification to address impacts to land use and agricultural resources (Energy Commission 2003b). Those conditions of certification were part of the project that was certified in 2003. An addendum to the final staff assessment included a minor adjustment to the total acreage of Prime Farmland that would be converted to nonagricultural use (Energy Commission 2003c).

The conditions of certification were modified again in 2005 as part of the process to approve a petition to amend the project. Condition of Certification **LAND-8** was added to address modifying the CUP for the project (Energy Commission 2005b). Changes to the project caused a moderate increase in the total acreage of Important Farmland that would be converted by the project, from 96 to 116 acres, which was reflected in changes to **LAND-6**.

The project description contained in the 2009 amendment petition proposes using the BR123 main plant site for construction laydown and parking areas, which were originally proposed in the area south of the project site (CE Obsidian Energy 2009a). The original conditions of certification addressed temporary land use impacts at the off-site construction areas with Condition of Certification **LAND-4.** With the proposal to relocate these construction areas to the main plant site, **LAND-4** is no longer considered applicable to the project and Energy Commission staff proposes that it be struck from the conditions of certification for this proposed amendment.

BR123 would convert approximately 81.4 acres of Prime Farmland and 108.3 acres of Farmland of Statewide Importance to nonagricultural uses (Land Use Table 2). Based on Appendix G of the State CEQA guidelines, this conversion is considered a significant impact of the amended project. **LAND-6** was originally proposed to address conversion of Prime Farmland and Farmland of Statewide Importance (CE Obsidian Energy 2002). Energy Commission staff proposes modifying **LAND-6** to clarify that the total acreage that would be converted to nonagricultural uses includes both farmland categories.

The Land Use Element of the Imperial County General Plan addresses industrial development standards and provides that: "Geothermal plants may be permitted with a conditional use permit subject to zoning and environmental review." The 2009 amendment petition states that Imperial County intends to either issue a CUP or amend the existing CUP that was issued by the County for the original SSU6 project (Imperial County Planning & Development Services 2008, CE Obsidian Energy 2009a). **LAND-8** was added to the conditions of certification to address compliance with CUP requirements. Energy Commission staff proposes modifying **LAND-8** to require the project applicant or owner to demonstrate compliance with Imperial County's new or amended CUP.

The 2009 amendment petition proposes establishing a 34-acre borrow site (Borrow Area 1) southeast of the BR123 plant site for construction of several project features at the plant site. As discussed above, the western portion of the proposed borrow site is classified by DOC as Prime Farmland. Although work at the borrow site would not result in a permanent conversion of agricultural lands to nonagricultural uses, a temporary construction-related impact to farmland would occur at the borrow site. Condition of Certification **LAND-9** is proposed to address this impact and to satisfy requirements of SMGB for returning the site to agricultural use.

Energy Commission staff proposes no changes to Conditions of Certification **LAND-1**, **LAND-2**, **LAND-3**, **LAND-5**, and **LAND-7**. Deleted language is shown in ~~strikethrough~~, and new text is shown in <u>**bold and underline**</u>.

LAND-1 The project owner shall comply with the minimum design and performance standards for the "A-3-G" Zone set forth in the Imperial County Land Use Ordinance.

<u>Verification:</u> At least 30 days prior to the start of construction, the project owner shall submit written documentation, including evidence of review by the Imperial County Planning/Building Department that the project meets the above standards.

LAND-2 The project owner shall comply with the parking standards established by the Imperial County Land Use Ordinance (Title 9, Division 4).

<u>Verification</u>: At least 30 days prior to start of construction, the project owner shall submit to the Compliance Project Manager, written documentation, including evidence of review by Imperial County Planning/Building Department that the project conforms to all applicable parking standards.

LAND-3 The project owner shall ensure that any signs erected (either permanent or for construction only) comply with the outdoor advertising regulations established by the Imperial County Land Use Ordinance (Title 9, Division 4).

<u>Verification:</u> At least 30 days prior to start of construction, the project owner shall submit to the Compliance Project Manager, written documentation, including evidence of review by Imperial County, that all erected signs will conform to the Land Use Ordinance.

~~**LAND-4** The project owner shall provide the Director of the Imperial County Planning/Building Department for review and comment and the CPM for review and approval, descriptions of the final lay down/staging areas identified for construction of the project. The description shall include:~~

~~Assessor's Parcel numbers;~~

~~addresses;~~

~~land use designations;~~

~~zoning;~~

~~site plan showing dimensions;~~

~~owner's name and address (if leased); and,~~

~~duration of lease (if leased); and, if a discretionary permit was required, copies of all discretionary and/or administrative permits necessary for site use as lay down/staging areas.~~

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

LAND-5 The project owner shall provide to the Compliance Project Manager for approval, a site plan with dimensions showing the locations of the proposed buildings and structures in compliance with the minimum yard area requirements (setbacks) from the property line as stipulated in the Imperial County Land Use Ordinance.

<u>Verification:</u> At least 30 days prior to the start of construction, the project owner shall submit a site plan showing that the project conforms to all applicable yard area requirements as set forth in the Imperial County Land Use Ordinance.

LAND-6 The project owner shall mitigate for the loss of ~~116~~ 190 acres at a 1:1 ratio for the conversion of Prime Farmland **and Farmland of Statewide Importance** as classified by the California Department of Conservation, to a nonagricultural use, for the construction of the power generation facility.

Verification: The project owner will provide a mitigation fee payment (payment to be determined) to an Imperial County agricultural land trust, or a statewide agricultural land trust, within 30 days following the construction start, as set forth in a prepared Farmlands Mitigation Agreement.

The project owner shall provide in the Monthly Compliance Reports a discussion of any land and/or easements purchased in the preceding month by the trust with the mitigation fee money provided, and the provisions to guarantee that the land managed by the trust will be ~~farmed~~ **available** in perpetuity **for farming**. This discussion must include the schedule for purchasing ~~116~~ **190** acres of prime farmland and/or easements within five years of start of construction as compensation for the ~~116~~ **190** acres of Prime Farmland **and Farmland of Statewide Importance** to be converted by ~~the SSU6~~ **BR123**.

LAND-7 The project owner shall provide to the Compliance Project Manager, copies of the BLM Right-of-Way grant and Plan Amendment for the CDCA.

Verification: At least 30 days prior to the start of any project-related construction the project owner shall submit copies of the BLM right-of-way grant and documentation that a Plan Amendment for the CDCA was approved.

LAND-8 The project owner shall comply with Imperial County's ~~Minor Modification to the Conditional Use Permit~~ requirements for ~~the additional 20 acres not covered by the CUP that was approved by Imperial County~~ **issuance of a conditional use permit (CUP), or an amendment to the CUP that was issued by the County for the project that was certified in 2003**.

Verification: At least 30 days prior to the start of construction, the project owner shall submit to the Compliance Project Manager, written documentation, including evidence of review and approval by Imperial County that the project conforms to all requirements of the ~~Minor Modification to the~~ CUP.

LAND-9 **The project owner shall ensure implementation of performance standards for reclamation of Prime Farmland at Borrow Area 1 southeast of the BR123 main plant site. Performance standards shall be established in accordance with the applicable SMARA regulation for reclamation of Prime Farmland (14 Cal. Code Regs. § 3707). Plans and performance standards for reclamation of the site shall fully comply with the requirements of the State Mining and Geology Board (SMGB) for returning the site to agricultural use. The following standards shall apply to agricultural land at the borrow site where the approved end use is agriculture:**

(a) Mining operations on Prime Farmland, as defined by the U.S. Soil Conservation Service, shall return all disturbed areas to the fertility

level that was present on the property before site disturbance occurred.

(b) All topsoil at the borrow site shall be salvaged. When distinct soil horizons are present, topsoil shall be segregated by defined A, B, and C soil horizons. Upon reconstruction of the soil, the sequence of horizons shall have the A atop the B, the B atop the C, and the C atop graded overburden.

(c) Reclamation shall be deemed complete when productive capability of the affected land is equivalent to or exceeds, for 2 consecutive crop years, that of the premining condition or similar crop production in the area.

(d) Use of fertilizers or other soil amendments shall not cause contamination of surface or groundwater.

These performance standards shall be part of the plan described under Condition of Certification SOIL & WATER-16 in the Soil & Water Resources section of this staff assessment.

Verification: Refer to verification requirements described under Condition of Certification SOIL & WATER-16 in this staff assessment, which shall also apply to Condition of Certification LAND-9.

REFERENCES

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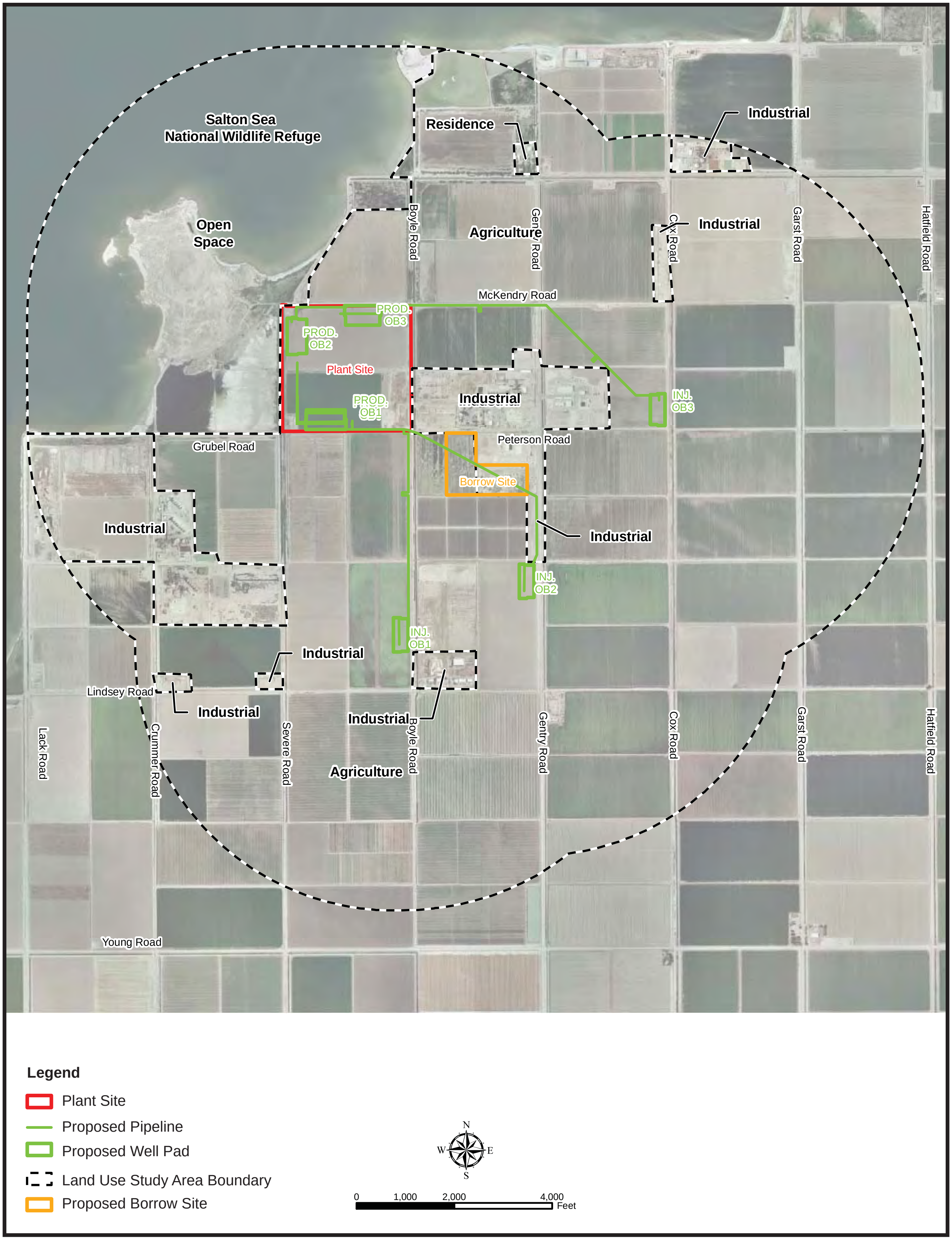
LAND USE - FIGURE 1

Blackrock 1, 2 and 3 Geothermal Power Project - Existing Land Uses



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: CE Obsidian Energy 2009a

NOISE AND VIBRATION

Testimony of Shahab Khoshmashrab

INTRODUCTION

The applicant's proposed amendment would allow conversion of the licensed 215 MW Salton Sea Geothermal Unit 6 (SSU6) project to the 159 MW Black Rock 1, 2, 3 (BR123) geothermal power project. The BR123 project would yield reduced noise and vibration impacts compared to those predicted for the SSU6project. The applicant has proposed to comply with the conditions of certification included in the SSU6 Commission Decision, and staff agrees that such compliance would provide adequate protection from noise and vibration impacts.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

Some applicable local LORS have been updated since the Commission Decision on SSU6. The result of these updates would have no effect on the amended project, as summarized in **NOISE AND VIBRATION Table 1**:

NOISE AND VIBRATION Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Protocol: Applicable Law	Protocol: Description
Imperial County General Plan Noise Element	No change from previous analysis
Imperial County General Plan Geothermal and Transmission Element (Imperial 2006)	Update in 2006 resulted in no change from previous analysis
Imperial County Noise Ordinance (Imperial 2002)	Update in 2002 echoes General Plan Noise Element; result is no change from previous analysis

ANALYSIS

Staff has reviewed the petition for potential environmental effects and consistency with applicable LORS. Based on this review, staff determined that compliance with the conditions of certification incorporated into the SSU6 Commission Decision would ensure adequate protection from adverse noise impacts.

The Commission Decision on the SSU6 project (CEC 2003a) included conditions of certification that ensures no significant adverse noise impacts would result from the construction and operation of that project. Staff analyzed the proposed BR123 project to compare its likely impacts to those of the SSU6 project.

CONSTRUCTION IMPACTS

Construction noise from power plant construction and from pile driving (the noisiest operation in constructing the project) would yield noise levels at the Wildlife Refuge residence (the nearest sensitive human receptor) of 38 dBA L_{eq} and 52 dBA L_{eq} respectively (CE Obsidian 2009, Amendment Petition, § 5.8.4.1), figures in compliance with LORS. This compares to levels of 56 dBA L_{eq} to 71 dBA L_{eq} at the residence predicted for the SSU6 project (CEC 2003, Staff Assessment, p. 4.6-9, p. 4.6-11). Construction noise from the BR123 project would thus be considerably less than previously analyzed for SSU6. The applicant proposes to comply with the conditions of certification included in the SSU6 Commission Decision. This would thus yield adequate protection from adverse noise impacts due to construction of BR123.

OPERATION IMPACTS

Noise due to operation of BR123 would attenuate to approximately 40 dBA L_{eq} at the Wildlife Refuge residence (CE Obsidian 2009, Amendment Petition, § 5.8.4.2), in compliance with LORS. This compares to 39 dBA L_{eq} for the SSU6 project (CEC 2003, Staff Assessment, p. 4.6-14). Both these figures are less than the existing ambient noise levels at the residence (CE Obsidian 2009, Amendment Petition, § 5.8.4.2; Table 5.8-6), and would thus create an insignificant adverse impact. Compliance with the SSU6 conditions of certification would yield adequate protection from adverse noise impacts due to operation of BR123.

CUMULATIVE IMPACTS

No projects have been identified that lie near enough to the Black Rock project to create cumulative noise impacts. As was determined in the initial staff analysis for SSU6, any future projects would be required to comply with applicable noise LORS. Therefore, staff concludes that no cumulative noise and vibration impacts are possible.

CONCLUSIONS AND RECOMMENDATIONS

The BR123 project, if constructed and operated in compliance with the conditions of certification included in the Salton Sea Unit 6 Commission Decision, would comply with applicable noise and vibration LORS, and would produce no significant adverse noise and vibration impacts on sensitive receptors. Staff recommends that BR123 be constructed and operated in compliance with the conditions of certification (Condition of Certification **NOISE-1** through **NOISE-8**) included in the SSU6 Commission Decision.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

Staff proposes no modifications to the Noise and Vibration conditions of certification.

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PUBLIC HEALTH

Testimony of Obed Odoemelam, Ph.D.

INTRODUCTION

The applicant, CE Obsidian Energy, LLC (CEOE), proposes to build three separate 53 MW power plants that would constitute the 159 MW Black Rock 1, 2, and 3 Geothermal Power Project (BR123), rather than the licensed 215 MW single-unit Salton Sea Unit 6 Geothermal Power Plant (SSU6). This analysis focuses on the impacts of the proposed 159 MW BR123 project version to determine whether or not to recommend approval as staff did for the licensed SSU6 project, for which staff determined that potential impacts would be below the levels of health significance. The applicant's Petition to Amend (CEOE 2009 pp. 5.10 through 5.10-3) identified engineering modifications that would lead to a reduction in emission of one of the project's problem pollutants (hydrogen sulfide) when compared with the licensed project. The pollutants of specific focus in this **Public Health** analysis are the toxic air pollutants (TACs) for which there are no ambient air quality standards. These are known as the noncriteria pollutants, which differ from the criteria pollutants that have specific air quality standards. The potential impacts from these criteria pollutants are assessed in the **Air Quality** section by comparing total exposures to the applicable standards.

The health risk estimates from the applicant's health risk assessment should reflect the effectiveness of the proposed mitigation measures in maintaining impacts below levels of health significance. If, as with the licensed version, this analysis confirms that the risk estimates are below these significance levels, staff would recommend approval of the proposed amendment; if not, staff would recommend further mitigation to ensure mitigation to acceptable impact levels.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

There are no new LORS associated with this amendment that were not considered in staff's analysis of the licensed version. The LORS applicable to this analysis are listed below in **PUBLIC HEALTH Table 1**.

PUBLIC HEALTH Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Protocol: Applicable Law	Protocol: Description
Federal	
Clean Air Act section 112 (Title 42, U.S. Code section 7412).	This act requires new sources that emit more than 10 tons per year of any specified Hazardous Air Pollutant (HAP) or more than 25 tons per year of any combination of HAPs to apply Maximum Achievable Control Technology.
State	
California Health and Safety Code section 25249.5 et seq. (Proposition 65).	These sections establish thresholds of exposure to carcinogenic substances above which Prop 65 exposure warnings are required.

California Health and Safety Code section 41700.	This section states that “no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause injury or damage to business or property.”
California Energy Commission Staff Cooling Water Management Program Guidelines for Wet and Hybrid Cooling Towers in Power Plants.	Provides examples of adequate contents of a biocide application and monitoring program designed to control microorganisms to the maximum extent feasible within cooling towers using open circulating water systems.
California Public Resource Code section 25523(a); Title 20 California Code of Regulations (CCR) section 1752.5, 2300–2309 and Division 2 Chapter 5, Article 1, Appendix B, Part (1); California Clean Air Act, Health and Safety Code section 39650, et seq.	These regulations require a quantitative health risk assessment for new or modified sources, including power plants that emit one or more toxic air contaminants (TACs).
Local	
Imperial County Air Pollution Control District (ICAPCD) Rule 216	Requires use of Best Available Control Technology for Toxics (T-BACT) for major sources.
ICAPCD Rule 309	Requires annual fees for the Air Toxic Hot Spots (AB2588) program to recover implementation costs.
ICAPCD Rule 407	States that no source shall cause injury, detriment, nuisance or annoyance to the public, which could endanger their comfort, repose, health and safety, or property.
ICAPCD Rule 1002	Implements California’s Airborne Toxic Control Measures.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

This section describes staff’s method of analyzing the potential health impacts of toxic pollutants together with the criteria used to determine their significance.

METHOD OF ANALYSIS

The toxic emissions addressed in this **Public Health** section are those to which the public could be exposed during project construction and routine operation. If such toxic contaminants are released into the air or water, people may come in contact with them through inhalation, dermal contact, or ingestion via contaminated food or water.

The ambient air quality standards for the criteria pollutants, such as ozone, carbon monoxide, sulfur dioxide, particulate matter or nitrogen dioxide, are set to ensure the safety of everyone including those with heightened sensitivity to the effects of environmental pollution in general. Since noncriteria pollutants do not have such standards, a process known as a health risk assessment is used to determine if people might be exposed to them at unhealthy levels. The health risk assessment procedure consists of the following steps:

- Identification of the types and amounts of hazardous substances that a source could emit into the environment;
- Estimation of worst-case concentrations of project emissions into the environment using dispersion modeling;
- Estimation of the amounts of pollutants to which people could be exposed through inhalation, ingestion, and dermal contact; and
- Characterization of the potential health risks by comparing worst-case exposures to safety standards based on known health effects.

For the BR123 project and other sources, a screening-level risk assessment is initially performed using simplified assumptions intentionally biased towards protecting public health. That is, the analysis is designed to overestimate rather than underestimate the public health impacts from exposure to the emissions in question. In reality, it is likely that the actual risks from the project would be much lower than the risks estimated by the screening-level assessment. This overestimation is mostly accomplished by identifying conditions that would lead to the highest, or worst-case risks, and then assuming them in the study. The process involves the following:

- using the highest levels of emissions for pollutants that could be emitted from the source;
- assuming weather conditions that would lead to the maximum ambient concentration of pollutants;
- using the type of air quality computer models that predict the greatest plausible impacts;
- calculating health risks at the location where the pollutant concentrations are estimated to be highest;
- using health-based standards designed to protect the most sensitive members of the population (i.e., the young, elderly, and those with respiratory illnesses); and
- assuming that an individual's exposure to cancer-causing agents would occur over a 70-year lifetime (i.e., the individual remains at the point of maximum impact for 70 years).

A screening-level risk assessment would, at a minimum, include the potential health effects from inhaling hazardous substances. Some facilities may also emit certain substances that could present a health hazard from non-inhalation pathways of exposure (see California Air Pollution Control Officers Association (CAPCOA) 1993, Table III-5). When these substances are present in facility emissions, the screening-level analysis is conducted to include the following additional exposure pathways: soil ingestion, dermal exposure, and mother's milk (CAPCOA 1993, p. III-19).

The risk assessment process addresses three categories of health impacts: acute (short-term) health effects, chronic (long-term) noncancer effects, and cancer risk (also long-term). Acute health effects result from short-term (one-hour) exposure to relatively high concentrations of pollutants. Acute effects are usually temporary in nature, and include symptoms such as irritation of the eyes, skin, and respiratory tract.

Chronic health effects are those that result from long-term exposure to lower concentrations of pollutants. The exposure period is considered to be approximately from 10 to 100 percent of a lifetime (that is from 7 to 70 years). Chronic health effects include diseases such as reduced lung function and heart disease.

The analysis for noncancer health effects compares the maximum project contaminant levels to safe levels called “reference exposure levels” or RELs, which are the amounts of the toxic substances to which even sensitive individuals could be exposed and suffer no adverse health effects (CAPCOA 1993, p. III-36). This means that such exposure limits would serve to protect such sensitive individuals as infants, school pupils, the aged, and people suffering from illnesses or diseases, whom are more susceptible to the effects of toxic substance exposure. The RELs are based on the most sensitive adverse health effects reported in the medical and toxicological literature, and include specific margins of safety, which address the uncertainties associated with inconclusive scientific and technical information available at the time the review was conducted. They are, therefore, intended to provide a reasonable degree of protection against hazards that research has not yet identified. Each margin of safety is designed to prevent pollution levels that have been demonstrated to be harmful, as well as to prevent lower pollutant exposures that may pose an unacceptable risk of harm, even if the risk is not precisely identified as to nature or degree. Health protection can be expected if the estimated worst-case exposure is below the relevant reference exposure level. In such a case, an adequate margin of safety would be assumed to exist between the predicted exposure and the estimated threshold for toxicity.

Exposure to multiple toxic substances may result in health effects that are equal to, less than, or greater than effects resulting from exposure to the individual chemicals. Only a small fraction of the thousands of potential combinations of chemicals have been tested for the health effects of combined exposures. In conformance with CAPCOA guidelines, the health risk assessment assumes that the effects of the individual substances are additive for a given organ system (CAPCOA 1993, p. III-37). In those cases where the actions may be synergistic (greater than the sum), this approach may underestimate the health impact in question. For carcinogenic substances, the health assessment considers the risk of developing cancer and conservatively includes the previously noted assumption that the individual would be continuously exposed over a 70-year lifetime. The risk that is calculated is not meant to project the actual expected incidence of cancer, but rather a theoretical upper-bound number based on worst-case assumptions.

Cancer risk is expressed in terms of chances per million of developing cancer and is a function of the maximum expected pollutant concentration, the probability that a particular pollutant will cause cancer (known as “potency factor,” and established by the California Office of Environmental Health Hazard Assessment, or OEHHA), and the length of the exposure period. Cancer risks for individual carcinogens are added together to yield the total cancer risk from the source being considered. The conservative nature of the screening assumptions used means that actual cancer risks are likely to be considerably lower than estimated.

The screening-level analysis was performed to assess worst-case public health risks associated with the proposed project. If the screening analysis were to predict a risk of no significance, no further analysis would be necessary. However, if the risk were to be above the significance level, further analysis using more realistic site-specific assumptions would be performed to obtain a more accurate estimate of the public health risk in question.

SIGNIFICANCE CRITERIA

Staff assesses the health effects of exposure to toxic emissions by first considering the impacts on the maximally exposed individual. This individual is the person hypothetically exposed to project emissions at a location where the highest ambient impacts were calculated using worst-case assumptions, as described above. If the potential risk to this individual is below established levels of significance, staff would consider the potential risk as also less than significant anywhere else in the project area. As described earlier, noncriteria pollutants are evaluated for short-term (acute) and long-term (chronic) noncancer health effects, as well as cancer (long-term) health effects. The potential significance of project health impacts is determined separately for each of the three categories of health effects.

Acute and Chronic Noncancer Health Effects

Staff assesses the significance of noncancer health effects by calculating a "hazard index" for the exposure being considered. A hazard index is a ratio obtained by comparing exposure from facility emissions to the reference (safe) exposure level for the toxicant. A ratio of less than one would signify a worst-case exposure within safe levels. The hazard indices for all toxic substances with the same types of health effect are added together to yield a total hazard index for the source being evaluated. This total hazard index is calculated separately for acute and chronic effects. A total hazard index of less than one indicates that the cumulative worst-case exposure would be within safe levels. Under these conditions, health protection would be assumed even for sensitive members of the population. In such a case, staff would assume that there would be no significant noncancer public health impacts from project operations.

Cancer Risk

Staff relies upon regulations implementing the provisions of Proposition 65, the Safe Drinking Water and Toxic Enforcement Act of 1986 (Health & Safety Code §§ 25249.5 et seq.) for guidance in establishing the level of significance for its assessed cancer risks. Title 22, California Code of Regulations, Section 12703(b) states in this regard, that "the risk level which represents no significant risk shall be one which is calculated to result in one excess case of cancer in an exposed population of 100,000, assuming lifetime exposure." This risk level is equivalent to a cancer risk of 10 in 1 million, or $10x10^{-6}$. An important distinction from the provisions in Proposition 65 is that the Proposition 65 significance level applies separately to each cancer-causing substance, whereas staff determines significance based on the total risk from all cancer-causing chemicals from the source in question. Thus, the manner in which the significance level is applied by staff is more conservative (health-protective) than with Proposition 65.

As noted earlier, the initial risk analysis for a project is normally performed at a screening level, which is designed to overstate actual risks, so that health protection can be ensured. When a screening analysis shows the cancer risks to be above the significance level, refined assumptions would likely result in a lower, more realistic risk estimate. If facility risk, based on refined assumptions, were to exceed the significance level of 10 in 1 million, staff would require appropriate measures to reduce risk to less than significant. If, after all risk reduction measures have been considered, a refined analysis still identifies a cancer risk of greater than 10 in 1 million, staff would deem such risk to be significant, and would not recommend project approval.

SETTING

This section describes the environment in the vicinity of the proposed project site from the public health perspective. Features of the natural environment, such as meteorology and terrain, affect the project's potential for causing impacts on public health. An emission plume from a facility may affect elevated areas before lower terrain areas, because of a reduced opportunity for atmospheric mixing. Consequently, areas of elevated terrain can often be subjected to increased pollutant impacts. Also, the types of land use near a site influences population density and, therefore, the number of individuals potentially exposed to the project's emissions. Additional factors affecting potential public health impacts include existing air quality and environmental site contamination.

SITE AND VICINITY DESCRIPTION

The three generating units that would constitute the proposed BR123 project would be co-located near the same site as the original and amended SSU6 in unincorporated Imperial County. The proposed site would include the 80-acre parcel for the original proposal plus an additional 80 acres immediately to the south. The site lies west of State Highway 111 and north of State Highway 86, approximately 6 miles west of Calipatria, and southwest of the Salton Sea. The project's three power units would be located in the middle of the proposed site.

The project site is currently used for agriculture with the surrounding areas used for geothermal power production, as open space, wildlife preservation, and for industrial facilities and residences. The site is at an average elevation of 225 feet below sea level in a lightly populated area where the nearest residence is located approximately 0.8 miles to the northeast. The applicant (CEOE 2009, p. 5.10-29) provided specific information showing that there are no sensitive receptor locations within the 3-mile radius that would encompass the project's zone of potentially significant impacts. Sensitive receptor locations in this context are non-home locations housing sensitive individuals such as the elderly, school pupils and individuals with respiratory diseases who, as previously noted, are usually more sensitive to the effects of environmental pollutants than the general public. In most cases these locations would include schools, pre-schools, daycare centers, nursing homes, medical centers, hospitals, and colleges.

METEOROLOGY

Meteorological conditions, including wind speed, wind direction, and atmospheric stability, affect the extent to which pollutants are dispersed into ambient air as well as the direction of pollutant transport. This, in turn, affects the level of public exposure to emitted pollutants and associated health risks. When wind speeds are low and the atmosphere is stable, for example, dispersion is reduced and localized exposure may increase.

The proposed project site has a distinct desert climate of hot summers, mild winters, and relatively low precipitation. This climate is strongly influenced by the large-scale warming and sinking of the air in the semi-permanent subtropical high-pressure center over the Pacific Ocean. This high-pressure system blocks most mid-latitude storms except in the winter when most of the area's 7 inches of rainfall occurs. The yearly maximum temperature averages more than 100°F while the minimum averages 48°F.

Because of the area's light winds (with little seasonal variation), the atmosphere has a limited capacity to disperse the area's air contaminants from the points of generation to other locations. Strong atmospheric temperature inversions frequently occur, especially in the late mornings and early afternoons. These inversions severely limit vertical air mixing and result in the buildup of air pollutants by restricting their movement from the ground level to the upper atmosphere where they could be transported out of the air basin.

Atmospheric stability is a measure of the turbulence that influences such pollutant dispersion. Mixing heights (the height above ground level below which the air is well mixed and in which pollutants can be effectively dispersed) are higher during the morning hours and then lower during the late morning and early afternoon because of temperature inversions. Staff's **Air Quality** section presents a more detailed discussion of the area's meteorology as related to pollutant dispersion.

EXISTING AIR QUALITY

The proposed site is within the jurisdiction of the Imperial County Air Pollution Control District (ICAPCD). By examining average toxic concentrations from representative air monitoring sites in California with cancer risk factors specific to each contaminant, lifetime cancer risk can be calculated to provide a background, toxic air contaminants (TAC) related risk level for inhalation of ambient air. For comparison purposes, it should be noted that the overall lifetime cancer risk for the average individual is about 1 in 3, or 330,000 in 1 million.

The closest air quality monitoring station to the project site is in Niland, approximately 5 miles to the northeast. Since only criteria pollutants are monitored at this station, there is no data to calculate the TAC-related background indicator cancer risk for the area. The significance of the cancer risk in this regard is the present recognition of the cancer endpoint as the most sensitive indicator of the potential for a significant health hazard for a source of both carcinogenic and non-carcinogenic pollutants. The proposed project's addition to the total area cancer risk should best be seen in terms of potential contribution to the noted average background risk of 330,000 in 1 million.

The criteria pollutant-related air quality for the project area is assessed in the **Air Quality** section by adding the existing levels (as measured at area monitoring stations), to the project-related levels, and comparing the resulting levels with the applicable air quality standards. Public health protection would be ensured only through specific technical and administrative measures that ensure below-standard exposures when the project is operating. It is such a combination of measures that is addressed in the **Air Quality** section.

IMPACTS

POTENTIAL IMPACTS OF PROJECT'S NONCRITERIA POLLUTANTS

The health impacts of the noncriteria pollutants of specific concern in this analysis can be assessed separately as construction-phase impacts and operational-phase impacts.

Construction Phase Impacts

Possible construction-phase health impacts, as noted in the 2003 Staff Assessment, are those from human exposure to the windblown dust from site excavation and grading, and emissions from construction-related equipment. The dust-related impacts may result from exposure to the dust itself as PM10, or PM2.5, or exposure to any toxic contaminants that might be absorbed into the dust particles. As more fully discussed in the **Waste Management** section, results of the applicant's site contamination assessments (CEOE 2002a, Appendix O) showed no areas of possible chemical contamination from past agricultural or other uses. This means that particulate-related chemical exposures of toxic substances would be unlikely during the site preparation and project erection phases.

The applicant has specified mitigation measures necessary to minimize construction-related fugitive dust as required by ICAPCD. The only soil-related construction impacts of potential significance would result from the possible impacts of PM10, or PM 2.5 as a criteria pollutant for the 20-month construction period.

As mentioned earlier, the potential for significant impacts from criteria pollutants during construction is assessed in the **Air Quality** section, in which the requirements for the identified mitigation measures are recommended as a specific condition of certification (AQ-C3). Staff's recommendations in this regard include the use of ARB-certified diesel engines, or installation of soot filters on diesel equipment.

The exhaust from diesel-fueled construction and other equipment is a potent human carcinogen. Thus, construction-related emission levels should be regarded as possibly adding to the carcinogenic risk of specific concern in this analysis. The applicant (CEOE 2002, Appendix G) presented the diesel emissions from the different types of equipment to be used in the construction phase. These emission levels are more fully discussed in staff's **Air Quality** section. The maximum cancer risk from these diesel emissions was calculated as 2.5 in 1 million for an uninhabited zone immediately beyond the project's boundaries. This risk estimate is significantly below staff's significance criterion of 10 in 1 million for such emissions. Staff considers the recommended control measures (presented in **Air Quality** as specific conditions of certifications) as adequate to minimize this cancer risk during the construction period.

Operational Impacts

The main TAC-related health risk from the proposed project's operations would be associated with emissions from combustion of natural gas from the Recuperative

Thermal Oxidizer (RTO) chemical storage tanks, the handling of brine, including steam vent tanks and steam blow lines, and the three cooling towers. The main differences in project impacts relate to specific steps intended by the applicant to reduce the emissions from the amended BR123 project compared with the licensed project. As described by the applicant, the main sources of the process-related emissions of concern in this analysis (the vent tanks, dilution water heaters, and the handling and disposal of solid silica and sulfur filter cake wastes) would remain the same except that the modified BR123 project would not require the use of dilution water heaters or handling of large amounts of filter cakes, thereby eliminating the emissions from these aspects of operations. The applicant also proposes to modify the hydrogen sulfide control system using activated charcoal in a way that would enhance the control of benzene and the reactive organic gas emissions. The control of hydrogen sulfide and the non-condensable gases would further be enhanced with installation of RTOs. The project would also use a chemical oxidation process in the cooling tower (rather than the less efficient biological oxidation process proposed for the licensed version) for enhanced hydrogen sulfide control. Ammonia emission would be reduced by 70 percent from use of a more effective absorption process.

The applicant also proposes to use Tier-4 diesel-fired engines for the emergency fire water pumps and emergency power instead of the licensed project's Tier-2 engines, which have higher emission levels. This combination of operational and engineering changes is the reason for the applicant's expectation of lower facility impacts from some problem pollutants such as hydrogen sulfide.

PUBLIC HEALTH Table 2 lists the toxic emissions of most concern in this analysis and shows how each contributes to the risk estimated from the health risk analysis. For example, the first row shows that oral exposure to acetaldehyde is not of concern but, if inhaled, may have cancer and chronic (long-term) noncancer health effects, but not acute (short-term) effects.

As noted in a publication by the South Coast Air Quality Management District (SCAQMD 2000, p. 6), one property that distinguishes the air toxics of concern in this analysis from the criteria pollutants is that the impacts from air toxics tend to be highest in close proximity to the source and quickly drop off with distance. This means that the levels of the project's air toxics would be highest in the immediate area and would decrease rapidly with distance. One purpose of this analysis, as previously noted, is to determine whether or not such exposures would be at levels of possible health significance as established using existing assessment methods.

The applicant's estimates of the project's potential contribution to the area's carcinogenic and non-carcinogenic pollutants were obtained from a screening-level health risk assessment conducted according to procedures specified in the 1993 CAPCOA guidelines. The applicant provided the lists of the TAC from the proposed generating units along with the toxicity factors used for the related risk assessment. The results from this assessment (summarized in staff's **PUBLIC HEALTH Table 3**) were provided to staff along with documentation of the assumptions used (CEOE 2009, pp. 5.10-12, through 5.10-20 and Appendix-E). This documentation included:

- pollutants considered;

- emission levels assumed for the pollutants involved;
- dispersion modeling used to estimate potential exposure levels;
- exposure pathways considered;
- the cancer risk estimation process;
- hazard index calculation; and
- characterization of project-related risk estimates.

Staff determined these assumptions are acceptable for use in this analysis and has validated the applicant's findings with regard to the numerical public health risk estimates expressed either in terms of the hazard index for each non-carcinogenic pollutant, or a cancer risk for estimated levels of the carcinogenic pollutants. These analyses were conducted to establish the maximum potential for acute and chronic effects on body systems such as the liver, central nervous system, the immune system, kidneys, the reproductive system, the skin and the respiratory system. The specific case of radon is from its potential emission from the temporary storage of the filter cake generated from extraction of the geothermal fluids, in addition to the cooling towers. The related health impact is cancer.

PUBLIC HEALTH Table 2
Types of Health Impacts and Exposure Routes Attributed to Toxic Emissions

Substance	Oral Cancer	Oral Non-cancer	Inhalation Cancer	Non-cancer (Chronic)	Non-cancer (Acute)
Acetaldehyde			✓	✓	
Acrolein				✓	✓
Ammonia				✓	✓
Arsenic	✓	✓	✓	✓	✓
Benzene			✓	✓	✓
1,3-Butadiene			✓	✓	
Cadmium		✓	✓	✓	
Chromium			✓	✓	
Copper				✓	✓
Ethylbenzene				✓	
Formaldehyde			✓	✓	✓
Hexane				✓	
Lead	✓	✓	✓	✓	
Mercury		✓		✓	✓
Naphthalene		✓		✓	
Nickel			✓	✓	✓
Polynuclear Aromatic Hydrocarbons (PAHs)	✓	✓	✓	✓	
Propylene				✓	
Radon			✓		
Toluene				✓	✓
Xylene				✓	✓
Zinc				✓	

Source: Prepared by staff using reference exposure levels and cancer unit risks from CAPCOA Air Toxics "Hot Spots" Program Revised 1992 Risk Assessment Guidelines, October 1993, SRP 1998, and Office of Environmental Health Hazard Assessment Air Toxics Hot Spots Program Risk Assessment Guidelines.

The applicant (CEOE 2009, Table 5.10-25, p. 5.10-25) provided a list of the toxicity values used to assess the cancer and noncancer impacts.

As shown in **PUBLIC HEALTH Table 3**, the chronic hazard index for the maximally exposed individual is 0.312 (compared to 0.156 for the licensed version) while the maximum hazard index for acute effects is 0.550 (compared to 0.881 for the licensed version). These values are higher than calculated for the licensed version because they reflect the higher emission rates established by the applicant from more accurate data on the physical and chemical characteristics of the geothermal brine, which is the main source of the pollutants in question (CEOE November 2009 Responses to Staff's Air Quality Data Requests 1 through 64). The calculations from the more refined data still show these noncancer risk indices to be significantly below staff's significance criterion of 1.0, suggesting that the pollutants in question would not pose a significant risk of chronic or acute noncancer health effects anywhere in the project area for any of the considered project versions.

PUBLIC HEALTH Table 3
Operational Hazard/Risk

Type of Hazard/Risk	**Hazard Index/Risk**	Significance Level	Significant?
Acute Noncancer	0.550	1.0	No
Chronic Noncancer	0.312	1.0	No
Individual Cancer	7.19×10^{-6}	10.0×10^{-6}	No

Staff's summary of information from CEOE 2009 pp. 5.10-25 through 5.10-32.

The cancer risk to the maximally exposed individual from normal project operation is shown as 7.19 in 1 million, which is higher than the 2.88 in 1 million for the licensed version. As with the noncancer health risks, the increased cancer risk estimate reflected the higher emission rates established by the applicant from more refined emission data. This risk estimate is still below staff's significance criterion of 10 in 1 million for this screening-level assessment. Thus, project-related cancer risk from routine operations would be less than significant for all individuals in the project area.

The conservatism in these assessments is reflected in the noted fact that (a) the individual considered is assumed to be exposed at the highest possible levels to all the carcinogenic pollutants from the project for a 70-year lifetime, (b) all the carcinogens are assumed to be equally potent in humans and experimental animals, even when their cancer-inducing abilities have not been established in humans, and (c) humans are assumed to be as susceptible as the most sensitive experimental animal, despite knowledge that cancer potencies often differ between humans and experimental animals. Only a relatively few of the many environmental chemicals identified so far as capable of inducing cancer in animals have been shown to also cause cancer in humans.

Although the population within the project site's 6-mile radius shows that the minority population from the 2000 census data as more than 50 percent, (from the

Socioeconomics Figure 1 in CEC staff's 2003 analysis), the finding that the operational cancer and noncancer risks would be below the levels of potential significance means that there would be no environmental justice concerns related to minority status. Such concerns arise only in cases of potentially significant impacts. The same census data showed the low-income population to be less than 50 percent. Given this percentage and the fact that there would be no significant impacts from operations, there would be no environmental justice concerns related to economic status.

While the cancer and noncancer risks from operating the project cooling towers would be below levels of potential significance, the cooling towers for the three generating units have been established by staff and the applicant as posing a potentially significant risk of bacterial infection (Legionnaires' disease) if operated without adequate safeguards. Implementing the related condition of certification for the licensed 215 MW project should offer adequate protection against such infection for the modified BR123 project as agreed to by the applicant (CEOE 2009, p. 5.10-34).

CUMULATIVE IMPACTS

As noted in the 2003 Staff Analysis and discussed by the applicant (CEOE 2009, p. 5.10-10), there are no identified existing sources of toxic air pollutants of concern in this analysis in the immediate vicinity of the project site, meaning there would be no cumulative impacts that could lead to exposures of possible health significance. The present approach to regulating this group of is to ensure that further additions from identifiable sources are maintained within insignificant levels as established using the methods discussed in this analysis.

As previously noted, the maximum impact locations for the three proposed generating units would be near the spot where pollutant concentrations would theoretically be highest. Even at this location, staff does not expect any significant project-related changes in the lifetime risk to any individual, given the calculated incremental cancer risk of only 7.19 in 1 million, which staff regards as not potentially contributing significantly to the previously noted average lifetime individual cancer risk of 330,000 in 1 million. This background risk should best be seen as reflecting the cumulative impacts of all encountered carcinogens whether man-made or naturally occurring. It is because of its related low cancer risk that staff considers the proposed project as not contributing significantly to any cancer-related impacts of a cumulative nature.

As previously noted, the worst-case long-term noncancer health impact from the project (represented as a chronic hazard index of 0.312) is well below staff's significance level of 1.0 at the location of maximum impact (which falls at the fence line) suggesting an insignificant contribution to the incidence of the area's noncancer health symptoms from cumulative TAC exposures. The cumulative impacts from emission of the criteria pollutants are addressed in the **Air Quality** section.

As more fully discussed in staff's **Air Quality** section, the applicant identified the pollutants associated with expected project commissioning (a one-time event) and start-up and shut-down activities (CEOE 2001, pp. 5.10-11 through 5.10-18, and Appendix E). As with the licensed project, there would be short-term, above-threshold emissions of hydrogen sulfide and particulate matter during the commissioning period. A related condition of certification (AQ-C6) is specified in the **Air Quality** section of the 2003 Staff

Assessment in this regard. Staff is in agreement with the applicant (CEOE 2009, pp.5.10-3 and 5.10-8) that this same **Air Quality** condition of certification would be adequate to mitigate the impacts of these commissioning-related pollutants for the proposed project and does not recommend further mitigation measures.

COMPLIANCE WITH LORS

The toxic pollutant-related cancer and noncancer risks from the proposed 159 MW BR123 project reflect the effectiveness of control measures proposed by the applicant. Since these risk estimates are below the significance levels in the applicable LORS, staff concludes that the related construction and operational plan would comply with these LORS.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Staff received no public or agency comments on the public health aspects of the proposed project amendment.

CONCLUSIONS AND RECOMMENDATIONS

Staff has determined that the toxic air emissions from the construction and operation of the proposed 159 MW BR123 project would be at levels that do not require mitigation beyond the specific emission control measures proposed by the applicant and deemed adequate for the licensed 215 MW project. Since (a) the potential impacts would be below levels of potential insignificance and (b) very few residences reside in the project's zone of potentially significant impacts, there would be no environmental justice issues when the project is operating. The conditions for ensuring compliance with all applicable air quality standards are specified in the **Air Quality** section for the area's criteria pollutants. With continued enforcement of Condition of Certification Public Health-1, staff recommends approval of the proposed modifications to the BR123 project with respect to the health impacts of concern in this analysis.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

No new or modified Public Health-related Conditions of Certification are proposed.

REFERENCES

American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) 1998. Legionellosis: Position Paper. June 25.

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Scientific Review Panel on Toxic Air Contaminants (SRP) 1998. Findings of the Scientific Review Panel on the Report on Diesel Exhaust as adopted at the Panel's April 22, 1998 Meeting.

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SOCIOECONOMICS

Testimony of Kristin Ford

INTRODUCTION

The Salton Sea Unit 6 Geothermal Power Project (SSU6) was originally granted a California Energy Commission license in December 2003 for a 185 MW plant utilizing multiple flash technologies. The license was amended in May 2005 to enable the plant to increase its capacity to 215 MW and to extend the deadline to start construction of the project to December 18, 2011.

The applicant proposes to amend the project license to allow for construction of three 53 MW single-flash units for a net total generating capacity of 159 MW. The renamed Black Rock 1, 2, 3 Geothermal Power Plant (BR123) would be located on the same 80-acre site as the original project; however, the amended project would utilize a contiguous 80-site to the south of the site for a total plant size of 160 acres. This analysis focuses on the potential impacts to Socioeconomics caused by the changes to the licensed project that are proposed in the applicant's Petition to Amend.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

At the time of certification, LORS applicable to Socioeconomics were identified in the Final Staff Assessment (FSA). Approval of the amendment would not require analysis or inclusion of any new LORS.

ANALYSIS

According to *Environmental Justice: Guidance Under the National Environmental Policy Act*, minority individuals are defined as members of the following groups: American Indian or Alaskan Native; Asian or Pacific Islander; Black, not of Hispanic origin; or Hispanic. A minority population is identified when the minority population of the potentially affected area is greater than 50 percent or when one or more U.S. Census blocks in the potentially affected area have a minority population greater than 50 percent.

For the proposed BR123 project, the population living within the 6-mile radius of the proposed site is 108 persons and the total minority population is 84 persons, or about 78 percent of the total population. Staff identified similar numbers for population and minority population for Imperial County in the Staff Assessment of the 2003 Application for Certification.

The below-poverty-level threshold is defined by the U.S. Census as a function of the size of a family unit and the number of children less than 18 years of age. For the 2000 Census, the poverty threshold income for a family of four with two children was $17,463. The 2000 Census data report that the median household income in the county was $31,870.

The BR123 project would employ for 46 months of construction an average of 323 workers and a peak of 642 workers, of which 60 percent would come from the local area in Imperial County, and 40 percent non-local. The licensed SSU6 project called for a peak workforce of 467 workers.

Construction workers can commute up to two hours to construction sites from their homes rather than relocate temporarily. The BR123 project could draw on Imperial County, Riverside County, San Bernardino County and San Diego County labor markets, which had approximately 222,000 construction workers in 2006 (CE Obsidian Energy, LLC 2009a). This represents less than 1 percent of the average workforce needed for project construction. Approximately 69 full-time permanent employees would staff the power plant at operation. Some of the specialized technical or managerial skill operation jobs would require relocation to the area. The applicant estimates that 90 percent of the full-time staff would commute from El Centro, Brawley, Calipatria or Niland areas, while 10 percent would commute from Indio or La Quinta in Riverside County. The population impacts created by project construction and operation would not be significant.

Approximately 257 construction workers at peak might reside in hotels/temporary housing during the work week and return to homes on the weekends. There are 1,148 hotel/motels in Imperial County. Imperial County had a hotel/motel vacancy rate of 12.3 percent or 51,590 units in 2006. For 2009, Imperial County listed 3,059 mobile home sites and 3,672 RV spaces in the county. The unemployment rate for Imperial County in March 2009 was 25.1 percent (not seasonally adjusted) (CE Obsidian Energy, LLC 2009a and State of California Employment Development Department 2009).

The BR123 project would not adversely impact community services for construction since most workers would commute and housing would be available for those who would relocate on a temporary basis. For operations, most of the workforce would be local and not adversely impact community services.

Benefit estimates for the BR123 project would be higher than for the original SSU6 project:

- Secondary construction employment for the four-county area of Imperial, San Diego, Riverside, and San Bernardino would increase from 570 jobs to 868 jobs;
- School impact fees would increase from $11,716 to approximately $18,083 for the Calipatria Union School District;
- Property taxes would increase from $2.9 million to $8.5 to $9.0 million for Imperial County;
- Construction/operations payroll would increase from $30 million/$5.9 million to $49 million/$6.6 million for the four-county area;
- Capital costs would increase from $460 million to $862 million; and,
- Sales tax would increase from $7.75 million during construction and $178,328 during operation to $10.2 million during construction and $199,000 during operation (CEOE 2002 and CE Obsidian Energy, LLC 2009a&b).

CONCLUSIONS AND RECOMMENDATIONS

Staff concludes that construction and operation of the BR123 project would not cause significant direct, indirect, or cumulative adverse socioeconomic impacts on the study area's housing, schools, parks and recreation, law enforcement, emergency services, or hospitals. The BR123 project, as proposed, is consistent with applicable LORS.

Estimated gross public benefits from the BR123 project include increases in employment and income for the four-county area. The project would create an estimated average of 323 direct project-related construction jobs for the 46 months of construction and 69 jobs for operations, and would result in an increase in property taxes, school impact fees and sales taxes compared to the licensed SSU6 project.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

Mitigation would remain unchanged with Condition of Certification **SOCIO-1** requiring payment of school impact fees.

REFERENCES

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SOIL AND WATER RESOURCES

Testimony of Paul Marshall and Abdel-Karim Abulaban, PE

INTRODUCTION

This section of the Staff Assessment analyzes potential impacts to soil and water resources from the construction and operation of the proposed Black Rock 1, 2, and 3 Geothermal Power Project (BR123). The BR123 is proposed as an amendment to the previously certified Salton Sea Unit 6 Geothermal Power Project (SSU6). This analysis examines only those aspects of the proposed amendment that represent significant changes to the originally certified project. In some cases, the proposed amendment elements are the same as those previously analyzed and only the physical location of the element or magnitude of the activity would change.

In evaluating the proposed BR123 amendments, staff has focused on the potential for the project changes to cause impacts in the following areas:

- Whether the project's use of surface water would cause a significant or potentially significant adverse change in the quantity or quality of groundwater or surface water.
- Whether project construction or operation would lead to degradation of surface or groundwater quality.
- Whether construction or operation would lead to accelerated wind or water erosion and sedimentation.
- Whether the project would increase flood hazards in the vicinity of the project.
- Whether the project would comply with all applicable laws, ordinances, regulations and standards (LORS).

Where the potential for significant adverse impacts is identified, staff has proposed mitigation measures in the form of conditions of certification to reduce the significance of the impact, if possible. Staff has also recommended conditions of certification as necessary to support compliance with LORS.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

In addition to the LORS identified for the original SSU6 project, the LORS identified in **SOIL & WATER Table 1** (below) also apply to BR123.

SOIL AND WATER Table 1
Additional Laws, Ordinances, Regulations, and Standards (LORS)
Applicable to the BR123 Project

Applicable LORS	Description
Federal	
Title 42, U.S.C., section 300f, et seq. – Public Health Service Act, section 1401 et seq. (known as the Safe Drinking Water Act).	The Safe Drinking Water Act (SDWA) establishes requirements and provisions for the Underground Injection Control (UIC) program to protect public health by preventing injection wells from contaminating underground sources of drinking water (USDW). General provisions for the UIC program (including state primacy for the program) are established in sections 1421 – 1426. The California Division of Oil, Gas, and Geothermal Resources (DOGGR) has been delegated the authority to issue federal Class V UIC permits for geothermal fluid injection.
Title 40, Code of Federal Regulations (CFR), Chapter I, Subchapter D – Water Programs (Parts 100 – 149).	These federal regulations provide specific requirements for implementation of water-related environmental laws by the U.S. EPA. Among other things, the regulations establish minimum administrative and technical standards and criteria for both the NPDES and UIC programs, including requirements for state implementation of the programs.
State	
Title 23, California Code of Regulations (CCR), Waters, Division 3 — State Water Resources Control Board (SWRCB) and Regional Water Quality Control Boards (RWQCBs)	These regulations implement provisions of the California Water Code (CWC) and the Porter-Cologne Water Quality Control Act. Among other things, the regulations address water rights, implementation of the federal Clean Water Act, discharges to land, underground tanks, and waste discharge requirements/National Pollutant Discharge Elimination System (NPDES) permits.
Title 27, CCR, Environmental Protection, Division 2, Solid Waste, Subdivision 1, Consolidated Regulations for Treatment, Storage, Processing or Disposal of Solid Waste.	These regulations address both the California Integrated Waste Management Board (CIWMB) and SWRCB requirements for solid waste management units (including brine ponds).
SWRCB Water Quality Order No. 2009-0009-DWQ	The SWRCB regulates storm water discharges associated with construction projects to protect water quality throughout the state. Effective July 1, 2010, Order No. 2009-0009-DWQ will supersede Order 99-08-DWQ and implement NPDES General Permit No. CAS000002 for storm water discharges associated with construction activity affecting areas greater than or equal to one acre. Those subject to the order can qualify for the permit if they meet the criteria, prepare and implement an acceptable Storm Water Pollution Prevention Plan (SWPPP) and other assessments as necessary, and file with the SWRCB all necessary Permit Registration Documents [including a Notice of Intent (NOI)] prior to beginning construction.
Colorado River Basin RWQCB, Order No. 98-300. NPDES General Permit No. CAG677001	This order establishes general waste discharge requirements for the discharge of wastewater from the hydrostatic testing of pipes, tanks, or any storage vessel to surface waters or tributaries of surface waters within the Colorado River Basin Region.
Warren-Alquist Act, Public Resources Code (PRC), Section 25000 et seq.	This law gives the California Energy Commission authority to certify the construction and operation of thermal electric power plants 50 megawatts (MW) or larger. However, geothermal

Applicable LORS	Description
	production wells and related facilities are not included in the definition of thermal power plant and are therefore excluded from the certification process (PRC section 25120). The Energy Commission certification is also “in lieu of” any permit required by state, regional, or local agencies, and federal agencies to the extent permitted by federal law (PRC section 25500).
Surface Mining and Reclamation Act of 1975, PRC, Division 2, Chapter 9, Section 2710 et seq.	The California Surface Mining and Reclamation Act (known as SMARA) requires that all surface mines in the state be reclaimed both to minimize any adverse effects from the mining and to ensure that mined lands are returned to a usable condition and creates no danger to public health and safety. The law requires local jurisdictions to enact ordinances to implement SMARA at the local level and to act as lead agency for issuance of permits, development of reclamation plans, and holder of reclamation financial assurances.
Title 14, CCR, Division 2, Chapter 8, Subchapter 1, State Mining and Geology Board Reclamation Regulations, Section 3500 et seq.	These regulations further clarify and implement the provisions of SMARA by establishing standards for reclamation plans and financial assurances, as well as administrative procedures for lead agency oversight and decision appeals.
CCR, Division 20,Chapter 6.5, Article 4, Section 25143.1, Health and Safety Code	This regulation defines the terms “waste” and “wastewater” and exempts wastes resulting from drilling for geothermal resources from management requirements set for managing hazardous wastes, because those wastes are regulated by the California regional water quality control boards.
Local	
Imperial County Municipal Code, Title 8, Health and Safety, Chapter 8.76, Subsidence Monitoring Program, Section 8.76.010 et seq.	Chapter 8.76 provides for implementation of a subsidence detection program within Imperial County and establishes participation, fees and changes applicable to all entities that may cause or contribute to subsidence in the county.
Imperial County Municipal Code, Title 9, Land Use Code, Division 10, Building, Sewer, and Grading Regulations, Section 91001.00 et seq.	These code sections establish minimum standards and permitting requirements for building construction, site grading, and sewage disposal systems within Imperial County. The Uniform Plumbing Code requirements are established in Chapter 4 (starting with section 91004.00; grading permit requirements are provided in Chapter 10 (starting with section 91010.00); and septic tank and sewage disposal system requirements are provided in Chapter 12 (starting with section 91012.00).
Imperial County Municipal Code, Title 9, Land Use Code, Division 20, Surface Mining & Reclamation, Section 92001.00 et seq.	These code sections establish requirements for surface mining operations in the County as required by California’s Surface Mining and Reclamation Act of 1975 (known as SMARA). The requirements include getting a permit for the activity, preparation of a site reclamation plan, and establishment of financial assurance for site reclamation.
Imperial County Municipal Code, Title 9, Land Use Code, Division 21, Water Well Regulations, Sections 92101.00 et seq.	These regulations establish the minimum well standards and permitting requirements for the construction, operation, and destruction of ground water wells within Imperial County. Wells subject to the regulations include domestic water wells, commercial wells, test or exploratory holes, and observation (monitoring) wells.
County of Imperial Code, Title 12, Chapter 12.10.020 Section B – Street Improvement Requirements	This code section establishes standards, specifications, and directions for design and construction of any road, or other land division improvements, required to be constructed in the

Applicable LORS	Description
	unincorporated territory of Imperial county.
State Policies and Guidance	
The 2003 California Energy Commission *Integrated Energy Policy Report (IEPR)*	The *2003 IEPR* was developed and adopted pursuant to Public Resources Code sections 25301 and 25302. It includes a water and wastewater policy, based on SWRCB Policy 75-58, which states that the Energy Commission will approve the use of fresh water for cooling purposes by power plants it licenses only where alternative water supply sources and alternative cooling technologies are shown to be “environmentally undesirable” or “economically unsound.” In addition, the policy states that the Energy Commission will also require that zero-liquid discharge technologies be used to manage project wastewater unless such technologies are shown to be “environmentally undesirable” or “economically unsound.”
Local Policies and Guidance	
Imperial Irrigation District, Interim Water Supply Policy for Non-Agricultural Projects, September 29, 2009. Resolution No. 31-2009.	Imperial Irrigation District (IID) adopted their Interim Water Supply Policy (IWSP) for Non-Agricultural Projects to address water requests from proposed projects while the District’s Integrated Water Resources Management Plan (IWRMP) is under development. The IWRMP will help IID manage existing water supplies and store water when available, or develop new water supplies. It is estimated that 50,000 acre feet per year (afy) may be needed for Non-Agricultural Projects over the next 10 to 20 years. The IWSP currently allocates up to 25,000 afy of water for Non-Agricultural Projects within IID's service area. Non-Agricultural Projects requesting water from IID may be required to pay a Reservation Fee. The reserved water would be made available for other users until the Non-Agricultural projects require the reserved water supply.

PROJECT DESCRIPTION AND SETTING

The proposed 160-acre BR123 project site is located southeast of the Salton Sea in an unincorporated portion of Imperial County, approximately 6 miles northwest of Calipatria, and 7.5 miles southwest of Niland, California. The site lies within the Salton Sea Known Geothermal Resource Area (KGRA), in the southwest quarter of Section 33 Southwest, Township 11 South, Range 13 East, San Bernardino Meridian. The average elevation in the project area is approximately 225 feet below mean sea level.

PROJECT DESCRIPTION

The original SSU6 project was certified by the Energy Commission on December 17, 2003, as a 185 MW multi-flash geothermal facility on an 80 acre site. The project was later amended in 2005 to, among other things, increase the facility generating capacity to 215 MW, add one production well and one injection well, as well as add 20 acres immediately south of the project site. The proposed BR123 would convert the single SSU6 facility into three separate 53 MW single-flash geothermal power plant units co-located on an enlarged 160 acre site (the original 80 acre site plus 80 acres on a contiguous parcel to the south that also includes the 20 acres added in 2005). The three units would share common infrastructure features including a control building, an electrical switchyard, two fire water pumps, a storm water detention basin, and fire water, process water and condensate storage facilities, a paved parking area, and a reverse osmosis (RO) system to treat supplied water for service water and domestic use onsite.

Each power plant unit would consist of a geothermal Resource Production Facility (RPF) and a geothermal-powered Power Generation Facility (PGF). The RPF would include geothermal brine production and injection wells, pipelines, and a brine pond. The PGF would include a steam turbine generator, a condenser, a cooling tower, and other associated equipment.

The transmission line elements of the BR123 are unchanged from the certified SSU6 project. Therefore, discussion of the transmission line elements and impacts is not included in this assessment.

A summary of the main soil and water related revisions to the BR123 project, compared to the SSU6 project "as certified," is provided below in **SOIL & WATER Table 2**.

SOIL & WATER Table 2
Summary of BR123 Changes Compared to "As Certified" Conditions

Project Element	As Certified	Amendment Request	Change
Geothermal power plant facility	One 215 MW multi-flash base-load[1] power plant	Three 53 MW single flash base-load units – 159 MW total generating capacity	-56 MW
Main plant site acreage	80 acres	160 acres	+80 acres
Temporary land disturbance	210.3 acres	242.8 acres	+32.5 acres
Permanent land disturbance	185.9 acres	213.4 acres	+27.5 acres
Earth moving/cut and fill	105,000 cu yds cut/ 287,000 cu yds fill	183,000 cu yds cut/ 362,000 cu yds fill	+78,000 cu yds cut/ +75,000 cu yds fill
Production wells	11 wells on 5 pads (offsite)	9 wells on 3 pads (onsite)	-2 wells and -2 pads
Brine injection wells	8 wells on 3 pads (offsite)	9 wells on 3 pads (offsite)	+1 well
Plant injection wells	2 wells (onsite)	4 wells (onsite)	+2 wells
Well drilling mud sumps (temporary)	9	6	-3
Brine ponds (permanent)	2	3	+1
"Conservative Case"[1] Water Use – Annual Maximum	987 AFY[3]	~609 AFY	-378 AFY
"Typical Case"[2] Water Use – Annual Average	293 AFY	~355 AFY	+62 AFY
Areas requiring CWA 401 Water Quality Certification	Transmission line areas plus road widening and pipeline installation near McKendry Road and Obsidian Butte; and potentially Bannister switchyard.	Transmission line route areas and Bannister switchyard (potentially).	Obsidian Butte and McKendry Road area disturbance no longer part of project.

1: continuous operation (24 hours per day; 7 days per week).
2: AFY = acre-feet per year

Project Area – Land Disturbance

The original SSU6 project was certified for permanent disturbance of approximately 198 acres of land. This total included the main 80 acre plant facility, along with offsite production and injection wells, pads, and pipelines, the transmission linears, and the switchyard. The BR123 would use the same 80 acres originally identified for the SSU6 main site, but would also include the 80 acre lot immediately south, along with 53.4 acres for the offsite injection well pads and pipelines, for a total permanent land disturbance of 213.4 acres.

Project site preparation and grading would require removal and stockpiling of approximately 180,200 cubic yards (cu yds) of topsoil off the main facility site. The project would then utilize approximately 362,000 cu yds of cement conditioned soil imported from a new borrow site immediately southeast of the main project lot. Fill material may also be imported from an existing borrow site located at the Leather's geothermal plant. The cement conditioned imported soil would be used to support the onsite plant structures and roads, to create the site perimeter berm, and to elevate the well pads, ponds, and other project structures. The stockpiled topsoil would be used to backfill the borrow site property. It is anticipated that grading work for all three power plants would be done concurrently during the early stages of construction and would cover the entire 160 acre site.

Site Soils

As a result of the increased project site size, offsite injection well pads and pipelines, and the new borrow site, two additional soil types would be disturbed by BR123 activities compared to the licensed SSU6 project. **SOIL & WATER Table 3** identifies the main soil types that would be affected, along with general soil characteristics and the project elements associated with each soil unit.

Flood Control, Drainage and Storm Water Management

The generally flat project site is located at 225 feet below sea level on average, and is within the 100-year flood plain. As with the certified SSU6 project, the BR123 would include an earthen berm around the entire site that averages 220 feet below sea level. During plant operation, the berm would also prevent storm water from being discharged offsite. The BR123 would also include a 576,000-cubic-foot volume retention basin to contain storm water onsite.

Production Wells

The original SSU6 project was licensed with 10 offsite brine production wells on five well pads. The SSU6 project was then amended in 2005 to add one additional production well, for a total of 11 offsite production wells on five pads. The BR123 would reduce the number of production wells to nine wells on three well pads, all located within the proposed 160 acre main project site. As with the original SSU6 project, the production wells would be drilled to a depth of approximately 7,400 feet below ground surface (bgs), with casing set to a depth of approximately 2,500 feet bgs.

SOIL & WATER Table 3
BR123 Main Soil Types and Characteristics

Primary Soil Unit Name and Composition	Slope Class (percent)	Water Erosion (K factor)[2]	Wind Erosion	Drainage	Project Element
Imperial-Glenbar Silty Clay Loams (wet)[1] – Nearly level, very deep calcareous soils formed in alluvial deposits on flood plains and lakebeds within irrigated areas.	0–2 percent	Moderate to High (0.37-0.43)	Moderate	Moderately Well Drained	▪ Plant Site; ▪ Production Wells OB-1, OB-3 pads and pipelines; ▪ Production Well OB-2 pipeline; ▪ Injection Well pipelines; ▪ Borrow Site
Holtville Silty Clay (wet)[1] – Nearly level, very deep stratified soil formed in alluvial sediment on flood plains and alluvial basin floors.	0-2 percent	Moderate to High (0.28-0.43)	Moderate	Moderately Well Drained	▪ Plant Site; ▪ Production Wells OB-2, OB-3 pads; ▪ Production Well OB-2 pipeline; ▪ Injection Wells OB-2, OB-3 pads; ▪ Injection Well pipelines; ▪ Borrow Site
Glenbar Clay Loam (wet) – Nearly level, very deep soils formed in alluvial sediment on flood plains and in alluvial basins within irrigated areas.	0-1 percent	Moderate (0.37)	Moderate	Moderately Well Drained	▪ Injection Wells OB-2, OB-3 pipelines; ▪ Borrow Site
Indio Loam (wet) – Nearly level, very deep soils formed in alluvium and eolian sediments on flood plains and basin floors.	0-2 percent	High (0.49-0.55)	Moderate	Moderately Well Drained	▪ Injection Wells OB-1, OB-3 pads and pipelines

1: Soils underlying the original SSU6 project.
2: K is a measure of relative susceptibility to sheet and rill erosion by water. K values measure from 0.02 – 0.69, with lower values representing a lower susceptibility to erosion.

Sources: CE Obsidian/AECOM 2009; and Natural Resources Conservation Service (NRCS) Web Soil Survey ,<websoilsurvey.nrcs.usda.gov>.

The general production well design and drilling program identified and analyzed for the original SSU6 project has not been changed; only the number and location of the wells would be changed by the proposed BR123.

Water Supply

The original SSU6 project was analyzed and certified to use condensed steam as the primary source for project cooling water and to use imported fresh water for cooling tower make-up, brine dilution, plant service water, and domestic water needs. Fresh water for the SSU6 project would have been supplied by the Imperial Irrigation District (IID). The project owner was required to use only fresh water from IID for the SSU6 project, and to file a Petition to Amend its license with the Energy Commission if another source of fresh water is deemed necessary or if the project would use more than the

1,000 acre-feet/year (AFY) described in the water supply availability letter. Staff's assessment of the SSU6 water use was based on the project's maximum (worst-case) water use of 987 AFY. In an average year, the SSU6 project would have used only 293 AFY. The BR123 would reduce the project's maximum fresh water use by 380 AFY, to approximately 607 AFY. However, the amendment would increase the average year/nominal design use by 61 AFY, to approximately 354 AFY. Water use estimates for operation of the BR123 are provided below in **SOIL & WATER Table 4**.

SOIL & WATER Table 4
BR123 Operations Water Use

Annual Canal Water Consumption Per Unit Basis (Acre-feet) Case		**New Estimate of Water Usage by Brine Flow and Megawatt Design Condition**		
		Case		
		A	**B**	**C**
		Low	**Medium**	**High**
Generation Annualized (net)	MW	48	53	58
Brine Enthalpy	btu/lb	400	403	408
Process Brine Flow	k lb/hr	6,000	6,300	6,500
Jan	Winter (AFY)	7.3	7.3	7.3
Feb		7.3	7.3	7.3
Mar		7.3	7.3	7.3
Apr		7.3	7.3	7.3
May		7.3	7.3	7.3
Jun	Summer (AFY)	36.0	14.9	7.9
Jul		36.0	14.9	7.9
Aug		36.0	14.9	7.9
Sep		36.0	14.9	7.9
Oct	Winter (AFY)	7.3	7.3	7.3
Nov		7.3	7.3	7.3
Dec		7.3	7.3	7.3
Annual Total (AFY)	**1 unit**	**202.4**	**118.0**	**90.0**
Annual Total for BR123 (AFY)	**3 units**	**607.2**	**354.0**	**270.0**

Source: CE Obsidian 2010a.

As with the SSU6 project, water for project construction would also be supplied by IID. The main water uses during construction would be for site grading and compaction, dust suppression, and pipeline hydrostatic testing. While construction of all three power plant units would occur over the course of three to four years, the greatest water demand for the project would occur during site grading in the first 2.5 years of construction. Total construction water consumption is estimated to be approximately 300 acre-feet over the multi-year construction period.

SOIL AND WATER Table 5
BR123 Construction Water Use

Activity	Duration	Annual Usage (AFY)	Total Consumption (acre-feet)	Daily Usage (gallons)
Flood Control Berm Compaction	31 days	9.5	9.5	100,000
Site Compaction	180 days	52.5	52.5	95,000
Dust Suppression for Grading	2.5 years	89.6	224	80,000
Hydrostatic Test Water	Intermittent	17.8	17.8	--

Source: CE Obsidian/CH2MHILL 2010a.

Brine Injection Wells

Under normal operating conditions, the produced geothermal brine remaining after steam separation in the RPF would be piped directly to the offsite brine injection wells. The licensed SSU6 project would have had eight offsite injection wells on three well pads. The proposed BR123 would add one injection well, thereby bringing the total to nine offsite injection wells on three well pads. As with the SSU6 project, the wells would be drilled to an average depth of 8,725 feet below ground surface.

Plant Injection Wells

Excess steam condensate, cooling tower blowdown, and aerated brine[30] would be injected into the geothermal formation via shallow (approximately 2,250 feet deep) injection wells located on the plant site. During construction of the project production and injection wells, the plant injection wells would also be used to inject well drilling and testing fluids. The original SSU6 project was certified to use two plant injection wells, one dedicated to managing condensate and cooling tower blowdown, and one dedicated to managing aerated brine. The BR123 would increase the number of plant injection wells to four, two for condensate and blowdown, and two for aerated brine.

Brine Ponds

As with the licensed SSU6 project, the BR123 would utilize lined brine ponds to manage aerated brines as necessary during plant upset conditions, well flow testing, or startup, along with excess condensate and associated geothermal drilling and production wastes. Each unit would have one brine pond, for a total of three ponds. The brine ponds would be designed and operated in accordance with Title 27 Division 2 of the California Code of Regulations (CCR) – Special Requirements for Surface Impoundments.

Mud Sumps

The BR123 would also use temporary, lined mud sumps for management of geothermal fluids, drilling muds, and cuttings generated during well construction and development. One mud sump is generally used for each well pad or drilling location. The SSU6 project would have used up to nine mud sumps. The BR123 would reduce the number of sumps used to six.

[30] Aerated brine is geothermal brine that has been exposed to air and discharged to ponds under plant upset conditions or well start-up.

Domestic Wastes

As with the SSU6 project, the BR123 would use a septic system to manage domestic wastes and sewage generated in the single control building that would be used for all three plants. The SSU6 project proposed to use a septic tank and onsite leach field for liquid waste disposal. The BR123 would not use a leach field and would instead use only a septic tank that would be pumped out regularly and the wastes disposed of offsite at an appropriate disposal facility.

Construction Duration and Facility Closure

If approved by the Energy Commission, construction of the modified facility is expected to commence in 2011 and continue for approximately 4 years (46-53 months), with each unit constructed sequentially. As with the licensed SSU6 facility, the amended BR123 project would have an operating life of 30 years.

REGIONAL SETTING

The regional setting for the proposed BR123 (including climate, surface and ground waters, general soil characteristics, and geothermal resource characteristics) is unchanged and is the same as that described in the soil and water staff assessment for the licensed SSU6 project.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

This section provides an evaluation of the potential direct, indirect, and cumulative impacts to soil and water resources that would be caused by construction, operation, and maintenance of the project. Staff's analysis of potential impacts consists of a brief description of the activity, identification and analysis of the relevant impacts of the activity, and evaluation of the significance of the identified impacts.

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

The significance of potential impacts to soil and water resources was determined based on the following criteria:

- whether the project's use of surface water provided by the IID would cause a significant, or potentially significant, adverse change in the quantity or quality of groundwater or surface water resources;
- whether project construction or operation would lead to degradation of surface or groundwater quality;
- whether construction or operation would lead to accelerated erosion and sedimentation;
- whether the project would increase flood hazards in the vicinity of the project; and
- whether the project would comply with all applicable LORS, including existing policies, related to water to be used for power plant cooling.

These criteria are based on the California Environmental Quality Act (CEQA) Guidelines and performance standards (CCR 2009). The threshold of significance for project impacts is based on the ability of the project to be built and operated without violating applicable erosion, sedimentation, flood, surface or groundwater quality, water supply, or wastewater discharge standards. The baseline for assessing the BR123 project's impacts is the SSU6 project "as certified" because the original SSU6 staff assessment is assumed to have already evaluated impacts for volumes and conditions equal to or less than the "as certified" SSU6 elements. Therefore, this analysis examines only those aspects of the proposed BR123 that represent changes to the originally certified and amended SSU6 project. In some cases, the proposed BR123 elements are the same as those previously analyzed and licensed for SSU6, but the physical location of the element or magnitude of the activity would change. For those elements, only changes that represent an increase from the "as certified" condition are evaluated here.

The federal, state, and local LORS and policies used for the BR123 analysis are presented in the original SSU6 staff assessment, with additional LORS provided in **SOIL & WATER Table 1**. These LORS represent a comprehensive regulatory system, with adopted standards and established practices designed to prevent or minimize adverse impacts to soil and water resources. For those BR123 activities that exceed standards or might result in a significant adverse impact, conditions of certification may be recommended to ensure compliance with standards or reduce any adverse impacts to a less than significant level. In some cases, pursuant to provisions of the Warren-Alquist Act[31], the Energy Commission's certification would act as an "in-lieu" permit for certain state and local permits by incorporating the regulatory requirements and conditions of those permits into the Commission's certification.

Staff's analysis, determination of potential impacts, and evaluation of appropriate mitigation measures relies in part on estimates and information provided by CE Obsidian regarding the construction and operation of BR123. Applicable scientific, technical, and LORS/policy-related literature and expert opinion were also consulted in the development of staff's analysis.

DIRECT/INDIRECT IMPACTS AND MITIGATION

The direct and indirect impact and mitigation discussion is presented below by project element. Impacts analysis related to both construction and operation is provided for each element, along with any proposed conditions of certification deemed necessary to mitigate impacts.

Land Disturbance and Soils

The original SSU6 project was certified for permanent disturbance of approximately 186 acres of land. This total included the main 80 acre plant facility, along with offsite production and injection wells, pads, and pipelines, the transmission linears, and the

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[31] The Warren-Alquist State Energy Resources Conservation and Development Act is the authorizing legislation for the California Energy Commission. The Act is codified as Public Resources Code (PRC), Section 25000 et seq.. PRC Section 25500 establishes the Commission's authority to certify all sites and related facilities for thermal power plants. The section further declares that "the issuance of a certificate by the commission shall be in lieu of any permit, certificate, or similar document required by any state, local or regional agency, or federal agency to the extent permitted by federal law, for such use of the site and related facilities, and shall supersede any applicable statute, ordinance, or regulation of any state, local, or regional agency, or federal agency to the extent permitted by federal law."

switchyard. The BR123 would use the same 80 acres originally identified for the SSU6 main site, but would also include the 80 acre lot immediately south, along with 53.4 acres for the offsite injection well pads and pipelines, for a total permanent land disturbance of 213.4 acres. Temporary land disturbance would increase approximately 16 percent to 243 acres from the 210 acres identified for the certified SSU6 project, and would include areas of temporary disturbance such as the borrow site. While the BR123 project would increase the number of acres of land disturbed by project construction and operation, application of existing and amended Conditions of Certification **CIVIL-1**, **SOIL & WATER-1**, **SOIL & WATER-2,** and **SOIL & WATER-3**, requiring development and implementation of storm water management and erosion control plans and compliance with local grading requirements, would ensure that impacts to soil and water resources in the area from project grading and land disturbance would be reduced to a less than significant level.

Soil Contaminants

The acreage added for the BR123 project is a combination of highly disturbed land (existing geothermal power plants/wells, etc.) and agricultural land. A Phase I Environmental Site Assessment (Phase I) was completed for all the properties included in the BR123 in order to identify any potential sources of soil or water contamination (CE Obsidian/AECOM 2009). The Phase I found no Recognized Environmental Conditions (REC)[32] in connection with the BR123 properties. However, due to the extensive agricultural development in the area and potential for pesticide accumulation in the soil, staff requested Phase II sampling and analysis for the main 160 acre site. Chemical analysis of the soil samples for organochlorine pesticides showed that very low concentrations of 4,4'-DDT[33] and 4,4'-DDE[34] remain in the soil at the site. The concentrations found are well below Residential California Human Health Screening Levels and USEPA Regional Screening Levels (CE Obsidian/CH2MHILL 2009a) and, consequently, soil remediation would not be required. (For more information on the Phase II soil sampling and results, please see the **Waste Management** section.) Given the lack of RECs and very low concentrations of pesticide residue in the project soil, no adverse impacts to soil and water resources in the area are expected from site grading, soil excavation and stockpiling, or other soil disturbance activities necessary for construction and operation of the BR123.

Borrow Areas

Project site preparation and grading would require removal and stockpiling of approximately 180,200 cubic yards (cu yds) of topsoil off the main facility site. The project would then utilize approximately 362,000 cu yds of cement conditioned soil imported from a new 34-acre borrow site (Borrow Area 1) located immediately southeast of the main project lot near the Vulcan 1 facility. Fill material may also be imported from an existing borrow site located at the Leather's geothermal plant. The cement conditioned imported soil would be used to support the onsite plant structures

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[32] A Recognized Environmental Condition is defined as the presence or likely presence of a hazardous substance or petroleum product on a property under conditions indicating an existing release, a past release, or a material threat of a future release of the hazardous substance or petroleum product into structures or to the ground, groundwater, or surface water.

[33] DDT stands for dichlorodiphenyltrichloroethane.

[34] DDE stands for dichlorodiphenyldichloroethylene.

and roads, to create the site perimeter berm, and to elevate the well pads, ponds and other project structures. Borrow Area 1 is owned by CalEnergy Obsidian Energy LLC (CE Obsidian) and is currently leased for agricultural use. This site would be used to obtain material for construction of the perimeter berm and foundations at the plant site. Topsoil stripped from the plant site will be "spoiled" back to the Borrow Area 1 in order to return the site to pre-project agricultural use conditions. No material removed from this site would be sold commercially and the site would be used solely to support construction of the BR123. As part of the BR123 project, grading and excavation activities at Borrow area 1 would be included under existing Conditions of Certification **CIVIL-1**, **SOIL & WATER-1**, **SOIL & WATER-2,** and **SOIL & WATER-3**, requiring development and implementation of storm water management and erosion control plans and compliance with local grading requirements. Therefore, as noted above, staff anticipates that impacts to soil and water resources in the area from project grading and land disturbance at Borrow Area 1 would be reduced to a less than significant level.

The borrow site near the Leathers plant (Borrow Area 2) is an existing facility that has been developed by CE Obsidian as a source for minor amounts of material to support on-going operations. No material is sold commercially from this site. CE Obsidian contacted the Imperial County Planning and Development Services (ICPDS) with respect to permitting requirements for the site and was advised that a grading or borrow area permit was not required as long as no more than 6" of soil was removed from any area. A Construction SWPPP was prepared on March 9, 2009 for the site, and a Notice of Intent (NOI) was submitted to the Storm Water Section of the SWRCB on March 13, 2009. Waste Discharger Identification (WDID) number 7 13C353850 was issued to CE Obsidian on March 24, 2009, for the site. CE Obsidian also prepared a Dust Control Plan for the site and notified the Imperial County Air Pollution Control District of the availability of the plan. CE Obsidian was recently informed by the SWRCB of changes in the construction SWPPP requirements, which will require preparation of a new NOI for Borrow Area 2. CE Obsidian will prepare and file this NOI as required. Given the site's enrollment under the construction storm water permit and the development of a dust control plan for the site, staff believes any impacts from project borrow activities at Borrow Area 2 would have a less than significant impact on soil and water resources in the area.

Surface Mining and Reclamation LORS

While staff believes that any impacts from excavation and grading activities at the borrow sites would be adequately mitigated through application of existing and amended conditions of certification, the extent of excavation at Borrow Area 1 is such that the activity is subject to state and local surface mining and reclamation provisions adopted pursuant to the California Surface Mining and Reclamation Act of 1975 (also known as SMARA). The California State Mining & Geology Board (SMGB) is charged with enforcing and administering SMARA, often through local planning departments acting as lead agency for SMARA enforcement within their jurisdictions. SMARA provisions require that surface extraction of mineral product (including soil aggregate used for construction) in excess of 1,000 cubic yards or with a total surface area disturbance of 1 acre: 1) apply for a mining permit; 2) prepare and post an appropriate reclamation bond; and 3) prepare and implement a site reclamation plan, consistent with reclamation standards, to protect the environment and return the site to a useable condition. However, SMARA allows for a one-time exemption pursuant to Article 1 of Public Resources Code (PRC), Division 2, Chapter 9, Section 2714(f), which allows an exemption for: "Any other surface mining operations that the [SMGB], as defined by Section 2001, determines to be of an infrequent nature and which involve only minor surface disturbances."

The Energy Commission in March 2010 requested a determination by SMGB whether the activities proposed for Borrow Area 1 were subject to SMARA, and if so, whether the site is eligible for a one-time exemption under Section 2714(f) as described above. At its regular Business Meeting on May 13, 2010, the Board determined that Borrow Site 1 is subject to SMARA, but that it also met the requirements for an exemption from SMARA under Section 2714(f). The exemption was granted under the condition that the site be restored to its present use as soon as practicable, and that SMGB or its designee review and approve all borrow site restoration activities. To ensure Borrow Area 1 is properly restored to its present use, staff recommends adoption of Condition of Certification **SOIL & WATER-16** requiring development of a site reclamation plan in compliance with SMARA Article 5, Sections 2772 and 2773. This would include a schedule for completing mining activities on Borrow Area 1 and for completing restoration of the site as quickly as practicable following completion of the mining activities. (Application of **SOIL & WATER-16** is not necessary at Borrow Area 2 because the County has already determined that activities there would not require a grading or mining permit.) Staff believes that adoption of **SOIL & WATER-16** would help ensure compliance with all applicable surface mining and reclamation LORS for protection of the environment and would also reduce impacts to soil and water resources from project activities at Borrow Area 1 to a less than significant impact.

<u>Water Quality</u>

Federal Clean Water Act (CWA) Section 404 Permit and Section 401 Water Quality Certification

While the increased project site acreage (the added 80-acre parcel, injection well pads and pipelines, and borrow site) would include agricultural channels around the perimeter of the added 80-acre lot and the borrow site, all construction activities would occur outside the bed and banks of canals, or would span them without altering the canals (CE Obsidian/CH2MHill 2009). Therefore, no adverse impacts to the waters of the US are anticipated from the added project acreage. In addition, the proposed project would no longer include road widening and pipeline installation between the west end of McKendry Road and Obsidian Butte, as identified in existing Conditions of Certification **SOIL & WATER-4** and **SOIL & WATER-5**. This would eliminate any potential adverse impacts to jurisdictional waters and wetlands in those areas from construction and operation of the BR123. However, a CWA Section 404 permit and Section 401 water quality certification would still be needed for areas along the transmission line route and the switchyard site that are unchanged from the licensed SSU6 project. Therefore, staff proposes to revise existing Conditions of Certification **SOIL & WATER-4** and **SOIL & WATER-5** to delete reference to the specific activities and locations identified and instead require the project to obtain a Section 404 permit from USACE (**SOIL & WATER-4)** and a Section 401 Water Quality Certification from the RWQCB (**SOIL & WATER-5)** for all project areas determined by USACE to be subject to Section 404 permit requirements. These proposed revisions to **SOIL & WATER-4** and **SOIL & WATER-5** are consistent with existing Conditions of Certification **BIO-9** and **BIO-11**, which address biological conditions that may be established by the Section 404 permit or Section 401 water quality certification.

Flood Control

The project site is located at 225 feet below sea level on average, and is within the 100-year flood plain. As with the certified SSU6 project, the amended BR123 project would include an earthen berm around the entire site to a height of 220 feet below sea level in order to provide flood protection consistent with local requirements. During BR123 plant operation, the berm would also prevent storm water from being discharged offsite. Although the BR123 would increase the size of the parcel enclosed by the berm, there would be no change in the level of flood protection provided by the berm. In addition, application of existing Condition of Certification **SOIL & WATER-13** to the BR123 project would ensure that project floodproofing methods meet the criteria established by the Imperial County Flood Damage Prevention Regulations. Therefore, expansion of the area to be enclosed by the site perimeter berm is expected to have a less than significant impact on flood conditions in the project area.

Drainage and Storm Water Management

Drainage conditions and considerations for the BR123 project are very similar to those evaluated for the SSU6 project. Drainage on the main project site generally flows from the southeast to the northwest, toward the Salton Sea. As with the SSU6 project, storm water would be directed to a retention basin in the northwest corner of the site through the use of ditches, swales, and culverts. Buildings and equipment would be placed on foundations and the site would be graded to allow storm water to flow around and away from structures.

Construction

The applicant has prepared a draft Drainage Erosion and Sediment Control Plan (DESCP) that included a list of erosion and sediment control Best Management Practices (BMPs) that would be implemented before, during, and post-construction, as well as sediment basin sizing calculations. The applicant has proposed implementation of both source control and treatment control BMPs to limit soil erosion and the transport of eroded sediments during construction. The applicant has identified source control BMPs, including soil stabilization with hydraulic mulch, straw mulch, and geotextiles to stabilize disturbed soils and limit erosion. To help trap eroded sediments, the applicant identified silt fences, sand bag barriers, and fiber rolls, as well as sediment traps as treatment control BMPs for use during construction. The applicant proposed that all BMPs would be inspected before and after storm events and daily during extended storm events and that all measures would be maintained in good working order (CE Obsidian/AECOM 2009).

The applicant proposes to use a construction retention basin that will be converted to the permanent retention basin after the construction phase. The operation retention basin proposed for the BR123 project in the draft DESCP would be 512 feet long, 321 feet wide, and 3.5 feet deep, with 2:1 side slopes, and a 576,000-cubic-foot capacity.

The applicant stated that this basin is designed to hold storm water generated onsite from a 100-year storm event, which would be three inches of rain in a 24-hour period. Retained storm water would be left to evaporate and no water would be discharged from the basin. However, Staff checked and found that the volume from 3 inches of rain over the site area of 160 acres, which is the criterion set by Imperial County, comes to 1,742,400 cubic feet, or 40 ac-ft. Staff therefore concludes that the size of the proposed basin is insufficient to retain the design storm. To ensure that there would be no offsite impact, the applicant should be required to demonstrate sufficient storage capacity for the design event according to Imperial County Code Title 12, Chapter 12.10.020 Section B. The applicant should also ensure that the storage facilities allow for complete drawdown within 72 hours as required by the Imperial County Design Code. Staff further believes that the applicant has to meet the requirements of the WQO 2009-0009 DWQ for the site.

If the retention facilities are designed to the Imperial County standard for volume, Staff believes that the site would have sufficient capacity to handle runoff generated during construction.

Staff recommends amending existing Condition of Certification **SOIL & WATER-2** to require that the applicant demonstrate sufficient onsite storage in accordance with the standards established by Imperial County, and to ensure that the onsite retention basin is designed to handle overflow situations while its structural integrity is maintained.

During construction and operation the applicant would need to monitor and remove trapped sediments from the onsite stormwater retention basin to maintain infiltration rates and storage volume as needed. Following construction, temporary erosion control and treatment control BMPs would be removed from the site, but the retention basin would remain as a permanent structure to be used during plant operation.

With the exception of the retention basin sizing, staff believes that the draft DESCP provided by the applicant is reasonable as a planning level document and that, through the proper application of the proposed BMPs, impacts to soil resources from water and wind erosion would be reduced to a level that is less than significant. To support compliance with LORS and ensure all areas of the BR123 project are addressed in erosion control documents, staff proposes adoption of revised Condition of Certification **SOIL & WATER-1**, requiring preparation and implementation of a Storm Water Pollution Prevention Plan (SWPPP) and compliance with the requirements of the General NPDES Permit for Discharges of Storm Water Associated with Construction Activity. In addition, implementation of a final DESCP for project construction, pursuant to amended Condition of Certification **SOIL & WATER-2** (formerly **SOIL & WATER-3** renumbered as **SOIL & WATER-2**) would assure that the proposed storm water management structures and BMPs are properly sized and implemented.

Operation

When addressing storm water management during plant operation in the BR123 amendment petition, the applicant cited a 1993 SWRCB memorandum that concluded that discharges of storm water from geothermal power plants are not subject to the requirements of the SWRCB General NPDES Permit for Discharges of Storm Water

Associated with Industrial Activity (Industrial General Permit). The applicant, therefore, recommended deletion of the existing SSU6 Condition of Certification **SOIL & WATER-2**, requiring compliance with the Industrial General Permit. Staff has confirmed the applicability of the 1993 memo and concurs with the applicant on removal of the condition requiring compliance with the Industrial General Permit. However, staff believes that proper application and implementation of permanent erosion/sediment control structures and plans for management of storm water during operation are still necessary to ensure protection of soil and water resources (especially groundwater) at the project site from exposure of storm water to contaminants, such as oil and grease or industrial chemicals. Therefore, staff recommends adoption of a new Condition of Certification **SOIL & WATER-3**, requiring preparation and implementation of a site-specific BR123 facility operation DESCP, detailing how storm water will be managed during plant operation, what permanent BMPs and materials management practices will be employed at the site, and explaining how and when inspections and maintenance of all plant operation storm water management structures will be undertaken. With adoption of a new **SOIL & WATER-3**, staff believes impacts to soil and water resources from management of storm water during plant operation would be reduced to a less than significant level.

Production Wells

While the Warren-Alquist Act (PRC section 25120) specifically excludes geothermal production wells and related facilities from certification by the Energy Commission,[35] analysis of the potential environmental impacts from construction and operation of the wells is still required to determine compliance with the provisions of CEQA. As noted previously, in the case of the BR123, the baseline for the project's CEQA analysis is the SSU6 project "as certified." Only those elements of the BR123 project that represent significant changes to the "as certified" SSU6 project, or that exceed the magnitude of the elements assessed for the SSU6, are considered in this BR123 soil and water staff assessment.

The SSU6 project was certified for eleven geothermal production wells to be located on five offsite well pads. The BR123 would reduce the number of production wells and well pads to nine wells on three pads to be located within the main 160-acre facility site. The relocation of the wells and pads would eliminate project impacts to jurisdictional waters and wetlands at the Obsidian Butte production well site previously authorized as part of the SSU6 certification. The BR123 production well design and drilling program would be essentially the same as that analyzed for the certified SSU6 project, so no additional analysis of well design or construction is provided here. While not specifically licensed by the Energy Commission, all production well construction activities would still be subject to the erosion control and stormwater management provisions associated with

[35] Public Resources Code Section 25120 defines the term "thermal powerplant", thereby establishing what facilities are to be included under the Energy Commission's powerplant certification jurisdiction. The section defines "thermal powerplant" as "any stationary or floating electrical generating facility using any source of thermal energy, with a generating capacity of 50 megawatts or more, and any facilities appurtenant thereto." The section further states that "exploratory, development, and production wells, resource transmission lines, and other related facilities used in connection with a geothermal exploratory project or a geothermal field development project are not appurtenant facilities for the purposes of this division." Therefore, by definition, geothermal production wells are excluded from the Energy Commission's powerplant licensing authority.

the SWRCB General NPDES Construction Stormwater permit that is also required for all BR123 project construction activities per Condition of Certification **SOIL & WATER-1**. Therefore, no significant adverse impacts to soil and water resources are anticipated from construction and operation of the BR123 production wells and well pads.

Brine and Plant Injection Wells

The original SSU6 project was certified and amended to construct eight brine injection wells on three offsite well pads located to the south and east of the main project site. The BR123 would increase the number of brine injection wells to nine wells, consisting of three wells on each of 3 offsite well pads. While the BR123 brine injection well pads would still be located to the south and east of the main project site, the wells and pads would be closer to the main site, which would reduce the length of injection well pipeline necessary thereby reducing any potential impacts from construction and operation of the injection well pipelines. The BR123 would also increase the number of plant injection wells from two to four, all located within the main 160-acre project site. The preliminary drilling depths and casing design for the wells would be basically the same as that analyzed for the SSU6 project.

As with the certified SSU6 project, the construction and operation of the BR123 injection wells would be subject to existing conditions of certification requiring compliance with the SWRCB General NPDES Construction Stormwater permit (**SOIL & WATER-1**), as well as development and implementation of erosion control and stormwater management BMPs for both project construction and operation (**SOIL & WATER-2** and **3**). The BR123 injection wells would also be subject to existing Condition of Certification **SOIL & WATER-7** requiring compliance with Underground Injection Control (UIC) permit provisions. The UIC permits are specifically designed and enforced to prevent contamination and adverse impacts to groundwater and sources of drinking water from wastewater injection.

Given application of the existing and amended conditions of certification to the BR123 injection wells, staff believes the increased number of injection wells and relocation of the wells and pads would have a less than significant impact on soil and water resources in the project area.

Water Supply

As noted above in the project description, the original SSU6 project was certified to use up to 1,000 AFY of fresh water from IID for cooling tower makeup, brine dilution, plant service water, and domestic use. When the BR123 amendment was first filed with the Energy Commission, the proposed maximum water use was identified as 987 AFY, and the average use was identified as 293 AFY. The water was to be provided by IID under an existing contract for delivery of up to 1,000 AFY. (CE Obsidian/AECOM 2009). However, the applicant later re-evaluated the project's water use and revised the maximum water use to 609 AFY and the average use to 355 AFY (CE Obsidian/ H2MHILL 2010). The revised BR123 water use volumes would reduce the project's maximum fresh water use by 378 AFY, but would increase the average year/nominal design use by 62 AFY. In addition, the applicant later notified staff that a new water contract with IID was being renegotiated. Consequently, a new fresh water supply availability letter from IID was provided for the BR123 project (IID 2010).

The original SSU6 staff assessment evaluated the project's proposed maximum (worst-case) water use of 987 AFY and average year use of 293 AFY in comparison to the volume of water used by agricultural activities for the 173 acres of farmland to be permanently taken out of production by the SSU6 project. Staff determined that 759 AFY of fresh water from IID on average was used for the project site properties and established 759 AFY as the baseline for the SSU6 project. In conducting the assessment for the BR123 project, staff used the "as certified" parameters of the SSU6 project as the baseline for its analysis and determination of the potential environmental impacts of the BR123. BR123 impacts below the SSU6 baseline are assumed to have already been addressed as part of the original SSU6 assessment. In the case of the BR123 project, the proposed maximum fresh water use of 609 AFY is substantially lower than both the 987 AFY maximum baseline amount certified for the SSU6 project as well as the historic agricultural use baseline of 759 AFY used for the original SSU6. Therefore, no additional analysis of the BR123 project's proposed maximum water use is provided here.

While the proposed BR123 maximum fresh water use is below the SSU6 baseline, the proposed average use of 355 AFY is 62 AFY above the 293 AFY average evaluated for the SSU6 project. However, the 355 AFY average use number for BR123 was taken from the revised BR123 medium case brine flow water use parameters shown in **SOIL & WATER Table 4**. Under high brine flow conditions, the project's fresh water use would actually be 271 AFY, 22 AFY below the SSU6 average use. In addition, BR123 project water use at all levels is well below even the baseline water use set for the original SSU6 project. Given all of those decreases in BR123 fresh water use, staff believes that adequate water conservation is provided by the BR123 project as a whole to mitigate the 62 AFY increase in BR123 average water use over the SSU6 baseline. Therefore, no significant adverse impact to water resources is expected from construction and operation of the BR123 project. Staff does, however, recommend adoption of revised Condition of Certification **SOIL & WATER-12** to reflect the reduced maximum fresh water use of 609 AFY now proposed for the BR123 and to require the project owner to provide documentation of a water supply agreement with IID prior to the start of project construction.

Service Water Pond Evaporation

As with the SSU6 project, the BR123 would utilize a raw water storage pond for onsite storage of fresh water supplied by IID. However, the SSU6 project was licensed to use ponds for all fresh service water, while the BR123 site plan and data requests indicate that fire water would be stored in a tank and only the fresh service water would be stored in a pond. Data Response Number 66 (CE Obsidian/CH2MHILL 2010) states that the service water pond would be 148 feet long and 121 feet wide with a surface area of 17,908 square feet. With this new design the evaporative losses from the surface of the raw water storage pond were significantly reduced from 30 AFY to 3.61 AFY. Staff had originally recommended that the applicant be required to offset the evaporative water losses by paying the IID elevated water conservation rate to mitigate water loss impacts. Staff notes that IID no longer has an elevated water conservation fee and has adopted a new policy and water rate structure for water supply to industrial users. This new fee structure includes a fee for water development and use for industrial purposes, which would address mitigation for evaporative losses. Given the significant reduction in the evaporative losses in the new design for the water storage, coupled with the new fee structure designed to address impacts from industrial users, staff believes Condition of Certification **SOIL&WATER-6** can be eliminated.

Brine Ponds (Waste Management Units)

As with the original SSU6 project, the BR123 would utilize three lined ponds to collect production brines discharged during plant upset conditions, well flow testing, or startup. The ponds would also be used to collect miscellaneous geothermal power production byproducts and wastestreams (such as blowdown from the cooling towers and scrubber wastes). The brines and wastewaters collected in the ponds would then be pumped to either the aerated brine or plant injection wells for disposal in the geothermal formation in accordance with the provisions of the injection well Class V geothermal UIC permit(s).

Each brine pond would be 636 feet long, 58 feet wide, and 7.5 feet deep and would include a built-in leak detection system and a surrounding 20-foot area for cleanout vehicle access and an entry ramp. The brine ponds would be earthen construction, and lined with the following layered liner materials:

- Geosynthetic clay liner (GCL)
- High-density polyethylene (HDPE) 80 mil
- HDPE 200 mil
- Textured – HDPE 80 mil
- 6-inch compacted soil
- 6-inch fiber-reinforced concrete

The SSU6 project was originally certified to use two brine ponds operated in compliance with all Title 27 regulations related to waste management units. This included lining and monitoring the ponds to prevent leaks and impacts to surface and groundwater from the high TDS brines and wastewaters. The project was also conditioned to obtain a permit (known as Waste Discharge Requirements or WDRs) from the Colorado River Basin RWQCB for use of the ponds to manage the brines and wastewaters (existing Condition of Certification **SOIL & WATER-8**).

While the BR123 would add one additional brine pond, the operation elements of the ponds would be basically the same as certified for the SSU6 project. Staff believes this element of the BR123 does not represent a significant change from the certified SSU6 project and any potential adverse impacts from construction and operation of the BR123 brine ponds would also be mitigated through implementation of existing Condition of Certification **SOIL & WATER-8**. However, since the SSU6 project's original licensing, it has been determined that the Energy Commission's in-lieu permitting authority for state and local permits also applies to non-federal Waste Discharge Requirements adopted by the California Regional Water Quality Control Boards (RWQCB). As noted previously in this section, the Warren-Alquist Act (Pub. Resources Code § 25500, et.seq.) identifies the Energy Commission's power plant siting certification to be "in lieu of" any other state, local, and regional permits. Commission staff continues to coordinate environmental review of project applications and amendment petitions with the RWQCBs, but now staff also incorporates into its analysis all non-federal Waste Discharge Requirements that might otherwise be adopted by the RWQCBs.

In light of the Energy Commission's in-lieu permitting, staff requested the applicant to provide a Report of Waste Discharge (ROWD) to both the Energy Commission staff and to the CRBRWQCB describing the wastes to be discharged, the proposed brine pond and mud sump designs, and the soil and water environment in the area of the ponds (CE Obsidian 2009). CRBRWQCB staff then reviewed the ROWD and associated BR123 documents and provided draft requirements to Energy Commission staff for waste discharge for the brine ponds. These requirements are included in this staff assessment as Appendices A, B, and C. Appendix A presents the Facts for Waste Discharge for the brine ponds, including all the necessary information describing the environment and waters potentially affected by the discharge, the proposed facility operation, the anticipated waste characteristics, and the proposed design of the brine ponds. Appendix B presents the Requirements for Waste Discharge for the brine ponds, including discharge specifications, prohibitions, and provisions for reporting and monitoring. Lastly, Appendix C presents the required Monitoring and Reporting Program for the brine ponds establishing how and when the project would monitor the discharge and operation of the ponds to document that there are no unauthorized releases of wastewater or adverse impacts to water resources. These requirements represent a comprehensive set of standards, specifications, and prohibitions that are designed to protect the waters of the state from any potential adverse impacts associated with onsite management of project wastewaters.

Staff concurs with the requirements provided by the CRBRWQCB staff in Appendices A, B, and C, and, pursuant to the in-lieu permitting function of the Energy Commission's certification, staff proposes adoption of a revised Condition of Certification **SOIL & WATER-8** requiring compliance with the provisions Appendices A, B, and C. Adoption of revised **SOIL & WATER-8** would satisfy the state LORS for protection of waters of the state and take the place of WDRs that, but for the Commission's exclusive authority, would have otherwise been adopted by the CRBRWQCB.

Monitoring Wells

The BR123 also proposes to use groundwater monitoring wells adjacent to the brine ponds to ensure compliance with RWQCB groundwater protection regulations and waste discharge requirements established under Condition of Certification **SOIL & WATER-8**. This element of the BR123 does not represent a significant change from the already certified SSU6 project.

However, to ensure proper monitoring well construction as well as compliance with local water well ordinances, staff proposes Condition of Certification **SOIL & WATER-15**. This condition would require that the design, construction, and operation of all project monitoring wells be done in compliance with the Imperial County water well regulations established in Title 9, Division 21 of the Imperial County Land Use Ordinance. These regulations, as well as the state water well standards, were established to prevent contamination of water resources from the drilling and operation of water wells in the County. The regulations require that 1) water wells in the County (including monitoring wells) be constructed, reworked or destroyed in accordance with California Water Well Standards (California Department of Water Resources Bulletins 74-81 and 74-90; and 2) persons planning to drill, refurbish, or destroy a water well must first obtain a well construction permit from the County prior to commencing work. **SOIL & WATER-15** would operate “in-lieu of” the required County well construction permit, in accordance with the Energy Commission’s exclusive permitting authority. Staff believes that the adoption of proposed Condition of Certification **SOIL & WATER-15** would help ensure that the construction, operation, and destruction of any monitoring wells necessary for the BR123 project would be done in compliance with LORS and would therefore not cause any adverse impacts to soil or water resources.

Mud Sumps

As with the certified SSU6 project, the BR123 drilling muds and rock cuttings would be managed in temporary, lined mud sumps. Six muds sumps would be used, one for each onsite brine production well pad/drilling location and one for each offsite injection well pad/drilling location. The sumps would be approximately 726 feet long, 11 feet wide and 5 feet deep with 2 feet of freeboard. They would be lined with a geosynthetic liner that would then be covered by 12 inches of compacted clay. This element of the BR123 does not represent a change from the certified SSU6 project and Condition of Certification **SOIL & WATER-9** would also have applied to the BR123 mud sumps. However, as described in the Brine Pond section above, since the SSU6 project’s original licensing, it has been determined that the Energy Commission’s in-lieu permitting authority for state and local permits also applies to non-federal Waste Discharge Requirements (WDRs) adopted by the California Regional Water Quality Control Boards (RWQCB). In addition, given that the Energy Commission’s licensing jurisdiction excludes geothermal production wells and related facilities, only the BR123 injection well mud sumps can be addressed by the in-lieu waste discharge requirements. The project owner will have to apply to the CRBRWQCB for issuance of WDRs for construction and operation of the production well mud sumps.

Information on the proposed mud sumps was also included in the ROWD provided by the applicant to both Energy Commission staff and to the CRBRWQCB (CE Obsidian 2009) describing the wastes to be discharged, the proposed brine pond and mud sump designs, and the soil and water environment in the area of the ponds. CRBRWQCB staff then reviewed the ROWD and associated BR123 documents and provided to Energy Commission staff draft requirements for waste discharge for the temporary mud sumps. These requirements are included in this staff assessment as Appendices D, E, and F. Appendix D presents the Facts for Waste Discharge for the mud sumps, including all the necessary information describing the environment and waters potentially impacted by the discharge, the proposed facility operation, the anticipated waste characteristics, and the proposed design of the mud sumps. Appendix E presents the Requirements for Waste Discharge for the mud sumps, including discharge specifications, prohibitions, and provisions for reporting and monitoring. Permanent (longer than one (1) year) disposal or storage of drilling waste to mud sumps/containment basins would be prohibited, unless authorized by the CPM, in consultation with the Regional Board Executive Officer. Lastly, Appendix F presents the required Monitoring and Reporting Program for the mud sumps that establishes how and when the project would monitor the discharge and operation of the sumps to document that there are no unauthorized releases of drilling wastes or adverse impacts to water resources. These requirements represent a comprehensive set of standards, specifications, and prohibitions that are designed to protect the waters of the state from any potential adverse impacts associated with onsite management of drilling wastes, fluids, and cuttings.

Staff concurs with the requirements provided by the Colorado River Basin RWQCB staff in Appendices D, E, and F and, pursuant to the in-lieu permitting function of the Energy Commission's certification, staff proposes adoption of a revised Condition of Certification **SOIL & WATER-9** requiring compliance with the provisions of Appendices D, E, and F. Adoption of revised **SOIL & WATER-9** would satisfy the state LORS for protection of waters of the state and take the place of the temporary WDRs for the injection well mud sumps that, but for the Commission's exclusive authority, would have otherwise been adopted by the CRBRWQCB.

In the original project analysis Staff was concerned about the potential environmental impact of an accidental spill of geothermal brine. Staff recommended that the applicant be required to develop an emergency plan, similar to a frac-out plan, in accordance with Condition of Certification **SOIL&WATER-10** which would address procedures for containment of spilled geothermal brine and subsequent treatment of affected areas. As a part of this amendment, staff has added waste discharge requirements in Appendices A through F as discussed above for brine ponds and mud sumps, which ensure there are no impacts from discharges, and plans would be in place to ensure any discharges or unauthorized releases are remediated. Appendix C includes requirements for reporting and clean up related to brine discharges for permanent operations of brine ponds and Appendix F includes requirements for reporting and remediation of unauthorized releases for use of mud sumps and during production well development. Staff has recommended the applicant be required to comply with the requirements outlined in these appendices in accordance with Conditions of Certification **SOIL&WATER-8 and -9**. Staff believes that if the applicant is required to comply with these conditions, there will be no need for Condition of Certification **SOIL & WATER-10**. Staff has therefore stricken Condition of Certification **SOIL & WATER-10**.

Domestic and Sanitary Wastewaters

The BR123 project would manage domestic and sanitary wastewaters in basically the same manner as proposed in the certified SSU6 project. During construction, sanitary wastes would be managed using portable toilets. During operation, the domestic and sanitary wastes from the common control building would be directed to a septic tank system. However, the BR123 septic system would not include a leach field for onsite disposal of liquid wastes due to shallow groundwater conditions in the area. Instead, both the solid and liquid wastes would be collected in the septic tank, then pumped out as necessary by a licensed sanitary waste contractor and disposed of in accordance with local sanitary waste management requirements. Existing Condition of Certification **SOIL & WATER-11,** requiring compliance with Imperial County septic system design and waste management standards, would still apply to the BR123 project.

Given the BR123 project's lack of onsite septage disposal and the existing condition of certification requiring compliance with local septic system standards, staff does not expect any significant adverse impacts to soil and water resources from construction and operation of the BR123 septic waste system.

CUMULATIVE IMPACTS

Cumulative impacts represent impacts that are created as a result of construction and operation of a proposed project in combination with impacts from other past, present, or reasonably foreseeable future projects. Cumulative impacts can result from collectively significant actions taking place over time in the same area. (Cal. Code Regs., tit. 14, §15355.) In addition to the BR123, other projects in the area include:

- Hudson Ranch Geothermal Development Project (commonly referred to as the CHAR project), in the Salton Sea KGRA (**Water demand: 800 AFY**).
- Ormat Geothermal Projects, in the Brawley KGRA.
  - North Brawley Geothermal Project (**Water demand: 6800 AFY**).
  - East Brawley Geothermal Project (**Water demand information not available**).
- Ram East Brawley, in the Brawley KGRA (**Water demand information not available**).
- Blackrock 4, 5, and 6, in the Salton Sea KGRA (**Water demand: similar to BR123**).

SOIL EROSION, STORM WATER, AND FLOODING

Construction and operation of the proposed BR123 would result in both temporary and permanent changes at the expanded project site. These changes could incrementally increase local soil erosion and storm water runoff. However, implementation of proper erosion and sediment control BMPs and storm water management structures in accordance with revised Conditions of Certification **SOIL & WATER-1, 2,** and **3** would ensure that the BR123 would not result in significant cumulative erosion and sedimentation impacts.

In addition, as with the certified SSU6 project, the BR123 would include a flood control berm, built to a height of 220 feet below sea level, surrounding the entire 160-acre main project site. The berm would be built in accordance with local flood protection requirements, per existing Condition of Certification **SOIL & WATER-13**, and would prevent inundation of the site in the event of Salton Sea flooding. The berm would also retain onsite storm water and prevent storm water discharges to surrounding properties. Consequently, no significant cumulative impacts for downstream or on-site flooding are expected.

WATER SUPPLY

Although IID receives Colorado River water in accordance with established rights to the water, increasing demands for fresh water in the region, along with uncertainties associated with legal challenges to a suite of 2003 agreements involving IID and other agencies to provide Colorado River Water to the Metropolitan Water District, have increased concerns about long-term availability of fresh water for industrial applications in Imperial County. Built-in measures to mitigate any further strain in fresh water use caused by the project consist of taking currently irrigated agricultural lands out of production. Staff determined in the SSU6 project analysis that historical water use at the SSU6 site averages approximately 759 AFY. Therefore, using 759 AFY as the baseline, the BR123 maximum fresh water use of 609 AFY would reduce water consumption by 150 AFY, while the average water use of 355 AFY would result in a larger reduction of water consumption of 404 AFY of fresh water by taking previously irrigated land out of agricultural production.

At this time, no cumulative water supply impacts are anticipated from construction and operation of the BR123. A sufficient supply of fresh water from IID is available to meet the needs of BR123 and other existing or potential users (IID 2010). The project would also free up fresh water resources formerly used for irrigation of the project site for use by others.

WATER QUALITY

Improper wastewater disposal or handling can contribute to soil, surface and ground water degradation, and impairment of beneficial uses of waters in the area. However, construction and operation of the proposed BR123 wastewater management units and implementation of BMPs in accordance with the revised conditions of certification would prevent further degradation of already adversely affected surface and groundwater supplies. Staff does not anticipate cumulative impacts to water quality resulting from the BR123 project.

FACILITY CLOSURE

As with the certified SSU6 project, the BR123 is expected to operate for a minimum of 30 years. Closure options range from “mothballing,” with the intent of restart at some future time, to the removal of all equipment and facilities. The facility closure plan would be submitted to the Energy Commission for approval prior to decommissioning. Compliance with all applicable LORS, and any local and/or regional plans would be required for all closure activities. The plan would also be required to address any concerns regarding soil and water resources.

COMPLIANCE WITH LORS

Staff has reviewed the proposed BR123 project elements and concludes that, with adoption of staff’s proposed conditions of certification, the BR123 would comply with all applicable LORS addressing protection of water resources, storm water management, erosion control, and wastewater discharge.

CONCLUSIONS AND RECOMMENDATIONS

Staff has not identified any immitigable potentially significant impacts to Soil and Water Resources from the proposed BR123 project and believes the project would comply with all applicable LORS provided the proposed conditions of certification are implemented.

SUMMARY OF CONCLUSIONS

Based on its assessment of the proposed BR123, staff has reached the following conclusions:

- Potential adverse impacts caused by soil erosion and storm water flows during construction and operation of the BR123 would be mitigated through:
    - o Implementation of a Construction Storm Water Pollution Prevention Plan and compliance with the provisions of the federal National Pollutant Discharge Elimination System (NPDES), General Permit for Discharges of Storm Water Associated with Construction Activity as required by existing Conditions of Certification **SOIL & WATER-1** (as revised), and **SOIL & WATER-2**;
    - o Implementation of Drainage, Erosion, and Sedimentation Control Plans for project construction and operation, as required in Condition of Certification **SOIL & WATER-2** (originally **SOIL & WATER-3**) and newly proposed Condition of Certification **SOIL & WATER-3**;
- Potential impacts to surface or groundwater quality from geothermal brines and industrial wastewaters generated by the BR123 would be mitigated to a less than significant level through compliance with waste discharge requirements established by the revised Conditions of Certification **SOIL & WATER-8 and -9**;
- The project would be constructed within a designated 100-year floodplain. However, construction of a site perimeter berm and floodproofing in accordance with the Imperial County Flood Damage Prevention Regulations, per existing Condition of Certification **SOIL & WATER-13**, would ensure that the project would not increase flood hazards in the vicinity of the project;
- The project's proposed water use would not result in significant adverse impacts on water resources and water quality with adoption of the proposed revisions to existing Condition of Certification **SOIL & WATER -12**. Staff also believes **SOIL & WATER-6** can be eliminated because there is no longer an elevated consumptive use rate and also because evaporative losses have been reduced to a level of insignificance;
- Condition of Certification **SOIL & WATER-10** can be eliminated because the subject of that condition is satisfactorily covered in the Contingency Reporting section in Appendix F provided in this amendment analysis;
- The proposed project would comply with applicable federal, state, and local laws, ordinances, regulations, and standards (LORS) with adoption and implementation of staff's proposed revised conditions of certification; and
- The BR123 would not result in any unmitigated cumulatively significant adverse impacts to soil or water resources with adoption of staff's proposed revised conditions of certification.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

Staff has proposed modifications to the Soil and Water Resources conditions of certification as shown below. (**Note:** Deleted text is in ~~strikethrough~~; new text is in **<u>bold and underlined</u>**.)

SOIL & WATER-1: The project owner shall comply with all of the requirements of the General NPDES Permit for Discharges of Storm Water Associated with

Construction Activity. The project owner shall develop and implement a Storm Water Pollution Prevention Plan (SWPPP**), in accordance with State Water Resources Control Board Water Quality Order No. 2009-0009 Division of Water Quality and any other documents as necessary**~~,~~ for the construction of the entire project**, including all areas of disturbance associated with the transmission and pipeline routes, transfer stations, and offsite borrow areas**. Prior to beginning any site mobilization associated with any project element, the project owner shall submit to the CPM a copy of the Notice of Intent for Construction **(and any other necessary documents)** accepted by the **SWRCB** ~~Colorado River Basin RWQCB~~, and obtain Energy Commission CPM approval of the construction activity SWPPP for ~~**SSU6**~~ **the project, as well as any other documents required by the permit**.

Verification: No later than 60 days prior to the start of site mobilization for any project element, the project owner shall submit a copy of the SWPPP**, and any other documents,** required under the General NPDES Permit for Discharges of Storm Water Associated with Construction Activity to Imperial County for review and comment, and to the CPM for review and approval. The SWPPP will include copies of the Notice of Intent for Construction accepted by the SWRCB/RWQCB and any permits for ~~SSU6~~ **the project** that specify requirements for the protection of storm water or water quality. Approval of the SWPPP**, and associated documents,** by the CPM must be obtained prior to site mobilization for any project element.

~~**SOIL & WATER-2**: The project owner shall comply with all of the requirements of the General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity. The project owner shall develop and implement a Storm Water Pollution Prevention Plan (SWPPP) for the operation of SSU6. The project owner shall submit to the CPM a copy of the Notice of Intent for Operation accepted by the Colorado River Basin RWQCB and obtain approval of the General Industrial Activities SWPPP from the Energy Commission CPM prior to commercial operation of the SSU6.~~

Verification: ~~No later than 60 days prior to the start of commercial operation, the project owner shall submit to the CPM a copy of the SWPPP required under the General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity to Imperial County for review and comment, and to the CPM for review and approval. The operational SWPPP shall include copies of the Notice of Intent for Operation accepted by the RWQCB and any permits for SSU6 that specify requirements for the protection of stormwater or water quality. Approval of the operational SWPPP by the CPM must be obtained prior to start of commercial operation.~~

SOIL & WATER-~~3~~2: Prior to beginning any site mobilization activities for any project element, the project owner shall obtain CPM approval for a **revised** site-specific Construction Drainage, Erosion and Sedimentation Control Plan **(DESCP**) that addresses all project elements **including an updated retention basin design**. The plan shall address revegetation and be consistent with the grading and drainage plan as required by **Condition of Certification CIVIL-1**. **The plan shall include design and plans that have**

been developed in accordance with Imperial County Code Title 12, Chapter 12.10.020 Section B and include an analysis demonstrating that the site storm retention facilities can store the volume required, are capable of handling overflow situations while maintaining structural integrity, and ensure that the facilities are designed to completely drain in 72 hours.

Verification: No later than 60 days prior to the start of any site mobilization for any project element, the project owner shall submit the construction **(DESCP)** ~~Drainage, Erosion and Sediment Control Plan~~ to the CPM for review and approval. No later than 60 days prior to start of any site mobilization, the project owner shall submit a copy of the plan to Imperial County for review and requesting any comments be provided to the CPM within 30 days. ~~The plan must be approved by the CPM prior to start of any site mobilization activities.~~ **The plan must be approved by the CPM prior to start of any site mobilization activities.**

SOIL & WATER-3: Prior to beginning facility operation, the project owner shall obtain CPM approval for a site-specific Facility Operation DESCP that addresses all plant site elements. The plan shall include detailed plans and information for all of the following:

1) a narrative discussion and appropriate site maps and plans showing how storm water and sediment erosion will be managed during plant operation, including locations of permanent BMPs to be employed; 2) a narrative discussion of what permanent BMPs and materials management practices will be employed at the site; and 3) a narrative discussion and schedule detailing how and when inspections and maintenance of all plant operation storm water management structures will be undertaken.

Verification: **No later than 60 days prior to the start of powerplant operation, the project owner shall submit the Facility Operation DESCP to the CPM for review and approval. The plan must be approved by the CPM prior to the start of powerplant operations.**

SOIL & WATER-4: Prior to the start of site mobilization activities associated with any project element subject to these requirements, including linear and off-site facilities, the project owner shall obtain a Clean Water Act Section 404 permit from the U.S. Army Corps of Engineers (USACE) for ~~the road widening and pipeline installation between the west end of McKendry Road and Obsidian Butte, and also for the construction of the Bannister switchyard if~~ all project areas ~~deemed necessary~~ determined by the USACE to require a Section 404 permit.

Verification: No later than 30 days prior to the start of site mobilization activities associated with any project element, including linear and off-site facilities, the project owner shall submit to the CPM **evidence of compliance with the USACE Clean Water Act Section 404 program, including** a copy of the Clean Water Act Section 404 permit from USACE for **all areas of** the project **determined by the USACE to require a Section 404 permit**.

SOIL & WATER-5: Prior to the start of site mobilization activities associated with any project element subject to these requirements, including linear and off-site facilities, the project owner shall obtain a Clean Water Act Section 401 Water Quality Certification, or certification waiver if appropriate, from the Colorado River Basin RWQCB for ~~the road widening and pipeline installation between the west end of McKendry Road and Obsidian Butte, and also for the construction of the Bannister switchyard if~~ all project areas subject to a Section 404 permit ~~is deemed necessary for those activities~~ issued by USACE.

Verification: No later than 30 days prior to the start of site mobilization activities associated with any project element, including linear and off-site facilities, the project owner shall submit to the CPM a copy of the Section 401 Certification**, or waiver if appropriate,** from the Colorado River Basin RWQCB for **all** ~~the~~ project **areas subject to a Section 404 permit issued by USACE**.

~~**SOIL & WATER-6**: The project's use of service ponds will create an average loss of up to 30 acre-feet/year (AFY) of fresh water through evaporation. To offset the loss of fresh water, the project owner shall pay IID the elevated conservation rate for 30 AFY fresh water supply to IID on an annual basis to account for the loss of such supply.~~

Verification: ~~No later than 30 days prior to power plant operation, the project owner shall provide verification that the project and IID have agreed upon the payment of the conservation rate for 30 AFY on an annual basis. Verification should be in the form of a written contract that demonstrates this pay schedule is valid. Verification must be received prior to power plant operation and shall be provided on an annual basis, reported in the Annual Compliance Report for the life of the project.~~

SOIL & WATER-7: The project owner shall provide a copy of the Underground Injection Control (UIC) permit issued by the California Department of Oil, Gas, and Geothermal Resources (DOGGR) for the construction and operation of the brine and wastewater disposal injection wells. The project owner shall not construct or discharge to these wells without the final permit in place or without emergency/temporary authorization from DOGGR or U.S. **Environmental Protection Agency** (EPA**)** Region IX. The project shall provide on a continuing basis copies of all monitoring or other reports, as well as any changes made to the permit by DOGGR related to the operation of these wells. The project shall not operate without a valid UIC permit.

Verification: No later than 15 days prior to the construction of the injection wells, the project owner shall submit copies of the final UIC permit to the CPM. All copies of permit changes and monitoring or other reports must be received within 30 days of their submittal to DOGGR.

SOIL & WATER-8: The project owner shall comply with the ~~obtain~~ ~~W~~waste ~~D~~discharge ~~R~~requirements (WDRs) established in Soil and Water Resources Appendices A, B, and C ~~issued by the Colorado River Basin RWQCB~~ for the construction and operation of the project's brine ponds.

Verification: No later than 60 days prior to any wastewater discharge to the brine ponds, the project owner shall ~~obtain and~~ **provide documentation to the CPM, with copies to the Colorado River Basin RWQCB, demonstrating compliance with the WDRs established in Appendices A, B, and C** ~~copy of the WDRs issued by the Colorado River Basin RWQCB for the project's discharge to the brine ponds to the CPM~~. Any change**s** to the design, construction, or operation of the ponds ~~permitted by the WDRs will be noticed~~ **shall be requested** in writing to ~~both~~ the CPM**, with copies to** ~~and~~ the Colorado River Basin RWQCB**, and approved by the CPM, in consultation with the Colorado River Basin RWQCB, prior to initiation of any changes.** ~~during both construction and/or operation. The project owner will notify the Energy Commission in writing of any changes to the WDRs that are instituted by either the project owner or the Colorado River Basin RWQCB, including WDRs permit renewal.~~ The project owner ~~will~~**shall** provide **to** the CPM, ~~with~~ **copies of the Colorado River Basin RWQCB, all** ~~the annual~~ monitoring report**s** ~~summary~~ required by the WDRs, and ~~will~~ fully explain any violations, exceedances, enforcement actions, or corrective actions **related to construction or operation of the brine ponds.**

SOIL & WATER-9: The project owner shall comply with the temporary ~~obtain~~ WDRs established in Soil and Water Resources Appendices D, E, and F ~~issued by the Colorado River Basin RWQCB~~ for the project's injection well mud sumps. Permanent (longer than 1 year) disposal or storage of drilling waste to the injection well mud sumps/containment basins is prohibited, unless authorized by the CPM, in consultation with the Regional Board Executive Officer. The project owner shall apply to the Colorado River Basin RWQCB for issuance of WDRs for construction and operation of the project production well mud sumps.

Verification: No later than 30 days prior to the use of mud sumps associated with drilling activities, the project owner shall **provide documentation to the CPM, with copies to the Colorado River Basin RWQCB, demonstrating compliance with the WDRs established in Appendices D, E, and F** ~~obtain and provide a copy of final WDRs issued by the Colorado River Basin RWQCB for the project's mud sumps to the CPM~~. Any change to the design, construction, or operation of the mud sumps **shall be requested** ~~permitted by the WDRs will be noticed~~ in writing to ~~both~~ the CPM**, with copies to** ~~and~~ the Colorado River Basin RWQCB**, and approved by the CPM, in consultation with the Colorado River Basin RWQCB, prior to initiation of any changes** ~~during their use~~. ~~The project owner will notify the Energy Commission in writing of any changes to the WDRs that are instituted by either the project owner or the Colorado River Basin RWQCB.~~ The project owner ~~will~~**shall** provide **to** the CPM**, copies of the Colorado River Basin RWQCB, all** ~~with any reporting or~~ monitoring **reports** required by the WDRs, and ~~will~~ fully explain any violations, exceedances, enforcement actions, or corrective actions related to construction or operation of the mud sumps.

~~**SOIL & WATER-10**: Prior to production of brines from the geothermal aquifer, the project owner shall receive approval for an Emergency Response Plan in consultation with appropriate agencies to ensure proper notification and mitigate any potential impacts resulting from an accidental brine release.~~

Verification: ~~No later than 30 days prior to production of brines from the geothermal aquifer, the project owner shall consult with appropriate agencies and submit an Emergency Response Plan to the CPM for approval. Approval of the final plan by the Energy Commission CPM must be obtained prior to the production of brines from the geothermal aquifer.~~

SOIL & WATER-11: The on-site septic system shall be designed according to the applicable county standards. The project owner shall submit the final designs for the septic system to the CPM for review and approval, and to the Imperial County Environmental Health Services, County Health Department for comment.

Verification: No later than 30 days prior to commencement of septic system construction activities, the project owner shall submit the final designs for the septic system to the CPM for review and approval, and to the Imperial County Environmental Health Services, County Health Department for comment. The project owner shall obtain CPM approval of the final plans prior to commencement of septic system construction activities.

SOIL & WATER-12: **T**he project shall not use any fresh water supplies in addition to water supplied by IID as proposed during these proceedings. **Use of fresh water supplied by IID shall not exceed 609 acre-feet per year (AFY). Prior to the start of project construction, the project owner shall provide to the CPM evidence of a valid water supply agreement with IID for supply of at least 609 AFY for both the project construction period and the expected 30 year life of the project power plants. Project construction shall not start until evidence of a valid water supply contract is provided to the CPM.**

Verification: At least 60 days prior to the start of project construction, the project owner shall provide to the CPM evidence of a valid water supply agreement with IID for supply of at least 609 AFY for both project construction period and the expected 30 year life of the project power plants. Project construction shall not start until evidence of a valid water supply contract is provided to the CPM. The project owner shall provide to the CPM in the monthly compliance report water use totals for each month of operation. After operation has begun, the project owner shall provide to the CPM in the annual compliance report a record of the monthly IID fresh water deliveries to the project. The project owner shall file an amendment with the CPM should another source of fresh water be deemed necessary, or should the project require more than the ~~1000~~ **609** AFY of IID fresh water **identified as the project's maximum annual fresh water demand as provided in the revised water use estimates for the project's amendment petition.** ~~as described in the will-serve letter provided during these proceedings.~~

SOIL & WATER-13: The project owner shall provide certification by a California registered civil engineer or architect that the floodproofing methods for the project meet the floodproofing criteria in Section 74301(c)(2) of the Imperial County Flood Damage Prevention Regulations.

Verification: No later than 30 days prior to start of commercial operation, the project owner shall provide certification by a registered civil engineer or architect that the floodproofing methods for the project meet the floodproofing criteria in Section 74301(c)(2) of the Imperial County Flood Damage Prevention Regulations to the CPM for review and approval and to Imperial County for review. This verification must be provided prior to the start of commercial operation.

SOIL & WATER-14: The project owner shall participate in regional subsidence monitoring conducted by Imperial County and the California Division of Oil, Gas and Geothermal Resources (DOGGR).

Verification: No later than 30 days prior to start of commercial operation, the project owner shall reach an agreement with Imperial County and DOGGR that incorporates the SSU6 project into current subsidence monitoring efforts. Verification of this agreement shall be provided in writing and shall be submitted to the CPM for review and approval prior to commercial operation. The project's participation shall be reported and summarized in the Annual Compliance Report for the life of the project.

SOIL & WATER-15: Prior to the start of construction of any project monitoring wells, the project owner shall submit to the County of Imperial (County) for review and comment, and to the CPM for review and approval, plans and diagrams for the construction and operation of the project's monitoring wells. These plans and diagrams shall comply with the monitoring well requirements set forth in the Title 9, Imperial County Municipal Code, Sections 92101.00 et seq., and applicable section of Appendices A, B, and C. Project construction shall not proceed until the CPM has approved the monitoring well construction plans and diagrams. The project owner shall remain in compliance with the County water well requirements (including requirements for reworking or destroying the monitoring wells) for the life of the project.

Verification: **At least 60 days prior to the start of monitoring well construction, the project owner shall submit to the County for review and comment all appropriate fees, plans and diagrams necessary for review of the construction and operation of the project's monitoring wells. At least 30 days prior to initiating monitoring well construction, the project owner shall submit to the CPM for review and approval all plans and diagrams necessary for compliance with County water well requirements, along with comments from the County on the required documents. The plans and diagrams shall demonstrate compliance with the County water well requirements and Appendices A, B, and C. The project owner shall also submit copies to the CPM of all comments and correspondence with the County regarding the project monitoring wells throughout the life of the project. In the event that a well or wells require reworking or destruction, the project owner must obtain prior approval for the activity from the CPM with concurrence from the County.**

SOIL & WATER-16: Prior to the start of any construction excavation at Borrow Area 1, the project owner shall submit to the California State Mining & Geology Board (SMGB) or its designee, such as the County of Imperial

(County), for review and comment, and to the CPM for review and approval, a plan detailing the surface mining activities and resultant restoration for all areas disturbed at Borrow Area 1. The plan must meet the requirements for site reclamation plans as set forth in Article 5, Sections 2772 and 2773, of the State Mining & Reclamation Act of 1975, including provision of a time schedule for the completion of surface mining on each segment of the mined lands so that reclamation can be initiated at the earliest possible time. All disturbed areas shall be restored to pre-existing use as quickly as practicable after Borrow Area 1 activities related to construction of the power plant site berm and structure foundations are complete.

Verification: At least 90 days prior to the start of construction excavation at Borrow Area 1, the project owner shall submit to the California SMGB or its designee, such as the County of Imperial, for review and comment all appropriate plans and diagrams necessary for review of the Borrow Area 1 mining reclamation plan. At least 60 days prior to initiating excavation at Borrow Area 1, the project owner shall submit to the CPM for review and approval all plans and diagrams necessary for compliance with SMARA surface mining reclamation plan requirements, along with comments from the SMGB or its designee on the required documents. The project owner shall also submit copies of all subsequent reports and correspondence required by the Borrow Area 1 reclamation plan regarding mining and reclamation activities at Borrow Area 1 to the CPM and to SMGB or its designee throughout excavation and reclamation at the site until the site is deemed to be fully restored. In the event changes to the reclamation plan are necessary, the project owner must obtain prior approval for the change from the CPM with concurrence from the SMGB or its designee before implementing said changes. Upon completion of restoration activities, the project owner shall allow access by the CPM and SMGB or its designee to inspect the Borrow Area 1 site to ensure it is adequately restored to its pre-existing agricultural use.

REFERENCES

California Energy Commission (CEC). 2003. Decision approving the Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Application for Certification, Docket No. 02-AFC-2, Imperial County, published on December 19, 2003.

California Energy Commission (CEC). 2003a. Staff Assessment for Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Application for Certification (02-AFC-2), Imperial County, California, published on August 5, 2003.

California Energy Commission (CEC). 2005. Decision approving the Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Petition to Amend, Docket No. 02-AFC-2, Imperial County, published on May 11, 2005.

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CCR 2008. California Environmental Quality Act (CEQA) Guidelines. Title 14, California Code of Regulations, section 15000 and the following (Cal. Code Regs., tit. 14, §15000 et seq.).

CE Obsidian Energy, LLC. (CE Obsidian) 2009a. Application/Report of Waste Discharge, Black Rock 1, 2, and 3 Geothermal Power Project. Submitted to the Colorado River Basin Regional Water Quality Control Board, July 30, 2009.

CE Obsidian Energy, LLC. (CE Obsidian) 2010a. Letter to the CEC Regarding Summary of the Revised Water Usage for Black Rock 1, 2, and 3 Geothermal Power Project, dated March 1, 2010.

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CE Obsidian, LLC (CE Obsidian/CH2MHILL). 2009a. CalEnergy Black Rock 1-3, Data Responses 1-64. Submitted to the California Energy Commission, November 2009.

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Imperial Irrigation District (IID). 2009. Interim Water Supply Policy for Non-Agricultural Projects, September 29, 2009. http://www.iid.com/Media/Final-Interim-Water-Supply-Policy.pdf

Imperial Irrigation District (IID). 2010. Letter from Tina Shields to Zachary Walton regarding the water supply for the Black Rock 1, 2 and 3 Geothermal Power Project. March 4, 2010.

State Water Resources Control Board (SWRCB). 1993. Memorandum from Elizabeth Miller Jennings, Senior Staff Counsel to Archie Matthews, Division of Water Quality, regarding Storm Water Permit: Geothermal Power Plants, February 23, 1993.

United States Department of Agriculture, Natural Resources Conservation Service (NRCS) Web Soil Survey, http:websoilsurvey.nrcs.usda.gov, 2010.

US EPA. 1999. The Class V Underground Injection Control Study, **Vol. 17**, Electric Power Geothermal Injection Wells, USEPA, Office of Ground Water and Drinking Water (4601), EPA/816-R-99-014q.

SOIL AND WATER RESOURCES – APPENDIX A

FACTS FOR WASTE DISCHARGE—Black Rock 1, 2 and 3 Geothermal Power Project Brine Ponds

1. CE Obsidian Energy, LLC (the Discharger) proposes to construct three 53-Megawatt geothermal power plants, identified as Black Rock 1, 2, and 3 (the Black Rock 1, 2, and 3 Geothermal Power Project, or Project), on land owned by Imperial Magma, LLC, an affiliate of CE Obsidian. The project is located within the Salton Sea Known Geothermal Resource Area (KGRA), 6 miles northwest of the town of Calipatria and approximately 7.5 miles southwest of community of Niland. The address for both CE Obsidian Energy, LLC and Imperial Magma, LLC is 1111 South 103rd Street, Omaha, NE 68124.

2. The Black Rock 1, 2 and 3 Geothermal Power Project will be operated by Cal Energy Operating Corporation, an affiliate of CE Obsidian Energy LLC. CalEnergy is located at 7030 Gentry Road, Calipatria, CA 92233.

3. Geothermal wells will be drilled at various locations on the Project property to provide geothermal brine to operate the plants. (The mud sumps for these wells will be regulated under a separate set of requirements for waste discharge).

4. The requirements for waste discharge (Waste Discharge Requirements, or WDRs) regulate the facilities' brine ponds. The brine ponds are designated as Class II Surface Impoundments Waste Management Units (WMU) and must meet the requirements of the California Code of Regulations (CCR), Title 27, §20200 et seq. The boundaries of the proposed Black Rock 1, 2 and 3 Geothermal Project are shown on Attachment A, as incorporated herein and made a part of these WDRs.

5. The Discharger submitted a Report of Waste Discharge dated July 30, 2009, for the Black Rock 1, 2 and 3 Geothermal Project Power Project.

6. The following are definitions of terms used in these WDRs:

   Facility – The entire parcel of property where the proposed Black Rock 1, 2 and 3 Geothermal Power Project industrial operations or related geothermal industrial activities are conducted.

   Waste Management Units (WMUs) – The area of land or the portions of the facility where geothermal or related wastes are discharged, and the brine holding ponds are WMUs.

   Discharger – The term Discharger means any person who discharges waste that could affect the quality of the waters of the State, and includes any person who owns the land, WMU or who is responsible for the operation of a WMU. Specifically, the terms "discharger" or "dischargers" in these WDRs means CE Obsidian Energy, LLC.

FACILITY LOCATION

7. The Project is located southeast of the Salton Sea in an unincorporated area of Imperial County, approximately 6 miles northwest of the community of Calipatria and approximately 7.5 miles southwest of the community of Niland. The project site is bounded by McKendry Road to the north, Severe Road to the west, Peterson Road to the south, and Boyle Road to the east. The approximately 160-acre project site (APN 020-110-08) is at an average elevation of 225 feet below mean sea level (msl). The property is owned by Imperial Magma, LLC, which is an affiliate of CE Obsidian. The project site is located in the southwest quarter of Section 33 Southwest, Township 11 South, Range 13 East, San Bernardino Meridian. Primary land uses in this region of the Imperial Valley include agriculture and geothermal power production. The project site is located within the Salton Sea Known Geothermal Resource Area and is covered by the County of Imperial's Geothermal Overlay Zone, which allows for development of geothermal resources and geothermal power plants.

FACILITY DESCRIPTION

8. The Project consists of three 53-megawatt (MW) net geothermal electric power plants (Black Rock Units 1, 2, and 3), which will produce a combined 159-MW net of geothermal power. These plants will be operated as base load plants that will be in continuous operation except during planned maintenance outages and so forth. The three units will be co-located on a 160 acre common site.

9. The Project includes 22 wells:
    a. Nine production wells on three pads (average pad size 6.6 acres)
    b. Nine injection wells on three pads (average size 4.7 acres, three wells each) offsite (approximately 8,000 to 10,000 feet south, southeast, and east of the Facility site)
    c. Two Facility wells
    d. Two aerated brine wells

10. The three geothermal power plants will be situated near the center of the site. A site map is included as Attachment B, as incorporated herein and made a part of these WDRs.

11. Each of the three proposed geothermal power plants consists of two major components, a Resource Production Facility (RPF) and a Power Generating Facility (PGF).

12. The three plants will share various support facilities and equipment. The RPF includes all the brine and steam handling facilities from the production wellheads to the injection wellheads. RPF equipment includes a brine injection system, a brine pond, steam-polishing equipment designed to provide turbine-quality steam to the PGFs, and appropriate steam-venting vessels to support operations during startup/shutdown and emergency conditions. Each PGF includes a condensing turbine/generator set, a noncondensable gas (NCG) removal and abatement system, and a cooling tower. Shared support facilities include a 230-kilovolt (kV)

switchyard, a control building, service water pond, plant injection wells, and a condensate storage/stormwater sedimentation basin.

CLIMATE

13. The climate of the region is arid. Climatologic data from measurements taken at three U. S. Weather Bureau stations located at El Centro, Blythe, and Yuma indicate that during 1980 to 1992, the maximum and minimum rainfall in the area were 10 inches and 1 inch, respectively, with an average annual rainfall of about 4 inches, and a mean annual pan evaporation rate of about 100 inches.

14. The wind direction follows two general patterns:

    a. From late fall to early spring, prevailing winds are from the west and northwest. Most of these winds originate in the Los Angeles basin area, enter the Coachella Valley and travel southeasterly through the Salton Sea Trough. The humidity is generally the lowest under these conditions.

    b. Summer weather patterns are often dominated by an intense, heat-induced low-pressure area that forms over the hot interior deserts, drawing air from the Gulf of California (southeast of the site) and northern portion of Mexico. The humidity is generally the highest during these conditions.

SURROUNDING LAND USE

15. Current land uses around the plant site include agriculture, geothermal production, and wildlife conservation habitat. The injection well pads and pipeline routes occur on and are surrounded by agricultural lands, roadways, ditches, and developed industrial area. Most of the agricultural areas on and adjacent to the project site are currently active, or have been recently used for, alfalfa, wheat, or onion production.

SITE GEOLOGY AND SOILS

16. Alluvial and non-marine deposits underlie the project area. Potential for water and wind erosion ranges from high to moderate for soil types in the project area. Soil types found at the project site are as follows:

    a. Glenbar Clay Loam, wet – Nearly level, very deep soils formed in alluvial sediment on floodplains and in alluvial basins within irrigated areas. Irrigation has caused a perched water table at a depth of 36 to 60 inches, and the water can rise to a depth of 18 inches during periods of heavy irrigation.

    b. Holtville Silty Clay, wet – Nearly level, very deep stratified soil formed in alluvial sediment on floodplains and alluvial basin floors. Irrigation has caused a perched water table at a depth of 36 to 60 inches, and the water table can rise to within 18 inches of the surface during periods of heavy irrigation.

    c. Imperial-Glenbar Silty Clay Loams, wet, 0 to 2 percent slopes – Nearly level, very deep calcareous soils formed in alluvial deposits on floodplains and lakebeds within the irrigated areas of Imperial Valley. Irrigation has caused a perched water table commonly at a depth of 36 to 60 inches, but which can rise to a depth of 18 inches during periods of heavy irrigation.

d. Indio Loam, wet – Nearly level, very deep soils formed in alluvium and eolian sediments on floodplains and basin floors. Irrigation has caused a perched water table commonly at a depth of 36 to 60 inches, but can rise to a depth of 18 inches during periods of heavy irrigation.

SURFACE WATER

17. Surface water features in the vicinity of the Project include the Salton Sea (0.3 mile to the west and north), New River (2.7 miles to the southwest), Alamo River (4.8 miles to the northeast), and two irrigation drains, Vail Drain 4a and Vail Lateral Drain 5 (on the east and west sides of the project site, respectively). All drainage from the project area drains toward the Salton Sea, which is a closed basin with no outlet for surface water discharge. Inflows to the Salton Sea are limited primarily to surface and groundwater return flows from agricultural irrigation and stormwater runoff during the rainy season. The New and Alamo Rivers are both perennial streams with headwaters starting in Mexico that convey primarily agricultural irrigation drainage and some treated wastewaters. The Sonny Bono Salton Sea Wildlife Refuge Headquarters is approximately 1 mile northeast of the project site.

18. Water contact is unauthorized in the Vail Drains. The New River is unfit for any recreational use because of existing contamination. The Salton Sea has a history of water quality issues associated with increasing salinity and nutrient concentrations. The Clean Water Act Section 303(d) requires states to list water bodies not meeting water quality standards (or impaired). The Salton Sea is listed for nutrients, salinity, and selenium with sources designated as agricultural return flows. The New River is listed for bacteria, nutrients, pesticides, and sedimentation/siltation and the Alamo River is listed for pesticides, sedimentation/siltation, and selenium. The sources of pollutants are all designated as agricultural runoff.

SITE DRAINAGE

19. The Project site is fairly level and proposed site drainage generally will flow from the southeast corner to the northwest corner toward the storm water detention pond located in the northwestern area of the plant site. The storm water detention pond will be an earthen structure. All buildings and equipment will be constructed on foundations with the overall site grading scheme designed to route surface water around and away from equipment and buildings. Storm water flows will be directed to the storm water detention pond via ditches, swales, and culverts. Chemical spills will not flow into the storm water collection system. Spill containment areas and sumps (subject to chemical spills) will be designed to route liquids to a diked area where they will be pumped out, characterized, and properly disposed.

20. The proposed storm water detention pond for the Project is designed for 3 inches of precipitation in a 24-hour period (100-year storm conditions) and will be approximately 500 feet long by 225 feet wide by 3.5 feet deep and the sides will have a 2:1 (horizontal: vertical) side slope. Storm water accumulated in the pond will evaporate and infiltrate.

21. Imperial County's Land Use Ordinance Section 90106.00, et seq., and Section 91604.00, et seq., require a Development Permit for construction below -220 feet

msl along any portion of the Salton Sea. For the Project, this will require the 160-acre project site to be enclosed by a perimeter berm designed with 2:1 (horizontal to vertical) sloping sides with a top elevation of -220 feet msl. This berm will meet the County's encroachment permit requirements because it will be of adequate height to provide flood protection to an elevation of at least -220 feet msl in accordance with the County's Land Use Ordinances and will reduce the potential for offsite drainage.

REGIONAL GROUNDWATER RESOURCES

22. The U.S. Geological Survey (USGS) undertook a comprehensive study of the water resources of both the Upper and Lower Colorado River region in the 1950s and 1960s. The often cited geohydrologic reconnaissance survey of the Imperial Valley conducted by Loeltz et al (1975) is one of a series of reports resulting from those USGS studies and is the classic assessment of ground water resources in the area. No substantive change in the geohydrologic conditions of the Imperial Valley ground water resource has subsequently occurred.

23. The Salton Sea is located within the Colorado River Hydrologic Region, as defined by the California Department of Water Resources (DWR 2003). The Project area is located in the Imperial Valley Basin, one of seven groundwater basins in the hydrologic region located adjacent to the Salton Sea.

24. The following discussion of regional groundwater hydrology within the Imperial Valley Basin was extracted from the recent Salton Sea Ecosystem Recovery Programmatic EIR (DWR and CDFG 2006).

    a. The Imperial Valley Basin is located south of the Salton Sea and is at the southernmost part of the Colorado Desert (sic) Hydrologic Region. The basin is bounded on the east by the Sand Hills and on the west by the impermeable rocks of the Fish Creek and Coyote Mountains. The basin extends from the Mexicali Valley to the Salton Sea (DWR, 2003). Imperial County is responsible for groundwater management in the Imperial Valley.

    b. Deep exploration boreholes have shown that most of the Imperial Valley Basin is underlain by thick, water-saturated lacustrine and playa deposits overlying older sediments. Perched groundwater exists over much of the basin and is recharged by seepage from irrigated lands and drains (IID and Reclamation, 2002b). The basin has two major aquifers separated by a semi-permeable aquitard (silt and clay lenses) that averages 60 feet thick and reaches a maximum thickness of 280 feet. Average thickness of the upper aquifer is 200 feet with a maximum thickness of 450 feet. The lower aquifer averages 380 feet thick with a maximum thickness of 1,500 feet (DWR, 2003). Studies have indicated that the hydraulic connection is poor between the water within the deeper deposits and that within the upper part of the aquifer (IID and Reclamation, 2002b). Well yields in this area are limited (Loeltz et al., 1975).

    c. The general direction of groundwater movement in the Imperial Valley Basin is from the Colorado River towards the Salton Sea. However, in the southern portion of the basin, a substantial amount of groundwater flows into the Alamo River and, to a lesser extent, the New River (USGS, 2004). Seepage from the

All-American Canal and other canals has caused formation of localized perched groundwater. Between the early 1940s and 1960, groundwater levels rose more than 40 feet along the All-American Canal. Seepage from the canal is expected to decrease substantially when the canal is lined.

d. Tile drains have been installed by IID to convey shallow groundwater away from the root zone of crops (IID and Reclamation, 2002b). Most of the shallow groundwater, leaching water, or excess irrigation water flows into the drains and New and Alamo rivers. Groundwater levels remained relatively stable within the majority of the basin between 1970 and 1990 because of a constant rate of discharge from canals and subsurface agricultural drains.

e. The San Andreas and Algodones faults do not appear to impede or control groundwater movement, based on review of groundwater levels in the 1960s (Salton Sea Authority, 1999).

f. Hely et al. (1966) estimated the groundwater discharge to the Salton Sea to be less than 2,000 acre-feet a year and IID and Reclamation (2002a) have estimated this value to be about 1,000 acre-feet a year. The IID estimate of 1,000 acre-feet a year has been adopted as a reasonable estimate of historical groundwater discharge to the Salton Sea from the Imperial Valley. It was developed using a method that was consistent with the hydrologic assumptions used in the Draft Programmatic Environmental Impact Report (PEIR) and it represents a period of time after the groundwater elevation became stable in the 1970s.

g. Groundwater quality varies extensively in the Imperial Valley Basin. Total dissolved solids, a measure of salinity, ranged from 498 to 7,280 mg/L when measured by DWR in 2003. High concentrations of fluoride have also been reported by IID and Reclamation (2002b).

h. Due to the low yield and the poor water quality, few production wells have been drilled in the Imperial Valley, most of which are domestic wells. Total production from these wells is estimated to be a few thousand acre-feet a year (Salton Sea Authority, 1999).

i. Extremely deep groundwater has been developed along the southern Salton Sea shoreline for geothermal resources. These wells access non-potable groundwater from several thousand feet below ground surface.

j. The amount of usable near-surface groundwater in the central Imperial Valley is unknown, but this resource has not been significantly exploited because of low well yields and poor water quality. The upper 500 feet of fine-grained deposits in the central portion of the Imperial Valley are estimated to have a transmissivity of less than 10,000 gallons per day per foot. Even lower permeabilities are estimated to occur at greater depths (Westec, 1981). Additionally, low vertical permeability inhibits mixing of waters from different depths such as between the shallow aquifer system and the underlying deeper groundwater that includes the geothermal resources.

k. The main source of groundwater recharge to the shallow aquifer system, and likely, but to a lesser extent, the deeper aquifer, is imported Colorado River water that seeps from canals and is applied as irrigation water to cultivated areas. Shallow groundwater, ranging in depth from about 5 to 20 feet, is drained by an extensive network of ditches and drains in agricultural areas and also discharges into the Alamo and New Rivers that drain toward the Salton Sea.

l. Groundwater discharge from the Imperial Valley into the Salton Sea has been estimated to be about 2,000 afy (U.S. Department of Interior and Resources Agency for California, 1974).

m. The amount of water in the deep aquifer has been estimated at 1.1 billion to 3 billion acre-feet, and the total recoverable water has been estimated to be about 20 percent of the total amount of water in storage. The deep aquifer is recharged with about 400,000 acre-feet of water per year. Some of the deepest groundwater in this aquifer system is believed to be moderately altered residual ocean water. Above this may be relatively fresh residual water of low to moderate salinity from prehistoric lakes that had filled the Salton Trough. Water in the upper portion of the deep aquifer is at high temperature and locally of high salinity.

25. Geothermal fluids in this portion of the Salton Sea KGRA contain approximately 25 percent (by weight) dissolvable solids. These fluids may be classified as hazardous in accordance with the criteria listed in Section 66699, Title 22 of the CCRs. However, the geothermal fluids are not required to be managed as hazardous waste under Title 22 because they are exempt from regulation as hazardous waste by Health & Safety Code Section 25143.1, subdivision (a). The brine ponds and leak detection systems are adequate for the geothermal fluids, considering the toxicity, persistence, degradability, solubility, and other biological, chemical, and physical properties of the wastes.

SITE SPECIFIC GROUNDWATER CONDITIONS

26. Previous geotechnical investigations performed at the Project site found that the depth to groundwater beneath the Facility is shallow, ranging from approximately 3 to 6 feet bgs. Naturally occurring groundwater in the area is hydraulically connected to the Salton Sea and is very saline. The fine-grained deposits that are characteristic of the area have transmissivities of 1,000 to 10,000 gallons per day per foot to depths of approximately 500 feet. The low transmissivity of these deposits limits the ability of water to percolate downward into deeper aquifers (greater than 500 feet bgs). As a result, depleted groundwater levels will recharge slowly, which limits the potential for development of groundwater in the area. The deep aquifer is too saline for irrigation and most other beneficial uses. The geothermal reservoir is not in hydraulic connection with surficial groundwater.

FACILITY OPERATIONAL WATER

27. The primary water demand for the Facility is for cooling tower makeup. This water demand will be satisfied largely (about 95 percent on an annual average basis) by condensate from steam extracted from the geothermal brine. After powering the

turbines, the steam will be sent to condensers and the resulting condensate will then be routed to the cooling towers. Condensed steam will also be the source of scrubber makeup water and will be the source of seal water for the mechanical pump seals.

28. Additional water from condensate will be required for the dilution of acid to be added to the injected brine, potable water treatment, and quench water for the regenerative thermal oxidizer (RTO) air emissions control equipment. Any “deficit” water will be supplied from an Imperial Irrigation District (IID) canal adjacent to the plant site via a new water supply pipeline. The water delivery will occur under a new water supply agreement currently being negotiated. The connection point to the IID canal will be the Vail 4A Lateral, Gate 459 and/or 460 at the southeast corner of the power plant site, along Boyle Road. The supply pipeline will be a 500-foot- long, buried, 10-inch pipeline. Water quality data for IID water are shown in Table 1.

TABLE 1
Expected Water Quality – IID Canal

Constituent	**IID Canal Water (mg/L)**
Calcium	88
Magnesium	34
Sodium	140
Potassium	5.5
Total alkalinity	150
Hydroxide	ND
Carbonate	ND
Bicarbonate	180
Chloride	120
Sulfate	320
Fluoride	0.6
Nitrate	1.0
pH	8.1
TDS	750
Bromide	0.12
CO_2	2.9
Sulfide	ND
Benzene	ND
Ethyl benzene	ND
Toluene	ND
Xylenes	ND
Ammonia-Nitrogen	ND
Aluminum	290
Antimony	ND
Arsenic	ND
Barium	130
Beryllium	ND
Boron	190
Cadmium	ND

TABLE 1
Expected Water Quality – IID Canal

Constituent	IID Canal Water (mg/L)
Total Chromium	ND
Copper	39
Iron	230
Lead	ND
Lithium	ND
Manganese	80
Mercury	ND
Nickel	ND
Selenium	ND
Total Silica	10
Silver	ND
Strontium	1,400
Zinc	30

ND = Not Detected

Source: AECOM, 2009

FACILITY OPERATION PROCESS

29. The Project includes three RPFs, three PGFs, ancillary facilities, and three high-efficiency condensing steam turbines with a net unit output of 53 MW each (159 MW total). The design of the RPF utilizes a single-stage flash to produce the required steam supply to the turbine. The single-stage flash starts at the production well pad that supports its associated PGF. Hot, high-pressure (HP) geothermal fluid (brine) is extracted from the geothermal reservoir through three production wells located on the aforementioned well pad. As the brine travels up the production well casing, it “flashes” producing two-phase steam and brine flow, which is conveyed to a steam handling system. The flash point is set to avoid precipitation of solids in the depleted brine. The depleted brine can be further chemically conditioned if necessary with hydrochloric acid to prevent scale formation in the process piping or injection wells, and injected back into the formation through the offsite injection wells. The facilities and equipment that handle the brine constitute the RPF. The steam handling system consists of a scrubber, HP separator, and demister.

30. Steam from the RPF is conditioned through scrubber and demister stages and sent to the steam turbine, which drives a generator for power production. The depleted steam leaves the turbine and enters a shell-and-tube heat exchanger that condenses it to water. Cooling water for the heat exchanger is provided by a piping loop from the cooling towers. Water condensed in the heat exchanger is used for cooling tower make-up water, among other (much smaller quantity) uses. NCGs released from the condensed steam are evacuated from the heat exchanger using a vacuum pump and sent to the RTO for control of hydrogen sulfide (H_2S), methane, benzene, and other trace gases. Exhaust from the RTO is routed to a wet scrubber before being released to the atmosphere. Wastewater from the wet scrubber flows to the cooling tower basin and then to the plant injection well for reinjection into the formation.

STEAM / LIQUID SEPARATOR SYSTEM

31. The common production header discharges the two-phase brine flow into one HP steam/liquid separator for each of the three RPFs. There will be three HP steam liquid separators (one per power plant). Production brine is discharged to the HP separator to separate the process steam from the brine and reduce its temperature and pressure prior to discharging the spent brine to the injection wells. HP steam is directed from the separator to a chloride scrubber and demister in series, then into the HP inlets of the steam turbine. The scrubber accomplishes chloride removal from the steam to prevent damage to the steam turbine using an injected water stream and chemical conditioning. The discharge stream from the scrubber is routed to the RPF brine injection system for re-injection into the geothermal reservoir. The demister is a device that removes liquid droplets entrained in the steam phase flow to the turbine. The demister aggregates water droplets entrained in the steam phase flow that will otherwise damage the steam turbine. This is accomplished with an injected water stream to the demister. The discharge stream from the demister is routed to the RPF brine injection system for re-injection into the geothermal reservoir. The steam handling system also has a rock muffler, which is an emergency bypass vessel. In the event of a plant trip or mechanical malfunction necessitating the shutdown of the PGF, HP steam can be released to the atmosphere through the rock muffler; its design is such that it muffles the noise levels associated with the event. This rock muffler is used for short periods of time until the plant can either be completely shutdown or returned to service.

HOT BRINE INJECTION SYSTEM

32. For each power plant, three hot brine injection wells will be situated on three new brine injection well pads. Injection well pads will be located to the south, southeast, and east approximately 8,000 to 10,000 feet from the plant site. Injection wells will be drilled to an average depth of 8,725 feet. The brine injection wells will each have an average injection rate of approximately 1.9 million pounds per hour of brine at a temperature of approximately 400°F to 420°F. Use of the single-stage flash technology for the Facility allows for maintaining this elevated injection temperature which, in turn, mitigates solids precipitation and allows the three power plants to be operated without producing large amounts of brine filter cake solids. The brine injection system operates as follows: brine from the HP separator is pumped from the RPF to the remote injection well pads via an aboveground pipeline. Each injection well is remotely metered for pressure, temperature, and flow rate. Brine injection will take place in accordance with California Division of Oil, Gas, and Geothermal Resources (CDOGGR) regulations.

PRODUCTION TEST UNIT

33. Each RPF will have a PTU, which is used for well startup. The PTU is an atmospheric flash tank into which brine flows during production well testing and startups until a sufficiently high temperature is reached. The brine flow is then directed to the HP separator for steam production to feed the PGF. Brine passing through the PTU is then discharged to the brine pond. The PTU will be designed for 1 million pounds per hour (lbs/hr) of brine flow with a 20 percent flash rate (200,000 lbs/hr of steam flow).

POWER GENERATION FACILITY

34. Each PGF includes the following components:
    a. STG – single-casing, single-pressure, down-exhaust condensing turbine
    b. Condenser – shell-and-tube type heat exchanger (part of the power cycle heat rejection system)
    c. One five-cell cooling tower (part of the power cycle heat rejection system)
    d. One RTO and scrubber system – air emission control system
    e. Chemical oxidization
    f. One rock muffler/pressure-relief vent system
    g. One1.5-MW emergency generator, diesel fueled, 4,160 volts (V)
    h. One 1.0-MW emergency generator, diesel-fueled, 480 V

STEAM TURBINE GENERATOR

35. The PGF includes a single-cased, single-pressure, down-exhaust condensing turbine. Geothermal steam from the RPF will be the only steam source used by the STG. Each turbine generator set will consist of a condensing turbine generator with HP steam entry pressure. The STG is nominally rated at 53 MW (net). Heat rejection for the steam turbines will be accomplished with a condenser and counter flow cooling tower.

CONDENSER

36. The condenser is a stainless steel shell-and-tube type heat exchanger designed to operate under vacuum. It receives steam from the turbine exhaust of the STG and condenses it to liquid for return to the cooling tower. During base load operation at design ambient conditions (83.7°F wet bulb temp, 105°F dry bulb temp), the condenser is expected to operate at a vacuum pressure of 2.34 inches mercury (atmospheric) and produce condensate flow of 804,935 lbs/hr. The warmed circulating water exits the condenser and returns to the cooling tower.

COUNTER FLOW COOLING TOWER

37. Each PGF will have a dedicated five-cell, induced-draft cooling tower. Each cooling tower will have three 50-percent capacity, vertical, wet-pit circulating water pumps to circulate water between the cooling tower and condenser and two 100 percent capacity, vertical, wet-pit auxiliary water pumps that will circulate water between the cooling tower and the plant auxiliary cooling loads. Each cooling tower has an inlet circulating water flow rate of 89,112 gpm and will be equipped with a high-efficiency mist eliminator to minimize drift losses to no more than 0.0005 percent of design flow rate to reduce particulate matter (PM10) emissions. The circulating water is distributed among multiple cells of the cooling tower, where it cascades downward through each cell and collects in the cooling tower basin. The circulating water is cooled through evaporation. The cooled circulating water is pumped from the cooling tower basin back to the condenser.

CLOSED-LOOP AUXILIARY EQUIPMENT COOLING WATER SYSTEM

38. The closed-loop auxiliary cooling water system will be filled with a coolant such as a mixture of glycol and water. The coolant is circulated through a closed-loop system to cool auxiliary equipment including the STG lubrication oil coolers, air compressor after coolers, and steam cycle sample coolers. The coolant absorbs heat from the various equipment items being cooled and is, in turn, cooled by non-contact heat exchange with a branch of the circulating water system.

STEAM RELIEF SYSTEM (ROCK MUFFLER)

39. The rock muffler is a system used during upset conditions when it is necessary to vent steam to the atmosphere. The proposed rock muffler vent system is a reinforced-concrete rectangular structure with dual chambers, to be designed to allow internal inspection of the diffuser at the bottom chamber through a manway into the vent chamber. The rock muffler's dimensions are 16 feet wide by 20 feet long by 24 feet high, and the wall thickness is approximately 1 foot. During these upset events, steam bypasses the turbine and is rerouted to the rock muffler for venting to the atmosphere. The rock muffler can receive the flow of steam generated from 6.3 million pounds per hour of geothermal brine. Condensate from the rock muffler will be routed to the brine pond rather than the cooling tower due to the potentially high concentration of chlorides in the condensate.

AIR EMISSION CONTROL SYSTEM (REGENERATIVE THERMAL OXIDIZER)

40. Air emissions control for each PGF will be accomplished using an RTO and scrubber primarily for control of sulfur dioxide (SO_2). NCGs are evacuated from the condenser heat exchanger using a vacuum pump and routed to the RTO for control of H_2S, methane, benzene, and other trace gas emissions. The RTO is a direct oxidizing process that allows for simultaneous destruction of benzene and H_2S and other combustible constituents present in the NCG in a compact unit that is easy to operate and maintain. Following the RTO, the exhaust gas enters a quench tower in which the temperatures of the gases are lowered using water injection. The quench water is discharged to the cooling tower basin.

41. The applicant has developed a chemical oxidation (Chem Ox) process that will be used for treatment of condensate prior to the use in the cooling tower. The Chem Ox system will oxidize H_2S found in the hot-well condensate into sulfates by the addition of air and an oxidant (hydrogen peroxide, bleach, or similar compound). The oxidant will be direct injected into the condensate line using metering pumps to facilitate the oxidization process. The oxidant will be stored in a 1,000-gallon storage tank. The byproduct of the oxidation process is a soluble sulfate salt that will remain dissolved in the condensate. The Chem Ox system is expected to have an overall H_2S control efficiency of 90 percent or more.

42. Following the RTO and quench tower, the gas stream enters a packed-bed SO_2 scrubber where a sodium hydroxide (NaOH) solution is introduced. The scrubbing solution is discharged to prevent sulfate and sulfite buildup in the scrubber tower. The sodium sulfite/sulfate solution created by operation of the SO_2 scrubber is of a sufficiently small volume that it can be safely introduced into the cooling tower basin

where it ultimately is re-injected into the underlying geothermal formation. The treated exhaust then vents to the atmosphere through a stack. Excess condensate (that is, not used in the cooling tower) will be sent to the plant injection well for reinjection into the formation.

FACILITY PRODUCTION WELLS

43. As part of the Facility, there are nine production wells (three for each 53-MW unit on three separate well pads). Each production well will be drilled to a depth of approximately 7,400 feet, with casing set at a depth of approximately 2,500 feet bgs. The proposed production wells are spatially separated from injection wells to optimize field development and reservoir management. The well pads will be equipped with production line warm-up headers used to start up the production wells after they are drilled and for facility startups. During initial startup, the warm-up headers will feed into a warm-up line that discharges into a PTU located near the brine pond. For each of the three power plants, there will be one PTU and one brine pond. Liquid from each PTU will discharge into the brine pond. Each production well will have an average flow rate of approximately 2.1 million pounds of brine per hour at wellhead pressures of 375 to 425 pounds per square inch (psi) and at temperatures of 450 degrees Fahrenheit (°F) to 480°F. Actual depths will vary based on the geology and reservoir.

44. Reservoir properties of the hyper-saline brine in the Project area are expected to have downhole temperatures of 500 to 600°F and a TDS content of approximately of 23.5 percent by weight, with NCGs of 0.212 percent by weight. Dissolved solids consist primarily of sodium chloride, calcium chloride, and potassium chloride salts. Zinc, manganese, iron, and silica are also dissolved in the brine. The major component of the NCG is carbon dioxide (CO_2). While the brine includes a broad range of other components, the other components each represent less than 0.3 percent by weight. Each well will produce an average of 2.1 million pounds per hour of a mixture of steam vapor, NCG, and brine in a two-phase flow.

45. The anticipated chemical composition of the produced fluids based on the applicant's operating experience is shown in Table 2.

TABLE 2
Anticipated Chemical Composition of Produced Fluids

Constituent	Concentration (mg/L)
Beryllium	ND[1]
Ammonium	369
Sodium	50,169
Magnesium	39
Aluminum	ND[1,2]
Potassium	12,784
Calcium	24,584
Chromium	ND[1]
Manganese	983
Iron	1,180

TABLE 2
Anticipated Chemical Composition of Produced Fluids

Constituent	Concentration (mg/L)
Nickel	ND[1]
Copper	4
Zinc	320
Rubidium	69
Strontium	443
Silver	ND[1]
Cadmium	1
Antimony	1
Cesium	12
Barium	177
Mercury	ND[1]
Lead	79
Bicarbonate	69
Nitrate	ND[1]
Fluorine	20
Sulfur Monoxide	98
Chlorine	137,670
Arsenate	20
Selenate	ND[1]
Bromine	89
Iodine	10
Silicon Dioxide	433
Carbon Dioxide	3,309
Boric Acid	1,800
Hydrogen Sulfide	15
Ammonia	59
Methane	10
Total Dissolved Solids	235,000

ND = Not Detected

[1] Several of the constituents listed as ND have been detected in brine from this resource, although the quantities may be present at trace levels.

[2] Aluminum is known to be present in measurable quantities in brine from this resource.

Source: AECOM, 2009

FACILITY INJECTION WELLS

46. In addition to the hot brine injection wells, four additional injection wells will be dedicated to managing excess condensate and cooling tower blowdown and aerated brine. Two injection wells for aerated brine (brine that has been exposed to the atmosphere) will be constructed for the management of brine pond liquids. Two separate injection wells, known as “plant” injection wells, will be dedicated to the management of excess condensate and cooling tower blowdown. The two plant

condensate injection wells and two aerated brine injection wells will be located within the Facility site. Generally, fluid from these two sources is not co-mingled in a single injection well, due to chemical incompatibility. Constituents of the cooling tower blowdown and injected brine are provided in Table 3.

TABLE 3
Cooling Tower Blowdown and Injected Process Brine Fluid Characterization

Constituent	**Cooling Tower Blowdown (mg/L)**	**Aerated Brine (mg/L)**
Lithium	ND	253.3
Beryllium	ND	0.01
Ammonia	900	500.0
Sodium	197	68,024
Magnesium	46	53.3
Aluminum	0.42	0.3
Potassium	7.3	17,333
Calcium	121	33,333
Chromium	ND	0.004
Manganese	0.13	1,333
Iron	0.21	1,600
Nickel	ND	0.03
Copper	0.06	5.3
Zinc	0.05	433.3
Rubidium	NA	93.3
Strontium	2.3	600.0
Silver	ND	0.3
Cadmium	ND	1.7
Antimony	ND	1.1
Cesium	NA	16.7
Barium	0.21	240.0
Mercury	ND	0.004
Lead	ND	106.7
Bicarbonate	NA	93.3
Nitrate	1.26	0.0
Fluoride	0.88	26.7
Sulfate	3,132	133.3
Chloride	210	186,667
Arsenic	0.53	14.7
Selenium	ND	0.007
Bromide	ND	120
Iodine	NA	13.3
Silica	13	586.7
CO_2	NA	2,007
Boron	399	426.6
Sulfide	11.76	20.1
Benzene	0.01	0.003
TDS	7,952	316,063

TABLE 3
Cooling Tower Blowdown and Injected Process Brine Fluid Characterization

Constituent	Cooling Tower Blowdown (mg/L)	Aerated Brine (mg/L)
pH	6.60	4 to 7

mg/L = milligrams per liter
ND = Not detected
NA = Not analyzed
Source: AECOM, 2009

FACILITY BRINE PONDS

47. Three brine ponds (636 feet by 58 feet by 7.5 feet each) will be constructed; one for each of the three power plants. In addition to the six mud sumps, the three brine ponds initially will be used to manage material from well construction. The brine ponds will be designed in accordance with CCR, Title 27, § 20375 – Special Requirements for Surface Impoundments. The design of the three brine ponds within the Facility site is depicted in Attachment C, as incorporated herein and made a part of these WDRs. Each brine pond will contain a surrounding 20-foot area for cleanout vehicle access with an entry ramp, and will include a built-in leak detection system. The brine ponds are of earthen construction, lined with the following layered liner materials:

    a. Geosynthetic clay liner (GCL)
    b. High-density polyethylene (HDPE) 80 mil
    c. HDPE 200 mil
    d. Textured – HDPE 80 mil
    e. 6-inch compacted soil
    f. 6-inch fiber-reinforced concrete

48. During plant-upset conditions, well flow testing, or startup, produced brines will be discharged to the brine ponds. The brine ponds will collect brine from production wells and steam will be vented to the PTU during startup. Aerated brine will be pumped into one of two aerated brine injection wells. Brine produced in startup will be infrequent because the project will be operated as a base load facility. During operational upset conditions, HP separator brine and condensate from the steam vented to the rock muffler will be directed to the brine ponds for temporary containment. Most of the material collected in the brine ponds will be managed by dilution as necessary and subsequently pumped to one of two aerated brine injection wells.

49. The brine ponds will be used for the collection of permitted wastewater streams prior to injection into the formation. The Facility is expected to generate a small amount of solids that are expected to precipitate out of the brine in the brine pond due to the low temperature (relative to reservoir temperatures). The rate of accumulation is not known, but is expected to be only a few tons per year. The brine pond solids will be removed annually, then dewatered in a filter press and transported by a licensed transporter to an appropriately permitted offsite facility. Liquids from the dewatering will be directed to the plant injection wells.

MUD SUMPS

50. Mud sumps associated with geothermal well drilling at the Facility are regulated under other waste discharge requirements.

FACILITY OPERATION AND MAINTENANCE WASTES

51. Spent Brine – The primary discharge from the Facility consists of spent brine that is injected directly into the brine injection wells. Spent brine is exempt from both federal and state regulations as hazardous waste. California Health and Safety Code Section 25143.1 exempts the spent brine so long as the spent brine is contained in a piping system or lined pond. Similarly, the US Environmental Protection Agency exempts the spent brine and views it as an integral part of the process of power generation and that it remains in the system loop consisting of the power plant, the piping, as well as the geothermal aquifer (USEPA, 1999). During normal operations, brine will be injected in the injection wells immediately following the HP separator. During startup and shutdown, some brine may be directed to the brine ponds and subsequently injected into the aerated brine injection wells.

52. Brine Solids – During plant-upset conditions, well flow testing, or startup, production brines will be discharged to the brine ponds. The brine ponds will be used for the collection of miscellaneous byproduct streams prior to their injection into the formation. The brine is then pumped into one of two aerated brine injection wells located at the Facility. As needed, brine pond liquids will be pumped out and injected, and the solids will be removed and dewatered with a portable pressure filter press. Solids will be transported by a licensed transporter to an appropriately permitted offsite facility.

53. Wastewater – Sources of wastewater and their dispositions include the following:

    a. Blowdown from the cooling towers will be injected into one of the two dedicated Facility injection wells.

    b. Blowdown from the quench and scrubber stages of the air emissions control system will be bled into the cooling tower basin, and will be injected into one of the two dedicated Facility injection wells along with the cooling tower blowdown.

    c. HP Steam is directed from the separator to a chloride scrubber and demister in series, then into the HP inlets of the steam turbine. The scrubber accomplishes chloride removal from the steam to prevent damage to the steam turbine using an injected water stream and chemical conditioning. The discharge stream from the scrubber is routed to the RPF brine injection system for re-injection into the geothermal reservoir.

    d. Reject water from the RO water purification system will be pumped to the cooling tower basin.

    e. Uncontaminated storm water collected in the chemical storage and feed containment areas that contain fixed or portable tanks and other containers will be directed to the brine ponds and discharged together with other plant wastewater to a dedicated Facility injection well.

54. Sanitary Waste – Sanitary waste for the Facility will be directed to a septic tank, which will be constructed according to the Imperial County building code. This tank will be pumped out as necessary. There are no drinking water wells in the area near the Facility.

55. Well Rehabilitation – Periodically (once every 5 to 10 years), production or injection wells have to be re-drilled to maintain their productive capacity. Wet materials from well construction consist of soils, brine effluent, and other materials removed from the ground during the re-drilling of production and injection wells. This waste will be allowed to dry out in the clay-lined mud sumps. By regulation, materials from geothermal drilling are non-hazardous; therefore, after evaporation, the remaining solid waste in the mud sumps will be disposed at the Desert Valley Company's Monofill Facility, a Class II landfill.

56. General Maintenance Wastes – Office waste and general refuse will be recycled to the extent practicable and the remainder will be disposed by the local sanitation service to a Class III landfill. Pipe maintenance and de-scaling activities that include hydroblasting or sandblasting will be performed in a designated containment area to prevent wastes generated from these activities from impacting the environment. Water from the hydroblasting process will be conveyed to the brine ponds for injection into the geothermal resource.

57. Hazardous Waste – Hazardous waste, as defined in CCR, Title 27, § 20164, and universal waste, as defined in CCR, Title 27, § 66273.9, expected to be generated by the Facility during normal operations include the limited amounts of brine pond solids (if testing reveals them to be hazardous), scale from the walls of piping and brine handling equipment (if testing reveals them to be hazardous), used oil, oil adsorbents, cleaning solutions and solvents, empty containers, fluorescent lamps, used batteries, and electronic equipment. If determined to be non-hazardous, these wastes will be removed regularly by a certified waste handling contractor to the Applicant's affiliate operated Class II monofill. Hazardous wastes will be disposed at an appropriate Class I hazardous waste management facility. Universal wastes will be recycled or disposed properly.

WASTE GENERATED DURING CONSTRUCTION OF THE FACILITY

58. Material from Well Construction – The construction of the production, injection, and plant wells associated with the Facility will result in the following:

    a. Spent drilling fluids and drilling cuttings.
    b. Material from well construction (solids).
    c. Fluids from performing "flowbacks" on the completed wells.

    Spent drilling fluids and cuttings will be managed in mud sumps or the brine ponds. Material from well construction will be pumped to the mud sumps and brine ponds where the liquid constituents will be allowed to separate by gravity and/or evaporate. Gravity-separated fluids may be pumped or conveyed by truck between sumps/ponds as management demands dictate. Decanted fluids will be injected into the geothermal formation to help preserve the geothermal resource. Materials from geothermal drilling are exempt from regulation as hazardous waste under California

Health and Safety Code Section 25143.1. Material from well construction generated from the project will be disposed in the Applicant's affiliate-operated local monofill.

After a well is completed, it must be "flowed back," which flushes the well to remove drilling mud remnants, cuttings, and other materials that ultimately might inhibit well performance. Depending on the well, a certain amount of geothermal brine may also be entrained in the flowback stream. The amount of material generated from this activity varies; however, in practice the well is flowed until such time as the fluids are clear. Solid waste from well construction will be managed in roll-off containers. These containers will be removed from the job site by a permitted hauler and conveyed to a permitted facility for ultimate disposal.

59. Hazardous Waste – Hazardous waste generated during construction of the Facility will be accumulated onsite for less than 90 days at specified accumulation points. Hazardous and universal wastes will be transported by a licensed transporter using a Uniform Hazardous Waste Manifest and disposed or recycled at an appropriate Treatment, Storage, or Disposal Facility (TSDF). Copies of manifests, reports, waste analysis, exception reports, land disposal restrictions, and other related documents will be maintained onsite as required.

60. Miscellaneous Construction Waste – During construction of the Facility, the primary type of waste generated will be solid non-hazardous wastes. Small quantities of non-hazardous liquid wastes, hazardous solid and liquid wastes, and universal wastes also may be generated during construction. Non-hazardous wastes generated during construction is expected to include scrap wood, concrete, empty containers (plastic, metal, glass, cardboard, and Styrofoam), packaging materials, scrap metals, insulation (silicate and mineral wool), and materials from well construction. Approximately 20 to 40 cubic yards per week of construction wastes are expected to be generated during construction of the Facility. Management of these wastes will be the responsibility of the construction contractor(s). Where practical, such as in the case of scrap steel, the wastes will be recycled. Non-hazardous wastes will be properly stored to prevent wind dispersion, and will be transported by a licensed transporter and disposed or recycled at an appropriately permitted facility.

61. Sanitary Waste – During construction, sanitary waste will be collected in portable, self-contained toilets. The sanitary wastes from the portable chemical toilets will be pumped out regularly by a licensed contractor and transported to a sanitary wastewater treatment plant.

BASIN PLAN

62. The Water Quality Control Plan for the Colorado River Basin Region of California (Basin Plan) was adopted on November 17, 1993, and designates the beneficial uses of ground and surface water in this Region.

63. The beneficial uses of groundwater in the Imperial Hydrological Unit are:

    a. Municipal Supply (MUN)
    b. Industrial Supply (IND)

64. The beneficial uses of nearby surface waters are as follows:

Imperial Valley Drains

a. Freshwater Replenishment
b. Water Contact Recreation (RECI)
c. Noncontact Water Recreation (RECII)
d. Warm Freshwater Habitat (WARM)
e. Wildlife Habitat (WILD)
f. Preservation of Rare, Threatened, or Endangered Species (RARE).

Alamo River

a. Fresh Water Replenishment (FRSH)
b. Water Contact Recreation (RECI)
c. Noncontact Water Recreation (RECII)
d. Warm Freshwater Habitat (WARM)
e. Wildlife Habitat (WILD)
f. Hydropower Generation (POW)
g. Preservation of Rare, Threatened, or Endangered Species (RARE)

Salton Sea

a. Aquaculture (AQUA)
b. Industrial Service Supply (IND)
c. Water Contact Recreation (RECI)
d. Noncontact Water Recreation (RECII)
e. Warm Water Habitat (WARM)
f. Wildlife Habitat (WILD)
g. Preservation of Rare, Threatened, or Endangered Species (RARE)

MONITORING PARAMETERS

65. Based on the chemical characteristics of the projected discharges to the brine pond from the flashed geothermal brine, the following list of monitoring parameters are required. These specific parameters are selected because they provide the best distinction between the chloride-rich brine and the sulfate-rich groundwater in the Project area that can be used to differentiate a potential brine pond release from other influences that could change the chemical composition of the groundwater.

Cations: Barium, Boron, Cadmium, Magnesium, Manganese, Iron, Lead, Potassium, Sodium, Strontium, and Zinc;

Anions: Ammonium, Bicarbonates, Chloride and Sulfate; and

Other: Total Dissolved Solids, Specific Conductivity, and pH.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA) -- PUBLIC RESOURCES CODE SECTION 21000 ET SEQ.

66. The environmental review program of the California Energy Commission (CEC), which has exclusive jurisdiction over the permitting of this Facility, has been certified by the Secretary for Natural Resources as meeting the requirements of Public Resources Code Section 21080.5 to exempt the CEC's power plant site certification program from the CEQA requirements to prepare EIRs, negative declaration, and

initial studies. (See CCR, Title 14, § 15251(k).) Accordingly, the CEC will prepare the appropriate substitute CEQA environmental documents pursuant to its responsibilities as Lead Agency for this site certification program.

INDUSTRIAL STORMWATER PERMIT

67. Federal regulations for storm water discharges were promulgated by the U.S. Environmental Protection Agency (40 CFR Parts 122, 123, and 124). The regulations require specific categories of facilities that discharge storm water associated with industrial activity to obtain NPDES permits and to implement Best Conventional Pollutant Technology (BCPT) to reduce or eliminate industrial storm water pollution.

68. The State Water Resources Control Board adopted Order No. 97-03-DWQ (General Permit No. CAS000001) specifying WDRs for discharges of storm water associated with industrial activities, excluding construction activities, requiring submittal of a Notice of Intent (NOI) by industries to be covered under the Permit. However, based on a legal memorandum provided by the Office of Chief Counsel, State Water Resources Control Board, dated February 23, 1993, titled “Storm Water Permit: Geothermal Power Plants,” discharges of storm water from geothermal power plants are not required to obtain coverage under the State Water Board’s general permit for industrial discharges of storm water. Therefore, the Discharger is not required to file an NOI to obtain coverage under this General Permit for any storm water discharges associated with its geothermal power plant operations.

CONSTRUCTION STORMWATER PERMIT

69. Federal regulations for storm water discharges were promulgated by the United States Environmental Protection Agency (USEPA) on November 16, 1990 (40 CFR Parts 122, 123, and 124). The regulations require discharges of storm water to surface waters associated with construction activity, including clearing, grading, and excavation activities (except operations that result in disturbance of less than 5 acres of total land area and which are not part of a larger common plan of development or sale) to obtain a National Pollutant Discharge Elimination System (NPDES) permit and to implement Best Conventional Pollutant Control Technology and Best Available Technology Economically Achievable to reduce or eliminate storm water pollution. (40 CFR 122.26(b)(14)(x).) On December 8, 1999, federal regulations promulgated by USEPA (40 CFR Parts 9, 122, 123, and 124) expanded the NPDES storm water program to include, in pertinent part, storm water discharges from construction sites that disturb a land area equal to or greater than 1 acre and less than 5 acres, or is part of a larger common plan of development or sale (small construction activity). (40 CFR 122.26(b)(15).)

70. To comply with these federal requirements, the State Water Resources Control Board (State Water Board) adopted in 1999 Water Quality Order No. 99-08-DWQ (NPDES) General Permit No. CAS000002, “Waste Discharge Requirements (WDRs) for Discharges of Storm Water Runoff Associated with Construction Activity” (General Permit). The General Permit specifies WDRs for discharges of storm water associated with construction activity that results in a land disturbance of 1 acre or more or is part of a larger common plan of development or sale. The General Permit specifies certain

construction activities that are exempted from coverage. Because these exemptions do not apply to the Discharger's proposed construction activity and because this activity will result in a land disturbance of more than 1 acre, the Discharger is subject to the General Permit requirements.

71. On September 2, 2009, the State Water Board adopted a new construction general permit (CGP) to replace Order No. 99-08-DWQ. The new CGP, Order No. 2009-0009-DWQ (NPDES No. CAS000002), will become effective on July 1, 2010. Until then, SWRCB Order No. 99-08-DWQ remains in effect. On and after July 1, 2010, however, Order No. 99-08-DWQ is superseded, except for enforcement purposes, by Order No. 2009-0009-DWQ. The website link to this new CGP is as follows:

    <http://www.waterboards.ca.gov/board_decisions/adopted_orders/water_quality/2009/wqo/wqo2009_0009_dwq.pdf>.

72. If the Discharger's construction activity continues after July 1, 2010, when the new CGP takes effect, the Discharger is required, pursuant to the new CGP, to obtain coverage under that new permit. (CGP, Section II.B.4.b, p. 68 of 285.) To obtain coverage, the Discharger must electronically file Permit Registration Documents (PRDs), which includes a Notice of Intent (NOI), Storm Water Pollution Prevention Plan (SWPPP), and other compliance-related documents required by the CGP and mail the appropriate permit fee to the State Water Board.

MONITORING AND REPORTING PROGRAM

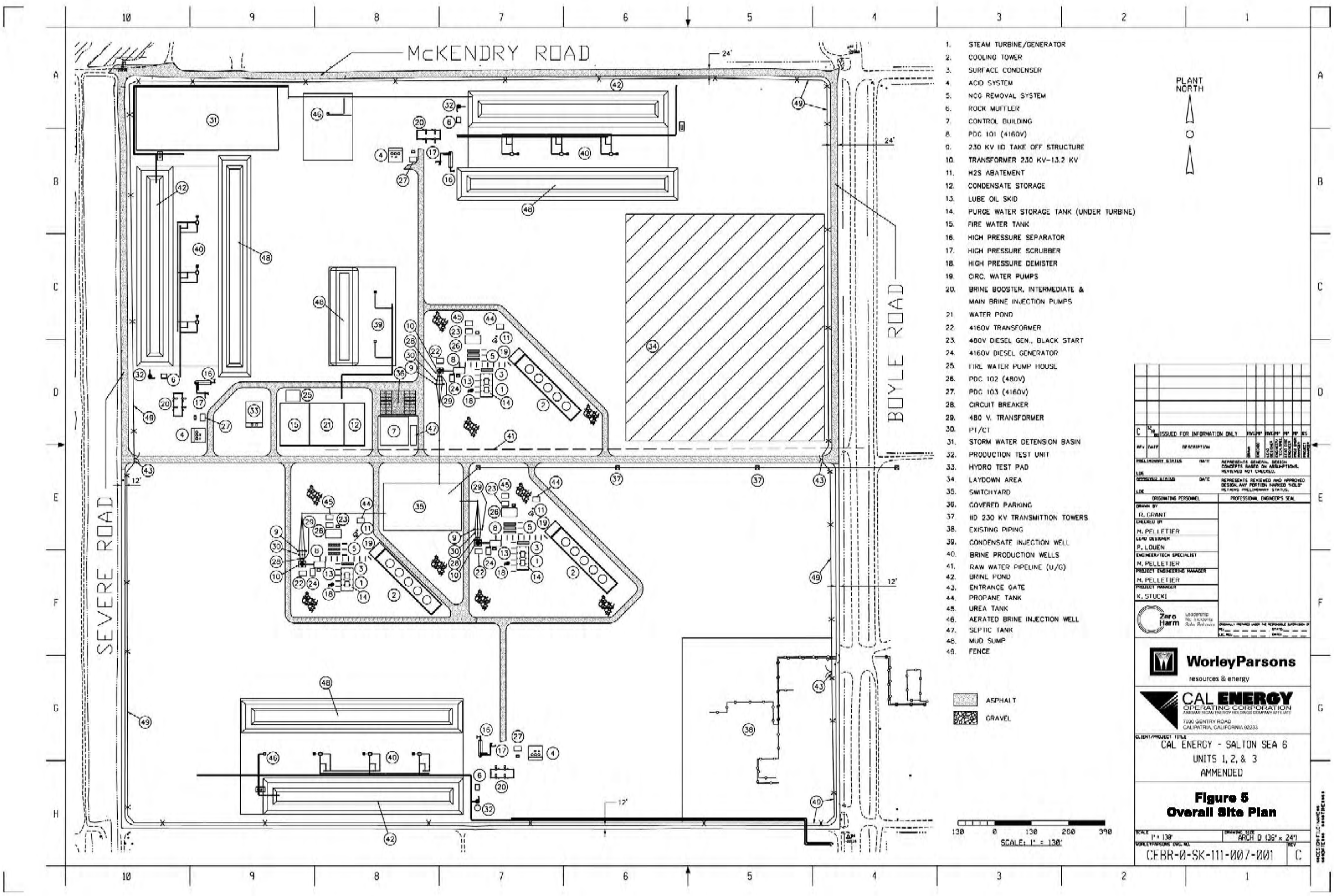
73. The monitoring and reporting requirements in the Monitoring and Reporting Program, Appendix C, and the requirement to install groundwater monitoring wells are necessary to determine compliance with these WDRs, and to determine the Facility's impacts, if any, on receiving water.

APPENDIX A, ATTACHMENT A

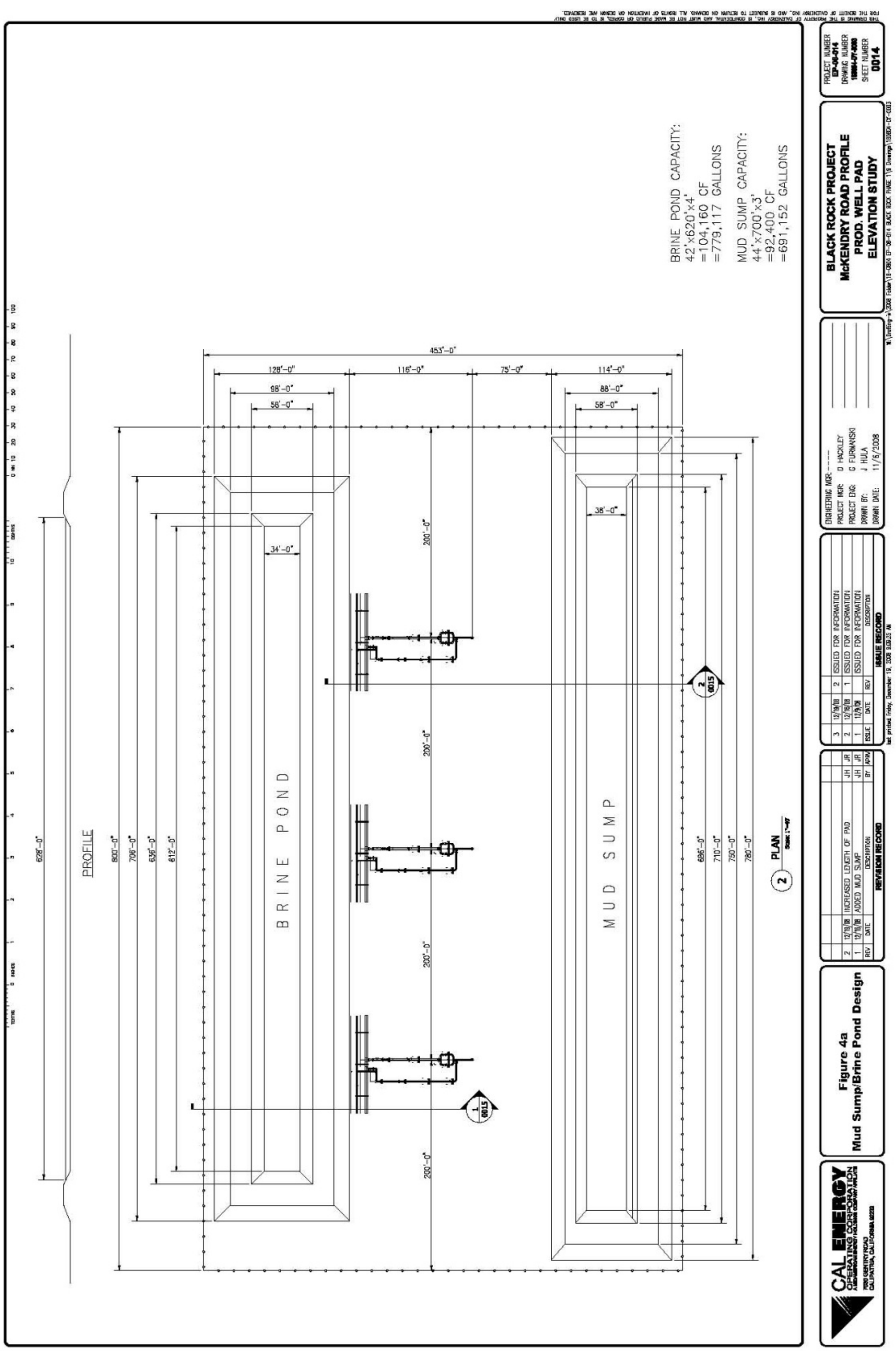
Black Rock 1, 2 and 3 Geothermal Power Project
Project Location
Imperial County

APPENDIX A, ATTACHMENT B

Black Rock 1, 2 and 3 Geothermal Power Project
Site Map
Imperial County



APPENDIX A, ATTACHMENT C
Black Rock 1, 2 and 3 Geothermal Power Project
Brine Ponds
Imperial County



SOIL AND WATER RESOURCES – APPENDIX B

REQUIREMENTS FOR WASTE DISCHARGE—Black Rock 1, 2 and 3 Geothermal Power Project Brine Ponds

A. Discharge Specifications

1. The treatment or disposal of wastes at this Facility shall not cause pollution or nuisance as defined in Sections 13050 of Division 7 of the California Water Code (CWC).

2. The Discharger will maintain the monitoring, production and injection wells in good working order at all times. Well maintenance may include periodic well re-development to remove sediments.

3. At least 30 days prior to introduction of a new waste stream into the brine ponds, the Discharger must receive approval from the Energy Commission's Compliance Project Manager (CPM), who will evaluate any proposed new waste streams in consultation with the Colorado River Basin Regional Water Quality Control Board's (Regional Board or RWQCB) Executive Officer.

4. Waste material shall be confined or discharged to the brine ponds.

5. Prior to drilling a new production well or conversion of a production well to an injection well at the Facility, the Discharger shall notify, in writing, both CPM and the Regional Board's Executive Officer of the proposed change.

6. Containment of waste shall be limited to the areas designated for such activities. Any revision or modification of the designated waste containment area, or any proposed change in operation at the Facility that changes the nature and constituents of the waste produced must be submitted in writing to the CPM, with copies to the Regional Board's Executive Officer, for review. The CPM, in consultation with the Regional Board's Executive Officer, must approve the proposed change before any change in operations or modification of the designated area is implemented.

7. Any substantial increase or change in the annual average volume of material to be discharged under these WDRs at the site must be submitted in writing to the CPM, with copies to the Regional Board's Executive Officer, for review. The CPM, in consultation with the Regional Board's Executive Officer, must approve of the proposed change before the change in discharge volume is implemented.

8. If any portions of the brine ponds are to be closed, the Discharger shall notify the CPM and the Regional Board's Executive Officer at least 180 days prior to beginning any partial or final closure activities.

9. Fluids and/or materials discharged to and/or contained in the brine ponds shall not overflow the ponds.

10. Prior to the use of new chemicals for the purposes of adjustment or control of microbes, pH, scale, and corrosion of the cooling tower water and geothermal brine, the Discharger shall notify the CPM and the Regional Board's Executive Officer in writing.

11. For the liquids in the brine ponds, a minimum freeboard of 2 feet shall be maintained at all times.

12. Fluids discharged by subsurface injection shall be injected below the fracture pressure of the receiving aquifer and of the confining layer immediately above the receiving aquifer.

13. Final disposal of residual waste from cleanup of the brine ponds shall be accomplished to the satisfaction of the CPM, in consultation with the Regional Board's Executive Officer, upon abandonment or closure of operations.

14. The brine ponds shall be designed, constructed, operated, and maintained to prevent inundation or washout due to floods having a predicted frequency of once in 100 years.

15. Geothermal well clean out fluid, test and production fluid, production and injection well startups and cleanouts shall be discharged in metal tanks, or containers approved by the CPM, in consultation with the Regional Board's Executive Officer, to receive this discharge. Mud sumps may not be used to store well cleanout or production fluids after initial well drilling and development.

16. Within one year after completion of a new geothermal well, the mud sump used to contain fluids during drilling and well development must be properly abandoned.

17. Prior to removal of solid material that has accumulated in the concrete cooling tower basins, an analysis of the material must be conducted and the material must be disposed of in a manner consistent with that analysis and applicable laws and regulations.

18. Conveyance systems throughout the plant area shall be cleaned out at least every 90 days to prevent the buildup of solids or when activity at the site creates the potential for release of solid materials from the conveyance systems.

19. Pipe maintenance and de-scaling activities that include hydroblasting and/or sandblasting shall be performed within a designated area that minimizes the potential for release to the environment. Waste generated as a result of these activities shall be disposed of in accordance with applicable laws and regulations. Water from the hydroblasting process shall be conveyed to the brine pond for injection into the geothermal resource.

20. Public contact with wastes containing geothermal fluids shall be precluded through such means as fences, signs, or other acceptable alternatives.

21. The brine ponds shall be managed and maintained to ensure their effectiveness, in particular,

    a. Implementation of erosion control measures shall assure that small coves and irregularities are not created.

    b. The liner beneath the brine pond shall be appropriately maintained to ensure its proper function.

    c. Solid material shall be removed from the brine ponds in a manner that minimizes the likelihood of damage to the liner.

22. At least 90 days prior to the cessation of discharge operations at the Facility, the Discharger shall submit a workplan, subject to approval of the CPM in consultation with the Regional Board's Executive Officer, for assessing the extent, if any, of contamination of natural geological materials and waters of the Imperial Hydrological Unit by the waste. No more than 120 days following workplan approval, the Discharger shall submit to the CPM a technical report presenting results of the contamination assessment, with copies to the Regional Board's Executive Officer. A California Registered Civil Engineer or Certified Engineering Geologist must prepare the workplan, contamination assessment, and engineering report.

23. Upon ceasing operation at the Facility, all waste, all natural geologic material contaminated by waste, and all surplus or unprocessed material shall be removed from the site and disposed of in accordance with applicable laws and regulations.

24. The Discharger shall establish an irrevocable bond for closure in an amount acceptable to the CPM in consultation with the Regional Board's Executive Officer, or provide other means to ensure financial security for closure if closure is needed at the discharging site. The closure fund shall be established (or evidence of an existing closure fund shall be provided) within 6 months of the certification of the Black Rock 1, 2 and 3 Geothermal Power Project by the Energy Commission.

25. Surface drainage from tributary areas or subsurface sources shall not contact or percolate through the waste discharged at this site.

26. The Discharger shall implement the attached Monitoring and Reporting Program, Appendix C, and revisions thereto, in order to detect, at the earliest opportunity, any unauthorized discharge of waste constituents from the Facility, or any impairment of beneficial uses associated with (caused by) discharges of waste to the brine pond.

27. The Discharger shall use the constituents listed in the Monitoring and Reporting Program (Appendix C), and revisions thereto, as "Monitoring Parameters."

28. The Discharger shall follow the Water Quality Protection Standard (WQPS) for detection monitoring established by the Regional Board, including the following:

a. The Discharger shall test for the monitoring parameters and the Constituents of Concern (COCs) listed in the Monitoring and Reporting and revisions thereto.

b. Concentration Limits – The concentration limit for each monitoring parameter and constituents of concern for each monitoring point (as stated in the Detection Monitoring Program), shall be its background valued as obtained during that reporting period.

c. All current, revised, and/or proposed monitoring points must be approved by the CPM, in consultation with the Region Board's Executive Officer.

29. Water used for the process and site maintenance shall be limited to the amount necessary in the process, for dust control, and for Facility cleanup and maintenance.

30. The Discharger shall not cause or permit the release of pollutants, or waste constituents, in a manner which could cause or contribute to a condition of contamination, nuisance, or pollution to occur.

31. The Discharger must develop and implement a Hazardous Materials Business Plan (HMBP), which will include, at a minimum, procedures for:

    a. Hazardous materials handling, use, and storage;
    b. Emergency response;
    c. Spill control and prevention;
    d. Employee training; and
    e. Reporting and record keeping.

32. Hazardous materials expected to be used during construction include: unleaded gasoline, diesel fuel, oil, lubricants (i.e., motor oil, transmission fluid, and hydraulic fluid), solvents, adhesives, and paint materials. There are no feasible alternatives to these materials for construction or operation of construction vehicles and equipment, or for painting and caulking buildings and equipment.

33. The construction contractor will be responsible for assuring that the use, storage and handling of these materials will comply with applicable federal, state, and local laws, ordinances, regulations, and standards (LORS), including licensing, personnel training, accumulation limits, reporting requirements, and recordkeeping.

34. During Facility operations, chemicals will be stored in chemical storage areas appropriately designed for their individual characteristics. Bulk chemicals will be stored outdoors on impervious surfaces in aboveground storage tanks with secondary containment. Secondary containment areas for bulk storage tanks will not have drains. Any chemical spills in these areas will be removed with portable equipment and reused or disposed of properly. Other chemicals will be stored and used in their delivery containers.

35. A portable storage trailer may be on site for storage of maintenance lube oils, chemicals, paints, and other construction materials, as needed. Drains from

chemical storage and feed areas that use portable vessels will be directed to the brine pond and discharged together with other plant wastewater to the dedicated injection well. All drains and vent piping for volatile chemicals will be trapped and isolated from other drains to eliminate noxious vapors. The storage, containment, handling, and use of these chemicals will be managed in accordance with applicable laws, ordinances, regulations, and standards.

36. Small quantities of hazardous wastes will be generated over the course of construction. These may include filter cake waste, paint, spent solvents, and spent welding materials. During normal operations, less than 5 percent of the filter cake is projected to be characterized as hazardous because of elevated concentrations of heavy metals. Some hazardous wastes will be recycled, including used oils from equipment maintenance, and oil-contaminated materials such as spent oil filters, rags, or other cleanup materials. Used oil must be recycled, and oil or heavy metal contaminated materials (e.g., filters) requiring disposal must be disposed of in a Class I waste disposal facility. Scale from pipe and equipment cleaning operations, and solids from the brine pond, will be disposed of in a similar manner.

37. All hazardous wastes generated during facility construction and operation must be handled and disposed of in accordance with applicable laws, ordinances, regulations, and standards. Any hazardous wastes generated during construction must be collected in hazardous waste accumulation containers near the point of generation and moved daily to the contractor's 90-day hazardous waste storage area located on site. The accumulated waste must subsequently be delivered to an authorized waste management facility. Hazardous wastes must be either recycled or managed and disposed of properly in a licensed Class I waste disposal facility authorized to accept the waste.

38. The Discharger shall monitor the brine pond in conformance with applicable CCR Title 27 requirements for Class II surface impoundment waste management units.

39. The leachate collection and removal system must be used to provide preliminary detection monitoring of leaks through the top liner of the double-lined brine pond. Physical evidence of brine beneath the upper concrete liner shall be interpreted as a warning that containment of the brine pond contents may be compromised.

40. Groundwater monitoring wells must be constructed adjacent to and both up gradient and down gradient of the brine pond to provide background and detection monitoring for any potential release from the brine pond containment. The Point of Compliance to be used for the detection monitoring must be the uppermost shallow groundwater beneath the brine pond. The groundwater monitoring wells must be constructed in conformance with Title 27 CCR Section 20415 requirements and all applicable Imperial County monitoring well requirements. The monitoring wells must be designed to meet the background and detection monitoring requirements in conformance with Title 27 CCR Section 20415(b)(1)(B) as applicable, including:

a. Providing a sufficient number of monitoring points to yield ground water samples from the uppermost aquifer that represent the quality of ground water passing the Point of Compliance and to allow for the detection of a release from the brine pond;

b. Providing a sufficient number of monitoring points installed at locations and depths to yield ground water samples from the upper most aquifer to provide the best assurance of the earliest possible detection of a release from the brine pond;

c. Providing a sufficient number of monitoring points and background monitoring points installed at appropriate locations and depths to yield ground water samples from zones of perched water to provide the best assurance of the earliest possible detection of a release from the brine pond; and

d. Selecting monitoring point locations and depths that include the zone(s) of highest hydraulic conductivity in the groundwater body monitored.

41. The detection monitoring wells shall be constructed to meet the well performance standards set forth in Title 27 CCR Section 20415(b)(4), as applicable, including:

    a. All monitoring wells shall be cased and constructed in a manner that maintains the integrity of the monitoring well bore hole and prevents the bore hole from acting as a conduit for contaminant transport.

    b. The sampling interval of each monitoring well shall be appropriately screened and fitted with an appropriate filter pack to enable collection of representative ground water samples.

    c. For each monitoring well, the annular space (i.e., the space between the bore hole and well casing) above and below the sampling interval shall be appropriately sealed to prevent entry of contaminants from the ground surface, entry of contaminants from the unsaturated zone, cross contamination between portions of the zone of saturation, and contamination of samples.

    d. All monitoring wells shall be adequately developed to enable collection of representative ground water samples.

42. The monitoring program must also meet the general requirements set forth in Title 27 CCR Section 20415(e), which require that all monitoring systems be designed and certified by a registered engineering geologist or a registered civil engineer. The applicable general requirements set forth for boring logs, quality assurance/quality control, sampling and analytical methods used, background sampling, data analysis, and other reporting as applicable will be implemented.

43. Baseline samples of the groundwater must be collected from each of the monitoring wells and analyzed prior to discharging geothermal fluid to the brine ponds. The groundwater must be initially sampled for each of the proposed monitoring parameters listed in the Monitoring and Reporting Program (Appendix C) and any additional Constituents of Concern (COC) identified by the Regional Board.

B. Prohibitions

1. The discharge or deposit of solid geothermal waste to the brine ponds as a final form of disposal is prohibited, unless authorized by the CPM, in consultation with the Regional Board's Executive Officer.

2. The Discharger is prohibited from discharging, treating or composting at this site the following wastes:

    a. Municipal solid waste;

    b. Sludge (including sewage sludge, water treatment sludge, and industrial sludge);

    c. Septage;

    d. Liquid waste, unless specifically approved by these WDRs or by the Regional Board's Executive Officer;

    e. Oily and greasy liquid waste; unless specifically approved by these WDRs or by the CPM, in consultation with the Regional Board's Executive Officer; and,

    f. Hot, burning waste materials or ash.

3. The Discharger shall not cause degradation of any groundwater aquifer or water supply.

4. The discharge of waste to land not owned or controlled by the Discharger is prohibited.

5. Use of geothermal fluids or cooling tower liquids on access roads, well pads, or other developed project locations for dust control is prohibited.

6. The discharge of hazardous or designated wastes to other than a waste management unit authorized to receive such waste is prohibited.

7. Any hazardous waste generated or stored at the facility will be contained and disposed in a manner that complies with federal and state regulations.

8. Permanent (longer than one year) disposal or storage of geothermal waste in on-site temporary mud sumps is prohibited, unless authorized by the CPM, in consultation with the Regional Board's Executive Officer.

9. Geothermal fluids or any fluids in the brine ponds shall not enter any canal, drainage, or drains (including subsurface drainage systems) that could provide flow to the Salton Sea.

10. The Discharger shall appropriately dispose of any materials, including fluids and sediments removed from the brine ponds.

11. The Discharger shall neither cause nor contribute to the contamination or pollution of groundwater via the release of waste constituents in either liquid or gaseous phase.

12. Direct or indirect discharge of any waste to any surface water or surface drainage courses is prohibited.

13. The Discharger shall not cause the concentration of any Constituent of Concern or Monitoring Parameter to exceed its respective background value in any monitored medium at any Monitoring Point assigned for Detection Monitoring pursuant to the Monitoring and Reporting Program (Appendix C).

C. Provisions

1. The Discharger shall comply with the Monitoring and Reporting Program (Appendix C) and future revisions thereto, as specified by the CPM, in consultation with the Regional Board's Executive Officer.

2. Unless otherwise approved by the CPM, in consultation with the Regional Board's Executive Officer, all analyses shall be conducted at a laboratory certified for such analyses by the California Department of Public Health. All analyses shall be conducted in accordance with the latest edition of "Guideline Establishing Test Procedures for Analysis of Pollutants," promulgated by the United States Environmental Protection Agency.

3. The laboratory shall use detection limits less than or equal to Environmental Protection Agency (EPA) Action Levels/Maximum Contaminant Levels (MCLs) or California Department of Public Health (CDPH) Notification Levels/MCLs for all samples analyzed. The lowest concentration, whether EPA or CDPH, of the two agencies must be used for the analysis.

4. Prior to any change in ownership of this operation, the Discharger shall transmit a copy of these WDRs to the succeeding owner/operator, and forward a copy of the transmittal letter to the Regional Board.

5. Prior to any modification in this facility that would result in material change in the quality or quantity of discharge, or any material change in the location of discharge, the Discharger shall report all pertinent information in writing to the CPM and the Regional Board's Executive Officer, and obtain revised waste discharge requirements before any modification is implemented.

6. All permanent containment structures and erosion and drainage control systems shall be certified by a California Registered Civil Engineer or Certified Engineering Geologist as meeting the prescriptive standards and performance goals.

7. The Discharger shall ensure that all site-operating personnel are familiar with the content of these WDRs, and shall maintain a copy of these WDRs at the site.

8. These WDRs do not authorize violation of any federal, state, or local laws or regulations.

9. The Discharger shall allow the CPM, the Regional Board, or an authorized representative, upon presentation of credential and other documents as may be required by law, to:

a. Enter upon the premises regulated by these WDRs, or the place where records must be kept under the conditions of these WDRs;

b. Have access to and copy, at reasonable times, any records that shall be kept under the condition of these WDRs;

c. Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under these WDRs; and

d. Sample or monitor at reasonable times, for the purpose of assuring compliance with these WDRs or as otherwise authorized by the California Water Code or the California Code of Regulations, any substances or parameters at this location.

10. The Discharger shall comply with all of the conditions of these WDRs. Any noncompliance with these WDRs constitutes a violation of both the terms of the project's certification and the Porter-Cologne Water Quality Act, and is grounds for enforcement action.

11. The Discharger shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) that are installed or used by the Discharger to achieve compliance with these WDRs. Proper operation and maintenance also includes adequate laboratory controls and appropriate quality assurance procedures.

12. These WDRs do not convey any property rights of any sort or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations.

13. The Discharger shall comply with the following:

    a. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.

    b. The Discharger shall retain records of all monitoring information, copies of all reports required by these WDRs, and records of all data used to complete the application for these WDRs, for a period of at least 5 years from the date of the sample, measurement, report or application. This period may be extended by request of the CPM at any time.

    c. Records of monitoring information shall include:

        1. The dates, exact places, and times of samplings or measurements.
        2. The individual(s) who performed the samplings or measurements.
        3. The date(s) analyses were performed.
        4. The individual(s) responsible for reviewing the analyses.
        5. The results of such analyses.

    d. Monitoring must be conducted according to test procedures described in the Monitoring and Reporting Program, unless other test procedures have been specified in these WDRs or approved by the CPM, in consultation with the Regional Board's Executive Officer.

14. All monitoring systems shall be readily accessible for sampling and inspection.

15. The Discharger is the responsible party for the WDRs, and the monitoring and reporting program for the facility. The Discharger shall comply with all conditions of these WDRs. Violations may result in enforcement actions, including Regional Boards Orders or court orders, requiring corrective action or imposing civil monetary liability, or in modification or revocation of these WDRs by the CPM, in consultation with the Regional Board.

16. The Discharger shall furnish, under penalty of perjury, technical monitoring program reports, and such reports shall be submitted in accordance with the specifications provided by the CPM, in consultation with the Regional Board's Executive Officer. Such specifications are subject to periodic revisions as may be warranted.

17. The Discharger may be required to submit technical reports as directed by the CPM, in consultation with the Regional Board's Executive Officer.

18. The procedure for preparing samples for the analyses shall be consistent with the Monitoring and Reporting Program (Appendix C) and any revisions thereto. The Monitoring Reports shall be certified to be true and correct, and signed, under penalty of perjury, by an authorized official of the company. All technical reports require the signature of a California Registered Professional Engineer or Professional Geologist.

19. All monitoring shall be done as described in Title 27 of the CCRs.

MONITORING AND REPORTING PROGRAM – Black Rock 1, 2 and 3 Geothermal Power Project Brine Ponds

PART I- GENERAL REQUIREMENTS

A. General

A Discharger who owns or operates a Class II Surface Impoundment is required to comply with the provisions of Title 27, Division 2, Chapter 3, Subchapter 3, Article 1 of the California Code of Regulations for the purpose of detecting, characterizing, and responding to releases to the groundwater. Section 13267, California Water Code gives the Regional Water Board authority to require monitoring program reports for discharges that could affect the quality of waters within its region.

1. This Monitoring and Reporting Program (MRP) is established pursuant to the Waste Discharge Requirements set forth in Appendices A and B. The principal purpose of this self-monitoring program is:
   a. To document compliance with Waste Discharge Requirements (WDRs) and prohibitions established by the California Energy Commission, in consultation with the Regional Water Board;
   b. To facilitate self-policing by the Discharger in the prevention and abatement of pollution arising from waste discharge;
   c. To conduct water quality analyses.
2. The Energy Commission's Compliance Project Manager (CPM), in consultation with the Regional Water Board Executive Officer, may alter the monitoring parameters, monitoring locations, and/or the monitoring frequency during the course of this monitoring program.

B. Definition Of Terms

1. Affected Persons – all persons who either own or occupy land outside the boundaries of the parcel upon which a waste management unit (surface impoundment or impoundment) is located that has been or may be affected by the release of waste constituents from the unit.
2. Background Monitoring Point – a device (e.g. well) or location (e.g. a specific point along a lakeshore) that is upgradient or side gradient from the impoundment assigned by this MRP, where water quality samples are taken that are not affected by a release from the impoundment and that are used as a basis of comparison against samples taken from downgradient Monitoring Points.
3. Constituents of Concern (COCs) – those constituents likely to be in the waste, or derived from waste constituents in the event of a release from the impoundment.

4. Matrix Effect – refers to any change in the Method Detection Limit (MDL) or Practical Quantitation Limit (PQL) for a given constituent as a result of the presence of other constituents - either of natural origin or introduced through a spill or release - that are present in the sample being analyzed.

5. Method Detection Limit (MDL) – the lowest constituent concentration that can support a non-zero analytical result with 99 percent reliability. The MDL is laboratory specific and should reflect the detection capabilities of specific procedures and equipment used by the laboratory.

6. Monitored Media – water-bearing media monitored pursuant to this Monitoring and Reporting Program. The Monitored Media may include: (1) groundwater in the uppermost aquifer, in any other portion of the zone of saturation (as defined in Title 27, Section 20164) in which it would be reasonable to anticipate that waste constituents migrating from the surface impoundment could be detected, and in any perched zones underlying the impoundment, (2) any bodies of surface water that could be measurably affected by a release, (3) soil-pore liquid beneath and/or adjacent to the surface impoundment, and (4) soil-pore gas beneath and/or adjacent to the surface impoundment.

7. Monitoring Parameters – the list of constituents and parameters used for the majority of monitoring activity.

8. Monitoring Point – a device (e.g. well) or location (e.g. a specific point along a lakeshore) that is downgradient from the surface impoundment assigned by this MRP, at which samples are collected for the purpose of detecting a release by comparison with samples collected at Background Monitoring Points.

9. Practical Quantification Limit (PQL) – the lowest constituent concentration at which a numerical concentration can be assigned with a 99 percent certainty that its value is within 10 percent of the actual concentration in the sample. The PQL is laboratory specific and should reflect the detection capabilities of specific procedures and equipment used by the laboratory.

10. Reporting Period – the duration separating the submittal of a given type of monitoring report from the time the next iteration of that report is scheduled for submittal. Unless otherwise stated, the due date for any given report shall be 30 days after the end of its Reporting Period.

11. Sample Size –

    a. For Monitoring Points – the number of data points obtained from a given Monitoring Point during a given Reporting Period – used for carrying out the statistical or non-statistical analysis of a given analyte during a given Reporting Period.

    b. For Background Monitoring Points – the number of new and existing data points from all applicable Background Monitoring Points in a given Monitored Medium – used to collectively represent the background concentration and variability of a given analyte in carrying out a statistical or non-statistical analysis of that analyte during a given Reporting Period.

12. Uppermost Aquifer – the geologic formation nearest the natural ground surface that is an aquifer, as well as lower aquifers that are hydraulically interconnected with this aquifer within the facility's property boundary.

13. Volatile Organic Constituents (VOCs) – the suite of organic constituents having a high vapor pressure. The term includes at least the 47 organic constituents listed in Appendix I to 40 CFR Part 258.

14. VOC_{water} – the composite monitoring parameter that includes all VOCs that are detectable in less than 10 percent of the applicable background samples. This parameter is analyzed, using the non-statistical method described in Part III.A.2. of this MRP, to identify releases of VOCs that are detected too infrequently in backgroundwater to allow for statistical analysis.

C. Sampling And Analytical Methods

Sample collection, storage, and analysis shall be performed according to the most recent version of Standard USEPA methods. Water and waste analysis shall be performed by a laboratory approved for these analyses by the California Department of Public Health. Specific methods of analysis must be identified. If methods other than USEPA-approved methods or Standard Methods are used, the exact methodology must be submitted for review and approval by the CPM, in consultation with the Regional Water Board Executive Officer, prior to use. The director of the laboratory whose name appears on the certification shall supervise all analytical work in his/her laboratory and shall sign all reports of such work submitted to the CPM and the Regional Water Board. All monitoring instruments and equipment shall be properly calibrated and maintained to ensure accuracy of measurement. In addition, the Discharger is responsible for verifying that laboratory analysis of all samples from Monitoring Points and Background Monitoring Points meet the following restrictions:

1. Methods, analysis, and detection limits used must be appropriate for expected concentrations. For detection monitoring of any constituent or parameter found in concentrations that produce more than 90 percent non-numerical determinations (i.e. "trace" or "ND") in data from Background Monitoring Points for that medium, the analytical methods having the lowest "facility-specific method detection limit (MDL)," defined in Part I.B.5., shall be selected from among those methods that provide valid results in light of any "Matrix Effects" (defined in Part I.B.4.) involved.

2. Analytical results falling between the MDL and the PQL shall be reported as "trace," and shall be accompanied both by the estimated MDL and PQL values for that analytical run, and by an estimate of the constituent's concentration.

3. MDLs and PQLs shall be derived by the laboratory for each analytical procedure, according to State of California laboratory accreditation procedures. These MDLs and PQLs shall reflect the detection and quantitation capabilities of the specific equipment used by the lab. If the lab suspects that, due to a change in matrix or other effects, the true detection limit or quantitation limit for a particular analytical run differs significantly from the laboratory-derived MDL/PQL values, the results shall be flagged accordingly, along with an estimate of the detection limit and quantitation limit actually achieved.

4. All Quality Assurance/Quality Control (QA/QC) data shall be reported, along with the sample results to which it applies, including the method, equipment, and analytical detection limits, the recovery rates, an explanation of any recovery rate that is less than 80 percent, the results of equipment and method blanks, the results of spiked and surrogate samples, the frequency of quality control analysis, and the name and qualifications of the person(s) performing the analyses. Sample results shall be reported unadjusted for blank results or spike recovery.

5. Upon receiving written approval from the CPM, in consultation with the Regional Water Board Executive Officer, an alternative statistical or non-statistical procedure can be used for determining the significance of analytical results for a constituent that is a common laboratory contaminant (i.e., methylene chloride, acetone, diethylhexyl phthalate, and di-n-octyl phthalate) during any given Reporting Period in which QA/QC samples show evidence of laboratory contamination for that constituent. Nevertheless, analytical results involving detection of these analytes in any background or downgradient sample shall be reported and flagged for easy reference by Regional Water Board staff.

6. In cases where contaminants are detected in QA/QC samples (i.e. field, trip, or lab blanks), the accompanying sample results shall be appropriately flagged.

7. The MDL shall always be calculated such that it represents a concentration associated with a 99 percent reliability of a non-zero result.

D. Records To Be Maintained

Written reports shall be maintained by the Discharger or laboratory, and shall be retained for a minimum of 5 years. This period of retention shall be extended during the course of any unresolved litigation regarding this discharge or when requested by the CPM, in consultation with the Regional Water Board. Such records shall show the following for each sample:

1. Identity of sample and of the Monitoring Point or Background Monitoring Point from which it was taken, along with the identity of the individual who obtained the sample;
2. Date and time of sampling;
3. Date and time that analyses were started and completed, and the initials of the personnel performing each analysis;
4. Complete procedure used, including method of preserving the sample, and the identity and volumes of reagents used;
5. Calculations of results; and
6. Results of analyses, and the MDL and PQL for each analysis.

E. Reports To Be Filed With The Board

1. <u>Detection Monitoring Reports</u> – For each Monitored Medium, all Monitoring Points and Background Monitoring Points assigned to detection monitoring under Part II.A.7 of this MRP shall be monitored semiannually for the Monitoring Parameters (Part II.A.4). A "Detection Monitoring Report" shall be submitted to the CPM, with copies to the Regional Water Board, in accordance with the schedule contained in

the Summary of Self-Monitoring and Reporting Requirements, and shall include the following:

a. A Letter of Transmittal that summarizes the essential points in each report shall accompany each report submittal. The letter of transmittal shall be signed by a principal executive officer at the level of vice-president or above, or by his/her duly authorized representative, if such representative is responsible for the overall operation of the facility from which the discharge originates. The letter of transmittal shall include:

   i. A discussion of any violations noted since the previous report submittal and a description of the actions taken or planned for correcting those violations. If no violations have occurred since the last submittal, that should be so stated;

   ii. If the Discharger has previously submitted a detailed time schedule or plan for correcting any violations, a progress report on the time schedule and status of the corrective actions being taken; and

   iii. A statement by the official, under penalty of perjury, that to the best of the signer's knowledge the report is true, complete, and correct.

b. A Compliance Evaluation Summary shall be included in each Detection Monitoring Report. The compliance evaluation summary shall contain at least:

   i. Velocity and direction of groundwater flow for each monitored groundwater body under and around the surface impoundment based upon the water level elevations taken during the collection of water quality data. A description and graphical presentation (e.g., arrow on a map) shall be submitted;

   ii. Methods used for water level measurement and pre-sampling purging for each monitoring well addressed by the report including:

      1. Method, time, and equipment used for water level measurement;

      2. Type of pump used for purging, placement of the pump in the well, pumping rate, and well recovery rate;

      3. Methods and results of field testing for pH, temperature, electrical conductivity, and turbidity, including;

         a. Equipment calibration methods, and
         b. Method for disposing of purge water

   iii. Methods used for sampling each Monitoring Point and Background Monitoring Point, including:

      1. A description of the type of pump, or other device used, and its placement for sampling;

      2. A detailed description of the sampling procedure: number and description of samples, field blanks, travel blanks, and duplicate samples; types of containers and preservatives used; date and time

of sampling; name and qualifications of individual collecting samples, and other relevant observations;

c. A map or aerial photograph showing the locations of Monitoring Points, and Background Monitoring Points;

d. For each Detection Monitoring Report, provide all relevant laboratory information including results of all analyses, and other information needed to demonstrate compliance with Part I.C.;

e. An evaluation of the effectiveness of the run-off/run-on control facilities;

f. A summary of reportable spills/leaks occurring during the reporting period; include estimated volume of liquids/solids discharged outside designated containment area, a description of management practices to address spills/leaks, and actions taken to prevent reoccurrence.

2. Annual Summary Report – The Discharger shall submit to the CPM, with copies to the Regional Water Board, an “Annual Summary Report” for the period extending from January 1 through December 31. The “Annual Summary Report” is due March 15 of each year, and shall include the following:

   a. A graphical presentation of analytical data for each Monitoring Point and Background Monitoring Point (Title 27, Section 20415(e)(14)). The Discharger shall submit, in graphical format, the laboratory analytical data for all samples taken within at least the previous 5 calendar years. Each such graph shall plot the concentration of one or more constituents over time for a given Monitoring Point and Background Monitoring Point, at a scale appropriate to show trends or variations in water quality. The graphs shall plot each datum, rather than plotting mean values. For any given constituent or parameter, the scale for background plots shall be the same as that used to plot downgradient data. On the basis of any aberrations noted in the plotted data, the CPM, in consultation with the Regional Water Board Executive Officer, may direct the Discharger to carry out a preliminary investigation (Title 27, Section 20080(d)(2)), the results of which will determine whether or not a release is indicated;

   b. A tabular presentation of all monitoring analytical data obtained during the previous two (2) Monitoring and Reporting Periods, submitted on hard copy within the annual report as well as digitally on electronic media in a file format acceptable to the CPM, in consultation with the Regional Water Board Executive Officer (Title 27, Section 20420(h)). The CPM and the Regional Water Board regard the submittal of data in hard copy and on diskette CD-ROM as "...a form necessary for..." statistical analysis in that this facilitates periodic review by the Regional Water Board statistical consultant;

   c. A comprehensive discussion of the compliance record and any corrective actions taken or planned, which may be needed to bring the Discharger into full compliance with WDRs;

d. A written summary of the groundwater analyses, indicating changes made since the previous annual report; and

e. An evaluation of the effectiveness of the run on/run-off control facilities, pursuant to Title 27, Section 20365.

3. Contingency Reporting

a. The Discharger shall report to the CPM and the Regional Water Board any spill of geothermal brine by telephone within 48 hours of discovery. The reportable quantity for geothermal brine is 150 gallons.

After reporting a spill, a written report shall be filed with the CPM, with copies to the Regional Board Executive Officer, within 7 days, containing at a minimum the following:

i. A map showing the location(s) of the discharge/spill;

ii. A description of the nature of the discharge (all pertinent observations and analyses including quantity, duration, etc.); and

iii. Corrective measures underway or proposed.

b. Should the initial statistical comparison (Part III.A.1.) or non-statistical comparison (Part III.A.2.) indicate, for any Constituent of Concern or Monitoring Parameter, that a release is tentatively identified, the Discharger shall immediately notify the CPM and the Regional Water Board verbally as to the Monitoring Point(s) and constituent(s) or parameter(s) involved, shall provide written notification by certified mail within 7 days of such determination (Title 27, Section 20420(j)(1)), and shall conduct a discrete retest in accordance with Part III.A.3. If the retest confirms the existence of a release, the Discharger shall carry out the requirements of Part I.E.3.d. In any case, the Discharger shall inform the CPM and the Regional Water Board of the outcome of the retest as soon as the results are available, following up with written results submitted by certified mail within 7 days of completing the retest.

c. If either the Discharger or the CPM, in consultation with the Regional Water Board, determines that there is significant physical evidence of a release (Title 27, Section 20385(a)(3)), the Discharger shall immediately notify the CPM and the Regional Water Board of this fact by certified mail (or acknowledge the CPM/Regional Water Board's determination) and shall carry out the requirements of Part I.E.3.d. for all potentially-affected monitored media.

d. If the Discharger concludes that a release has been discovered:

i. If this conclusion is not based upon "direct monitoring" of the Constituents of Concern, pursuant to Part II.A.5., then the Discharger shall, within 30 days, sample for all Constituents of Concern at all Monitoring Points and submit them for laboratory analysis. Within 7 days of receiving the laboratory analytical results, the Discharger shall notify the CPM and the Regional Water Board, by certified mail, of the concentration of all Constituents of Concern at each Monitoring Point.

Because this scan is not to be tested against background, only a single datum is required for each Constituent of Concern at each Monitoring Point (Title 27 Section 20420(k)(1));

ii. The Discharger shall, within 90 days of discovering the release (Title 27, Section 20420(k)(5)), submit a Revised Report of Waste Discharge to both the CPM and the Regional Water Board proposing an Evaluation Monitoring Program meeting the requirements of Title 27, Section 20425; and

iii. The Discharger shall, within 180 days of discovering the release (Title 27, Section 20420(k)(6), submit a preliminary engineering feasibility study meeting the requirements of Title 27, Section 20430.

e. Any time the Discharger concludes - or the CPM, in consultation with the Regional Water Board Executive Officer, directs the Discharger to conclude that a liquid phase release from the surface impoundment has proceeded beyond the facility boundary, the Discharger shall so notify all persons who either own or reside upon the land that directly overlies any part of the plume (Affected Persons).

   i. Initial notification to Affected Persons shall be accomplished within 14 days of making this conclusion and shall include a description of the Discharger's current knowledge of the nature and extent of the release; and

   ii. Subsequent to initial notification, the Discharger shall provide updates to all Affected Persons, including any persons newly affected by a change in the boundary of the release, within 14 days of concluding a material change in the nature or extent of the release has occurred.

4. <u>Monitoring of Injection Wells</u>

   a. Sampling and reporting shall be conducted semi-annually.

   b. For brine injection wells, collect one grab sample semi-annually from the main injection header leaving the facility, and analyze for Total Dissolved Solids (mg/L, grab sample).

   c. Provide a summary of integrity tests (if any) conducted pursuant to requirements ordered by the State of California Department of Conservation, Division of Oil, Gas, and Geothermal Resources.

   d. Provide a summary of major repairs (if any).

5. <u>Surface Impoundment - Leakage Detection System (LDS), and Solids Monitoring</u>

   a. Sampling and reporting shall be conducted semi-annually.

   b. Provide volume of solids removed from the holding pond each month for that reporting period, and transported to a waste management facility for disposal. Include name and location of waste management facility.

   c. Conduct quarterly inspections of Leakage Detection System (LDS), and holding pond.

PART II - MONITORING REQUIREMENTS FOR GROUNDWATER

A. Groundwater Sampling And Analysis For Detection Monitoring

1. Groundwater Surface Elevation and Field Parameters – Groundwater sampling and analysis shall be conducted semiannually pursuant to California Environmental Laboratory Accreditation Program (ELAP) rulings, and include an accurate determination of the groundwater surface elevation and field parameters (temperature, electrical conductivity, turbidity) for each Monitoring Point and Background Monitoring Point (Title 27, Section 20415(e)(13)). Groundwater elevation obtained prior to purging the well and sample collection, shall be used to fulfill the semi-annual groundwater flow rate/direction analyses required under Part I.E.1.b.i. Groundwater wells shall be gauged using an electronic sounder capable of measuring depth to groundwater within 100th of an inch. Following gauging, wells shall be purged according to EPA groundwater sampling procedures until:

    a. pH, temperature, and conductivity are stabilized within 10 percent, and

    b. turbidity has been reduced to 10 NTUs or the lowest practical levels achievable.

    The above identified parameters shall be recorded in the field, and submitted in the monitoring report. Sampling equipment shall be decontaminated between wells. Purge water may be discharged to the brine pond; discharge to the ground surface is prohibited.

2. Groundwater Sample Collection - Groundwater samples shall be collected from all monitoring points and background monitoring points after wells recharge to within at least 80 percent of their original static water level. Groundwater samples shall be collected with a paristaltic pump that is decontaminated between sampling events. Samples shall be labeled, logged on chain-of-custody forms, and placed in cold storage pending delivery to a State certified analytical laboratory.

3. Five-Day Sample Procurement Limitation – To satisfy data analysis requirements for a given reporting period, samples collected from all Monitoring Points and Background Monitoring Points shall be taken within a span not exceeding 5 days, and shall be taken in a manner that insures sample independence to the greatest extent feasible (Title 27, Section 20415(e)(12)(B)).

4. Groundwater Monitoring Parameters for Detection Monitoring – Groundwater samples collected from monitoring points and background monitoring points shall be analyzed for the following:

Parameter	Unit	Sample Type
Total Dissolved Solids (TDS)	mg/L	Grab
pH	#	Grab
Specific Conductance	μohms/cm	Grab
Total Petroleum Hydrocarbon (TPH-gas & diesel)	mg/L	Grab
Heavy Metals (As, Ba, Cd, Pb, Zn)	mg/L	Grab
Oil & Grease	mg/L	Grab

All Monitoring Points and Background Monitoring Points assigned to Detection Monitoring shall be sampled semi-annually in October and April of each year in accordance with Part I of this MRP. Monitoring results shall be reported in the semi-annual Detection Monitoring Report.

5. Data Analysis – Statistical or non-statistical analysis shall be carried out as soon as the data is available, in accordance with Part III of this monitoring program.

   Monitoring Points and Background Monitoring Points – At a minimum of 90 days prior to the operation of the facility, the Discharger shall submit a proposed groundwater monitoring program, including background and detection monitoring locations, to the CPM for review and approval in consultation with the Regional Water Board Executive Officer.

6. Initial Background Determination: For the purpose of establishing an initial pool of background data for each Constituent of Concern at each Background Monitoring Point (Title 27, Section 20415(e)(6)):

   a. Whenever a new Constituent of Concern is added to the Water Quality Protection Standard, including any added by the adoption of these WDRs, the Discharger shall collect at least one sample quarterly for at least 1 year from each Background Monitoring Point in each monitored medium and analyze for the newly-added constituent(s); and

   b. Whenever a new Background Monitoring Point is added, including any added by these WDRs, the Discharger shall sample the new monitoring point at least quarterly for at least 1 year, analyzing for all Constituents of Concern and Monitoring Parameters.

7. Semiannual Determination of Groundwater Flow Rate/Direction (Title 27, Section 20415(e)(15): The Discharger shall measure the water level in each well and determine groundwater flow rate and direction in each groundwater body described in Part II.A.1. at least semiannually. This information shall be included in the semi-annual Detection Monitoring Reports required under Part I.E.1.

PART III - STATISTICAL AND NON-STATISTICAL ANALYSES

A. Statistical And Non-Statistical Analysis

The Discharger shall use the most appropriate of the following methods to compare the downgradient concentration of each monitored constituent or parameter with its respective background concentration to determine if there has been a release from the surface impoundment. For any given data set, proceed sequentially down the list of statistical analysis methods listed in Part III.A.1., followed by the non-statistical method in Part III.A.2., using the first method for which the data qualifies. If that analysis tentatively indicates the detection of a release, implement the retest procedure under Part III.A.3.

1. Statistical Methods. The Discharger shall use one of the following statistical methods to analyze Constituents of Concern or Monitoring Parameters that

exhibit concentrations exceeding their respective MDL in at least 10 percent of the background samples taken during that Reporting Period. Each of these statistical methods is more fully described in the Statistical Methods discussion below. Except for pH, which uses a two-tailed approach, the statistical analysis for all constituents and parameters shall be a one-tailed (testing only for statistically significant increase relative to background) approach:

a. <u>One-Way Parametric Analysis of Variance (ANOVA) followed by multiple comparisons</u> <u>(Title 27, Section 20415(e)(8))</u> – This method requires at least four independent samples from each Monitoring Point and Background Monitoring Point during each sampling episode. It shall be used when the background data for the parameter or constituent obtained during a given sampling period, has not more than 15 percent of the data below PQL. Prior to analysis, replace all 'trace' determinations with a value halfway between the PQL and the MDL values reported for that sample run, and replace all "non-detect" determinations with a value equal to half the MDL value reported for that sample run. The ANOVA shall be carried out at the 95 percent confidence level. Following the ANOVA, the data from each downgradient Monitoring Point shall be tested at a 99 percent confidence level against the pooled background data. If these multiple comparisons cause the Null Hypothesis (i.e., that there is no release) to be rejected at any Monitoring Point, the Discharger shall conclude that a release is tentatively indicated from that parameter or constituent; or

b. <u>One-Way Non-Parametric ANOVA (Kruskal-Wallis Test), followed by multiple comparisons</u> – This method requires at least nine independent samples from each Monitoring Point and Background Monitoring Point; therefore, the Discharger shall anticipate the need for taking more than four (4) samples per Monitoring Point, based upon past monitoring results. This method shall be used when the pooled background data for the parameter or constituent, obtained within a given sampling period, has not more than 50 percent of the data below the PQL. The ANOVA shall be carried out at the 95 percent confidence level. Following the ANOVA, the data from each downgradient Monitoring Point shall be tested at a 99 percent confidence level against the pooled background data. If these multiple comparisons cause the Null Hypothesis (i.e., that there is no release) to be rejected at any Monitoring Point, the Discharger shall conclude that a release is tentatively indicated for that parameter or constituent; or

c. <u>Method of Proportions</u> – This method shall be used if the "combined data set" – the data from a given Monitoring Point in combination with the data from the Background Monitoring Points – has between 50 percent and 90 percent of the data below the MDL for the constituent or parameter in question. This method; (1) requires at least nine downgradient data points per Monitoring Point per Reporting Period, (2) requires at least 30 data points in the combined data set, and (3) requires that $n * P > 5$ (where n is the number of data points in the combined data set and P is the proportion of the combined set that exceeds the MDL); therefore, the Discharger shall anticipate the number of samples required, based upon past monitoring results. The test shall be carried out at the 99 percent confidence level. If the analysis results in rejection of the Null Hypothesis (i.e., that there is no release), the Discharger shall conclude that a release is tentatively indicated for that constituent or parameter; or

d. Other Statistical Methods. – These include methods pursuant to Title 27, Section 20415(e)(8)(c-e).

2. Non-Statistical Method. The Discharger shall use the following non-statistical methods for all constituents that are not amenable to statistical analysis by virtue of having been detected in less than 10 percent of applicable background samples. A separate variant of this test is used for the VOC_{water} Composite Monitoring Parameters. Regardless of the test variant used, the method involves a two-step process: (1) from all constituents to which the test variant applies, compile a list of those constituents which equal or exceed their respective MDL in the downgradient sample from a given Monitoring Point, then (2) evaluate whether the listed constituents meet either of the test variant's two possible triggering conditions. For each Monitoring Point, the list described above shall be compiled based on either the data from a single sample taken during the Monitoring Period for that Monitoring Point, or (where several independent samples have been analyzed for that constituent at a given Monitoring Point) from the sample that contains the largest number of detected constituents. Background shall be represented by the data from all samples taken from the appropriate Background Monitoring Points during that Reporting Period (at least one (1) sample from each Background Monitoring Point). The method shall be implemented as follows:

   a. VOC_{water} Composite Monitoring Parameter – For any given Monitoring Point, the VOC_{water} Monitoring Parameter is a composite parameter addressing all detectable VOCs including at least all 47 VOCs listed in Appendix I to 40 CFR 258 and all unidentified peaks. The Discharger shall compile a list of each VOC which (1) exceeds its MDL in the Monitoring Point sample (an unidentified peak is compared to its presumed (MDL), and also (2) exceeds its MDL in less than ten percent of the samples taken during that Reporting Period from that medium's Background Monitoring Points. The Discharger shall conclude that a release is tentatively indicated for the VOC_{water} composite Monitoring Parameter if the list either (1) contains two or more constituents, or (2) contains one constituent that exceeds its PQL;

   b. Constituents of Concern: As part of the COC monitoring required under Part 2.A.5 of this MRP, for each Monitoring Point, the Discharger shall compile a list of COCs that exceed their respective MDL at the Monitoring Point, yet do so in less than ten percent of the background samples taken during that Reporting Period. The Discharger shall conclude that a release is tentatively indicated if the list either (1) contains two or more constituents, or (2) contains one constituent that exceeds its PQL.

3. Discrete Retest – In the event that the Discharger concludes that a release has been tentatively indicated (under Parts III.A.1. or III.A.2.), the Discharger shall, within 30 days of that conclusion, collect two (2) new suites of samples for the

indicated Constituent(s) of Concern or Monitoring Parameter(s) at each indicated Monitoring Point, collecting at least as many samples per suite as were used for the initial test. Re-sampling of Background Monitoring Points is optional. As soon as the retest data is available, the Discharger shall use the same statistical method or non-statistical comparison separately on each suite of retest data. For any indicated Monitoring Parameter or Constituent of Concern at an affected Monitoring Point, if the test results of either (or both) of the retest data suites confirms the original indication, the Discharger shall conclude that a release has been discovered. All retests shall be carried out only for the Monitoring Point(s) for which a release is tentatively indicated, and only for the Constituent of Concern or Monitoring Parameter that triggered the indication there, as follows:

a. If an ANOVA method was used in the initial test, the retest shall involve only a repeat of the multiple comparison procedure, carried out separately on each of the two (2) new suites of samples taken from the indicating Monitoring Point;

b. If the Method of Proportions statistical test was used, the retest shall consist of a full repeat of the statistical test for the indicated constituent or parameter, carried out separately on each of the two (2) new sample suites from the indicating Monitoring Point;

c. If the non-statistical comparison was used:

    i. Because the VOC Composite Monitoring parameters (VOC_{water}) each address, as a single parameter, an entire family of constituents that are likely to be present in any surface impoundment release, the scope of the laboratory analysis for each retest sample shall include all VOCs detectable in that retest sample. Therefore, a confirming retest for either parameter shall have validated the original indication even if the suite of constituents in the confirming retest sample(s) differs from that in the sample that initiated the retest;

    ii. Because all Constituents of Concern that are jointly addressed in the non-statistical testing under Part III.A.2. remain as individual Constituents of Concern, the scope of the laboratory analysis for the non-statistical retest samples shall be narrowed to involve only those constituents detected in the sample which initiated the retest.

SUMMARY OF SELF-MONITORING AND REPORTING REQUIREMENTS

A. Groundwater Monitoring

1. Groundwater monitoring wells shall be sampled/analyzed semi-annually for the following parameters/constituents:

Parameters & Constituent	Unit	Type of Sample	Reporting Frequency
a. Total Dissolved Solids (TDS)	mg/L	grab	semiannual
b. pH	#	field measurement	semiannual
c. Specific Conductance	μohms/cm	field measurement	semiannual
d. Total Petroleum Hydrocarbons (TPH-Gas & Diesel)	mg/L	grab	semiannual
e. Heavy Metals (As, Ba, Cd, Pb, Zn) mg/L		grab	semiannual
f. Oil & Grease	mg/L	grab	semiannual

2. The collection, preservation, and holding times of all samples shall be in accordance with the U.S. Environmental Protection Agency approved procedures. All analyses shall be conducted by a laboratory certified by the California Department of Public Health to perform the required analyses.

B. Surface Impoundment: Leakage Detection System (Lds), And Solids Monitoring

	Unit	Sampling Frequency	Observation or Reporting Frequency
1. Estimated volume of solid/liquid in holding pond	ft^3	Monthly	semiannual
2. Measurement of freeboard	ft	Monthly	semiannual
3. Volume of solids removed and shipped to off site waste management facility	tons	Monthly	semiannual

C. Injection Well Monitoring

	Unit	Sampling Frequency	Observation or Reporting Frequency
1. Volume of fluid injected into each well		Monthly	semiannual
2. Grab sample from main injection header analyzed for the following:			
a. Total Dissolved Solids (TDS)	mg/L	semiannual	semiannual
b. pH	#	semiannual	semiannual

D. Monitoring Reports And Observation Schedule

"Reporting Period" means the duration separating the submittal of a given type of monitoring report from the time the next iteration of that report is scheduled for submittal. An annual report, which is a summary of all the monitoring during the previous year, shall also be submitted to the CPM, with copies to the Regional Water Board. The submittal dates for Detection Monitoring Reports and the Annual Summary Report are as follows:

1. Detection Monitoring Reports

   a. 1st Semiannual Report (January 1 through June 30) – report due by August 1
   b. 2nd Semiannual Report (July 1 through December 31) – report due by March 1

2. Annual Summary Report

   January 1 through December 31 – report due March 15 of the following year.

3. The Detection Monitoring Reports and the Annual Summary Report shall include the following:

   a. The Discharger shall arrange the data in tabular form so that the specified information is readily discernible. The data shall be summarized in such a manner as to clearly illustrate whether the facility is operating in compliance with WDRs.

   b. Records of monitoring information shall include:

      i. The date, exact place, and time of sampling or measurement;
      ii. The individual performing the sampling or measurement;
      iii. The date the analysis was performed;
      iv. The initials of the individual performing the analysis;
      v. The analytical technique or method used; and
      vi. The result of the analysis.

   c. Each report shall contain the following statement:

      "I declare under the penalty of law that I have personally examined and am familiar with the information submitted in this document, and that based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of a fine and imprisonment for knowing violations."

   d. A duly authorized representative of the Discharger may sign the documents if:

      i. Authorization is made in writing by the person described in Part I.E.1.a;

      ii. Authorization specifies an individual or person having responsibility for the overall operation of the regulated disposal system; and

      iii. Written authorization is submitted to the CPM with copies to the Regional Water Board Executive Officer.

      iv. Monitoring reports shall be certified under penalty of perjury to be true and correct, and shall contain the required information at the frequency designated in this monitoring report.

FACTS FOR WASTE DISCHARGE—Black Rock 1, 2 and 3 Geothermal Power Project—Wellfield Mud Sumps/Containment Basins

1. CE Obsidian Energy, LLC (the Discharger) proposes to drill 22 geothermal wells on land owned by Imperial Magma, LLC, an affiliate of CE Obsidian. The wells will support three 53-megawatt geothermal power plants, identified as Black Rock 1, 2 and 3 (the Black Rock 1, 2, and 3 Geothermal Power Project, or Project). The wells are located within the Salton Sea Known Geothermal Resource area (KGRA), 6 miles northwest of the community of Calipatria and approximately 7.5 miles southwest of the community of Niland. The address for both CE Obsidian Energy, LLC and Imperial Magma, LLC is 1111 South 103rd Street, Omaha, NE 68124.

2. These requirements for waste discharge (Waste Discharge Requirements or WDRs) regulate the handling and disposal of drilling wastes generated by CE Obsidian Energy, LLC, during geothermal well drilling, testing, and maintenance in the vicinity of the Salton Sea KGRA. The boundaries of the Black Rock 1, 2, and 3 Geothermal Power Project are shown on Attachment A.

3. The Discharger reports that the exploration program will initially consist of 22 geothermal wells and six mud sumps. Locations of the proposed wells are shown on Attachment B. All geothermal well drilling performed by Obsidian Energy, LLC, within Salton Sea KGRA will be regulated under these WDRs.

4. CE Obsidian Energy, LLC, submitted a Report of Waste Discharge, dated July 30, 2009, for the Black Rock 1, 2 and 3 Geothermal Power Project.

5. The project will consist of well pad construction, geothermal exploration drilling, and waste handling and disposal. A typical well pad configuration is shown on Attachment C.

6. The wells will be drilled for production and injection of geothermal brine associated with the proposed geothermal power plants.

7. Definition of terms used:

   a. **Facility** – The entire parcel of property where CE OBSIDIAN ENERGY, LLC, or related geothermal industrial and drilling activities are conducted.

   b. **Waste Management Units (WMUs)** – Mud sumps/containment basins are WMUs.

   c. **Discharger** – The term “discharger” means any person who discharges waste that could affect the quality of the waters of the State, and includes any person who owns the land, waste management unit, or who is responsible for the operation of a waste management unit.

GEOTHERMAL DRILLING WASTES

8. The following wastes are generated during construction, operation, and maintenance of geothermal exploration wells:

   a. **Geothermal brine** - The Discharger reports geothermal brines in the area of the Salton Sea KGRA are hot saline solutions that contain Total Dissolved Solids (TDS) up to 235,000 mg/L. Based on nearby geothermal projects, major constituents of the brine are predicted to be as follows:

Anticipated Chemical Composition of Produced Fluids

Constituent	**Concentration (ppm)**
Beryllium	ND[1]
Ammonium	369
Sodium	50,169
Magnesium	39
Aluminum	ND[1,2]
Potassium	12,784
Calcium	24,584
Chromium	ND[1]
Manganese	983
Iron	1,180
Nickel	ND[1]
Copper	4
Zinc	320
Rubidium	69
Strontium	443
Silver	ND[1]
Cadmium	1
Antimony	1
Cesium	12
Barium	177
Mercury	ND[1]
Lead	79
Bicarbonate	69
Nitrate	ND[1]
Fluorine	20
Sulfur Monoxide	98
Chlorine	137,670
Arsenate	20
Selenate	ND[1]
Bromine	89
Iodine	10

Anticipated Chemical Composition of Produced Fluids

Constituent	Concentration (ppm)
Silicon Dioxide	433
Carbon Dioxide	3,309
Boric Acid	1,800
Hydrogen Sulfide	15
Ammonia	59
Methane	10
Total Dissolved Solids	235,000

ND = Not Detected

[1] Several of the constituents listed as ND have been detected in brine from this resource, although the quantities may be present at trace levels.

[2] Aluminum is known to be present in measurable quantities in brine from this resource.

Source: AECOM, 2009

b. **Drilling muds with additives –** Drilling mud is inert mineral clay such as bentonite clay. Drilling mud additives may include sodium bicarbonate, soda ash, drilling soap, organic polymers, wood fibers, graphite, cottonseed hulls, walnut shells and cement. Drilling mud additives do not render the drilling mud hazardous when used according to manufacturer's specifications.

c. **Drill cuttings (rock)** – small rock fragments pulverized during drilling and forced to the surface by drilling mud, aerated mud, and/or air.

DRILLING WASTE CONTAINMENT (WMUS)

9. The Discharger proposes to contain geothermal brine generated during drilling, testing, or maintenance by discharging into large portable tanks. Geothermal brine will be returned to the geothermal resource via injection, or discharged offsite into permanent Class II surface impoundments constructed pursuant to Title 27 of the California Code of Regulations (hereafter, Title 27).

10. Drilling muds and rock cuttings generated during well drilling, testing, or maintenance will be discharged to mud sumps/containment basins designed to temporarily (less than 1 year) contain the material while drying. The six mud sumps are temporary containment ponds that will be decommissioned and removed subsequent to completion of the well construction activities. The mud sumps will be lined impoundments employing polyester fabric/fluoropolymer-coated geosynthetic liner rated for a minimum temperature of 200°F. The liner will be covered with approximately 12 inches of compacted clay to hydraulically isolate the mud sump from the underlying groundwater table. Nominal sump dimensions will be 726 feet

long by 11 feet wide by 5 feet deep, with 2 feet of freeboard. Attachment C shows the design of the mud sumps.

DRILLING WASTE DISPOSAL

11. Liquid wastes produced from drilling, testing, and maintenance of geothermal wells, will be contained in portable tanks and returned to the geothermal resource, or discharged off-site to Class II surface impoundments built to construction standards prescribed in Title 27.

12. Solids discharged to mud sumps/containment basins will be removed offsite or closed in place, provided representative samples of solids are shown not to be hazardous or designated waste.

SURFACE WATER

13. Surface water in the area of the Salton Sea KGRA consists of canals and agricultural drains operated and maintained by Imperial Irrigation District.

14. The Facility is located in a 100-year flood plain. However, Imperial County's Land Use Ordinance Section 90106.00, et seq., and Section 91604.00, et seq., require a Development Permit for construction below -220 feet msl along any portion of the Salton Sea. For the Project, this will require the 160-acre project site to be enclosed by a perimeter berm designed with 2:1 (horizontal to vertical) sloping sides with a top elevation of -220 feet msl. This berm will meet the County's encroachment permit requirements because it will be of adequate height to provide flood protection to an elevation of at least -220 feet msl in accordance with the County's Land Use Ordinances and will reduce the potential for offsite drainage.

REGIONAL GROUNDWATER

15. The regional groundwater flow direction within the Imperial Valley is toward the Salton Sea, a closed basin with a surface elevation of approximately 225 feet below sea level. The Salton Sea KGRA is located approximately 120 feet below sea level; groundwater flows in a general northwest direction.

LOCAL GROUNDWATER

16. The Discharger reports that shallow groundwater in the area of the Salton Sea KGRA occurs approximately 3-6 feet below ground surface and flows generally to the northwest. Groundwater from wells within the immediate vicinity of the project contains 10,000 to 20,000 mg/L TDS.

17. Groundwater depth, gradient, and quality in the area of the Salton Sea KGRA may be influenced, at times, by irrigation of adjacent agricultural fields, and by recharge from nearby canals.

REGIONAL GEOLOGY

18. The Black Rock 1, 2 and 3 Geothermal Power Project is located within the Salton Trough area of southeast California. The Salton Trough is a tectonically active zone containing numerous faults associated with the San Andreas Fault Zone. The site is

located on the north central portion of the trough, and is underlain by deltaic and lacustrine formations associated with the Colorado River delta. Bedrock in this part of the Salton Trough is approximately three miles below ground surface.

CLIMATE

19. Climate in the region is arid. Climatological data obtained from 1951 to 1980 indicate an average seasonal precipitation of 2.5 inches, and an average annual pan evaporation rate greater than 100 inches.

20. The wind direction follows two general patterns:

    a. Seasonally from fall through spring, prevailing winds are from the west and northwest. Most of these winds originate in the Los Angeles basin, and tend to decrease the humidity in the Salton Sea area.

    b. Summer weather patterns are dominated by intense heat induced low-pressure areas that form over the interior desert, drawing air south of the Facility, which typically increases the humidity in the Salton Sea area.

BASIN PLAN

21. The Water Quality Control Plan (Basin Plan) for the Colorado River Basin Region, designates the beneficial uses of ground and surface waters in this region.

22. The beneficial uses of groundwater in the Imperial Hydrological Unit are:

    a. Municipal Supply (MUN)*
    b. Industrial Supply (IND)

    *With respect to the MUN designation, the Basin Plan states: "At such time as the need arises to know whether a particular aquifer which has no known existing MUN use should be considered as a source of drinking water, the Regional Board will make such a determination based on the criteria listed in the 'Sources of Drinking Water Policy' in Chapter 2 of the Basin Plan. An indication of MUN for a particular hydrologic unit indicates only that at least one of the aquifers in that unit currently supports a MUN beneficial use. For example, the actual MUN usage of the Imperial Hydrologic Unit is limited only to a small portion of that ground water unit."

23. The beneficial uses of surface waters in the area of the Salton Sea Geothermal Exploration Project are as follows:

    a. Imperial Valley Drains

        i. Freshwater Replenishment (FRSH)
        ii. Water Contact Recreation (RECI)
        iii. Non-contact Water Recreation (RECII)
        iv. Warm Freshwater Habitat (WARM)
        v. Wildlife Habitat (WILD)
        vi. Preservation of Rare, Threatened, or Endangered Species (RARE)

b. All American Canal System

vii. Municipal (MUN)
viii. Agricultural (AGR)
ix. Aquaculture Supply (AQUA)
x. Freshwater Replenishment (FRSH)
xi. Industrial (IND)
xii. Groundwater Recharge (GWR)
xiii. Water Contact Recreation (RECI)
xiv. Non-Contact Water Recreation (RECII)
xv. Warm Freshwater Habitat (WARM)
xvi. Wildlife Habitat (WILD)
xvii. Hydropower Generation (POW)
xviii. Preservation of Rare, Threatened, or Endangered Species (RARE)

STORM WATER

24. Federal regulations for storm water discharges were promulgated by the United States Environmental Protection Agency (USEPA) on November 16, 1990 (40 CFR Parts 122, 123, and 124). These regulations required discharges of storm water to surface waters associated with construction activity, including clearing, grading, and excavation activities (except operations that result in disturbance of less than 5 acres of total land area and which are not part of a larger common plan of development or sale) to obtain a National Pollutant Discharge Elimination System (NPDES) permit and to implement Best Conventional Pollutant Control Technology and Best Available Technology Economically Achievable to reduce or eliminate storm water pollution. (40 CFR 122.26(b)(14)(x).) On December 8, 1999, federal regulations promulgated by USEPA (40 CFR Parts 9, 122, 123, and 124) expanded the NPDES storm water program to include, in pertinent part, storm water discharges from construction sites that disturb a land area equal to or greater than one acre and less than five acres, or is part of a larger common plan of development or sale (small construction activity). (40 CFR 122.26(b)(15).)

25. To comply with these federal requirements, the State Water Resources Control Board (State Water Board) adopted in 1999 Water Quality Order No. 99-08-DWQ (NPDES) General Permit No. CAS000002, “Waste Discharge Requirements (WDRs) for Discharges of Storm Water Runoff Associated with Construction Activity” (General Permit). The General Permit specifies WDRs for discharges of storm water associated with construction activity that results in a land disturbance of one acre or more or is part of a larger common plan of development or sale. The General Permit specifies certain construction activities that are exempted from coverage. Because these exemptions do not apply to the Discharger’s proposed construction activity and because this activity will result in a land disturbance of more than 1 acre, the Discharger is subject to the General Permit requirements.

26. On September 2, 2009, the State Water Board adopted a new construction general permit (CGP) to replace Order No. 99-08-DWQ. The new CGP, Order No. 2009-0009-DWQ (NPDES No. CAS000002), will become effective on July 1, 2010. Until then, SWRCB Order No. 99-08-DWQ remains in effect. On and after July 1, 2010, however, Order No. 99-08-DWQ is superseded, except for enforcement purposes, by

Order No. 2009-0009-DWQ. The website link to this new CGP is as follows: <http://www.waterboards.ca.gov/board_decisions/adopted_orders/water_quality/2009/wqo/wqo2009_0009_dwq.pdf>.

27. If the Discharger's construction activity continues after July 1, 2010, when the new CGP takes effect, the Discharger is required, pursuant to the new CGP, to obtain coverage under that new permit. (CGP, Section II.B.4.b, p. 68 of 285.) To obtain coverage, the Discharger must electronically file Permit Registration Documents (PRDs), which includes a Notice of Intent (NOI), Storm Water Pollution Prevention Plan (SWPPP), and other compliance-related documents required by the CGP and mail the appropriate permit fee to the State Water Board.

ANTI-DEGRADATION POLICY

28. State Water Resources Control Board (State Water Board) Resolution No. 68-16 ("Policy with Respect to Maintaining High Quality Waters of the State"; hereafter Resolution No. 68-16) requires a Regional Board in regulating the discharge of waste to maintain high quality waters of the state (i.e., background water quality) until it is demonstrated that any change in quality will be consistent with maximum benefit to the people of the State, will not unreasonably affect beneficial uses, and will not result in water quality less than that described in plans and policies (e.g. violation of any water quality objective). The discharge is required to meet waste discharge requirements that result in the best practicable treatment or control of the discharge necessary to assure pollution or nuisance will not occur, and the highest water quality consistent with maximum benefit to the people will be maintained.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

29. The environmental review program of the California Energy Commission (CEC), which has exclusive jurisdiction over the permitting of this Facility, has been certified by the Secretary for Natural Resources as meeting the requirements of Public Resources Code Section 21080.5 to exempt the CEC's power plant site certification program from the CEQA requirements to prepare EIRs, negative declaration, and initial studies. (See CCR, Title 14, § 15251(k).) Accordingly, the CEC will prepare the appropriate substitute CEQA environmental documents pursuant to its responsibilities as Lead Agency for this site certification program.

APPENDIX D, ATTACHMENT A

Black Rock 1, 2 and 3 Geothermal Power Project
Mud Sump\Containment Basins
Imperial County

REQUIREMENTS FOR WASTE DISCHARGE—Black Rock 1, 2 and 3 Geothermal Power Project—Wellfield Mud Sumps/Containment Basins

A. Discharge Specifications

1. The treatment or disposal of wastes at this facility shall not cause pollution or nuisance as defined in Section 13050 of Division 7 of the California Water Code.

2. Waste material at this facility must be contained at all times.

3. Containment of waste shall be limited to the areas designated for such activity. Any revision or modification of the waste containment area, or change in operation that alters the nature and constituents of the waste produced, must be submitted in writing to the Energy Commission's Compliance Project Manager (CPM), with copies to the Regional Board Executive Officer, for review. The CPM, in consultation with the Regional Board Executive Officer, must approve the proposed change before the change in operation or modification of the designated area is implemented.

4. Prior to drilling a new well at the facility other than those shown on Attachment B, the Discharger shall notify, in writing, both the CPM and the Regional Board Executive Officer of the proposed change.

5. Any substantial increase or change in volume of material to be discharged under these Waste Discharge Requirements (WDRs) must be submitted in writing to the CPM, with copies to the Regional Board Executive Officer, for review. The CPM, in consultation with the Regional Board Executive Officer, must approve of the proposed change before the change in discharge volume is implemented.

6. Liquid or solid geothermal waste discharged to tanks shall be contained at all times.

7. A minimum freeboard of two-feet shall be maintained in mud sumps/containment basins at all times.

8. Following well completion, residual solids and semisolids contained in tanks shall be tested for constituents listed in the Monitoring and Reporting Program for these WDRS, Appendix F, and for additional constituents requested by the CPM, in consultation with the Regional Board Executive Officer (if any). Disposal of this material shall be in accordance with applicable laws and regulations based on analytical results of sampling and analysis.

9. Prior to removing solid material discharged to mud sumps/containment basins, the material shall be tested for constituents listed in the Monitoring and Reporting Program (Appendix F), and for additional constituents requested by the CPM, in

consultation with the Regional Board Executive Officer (if any). Disposal of this material shall be in accordance with applicable laws and regulations based on analytical results of sampling and analysis.

10. Public contact with material containing geothermal wastes shall be precluded through fences, signs, or other appropriate alternatives.

11. Mud sumps/containment basins shall be constructed, operated and maintained to ensure their effectiveness, in particular:

    a. Erosion control measures shall be implemented;

    b. Liners in mud sumps/containment basins shall be maintained to ensure proper function, and

    c. Solid material shall be removed from mud sumps/containment basins in a manner that minimizes the likelihood of damage to the liner.

12. Upon ceasing operation at the facility, all waste, natural geologic material contaminated by waste, and surplus or unprocessed material shall be removed from the site and disposed of in accordance with applicable laws and regulations.

13. Surface drainage from tributary areas or subsurface sources shall not contact or percolate through waste discharged at this site.

14. The Discharger shall use the constituents listed in the Monitoring and Reporting Program (Appendix F) and revisions thereto, as “Monitoring Parameters.”

15. The Discharger shall implement the Monitoring and Reporting Program (Appendix F) and revisions thereto, to detect at the earliest opportunity, any unauthorized discharge of waste constituents from the facility, or any impairment of beneficial uses associated with (caused by) discharges of waste to the mud sumps/containment basins.

16. Water used for the process and site maintenance, shall be limited to the amount necessary for the process, dust control, and for cleanup and maintenance.

17. The Discharger shall not cause or permit the release of pollutants, or waste constituents in a manner that could cause or contribute to a condition of contamination, nuisance, or pollution.

B. Prohibitions

1. Geothermal wells shall be drilled to minimize mixing of drilling mud and cuttings with geothermal brine. Only a small amount of brine may commingle with drilling mud, primarily brines in that part of the formation displaced by the drill bit. Geothermal brine will not be discharged into mud sumps/containment basins. Standing fluid observed in mud sumps/containment basins (if any) will be removed immediately, stored in portable tanks, and returned to the geothermal resource, or discharged offsite into Class II surface impoundments constructed pursuant to Title 27 of the California Code of Regulations.

2. The discharge of solid geothermal waste to mud sumps/containment basins as a final means of disposal is prohibited without authorization by the CPM, in consultation with the Regional Board Executive Officer.

3. The Discharger shall not cause degradation of any groundwater aquifer or supply water.

4. The discharge of waste to land not owned or controlled by the Discharger is prohibited.

5. Use of geothermal brine or drilling muds for dust control on access roads or well pads is prohibited.

6. The discharge of hazardous or designated wastes to areas other than a waste management unit authorized to receive such waste is prohibited.

7. Permanent (longer than 1 year) disposal or storage of drilling waste to mud sumps/containment basins is prohibited, unless authorized by the CPM, in consultation with the Regional Board Executive Officer.

8. All mud sumps/containment basins must be lined. Drilling waste shall not penetrate the lining during the containment period.

9. Direct or indirect discharge of geothermal drilling wastes in mud sumps/containment basins or tanks, to surface water or surface drainage courses (including canals, drains, or subsurface drainage systems) is prohibited except as allowed under an appropriate NPDES permit.

10. The Discharger shall neither cause nor contribute to the contamination or pollution of groundwater via the release of waste constituents.

C. Provisions

1. The Discharger shall comply with the Monitoring and Reporting Program (Appendix F) and future revisions thereto, as specified by the CPM, in consultation with the Regional Board Executive Officer.

2. Unless otherwise approved by the CPM, in consultation with the Regional Board Executive Officer, all analyses shall be conducted at a laboratory certified for such analyses by the California Department of Public Health. All analyses shall be conducted in accordance with the latest edition of “Guidelines Establishing Test Procedures for Analysis of Pollutants”, promulgated by the U.S. Environmental Protection Agency.

3. Prior to any change in ownership of this operation, the Discharger shall transmit a copy of these WDRs to the succeeding owner/operator, and forward a copy of the transmittal letter to both the CPM and the Regional Board.

4. Prior to any modification that would result in a material change in the quality or quantity of discharge, or material change in the location of the discharge, the Discharger shall report all pertinent information in writing to the CPM with copies

to the Regional Board Executive Officer, and obtain revised requirements before implementing the modification.

5. Synthetic liner placement and welding must be certified by the installer to verify factory requirements were satisfied, and no damage occurred during placement. Certification must be submitted, in writing, to the CPM, with copies to the Regional Board, prior to use of the temporary mud sump/containment basin, or equivalent system approved by the CPM, in consultation with the Regional Board's Executive Officer.

6. The Discharger shall ensure that all site-operating personnel are familiar with the content of these WDRs, and shall maintain a copy of these WDRs at the site.

7. These WDRs do not authorize violation of any federal, state, or local laws or regulations.

8. The Discharger shall allow the CPM, the Regional Board, or an authorized representative, upon presentation of credentials and other documents, as may be required by law, to:

   a. Enter upon the premises regulated by these WDRs, or the place where records must be kept under the conditions of these WDRs;

   b. Have access to and copy, at reasonable times, any records that shall be kept under the condition of these WDRs;

   c. Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under these WDRs; and

   d. Sample or monitor at reasonable times, for the purpose of assuring compliance with these WDRs or as otherwise authorized by the California Water Code, any substances or parameters at this location.

9. The Discharger shall at all times properly operate and maintain all facilities and systems of treatment and control, and related appurtenances, that are installed or used by the Discharger to achieve compliance with these WDRs. Proper operation and maintenance also includes adequate laboratory controls, and appropriate quality assurance procedures.

10. The Discharger shall comply with the following:

   a. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity;

   b. The Discharger shall retain records of all monitoring information, copies of all reports required by these WDRs, and records of all data used to complete the application of these WDRs, for a period of at least 5 years from the date of the sample, measurement, report or application. This period may be extended by the CPM, in consultation with the Regional Board Executive Officer, at any time;

   c. Records of monitoring information shall include:

i. The date, exact place(s), and time of sampling or measurement(s);
ii. The individual(s) who performed the sampling or measurement(s);
iii. The date(s) analyses were performed;
iv. The individual(s) responsible for reviewing the analyses;
v. The results of such analyses; and

d. Monitoring must be conducted according to test procedures described in the Monitoring and Reporting Program (Appendix F), unless other test procedures have been approved by the CPM, in consultation with the Regional Board Executive Officer.

11. The Discharger is the responsible party for these WDRs, and the Monitoring and Reporting Program (Appendix F) for the Facility. CE Obsidian Energy, LLC., shall comply with all conditions of these WDRs. Violations may result in enforcement action, including Regional Board Orders or court orders that require corrective action or impose civil monetary liability, or modification or revocation of these WDRs by the CPM, in consultation with the Regional Board.

12. The Discharger shall furnish, under penalty of perjury, technical monitoring program reports submitted pursuant to the specifications provided by the CPM, in consultation with the Regional Board Executive Officer. Specifications are subject to periodic revision as may be warranted.

13. The monitoring reports shall be certified to be true and correct, and signed, under penalty of perjury, by an authorized official of the company.

14. These WDRs do not convey property rights of any sort, or any exclusive privileges; nor do they authorize injury to private property, invasion of personal rights, or infringement of federal, state, or local laws and regulations.

15. These WDRs may be modified, rescinded, or reissued for cause. The filing of a request by the Discharger to modify, or rescind or reissue these WDRs does not stay any WDR condition. Likewise, notification of planned changes or anticipated noncompliance does not stay any WDR condition. Causes for modification include: changes in land application plans, sludge use, or disposal practices; or promulgation of new regulations by the State or Regional Boards, including revisions to the Basin Plan.

16. Within 30 days of the adoption of these WDRs, the Discharger shall submit to the CPM, with copies to the Regional Board, a list of surface landowners (including responsible contact's name, address and phone number) for all land containing existing or proposed facilities and/or appurtenances related to the operation of this geothermal exploration project. This list will be used to contact responsible parties if corrective action measures become necessary due to a release of pollutants to the environment.

MONITORING AND REPORTING PROGRAM FOR BLACK ROCK 1, 2 and 3 GEOTHERMAL POWER PROJECT—Wellfield Mud Sumps/Containment Basins

A. General Monitoring

1. The reporting responsibilities of the discharger are specified in the California Water Code. This self-monitoring program is established in accordance with the Waste Discharge Requirements set forth in Appendix D. The principal purpose of this Monitoring Program is:
   a. To document compliance with the Waste Discharge Requirements.
   b. To facilitate self-policing by the Discharger (CE Obsidian Energy, LLC) in the prevention and abatement of pollution arising from the discharge.
   c. To conduct soil analyses.

2. All sampling methods not specified below or in the Monitoring and Reporting Program shall be conducted in accordance with United States Environmental Protection Agency approved procedures. Analyses shall be conducted by a laboratory certified by the California Department of Public Health to perform the required analyses, unless a field analysis is specified.

3. The Energy Commission's Compliance Project Manager (CPM), in consultation with the Regional Board Executive Officer, may alter the monitoring parameters and/or the monitoring frequency during the course of this monitoring program.

4. The Discharger shall arrange the data in tabular form so that the specified information is readily discernible. The data shall be summarized in such a manner as to clearly illustrate whether the facility is operating in compliance with Waste Discharge Requirements.

5. Each report shall contain this statement; "I declare under the penalty of law that I have personally examined and am familiar with the information submitted in this document, and that based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of a fine and imprisonment for knowing violations."

6. A duly authorized representative of CE OBSIDIAN ENERGY, LLC, may sign the documents if:
   a. The authorization is made in writing by the Discharger;
   b. The authorization specifies an individual or person responsible for the overall operation of the regulated disposal system; and

c. The written authorization is submitted to the CPM, with copies to the Regional Board Executive Officer.

B. Monitoring Reports And Observation Schedule

"Reporting Period" means the duration separating the submittal of a given type of monitoring report from the time the next iteration of that report is scheduled for submittal. The reporting period is quarterly. An annual report, which is a summary of all monitoring collected during the previous year, shall also be submitted to both the CPM and the Region Board. The submittal dates for each reporting period shall be as follows:

1. Quarterly Monitoring Reports

   a. 1st Quarter (January 1 through March 31)………. report due April 15
   b. 2nd Quarter (April 1 through June 30)……………. report due July 15
   c. 3rd Quarter (July 1 through September 30)……… report due October 15
   d. 4th Quarter (October 1 through December 31)…. report due January 15

2. Annual Summary Report

   January 1 through December 31 – report due March 15 of the following year.

C. Reports To Be Filed With The Board

Written Quarterly Reports shall be submitted four times per year, in addition to an Annual Summary Report. The reports shall be submitted by the above-specified dates. The following information/data shall be included in each report:

1. Quarterly Report Requirements

   a. General Information

      1. Letter of Transmittal – A letter transmitting the essential points shall accompany each report. Such a letter shall include a discussion of any violation found since the last such report was submitted, and shall describe actions taken or planned for correcting those violations. If the discharger has previously submitted a detailed time schedule for correcting violations, a reference to the correspondence transmitting the schedule will be satisfactory. If no violations have occurred since the last submittal, this shall be stated in the letter of transmittal. Monitoring reports and the letter transmitting the monitoring reports shall be signed by a principal executive officer, at the level of vice-president or above, or by his/her duly authorized representative, if such representative is responsible for the overall operation of the facility from which the discharge originates. The letter shall contain a statement by the official, under penalty of perjury, that to the best of the signer's knowledge the report is true, complete, and correct.

      2. For all occurrences of spills/leaks of reportable quantities during the reporting period, a summary of each incident detailing the essential points of the cause of the spill/leak shall be transmitted in the Quarterly report. The summary shall include estimated volumes of liquid or solids that have spilled outside containment, and a description of the management

practices addressing each spill or leak occurring during the reporting period. The reportable quantity for liquid is 150 gallons, or more, of geothermal brine, or cooling tower condensate.

b. Monitoring of Mud Sumps/Containment Basins

1. Volume of solids discharged into each mud sump/containment basin during reporting period.

2. Volume of waste from all mud sumps/containment basins shipped to an offsite waste management facility during reporting period. Name and location of waste management facility.

3. Description of sampling equipment and methods implemented during monitoring.

4. For each mud sump/containment basin receiving solids during reporting period, collect one discrete sample of discharged solids, and analyze for:

Constituent	Unit	Sample Type
Heavy Metals (Title 22)	mg/kg	Grab
Total Petroleum Hydrocarbons (TPH)	mg/kg	Grab

5. Description of general conditions of mud sumps/containment basins including any observation of erosion or plant growth.

6. Description of any construction or maintenance done to mud sumps/containment basins.

2. Annual Summary Report

The discharger shall submit an annual report by March 15th of the following year to the CPM, with copies to the Regional Board, covering the previous monitoring year. The reporting period ends December 31st of each year. This report shall contain:

a. All monitoring data, presented in tabular form, obtained during the previous four Quarters.

b. A comprehensive discussion of compliance, and the result of any corrective actions taken or planned, which may be needed to bring the discharge into full compliance with Waste Discharge Requirements.

c. A written summary of solid waste analyses.

3. Contingency Reporting

b. The discharger shall report to the CPM and the Regional Water Board by telephone any spill of reportable quantity within 48 hours after it is discovered. The reportable quantity for geothermal brine and cooling tower condensate at this facility is 150 gallons. Any other type of spill, regardless of type or size, is to be reported within 48 hours.

After reporting a spill, a written report shall be filed with the CPM, with copies to the Regional Board, within 7 days containing at least the following information:

1. A map showing the location(s) of the discharge.
2. A description of the nature of the discharge (all pertinent observations and analyses including quantity, duration, etc.).

c. If either the discharger or the CPM, in consultation with the Regional Board, determines that there is significant physical evidence of a release, the discharger shall immediately notify the CPM and the Regional Board (or acknowledge the CPM/Regional Board's determination) and shall carry out the requirements of 3.c. below.

d. If the discharger concludes that a release has been discovered:

1. The discharger shall, within 90 days of discovering the release, submit a Revised Report of Waste Discharge to both the CPM and the Regional Board proposing an Evaluation Monitoring Program.
2. The discharger shall, within 180 days of discovering the release, submit a Preliminary Engineering Feasibility Study to both the CPM and the Regional Board detailing corrective action measures.

e. Any time the discharger concludes (or the CPM, in consultation with the Regional Board Executive Officer, concludes) that a solid and/or liquid release has proceeded beyond the facility boundary, the discharger shall so notify all affected persons who either own or reside upon the land impacted.

1. Initial notification to affected persons shall be accomplished within 7 days of making this conclusion and shall include a description of the discharger's current knowledge of the lateral and vertical extent of the release.
2. Subsequent to initial notification, the discharger shall provide updates to all affected persons within 7 days of concluding there has been any material change in the lateral or vertical extent of the release.

D. Records To Be Maintained

Written reports shall be maintained by the discharger or laboratory, and shall be retained for a minimum of 5 years. The period of retention shall be extended during the course of any unresolved litigation regarding this discharge or when requested by the CPM, in consultation with the Regional Board. Such records shall show the following for each sample.

1. Identity of sample and of the monitoring point from which it was taken, along with the identity of the individual who obtained the sample.
2. Date and time of sampling.
3. Date and time that analyses were started and completed, and the name of the personnel performing each analysis.

4. Complete procedure used, including method of preserving the sample, and the identity and volumes of reagent used.
5. Result of analysis (including calculations), and the Maximum Detection Limit (MDL) for each analysis.

SUMMARY OF MONITORING AND REPORTING REQUIREMENTS

1. The Discharger shall arrange data in tabular form so that the specified information is readily discernible. The data shall be summarized in such a manner as to clearly illustrate whether the facility is operating in compliance with Waste Discharge Requirements.

2. Each report shall contain the following statement:

   "I declare under the penalty of law that I have personally examined and am familiar with the information submitted in this document, and that based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of a fine and imprisonment for knowing violations."

3. A duly authorized representative of the Discharger may sign the documents if:

   a. The authorization is made in writing by the person described above;

   b. The authorization specified an individual or person having responsibility for the overall operation of the regulated disposal system; and

   c. The written authorization is submitted to both the CPM and the Regional Board Executive Officer.

4. Quarterly Monitoring Reports

	Unit	Sampling Frequency	Reporting Frequency
a. General Information (C.1.a)			
1. Letter of Transmittal	----	-------------	Quarterly
2. Summary of spills	----	-------------	Quarterly
b. Monitoring of Mud Sumps/Containment Basins (C.1.b)			
1. Estimate volume of solids discharged to each mud sump/containment basin during quarter	tons	Quarterly	Quarterly
2. Volume of material removed and shipped to waste facility during quarter	tons	Quarterly	Quarterly
c. Sample solids discharged to basins receiving wastes during reporting period (C.1.b.4)			
1. Analyze for Heavy Metals (Title 22 metals)	mg/kg	Quarterly	Quarterly
2. Analyze for Total Petroleum Hydrocarbons (TPH)	mg/kg	Quarterly	Quarterly

5. Annual Summary Reports (C.2) shall be submitted to the CPM, with copies to the Regional Board, by March 15th of the each year, covering the Reporting Period from January 1st through December 31st of the previous year.

6. Contingency Reports Notify immediately by telephone, and submit a written report pursuant to Part C.3.a of this Monitoring and Reporting Program.

7. Monitoring Reports Submit all monitoring reports to both the CPM and the Regional Board. Regional Board copies should be sent to:

   California Regional Water Quality Control Board
   Colorado River Basin Region
   73-720 Fred Waring Drive, Suite 100
   Palm Desert, CA 92260

TRAFFIC AND TRANSPORTATION

Testimony of James Adams

INTRODUCTION

Staff's traffic and transportation analysis focuses on the differences in construction schedules and resultant traffic patterns for the Black Rock 1, 2, 3 Geothermal Power Plant (BR123) compared to the licensed Salton Sea Unit 6 Geothermal Power Project (SSU6).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

There has been no change in the applicable traffic and transportation LORS, nor has the project been modified sufficiently to warrant consideration of additional LORS.

ANALYSIS

Staff has reviewed the petition for potential environmental effects and consistency with applicable LORS. Based on this review, staff determined that the amended project will not have any significant and adverse traffic and transportation impacts.

There are some minor changes in the construction traffic and transportation impacts when comparing the proposed BR123 project with the licensed SSU6 project. The construction period would increase from 26 to 46 months. The average number of construction workers would increase from 265 to 325 and the peak number of workers would increase from 467 to 572. The average number of truck deliveries per day would increase from 10 to 34 and peak day deliveries would increase from 18 to 64 (CEC 2003, CE Obsidian/AECOM 2009). Because of the very light vehicular traffic in the project area, the Levels of Service (LOS) on the roads and highways (LOS A & B) that would be used during project construction would not deteriorate with the increased construction traffic and would remain within Imperial County's acceptable standards (LOS C or better). There would be a significant reduction in truck trips during operation of the amended project due to the use of single-flash technology. The SSU6 project would have used multi-flash technology, which would have generated substantial amounts of waste (CEC 2010) requiring a minimum of 32 trucks per day to dispose of the waste offsite (CEC 2003). The BR123 project would only require three trucks per day for waste disposal (Obsidian/AECOM 2010).

Staff has been advised by Imperial County Planning Department staff of their determination that project generated increase in construction traffic and lengthened schedule would not adversely impact the traffic and transportation system in the local area. Staff concurs with this determination.

CUMULATIVE IMPACTS

As noted in the **Visual Resources, Land Use, Biological Resources** and other sections of this assessment, the applicant has identified and staff has reviewed information regarding a proposed geothermal plant being developed by the firm Catalyst Hannon Armstrong Renewables (CHAR). This facility would be located 3.4 miles northeast of the BR123 site. In addition, the CHAR project construction is expected to be completed before the BR123 construction begins and the CHAR operational workforce is expected to be small (CE Obsidian/AECOM 2009). Staff is not aware of any other project in the general area that would contribute to a significant cumulative traffic and transportation impact.

CONCLUSIONS AND RECOMMENDATIONS

The changes in traffic and transportation impacts related to the amended project are relatively minor compared to the original project with the exception of the reduction in truck trips during operation. LOS ratings for the local roads and highways would not deteriorate and the project would be consistent with all applicable LORS.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

Staff is not proposing modifications to the Traffic and Transportation Conditions of Certification for the original project.

REFERENCES

California Energy Commission (CEC). 2003. Decision for the Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Application for Certification, Docket No. 02-AFC-2, Imperial County, published on December 19, 2003.

California Energy Commission (CEC). 2003. Staff Assessment for Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Application for Certification (02-AFC-2), Imperial County, California, published on August 5, 2003.

California Energy Commission (CEC) 2003. Commission Decision regarding the Salton Sea Geothermal Unit #6, published in December 2003.

California Energy Commission (CEC) 2010. E-mail from Matt Trask, California Energy Commission, to James Adams, California Energy Commission, on January 8, 2010. Submitted to CEC/Docket Unit on January 11, 2010.

CE Obsidian Energy, LLC (CE Obsidian/AECOM). 2009. Salton Sea Geothermal Unit 6 (now Black Rock 1, 2) Power Plant, Petition for License Amendment, to Modify Project to Allow Construction of Three 53 MW Units, totaling 159 MW. Submitted to the California Energy Commission, March 13, 2009.

CE Obsidian Energy, LLC (CE Obsidian /AECOM) 2010. E-mail from Jerry Salamy, Black Rock project manager, to James Adams on January 8, 2010. Submitted to CEC/Docket Unit on January 11, 2010.

Country of Imperial 2006. Circulation and Scenic Highway Element of the Imperial County General Plan, dated December 16, 2003.

County of Imperial 2010. Report of Conversation between Jim Minnick, Imperial County Planning Department, and James Adams on January 5,2010. Submitted to CEC/Docket Unit on January 5, 2010.

TRANSMISSION LINE SAFETY AND NUISANCE

Testimony of Obed Odoemelam, Ph.D.

INTRODUCTION

This analysis addresses whether the transmission line safety and nuisance aspects of the Black Rock 1, 2, and 3 Geothermal Power Project (BR123), formerly known as Salton Sea Unit 6 Geothermal Power Plant, would be changed by the currently proposed amendment to build three generating plants with a net generating capacity of 159 megawatts (MW). A previous amendment allowing operation at 215 MW was approved in May 2005, amending the Energy Commission's original December 17, 2003 decision. Any changes to the related safety and nuisance impacts would necessitate specific changes to the conditions of certification specified in the Commission Decisions approving the original and amended project.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS) COMPLIANCE

There are no new or changed transmission line and safety-related laws, ordinances, regulations, and standards (LORS) that would be applicable to the project as proposed to be amended.

ANALYSIS

This analysis is based, in part, on information provided in the Application for Certification for the original project by the applicant, CE Obsidian Energy, LLC (CEOE 2002), staff's assessments for the original project (CEC 2003), and the applicant's 2009 Petition to Amend seeking authority to construct the 159 MW BR123 project (CEOE 2009). The purpose of this analysis is to determine whether or not the proposed line construction and operational plan adequately incorporated the measures necessary for compliance with the health and safety laws, ordinances, regulations, and standards (LORS) of concern for the 161-kV lines of the types proposed for the original and the amended versions of the project. The analyses focused on the following issues relating primarily to the physical presence of the lines or secondarily to the physical interactions of the lines' electric and magnetic fields:

- Aviation safety
- Interference with radio-frequency communication
- Audible noise
- Fire hazards
- Hazardous shocks
- Nuisance shocks, and
- Electric and magnetic field (EMF) exposure

Staff assessed the applicant's proposed mitigation measures and determined that their implementation would be adequate to ensure that the line impacts of concern would be below the levels of potential significance for the original, amended and the presently proposed project. Staff's proposed conditions of certification (which were specified in the December 17, 2003 Energy Commission Decision and later amended by the Energy Commission in May 2005), were intended to ensure implementation. The present proposal to build three separate power plants would lead to a reduction in net generating capacity from the permitted 215 MW to 159 MW without requiring changes to the design, construction and operational plan necessary to ensure that the line impacts of concern would remain at less than significant levels.

CONCLUSIONS AND RECOMMENDATIONS

Since the proposed project modification would not involve any changes to the already-licensed transmission lines whose field and non-field impacts would be below levels of potential significance, staff does not consider it necessary to recommend modifications to the five conditions of certification specified in the December 2003 Energy Commission Decision approving the original SSU6 project, as modified in May 2005.

CONDITIONS OF CERTIFICATION

Staff proposes no changes to the existing Transmission Line Safety & Nuisance Conditions of Certification as specified in the December 2003 Energy Commission Decision approving the SSU6 project, as modified in the May 2005 Decision approving expansion of the project to 215 MW.

REFERENCES

California Energy Commission (CEC). 2003. Staff Assessment for the Salton Sea Unit 6 Project, published on December 17, 2003.

California Energy Commission (CEC). 2003a. Decision on the Salton Sea Unit 6 Project's Application for Certification (AFC). Published Dec .2003.

California Energy Commission Decision on Amendment to the original license to the Salton Sea Project. May 2005.

CEOE (CE Obsidian Energy, LLC) 2002. Application for Certification (AFC) Volumes I and 2 for the Salton Sea Unit 6 Project. July 26, 2002

CEOE (CE Obsidian) 2009. Petition for License Amendment, for the Black Rock 1, 2, 3 Geothermal Power Plant, formerly known as Salton Sea Unit 6 Geothermal Power Plant. (02-AFC-2C). March 13, 2009.

VISUAL RESOURCES

Testimony of James Adams

INTRODUCTION

Staff's visual resources analysis focuses on the differences in design and construction of the Black Rock 1, 2, 3 Geothermal Power Plant (BR123), and the resultant effect on visual resources in the project area, compared to the licensed Salton Sea Unit 6 Geothermal Power Project (SSU6).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

The applicable local LORS have changed since the project was permitted and are listed in **VISUAL RESOURCES Table 1**. The federal and state LORS are the same and the project has not been changed sufficiently to warrant consideration of additional LORS.

VISUAL RESOURCES Table 1
Local Laws, Ordinances, Regulations, and Standards (LORS)

Protocol: Applicable Law	Protocol: Description
Local	
Conservation and Open Space Element of the Imperial County General Plan	The intent of this element is to protect the County's visual resources.
Goal 7	The aesthetic character of the region shall be protected and enhanced to provide a pleasing environment for residential, commercial, recreational, and tourist activity.

ANALYSIS

The primary changes in the amended project, BR123, regarding visual resources when compared to the SSU6 project is that there will be three 53 megawatt (MW) plants (with stacks and plumes) instead of one 215 MW plant, and three cooling tower plumes instead of two.

BR123 would be the 10^{th} geothermal facility within two miles of the project site. All of the facilities generate visible plumes from various plant exhaust or vent stacks and/or cooling towers. The BR123 project cooling towers would be 55 feet high, 282 feet long, and 54 feet wide. The original project cooling towers would have been 58 feet high and 538 feet long. They would have generated a visible plume only 1 percent of the time that would have been 64 feet long, 115 feet high, and 57 feet wide.

Since the time of the original project being permitted in 2005, staff has adopted a visual plume frequency of 20 percent seasonal daylight hours as a plume impact study threshold. Because the amended project cooling towers would generate three visible plumes approximately 11 percent of the time during plant operation (daylight clear hours), plume dimension modeling was not required. The three regenerative thermal oxidizer (RTO) exhaust stacks would be 99 feet tall, 29 feet long, and 16 feet wide. The RTO plumes would occur well over 20 percent of the seasonal daylight clear hours. At the 10 percent threshold during plant operation, the plumes would be 60 feet long, 110 feet high, and 29 feet wide (Aspen 2009). The original project proposal envisioned two dilution water heaters that would have been 45 feet high and 8 feet wide. For approximately 10 percent of the time, the heater plumes would have been 439 feet long, 275 high, and 72 feet wide.

The plume dimensions of the amended project are comparable to plumes generated by the existing geothermal facilities and would not stand out in the visual setting. The amended project structures and visible plumes would be smaller in size and less visible from Key Observation Points (KOPs) 1 through 4 than the original project. KOPs 5 and 6 would not be affected since they deal with the project transmission lines crossing SR-86 and SR-111.

Imperial County Planning Department has informed staff that under the County's criteria the project generated plumes would not have an adverse impact on the visual character of the local area. Staff concurs with this determination.

CUMULATIVE IMPACTS

The applicant has identified and staff has reviewed information regarding a proposed geothermal plant being developed by the firm Catalyst Hannon Armstrong Renewables (CHAR). This facility would be located 3.4 miles northeast of the Black Rock 1&2 site (CE Obsidian/AECOM 2009, pg. 5.15-13 and IEC 2009, pg. 4). Staff agrees with the applicant that the CHAR project as well as the Los Angeles Department of Water & Power solar project near Niland, and Ormat's East Brawley geothermal project are too far from the BR123 site to cause cumulative visual resource impacts. Staff is unaware of any other projects that would contribute to a cumulative visual impact. Given the dominant landscape features of the Salton Sea and vast agricultural lands in this part of Imperial County, the project plus the existing geothermal facilities would not constitute an adverse cumulative visual impact.

CONCLUSIONS AND RECOMMENDATIONS

The amended project's visual change from the original project is that there will be three 53 MW plants (with stacks) instead of one 215 MW plant, and three cooling tower plumes instead of two. The RTO exhaust stack plumes would be visible during daylight clear hours but would be comparable in size to existing plumes at other geothermal facilities, and would occur over 20 percent of the time. The cooling tower plumes are estimated to occur less than 20 percent of daylight clear hours and would not have a significant visual impact. The project, when combined with other geothermal facilities in the local area and additional proposed projects in the general area, would not constitute an adverse cumulative impact.

The amended project is consistent with all applicable visual resources LORS. The aesthetic character of the amended project is a slight improvement compared with the original project due to smaller plume dimensions. Thus, the aesthetic character of the local area would not be degraded in comparison to the permitted project and would be consistent with Goal 7 of the Conservation and Open Space Element listed in **VISUAL RESOURCES Table 1**. Viewers on local roads and visitors to the Salton Sea National Wildlife Refuge (KOP 1) and Rock Hill (KOP 4) would see structures and plumes similar to the existing geothermal facilities and would not experience a significant change in the visual setting. If the Commission approves the amendment, staff believes that the visual resources conditions from the original decision do not need to be modified.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

Staff proposes no modifications to the original conditions of certification for visual resources.

REFERENCES

California Energy Commission (CEC). 2003. Decision for the Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Application for Certification, Docket No. 02-AFC-2, Imperial County, published on December 19, 2003.

California Energy Commission (CEC). 2003. Staff Assessment for Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Application for Certification (02-AFC-2), Imperial County, California, published on August 5, 2003.

CE Obsidian Energy, LLC (CE Obsidian/AECOM). 2009. Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant, Petition for License Amendment, to Modify Project to Allow Construction of Three 53 MW Units, totaling 159 MW. Submitted to the California Energy Commission, March 10, 2009.

Country of Imperial 2006. Conservation and Open Space Element of the Imperial County General Plan, dated February 1, 2006.

County of Imperial 2010. Report of Conversation between Jim Minnick, Imperial County Planning Department, and James Adams, California Energy Commission, on January 5,2010. Submitted to CEC/Docket Unit on January 5, 2010.

Integrated Engineers & Contractors Corporation (ICE) 2009. Memorandum Regarding Imperial Irrigation District Power Plant Water Use Evaluation.

APPENDIX VR-1
VISIBLE PLUME MODELING ANALYSIS
Testimony of William Walters

INTRODUCTION

The following provides the assessment of the Black Rock 1, 2, and 3 Geothermal Power Project (BR123) regenerative thermal oxidizers (RTOs) and cooling towers exhaust stacks visible plumes. Staff completed a modeling analysis for the applicant's proposed unabated cooling tower and turbine design based on data provided by the applicant.

PROJECT DESCRIPTION

The proposed project will utilize three identical RTOs and three identical five-cell cooling towers. The RTOs will have a wet scrubber control system that is assumed to saturate the exhausts at their assumed stack temperature. The cooling towers will serve the heat load from the condenser. The applicant has not proposed to use any methods to abate visible plumes from the RTO or cooling tower exhausts.

There are other temporary visible water vapor plume sources that occur when wells are tested, when steam is vented during startups/shutdown, and during other temporary short-term events. While the plumes from some of these temporary events may be large, their low frequency is such that they do not trigger visual resources impact analysis.

VISIBLE PLUME MODELING METHODS

PLUME FREQUENCY AND DIMENSION MODELING

The Combustion Stack Visible Plume (CSVP) model was used to estimate plume frequency and plume dimensions for the cooling tower exhaust. This model provides conservative estimates of both plume frequency and plume size. This model uses hourly cooling tower exhaust parameters and hourly ambient condition data to determine the plume frequency. This model is based on the algorithms of the Industrial Source Complex model (Version 2), that determine temperatures at the plume centerline, but this model does not incorporate building downwash.

The modeling method combines the cooling tower cell exhausts into an equivalent single stack. This method may overestimate cooling tower plume size (particularly height) during plume hours with higher winds due to little cell interaction and the potential for building downwash, but will be more accurate during low wind and calm periods when the exhausts from the cooling tower cells will combine into one coherent body. Wind speeds are set to one meter per second during calm hours.

CLOUD COVER DATA ANALYSIS METHOD

A plume frequency of 20 percent of seasonal (November through April) daylight clear high visual contrast (i.e. "clear") hours is used to determine potential plume impact significance. The methodology used to determine high visual contrast hours is provided below:

> Energy Commission staff has identified a "clear" sky category during which plumes have the greatest potential to cause adverse visual impacts. For this project the meteorological data set[36] used in the analysis categorizes total sky cover as "clear", "scattered", "broken", and "overcast". For the purpose of estimating the high visual contrast hours staff has included in the "Clear" category a) all hours with total sky cover defined as "clear" plus b) half of the hours with unlimited ceiling height (i.e. half of the hours with a total sky cover equal to or greater than 20% and equal to or less than 90%). The rationale for including these two components in this category is as follows: a) plumes typically contrast most with sky under clear conditions and b) for a substantial portion of the time when total sky cover is not clear and these clouds do not substantially reduce contrast with plumes. Staff has estimated that approximately half of the hours with total sky cover between 20% and 90% can be considered high visual contrast hours and are included in the "clear" sky definition.

If it is determined that the seasonal daylight clear hour plume frequency is greater than 20 percent then plume dimensions are calculated, and a significance analysis of the plumes is included in the Visual Resources section of the Staff Assessment.

COOLING TOWER VISIBLE PLUME MODELING ANALYSIS

COOLING TOWER DESIGN AND OPERATING PARAMETERS

The proposed project would have three identical cooling towers, each of which would have the following design parameters in **VISIBLE PLUME Table 1** provided from the applicant's data responses (CE Obsidian/CH2MHILL 2009a). These data responses were used to model the cooling tower plume frequency and dimensions.

VISIBLE PLUME Table 1
Cooling Tower Operating and Exhaust Parameters

Parameter		**Cooling Tower Design Parameters**		
Number of Cells		5 Cells		
Cell Height		45 feet (13.7 meters)		
Cell Stack Diameter		32.8 feet (10.0 meters)		
Case	**Inlet Air Ambient Condition**	**Heat Rejection Rate (MW)**	**Exhaust Flow Rate (K lbs/hr)**	**Exhaust Temperature (°F)**
1	40°F (WB), 80% RH	208.5	31,129	76.1
2	60°F (WB), 60% RH	208	30,112	87.0
3	90°F (WB), 20% RH	207	28,027	111.9

Source: CE Obsidian/CH2MHILL 2009a, Data Response #44.
* WB: Web bulb temperature

[36] This analysis uses a five-year meteorological data set (2002-2006), provided by the applicant, that was collected at the Imperial County Airport (CE Obsidian/AECOM 2009).

COOLING TOWER VISIBLE PLUME MODELING RESULTS

VISIBLE PLUME Table 2 provides the CSVP model visible plume frequency results for the three separate full load operating scenarios. Due to lack of meteorological information on hours of rain and fog, daylight hours without rain or fog are not provided in **VISIBLE PLUME Table 2**. However, considering that the location of the project site is located in a desert very few hours of rain and fog would occur.

VISIBLE PLUME Table 2 – Predicted Hours with Cooling Tower Steam Plumes Imperial County Airport\ 2002-2006 Meteorological Data

Case	Modeled Hours	Plume (hr)	Percent
All Hours	40,794	7,058	17.30%
Daylight Hours	19,564	1,175	6.01%
Seasonal Daylight	9,178	1,096	11.94%
Seasonal Daylight Clear Hours*	8,548	944	11.04%

*Seasonal conditions occur from November through April.

The plant design, incorporating several conservative operating assumptions indicates that the cooling tower plume frequency potential (assuming year round full load operation, 100 percent capacity factor) will be less than the 20 percent of seasonal clear hours.

A visible plume frequency of 20 percent of seasonal (November through April) daylight clear hours is used as a plume impact study threshold trigger, therefore plume dimension modeling and additional impact analysis for the cooling tower visible plumes is not required for this project.

COOLING TOWER GROUND FOGGING MODELING RESULTS

The Seasonal/Annual Cooling Tower Impacts (SACTI) model was used to determine frequency and direction of potential plume ground fogging events that could impact traffic safety, in this case Boyle Road, Severe Road, and McKendry Road.

Four conditions were modeled, including three cases presented in **VISIBLE PLUME Table 1** and a base case with the heat rejection rate of 208.5 MW and the exhaust flow rate of 30,524,000 lbs/hr. The SACTI model predicts that no ground fogging plume would occur for the five years modeled under all four cases. Therefore, there would be no impact on traffic safety.

RTO VISIBLE PLUME MODELING ANALYSIS

RTO PARAMETERS

Based on the stack exhaust parameters anticipated by the Applicant, the frequency of visible plumes can be estimated. The operating data for these three RTO stacks, used to model the potential visible plume frequency, are provided in **VISIBLE PLUME Table 3**.

VISIBLE PLUME Table 3
RTO Operating and Exhaust Parameters

Parameter	RTO Exhaust Parameters	
Stack Height	64.5 feet (19.7 meters)	
Stack Diameter	3.6 feet (1.1 meters)	
Moisture Content (% by volume)	**Exhaust Flow Rate (klb/hr)**	**Exhaust Temp (°F)**
20.37	81.9 [a]	156

Sources: CE Obsidian/CH2MHILL 2009a, CE Obsidian/CH2MHILL 2009a, with staff's mass balance correction for the moisture content.
Note:
[a] – This flow rate is based on the air quality modeling file value. The applicant noted a lower value in the data responses but the ACFM and flow rate (lb/hr) values in this response did not match and staff's inquiries into the overall changes to the RTO stack parameters (height, diameter, velocity, flow rate) were not answered by the applicant, so this more conservative flow value based on the original design for the RTO was used.

RTO VISIBLE PLUME MODELING ANALYSIS

Staff modeled the RTO plumes using the CSVP model with a five-year meteorological data set provided by the applicant that combined most ambient conditions from Imperial County Airport. **VISIBLE PLUME Table 4** provides the CSVP model visible plume frequency results.

VISIBLE PLUME Table 4 – Predicted Hours with RTO Exhaust Plumes
Imperial County Airport 2002-2006 Meteorological Data

Case	Modeled Hours	Full Load	
		Plume (hr)	Percent
All Hours	40,794	40,164	98.46%
Daylight Hours	19,564	18,934	96.78%
Seasonal Daylight	9,178	9,178	100.00%
Seasonal Daylight Clear Hours*	8,548	8,548	100.00%

*Seasonal conditions occur from November through April.

The plume from the RTO would be observed every hour modeled, well over 20 percent of the seasonal (from November through April), daylight clear hours, therefore the seasonal daylight clear RTO plume dimensions were estimated. The plume dimensions during seasonal clear hours were estimated using the CSVP model and are presented in **VISIBLE PLUME Table 5**.

VISIBLE PLUME Table 5
Predicted RTO Visible Plume Dimensions

	RTO Seasonal "Clear" Hours Plume Dimensions, Feet (Meters)		
Percentile	**Length**	**Height**	**Width**
1%	210 (64)	166 (51)	81 (25)
5%	97 (29)	123 (37)	43 (13)
10%	60 (18)	110 (34)	29 (9)
15%	54 (17)	102 (31)	25(8)
20%	**53 (16)**	**96 (29)**	**25 (8)**
30%	45 (14)	86 (26)	22 (7)
40%	36 (11)	81 (25)	19 (6)
50%	30 (9)	77 (23)	17 (5)
60%	25 (8)	74 (22)	16 (5)
70%	22 (7)	71 (22)	14 (4)
80%	21 (6)	70 (22)	13 (4)
90%	19 (6)	68 (21)	12 (4)

Results include the cooling tower stack height of 19.7 meters (64.5 feet), see **VISIBLE PLUME Table 3**.

These results show that the plume frequency due to RTO operation would be very high, but the size of the visible plume would be relatively small.

CONCLUSIONS

Visible water vapor plumes from the proposed BR123 cooling towers are expected to occur less than 20 percent of seasonal daylight clear hours. Therefore, further visual impact analysis of the cooling tower visible plumes is not required. Ground plume fogging was not predicted to occur.

Visible water vapor plumes from the proposed RTO exhaust stack are expected to occur more than 20 percent of seasonal daylight clear hours. Therefore, further visual impact analysis of the twenty percentile plume size has been completed in the Visual Resources section.

REFERENCES

CE Obsidian Energy, LLC (CE Obsidian/AECOM). 2009. Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant, Petition for License Amendment, to Modify Project to Allow Construction of Three 53 MW Units, totaling 159 MW. Submitted to the California Energy Commission, March 10, 2009.

CE Obsidian, LLC (CE Obsidian/CH2MHILL). 2009a. CalEnergy Black Rock 1-3, Data Responses 1-64. Submitted to the California Energy Commission, November 2009.

WASTE MANAGEMENT

Testimony of Ellen Townsend-Hough

INTRODUCTION

On March 13, 2009, CE Obsidian Energy, LLC (project owner) filed a petition with the California Energy Commission to modify the Black Rock 1, 2 and 3 Geothermal Power project (BR123), originally licensed as the Salton Sea Unit 6 (SSU6) project. The project is located in Imperial County, California, southeast of the Salton Sea. The Imperial Valley is the southwest part of the Colorado Desert that merges northwestward into the Coachella Valley. The plant site is used for agriculture and is bounded by McKendry Road to the north, Severe Road to the west, Peterson Road to the south, and Boyle Road to the east. Land uses in the area consist of geothermal power facilities, agriculture, and the Sonny Bono Salton Sea National Wildlife Refuge. The petition proposes to modify the licensed 215 MW multi-flash, single-generator geothermal plant to allow for the construction of three 53 MW single-flash geothermal units with a combined total of 159 MW generating capacity (CE Obsidian/AECOM 2009). All proposed modifications are described in the **Project Description** section of this document.

This analysis addresses project changes associated with managing waste generated from the construction and operation of the proposed modifications to the project and any wastes already existing on-site. Only those aspects of the licensed facility that would change because of the proposed amendment and those aspects that would affect staff's past testimony for **Waste Management**, as written in the Commission Decision approving the SSU6 project and in later modifications, are examined in this analysis. The technical scope of this analysis encompasses solid wastes existing on-site and those generated during facility construction and operation. Wastewater is more fully discussed in the **Soil and Water Resources** section of this document.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

The LORS applicable to the original and previously amended SSU6 project have not changed with the changes proposed by this amendment.

ANALYSIS

As the first step in its analysis, staff assesses whether any existing or potential releases of hazardous substances at the project site could pose a risk to public health and environmental receptors.

The applicant completed and submitted a Phase I Environmental Site Assessment (ESA) conducted according to the American Society for Testing and Materials (ASTM) Standard Practice E 1527-05 for ESAs. AECOM Environment completed the Phase I ESA in January 2009. The area studied included the 160-acre amended project site, which includes the original 80-acre project site licensed by the Commission. The studied area also included three 4.7-acre properties for the three proposed injection well pad sites, 3.22 miles of right-of-way for the proposed brine injection pipelines, and an approximately 34-acre borrow site. The 34-acre off-site borrowing site would be used as the source of 362,000 cubic yards of fill required to raise foundations and build the flood-protection berm (CE Obsidian/AECOM 2009, page 5.12-1). Historical research indicates that the subject property and surrounding lands have been used for agricultural production since the early 1900s (CE Obsidian/AECOM 2009).

The Phase I ESA did not reveal any recognized environmental conditions (REC). However, staff concluded the long term use of the property for agricultural purposes on the proposed site may have contaminated soil and ground water and recommended further analysis. An REC is the presence or likely presence of any hazardous substances or petroleum products on a property under the conditions that indicate an existing release, past release, or a material threat of a release of any hazardous substance or petroleum products into structures on the property or in the ground, groundwater, or surface water of the property. Given the past land uses and proposed construction, Energy Commission staff requested that the project owner provide a Phase II ESA and verify that no harmful concentrations of any contaminants would be encountered at the proposed project site (CE Obsidian/CH2MHILL 2009 Data Response 64). A non-contaminated working environment protects the workers and reduces or eliminates damage to the environment. Staff requested that the project owner sample the project site in accordance with the California Department of Toxic Substances Control (DTSC) “Interim Guidance for Sampling Agricultural Fields for School Sites (Second Revision August 26, 2002).” DTSC uses the guidance for all types of commercial and industrial businesses constructed on agricultural properties. The guidance is intended to assist environmental assessors in designing an initial investigation for sites with historical agricultural uses.

The applicant completed a Phase II ESA for the BR123 project site. The soil samples from the project site were collected on September 23 and 24, 2009, and results were submitted to staff (CE Obsidian/CJ2MHILL 2009 Data Response 64). DTSC guidance recommended one discrete sample for every 2 acres, for a total of 24 point composite samples (Holmes 2009a, 2009c, 2009d). The samples were analyzed for organochlorine pesticides using United States Environmental Protection Agency (U.S. EPA) Method 8081A. The analytical results were compared to the Residential California Human Health Screening Levels (CHHSLs) and the U.S. EPA Residential Regional Screening Levels (RSL).[37] Two organochlorine pesticides were detected in the soil samples: 4,4’-DDE and 4,4’-DDT.

[37] CHHSLs were developed as a tool to assist in the evaluation of contaminated sites for potential adverse threat to human health. The soil CHHSLs are modeled after the EPA Region IX Preliminary Remediation Goal (PRG). The Region 9 PRGs have been harmonized with similar risk-based screening levels used by Regions 3 and 6 into a single table: Regional Screening Levels (RSL) for Chemical Contaminants at Superfund Sites.

WASTE MANAGEMENT Table 1
Detected Organochlorine Pesticides

Constituent of Concern	CHHSL (mg/kg)	RSL (mg/kg)	Concentration Range (mg/kg)
4,4'-DDE	1.6	1.4	0.008 - 0.037
4,4'-DDT	1.6	1.7	0.004 - 0.014
DDE – dichlorodiphenyldichloroethylene, detected in 100% of samples			
DDT- dichlorodiphenyltrichloroethane, detected in 25% of samples			

The results of the Phase II assessment indicate that the levels of organocholoride remaining in the soil are persistent but do not exceed regulatory screening levels and will not require soil remediation. Condition of Certification **WORKER SAFETY-1** would be adequate to address any soil contamination contingency that may be encountered during construction.

As the next step in its analysis, staff reviews the capacity available at off-site treatment and disposal sites and determines whether or not the proposed power plant's waste would have a significant impact on the volume of waste a facility is permitted to accept. Staff uses a waste volume threshold equal to 10 percent of a disposal facility's remaining permitted capacity to determine if the impact from disposal waste at a particular facility would be significant.

BR123 will generate nonhazardous solid waste, hazardous waste and waste required to be disposed of in a Class II landfill, these wastes will add to the total waste generated in Imperial County and in California. The estimated amounts of waste generated from the project are shown in **WASTE MANAGEMENT Table 2**.

WASTE MANGEMENT Table 2
Waste Generated and Landfill Capacity

	Construction[1] cubic yards	**Operation**[2] cubic yards per year	**Remaining Landfill Capacity**[3] cubic yards
Non-Hazardous	50	156	5,127,575
Hazardous	1	52	15,500,000
Class II Waste (drilling waste)	19,000	100	1,314,800

1. Source: Tables 5.16-4 and 5.16-5, BR123 Amendment Petition
2. Source: Table 5.16-6, BR123 Amendment Petition
3. Imperial County 2009 landfill totals- www.calrecycle.ca.gov/SWFacilites/Direcrory//13-AA-0022/Detail
4. Source: Beacon Solar Energy Project -Combined permitted capacity of Clean Harbors' Buttonwillow Landfill (Kern County) and the Waste Management Kettleman Hills Facility.

Based on **WASTE MANAGEMENT Table 2**, the waste generated by BR123 would represent less than 1 percent of the county's total remaining landfill capacity. Therefore, staff concludes that disposal of the waste generated during construction and operation of the modified BR123 project would not result in any significant adverse waste disposal impacts.

There will be no new or additional unmitigated significant environmental impacts due to hazardous or non-hazardous wastes associated with the changes proposed in the BR123 amendment.

CONCLUSIONS AND RECOMMENDATIONS

The BR123 project would produce solid non-hazardous waste and both liquid and solid hazardous waste. There is sufficient landfill capacity in the region to dispose of non-hazardous and hazardous waste during construction and operation. Chemical analysis of soil samples taken at the proposed project site did not yield concentrations of organochlorines above state or federal regulatory levels. Management of the waste generated during construction and operation of BR123 would not generate significant adverse impacts, and would comply with applicable LORS, if the waste management practices and mitigation measures proposed in the amendment petition and staff's proposed conditions of certification, are implemented.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

Staff does not propose modifications to the **Waste Management** Conditions of Certification as written in the SSU6 Commission Decision (CEC 2003). Those conditions of certification should also apply to the facilities constructed and operated as a result of the proposed BR123 project amendment.

REFERENCES

California Energy Commission (CEC). 2003. Decision approving the Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Application for Certification, Docket No. 02-AFC-2, Imperial County, published on December 19, 2003.

California Energy Commission (CEC). 2003a. Staff Assessment for Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Application for Certification (02-AFC-2), Imperial County, California, published on August 5, 2003.

CE Obsidian Energy, LLC (CE Obsidian/AECOM). 2009. Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant, Petition for License Amendment, to Modify Project to Allow Construction of Three 53 MW Units, totaling 159 MW. Submitted to the California Energy Commission, March 10, 2009.

CE Obsidian, LLC (CE Obsidian/CH2MHILL). 2009a. CalEnergy Black Rock 1-3, Data Responses 1-64. Submitted to the California Energy Commission, November 2009.

Holmes 2009a - Holmes, Greg. Letter from Greg Holmes, Department of Toxic Substances Control, discuss CalEnergy Black Rock 1 -3 Soil Sampling Protocol, submitted August 28, 2009.

Holmes 2009b - Holmes, Greg.E-mail from Greg Holmes, Department of Toxic Substances Control, Clarify June 10, 2009 letter to Matt Trask response to agency participation for Amended Salton Sea Unit 6 Project, Imperial County (tn:51975), submitted July 27, 2009.

Holmes 2009c - Holmes, Greg. Letter from Greg Holmes, Department of Toxic Substances Control, July 7, 2009 letter to Ellie Townsend, Hough in reference to CalEnergy Environmental Site Assessment for Amended Salton Sea Unit 6 Project, Imperial County (tn:52580), submitted July 7, 2009.

Holmes 2009d - Holmes, Greg. E-mail from Greg Holmes, Department of Toxic Substances Control, Clarify July 7, 2009 letter to Ellie Townsend-Hough in reference to CalEnergy Environmental Site Assessment for Amended Salton Sea Unit 6 Project, Imperial County (tn:52583), submitted July 27, 2009.

ENGINEERING ANALYSIS

FACILITY DESIGN ANALYSIS
Testimony of Erin Bright

INTRODUCTION

CE Obsidian Energy, LLC seeks approval to modify the Black Rock Geothermal Power Plant Project Units 1, 2, & 3 Project (previously the Salton Sea Unit 6 Project) from one multi-flash geothermal power plant to three smaller single-flash geothermal power plants. The change would require less facility infrastructure compared to the licensed project.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

The Energy Commission Decision (original Decision) included 20 Conditions of Certification relating to Facility Design, including **GEN-1** and **GEN-2**. Those conditions recognize that the project was to be designed and built in accordance with the 2001 edition of the California Building Code (CBC). The applicable edition of the CBC is currently the 2007 edition (see below).

ANALYSIS

The analysis associated with the original application has not changed as a result of the proposed modification, with two minor exceptions. The project must be designed and constructed in compliance with the current (2007) edition of the California Building Standards Code (CBSC), which encompasses the CBC, California Building Standards Administrative Code, California Electrical Code, California Mechanical Code, California Plumbing Code, California Energy Code, California Fire Code, California Code for Building Conservation, California Reference Standards Code, and all other applicable engineering LORS. Also as the result of this amendment, some alternative and additional components must be added to the project while some components would no longer be necessary. The conditions of certification included in the original Decision would still apply, with two changes (see below).

CONCLUSION

The proposed modification from one multi-flash plant to three single-flash plants will not result in impacts on facility design. Staff recommends approval of this request and proposes the following changes to two existing conditions of certification.

PROPOSED CHANGES TO CONDITIONS OF CERTIFICATION

No mitigation measures are required for Facility Design beyond the requirements embodied in the conditions of certification. Conditions of Certification **GEN-1** and **GEN-2** require the following revisions due to this amendment. (note: Deleted text is in ~~strikethrough~~ and new text is in **<u>bold and underlined</u>**.)

Condition of Certification **GEN-1** must be updated to reflect that the current version of the applicable laws, ordinances, regulations and standards (LORS), the California

Building Standards Code, applies to all new construction. **GEN-1** should be revised thus:

GEN-1 The project owner shall design, construct and inspect the project in accordance with the ~~2001~~**<u>2007</u>** California Building Standards Code (CBSC) and all other applicable engineering LORS in effect at the time initial design plans are submitted to the CBO for review and approval. (The CBSC in effect is that edition that has been adopted by the California Building Standards Commission and published at least 180 days previously.) All transmission facilities (lines, switchyards, switching stations, and substations) are addressed in the Conditions of Certification in the **Transmission System Engineering** section of this document.

In the event that the initial engineering designs are submitted to the CBO when a successor to the ~~2001~~**<u>2007</u>** CBSC is in effect, the ~~2001~~**<u>2007</u>** CBSC provisions identified herein shall be replaced with the applicable successor provisions. Where, in any specific case, different sections of the code specify different materials, methods of construction, or other requirements, the most restrictive shall govern. Where there is a conflict between a general requirement and a specific requirement, the specific requirement shall govern.

<u>Verification</u>: Within 30 days after receipt of the Certificate of Occupancy, the project owner shall submit to the California Energy Commission Compliance Project Manager (CPM) a statement of verification, signed by the responsible design engineer, attesting that all designs, construction, installation and inspection requirements of the applicable LORS and the Energy Commission's Decision have been met in the area of facility design. The project owner shall provide the CPM a copy of the Certificate of Occupancy within 30 days of receipt from the CBO [~~2001 CBC, Section~~ ~~**109**~~**<u>2007 CBC, Appendix Chapter 1, §110</u>** – Certificate of Occupancy].

Condition of Certification **GEN-2**, including **Table 1**, must be changed to reflect the added and deleted equipment embodied in this amendment:

GEN-2 Prior to submittal of the initial engineering designs for CBO review, the project owner shall furnish to the CPM and to the CBO a schedule of facility design submittals, a Master Drawing List, and a Master Specifications List. The schedule shall contain a list of proposed submittal packages of designs, calculations, and specifications for major structures and equipment. To facilitate audits by Energy Commission staff, the project owner shall provide specific packages to the CPM when requested.

<u>Verification</u>: At least 60 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of rough grading, the project owner shall submit to the CBO and to the CPM the schedule, the Master Drawing List, and the Master Specifications List of documents to be submitted to the CBO for review and approval. These documents shall be the pertinent design documents for the major structures and equipment listed in Table 1 below. Major structures and equipment shall be added to or deleted from the Table only with CPM approval. The project owner shall provide schedule updates in the Monthly Compliance Report.

~~**TABLE 1: MAJOR STRUCTURES AND EQUIPMENT LIST**~~

~~**EQUIPMENT/SYSTEM**~~	~~**QUANTITY (PLANT)**~~
~~Steam Turbine (ST) Foundation and Connections~~	~~1~~
~~Steam Turbine Generator Foundation and Connections~~	~~1~~
~~Steam Condenser and Auxiliaries Foundation and Connections~~	~~1~~
~~Condensate (HP) Hotwell Pumps Foundation and Connections~~	~~2~~
~~Condensate (SP/LP) Hotwell Pumps Foundation and Connections~~	~~2~~
~~Condensate Storage Tank Foundation and Connections~~	~~1~~
~~Filter Press System Structure, Foundation and Connections~~	~~1~~
~~Thickener Foundation and Connections~~	~~2~~
~~Brine Production Wellpads~~	~~5~~
~~Brine Injection Wellpads~~	~~3~~
~~Purge Water Pumps (HP/SP/LP) Foundation and Connections~~	~~6~~
~~Main Transformer Foundation and Connections~~	~~1~~
~~Counterflow Cooling Tower Foundation and Connections – 10 cells each~~	~~2~~
~~Vertical Circulating Water Pumps Foundation and Connections~~	~~6~~
~~Blowdown Pumps Foundation and Connections~~	~~2~~
~~Cooling Tower Wetdown Pumps Foundation and Connections~~	~~2~~
~~Auxiliary Cooling Water Pumps Foundation and Connections~~	~~2~~
~~Benzene Abatement Structure, Foundation and Connections~~	~~1~~
~~H_2S Abatement Structure, Foundation and Connections~~	~~1~~
~~NCG Removal System Structure, Foundation and Connections~~	~~1~~
~~Steam Vent Tank Foundation and Connections~~	~~4~~
~~Waste Water Collection System Foundation and Connections~~	~~1~~
~~Main Injection Pumps Foundation and Connections~~	~~4~~
~~Fire Protection System~~	~~1~~
~~Injection Booster Pump Foundation and Connections~~	~~4~~
~~Brine Pond Pumps Foundation and Connections~~	~~2~~
~~Generator Breakers Foundation and Connections~~	~~3~~
~~Transformer Breakers Foundation and Connections~~	~~3~~
~~Wellhead Separators Foundation and Connections~~	~~4~~
~~SP Crystallizers Foundation and Connections~~	~~4~~
~~LP Crystallizers Foundation and Connections~~	~~4~~
~~Atmospheric Flash Tanks Foundation and Connections~~	~~4~~
~~Dilution Water Heater/Pumps Foundation and Connections~~	~~2~~
~~Scrubbers Foundation and Connections~~	~~6~~
~~Demisters Foundation and Connections~~	~~6~~
~~Primary Clarifiers Foundation and Connections~~	~~2~~
~~Secondary Clarifiers Foundation and Connections~~	~~2~~
~~Vacuum System Foundation and Connections~~	~~4~~

~~Equipment/System~~	~~Quantity (Plant)~~
~~Electric Motor Driven Fire Pump Foundation and Connections~~	~~1~~
~~Diesel Engine Fire Pump Foundation and Connections~~	~~1~~
~~Firewater Storage Tank Foundation and Connections~~	~~1~~
~~Compressed Air System Foundation and Connections~~	~~2~~
~~HCl Tank Foundation and Connections~~	~~1~~
~~Emergency Relief Tanks Structure, Foundation and Connections~~	~~4~~
~~Seed Pumps Foundation and Connections~~	~~4~~
~~Control Room Structure, Foundation and Connections~~	~~1~~
~~RO/Potable Water Systems~~	~~2~~
~~Drainage Systems (including sanitary drain and waste)~~	~~1 Lot~~
~~High Pressure and Large Diameter Piping and Pipe Racks~~	~~1 Lot~~
~~HVAC and Refrigeration Systems~~	~~1 Lot~~
~~Temperature Control and Ventilation Systems (including water and sewer~~	~~1 Lot~~
~~Building Energy Conservation Systems~~	~~1 Lot~~
~~Substation/Switchyard, Buses and Towers~~	~~1 Lot~~
~~Electrical Duct Banks~~	~~1 Lot~~

Table 1: Major Structures and Equipment List

#	**Equipment/System**	**Quantity (Plant)**
1	**Brine Production Wellpads**	**3**
2	**Brine Pond Foundations**	**3**
3	**Brine Injection Wellpads**	**3**
4	**Brine Production Aerated Brine Wellpads**	**1**
5	**Brine Injection Condensate Wellpads**	**1**
6	**Steam Turbine (single-flash) Foundation and Connections**	**3**
7	**Steam Turbine Generator Foundation and Connections**	**3**
8	**Steam Condenser and Auxiliaries Foundation and Connections**	**3**
9	**HP Separators Foundation and Connections**	**3**
10	**HP Scrubbers Foundation and Connections**	**3**
11	**HP Demisters Foundation and Connections**	**3**
12	**High Pressure and Large Diameter Piping and Pipe Racks**	**1 Lot**
13	**Rock Mufflers Foundations and Connections**	**3**
14	**Condensate Storage Tank Foundation and Connections**	**1**
15	**Filter Press System Containment Structure, Foundation and Connections**	**3**
16	**Cooling Tower Foundation and Connections**	**3**
17	**Acid System Foundations and Connections**	**3**
18	**Lube Oil Skid Foundations and Connections**	**3**
19	**230kV Transformer Foundation and Connections**	**3**
20	**Substation/Switchyard, Buses and Towers**	**1 Lot**

#	Equipment/System	Quantity (Plant)
21	Electrical Duct Banks	1 Lot
22	PDC 101 (4160V) Foundations and Connections (Note: PDC is power distribution center)	3
23	230kV Take-off Structure / circuit breakers Foundations and Connections	3
24	4160V Transformer Foundations and Connections	3
25	PDC 102 (480V) Foundations and Connections	3
26	PDC 103 (4160V) Foundations and Connections	3
27	480V Transformer Foundations and Connections	3
28	PT/CT Foundations and Connections (potential transformer and current transformer)	3
29	230kV Transmission Towers Foundations and Connections	2
30	Chemical H2S Abatement Structure, Foundation and Connections	3
31	NCG Removal System Structure, Foundation and Connections	3
32	Booster/Injection/ Pumps Foundation and Connections	3
33	Production Test Unit Foundations and Connections	3
34	Fire Protection System	1 Lot
35	Raw/Fire/Condensate Water Storage Tank Foundation and Connections	1
36	Control Room Structure, Foundation and Connections	1
37	Drainage Systems (including sanitary drain and waste)	1 Lot
38	HVAC and Refrigeration Systems	1 Lot
39	Temperature Control and Ventilation Systems (including water and sewer connections)	1 Lot
40	Building Energy Conservation Systems	1 Lot
41	Circulating Water Pumps Foundations and Connections	3
42	Fire Water Pump House Foundation and Connections	1
43	Hydro Test Blast Pad Foundation and Connections	1
44	Propane Tank Foundation and Connections	3
45	Septic Tank Foundations and Connections	1

REFERENCES

California Energy Commission (CEC). 2003. Decision approving the Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Application for Certification, Docket No. 02-AFC-2, Imperial County, published on December 19, 2003.

California Energy Commission (CEC). 2003a. Staff Assessment for Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Application for Certification (02-AFC-2), Imperial County, California, published on August 5, 2003.

California Energy Commission (CEC). 2005. Decision approving the Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Petition to Amend, Docket No. 02-AFC-2, Imperial County, published on May 11, 2005.

California Energy Commission (CEC). 2005a. Staff Assessment for Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Petition to Amend, (02-AFC-2), Imperial County, California, published on April 20, 2005.

CE Obsidian Energy, LLC (CE Obsidian/AECOM). 2004. Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant, Petition to Amend, to Modify Project to Add Binary Turbine and Increase Generating Capacity to 215 MW. Submitted to the California Energy Commission, December 14, 2004.

CE Obsidian Energy, LLC (CE Obsidian/AECOM). 2009. Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant, Petition for License Amendment, to Modify Project to Allow Construction of Three 53 MW Units, totaling 159 MW. Submitted to the California Energy Commission, March 10, 2009.

GEOLOGICAL AND PALEONTOLOGICAL RESOURCES

Testimony of Dal Hunter, Ph.D., C.E.G.

INTRODUCTION

CE Obsidian Energy, LLC is seeking to amend their existing license for construction of the proposed Black Rock 1, 2, and 3 Geothermal Power Plant (formerly Salton Sea Unit 6 Geothermal Power Plant Project). The amended project would consist of construction of 3 smaller geothermal power plants with a total of 159 MW output. Modification to construct 3 smaller power plants will result in changes to the locations and orientations of building footprints and other facility infrastructure foundations which could have a potential effect on the areas geology, mineral resources, and paleontology.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

At the time of certification, LORS applicable to Geology, Mineral Resources, and Paleontology were identified in staff's Final Staff Assessment. These LORS will continue to apply to the amended project, and no new LORS have been identified. The California Building Code has been updated to the 2007 edition and is in effect for the proposed upgraded project.

ANALYSIS

Energy Commission Geology, Mineral Resources, and Paleontology staff reviewed the petition and assessed the impacts of this proposal on environmental quality, public health, and safety. No significant impacts to geology or mineralogic resources are expected due to construction of the proposed amended project. Paleontological resources that might be encountered during construction will be safeguarded by implementation of the standard Paleontological Conditions of Certification as presented in the original license.

CUMULATIVE IMPACTS

No cumulative impacts to geology, mineral resources, and paleontologic resources are anticipated due to implementation of the proposed amended project.

CONCLUSIONS AND RECOMMENDATIONS

Energy Commission Geology, Mineral Resources, and Paleontology staff reviewed the amendment petition and assessed the impacts of this proposal on environmental quality, public health, and safety. It is staff's opinion that revisions to Geology, Mineral Resources, and Paleontology Conditions of Certification are not required and that the project as modified will not result in a significant adverse direct or cumulative impact on the environment (Title 24, California Code of Regulations).

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

No modifications to Geology, Mineral Resources, and Paleontology Conditions of Certification are proposed.

REFERENCES

California Code of Regulations, Title 24, 2007, (*California Building Standards Code* [CBSC]), Part 2, *California Building Code* (CBC).

CEC 2003, California Energy Commission, Part 1 of Final Staff Assessment of the AFC (02-AFC-2), Salton Sea Unit 6 Geothermal Power Plant, Imperial County, California, published on August 5, 2003.

CEC 2003, Salton Sea Geothermal Unit 6 Power Project, Commission Decision, Application for Certification (02-AFC-2), Imperial County, California.

CE Obsidian Energy LLC 2009, Amended Salton Sea Unit 6 Project Amendment Petition, February 2009.

POWER PLANT EFFICIENCY
Testimony of Shahab Khoshmashrab

INTRODUCTION

The proposed amendment would yield efficiency impacts that are less than significant. From the standpoint of power plant efficiency, staff believes the proposed Black Rock 1, 2, 3 Geothermal Power Plant project (BR123) can be certified as proposed.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

No LORS apply to power plant efficiency.

ANALYSIS

Staff has reviewed the petition for potential environmental effects. Based on this review, staff determined that since BR123 would consume a renewable resource of energy, it would not create significant adverse effects on energy supplies or resources, nor would it require additional sources of energy supply or consume energy in a wasteful or inefficient manner. The use of the single flash geothermal technology proposed for BR123, as opposed to the multiple flash geothermal technology proposed for the licensed Salton Sea Unit 6 Geothermal Power Project, would not significantly impact power plant efficiency, because most of the energy not utilized as the result of this modification will be injected back into the ground.

CUMULATIVE IMPACTS

No projects have been identified that lie near enough to BR123 to create cumulative impacts. Therefore, staff concludes that no cumulative efficiency impacts are possible.

CONCLUSIONS AND RECOMMENDATIONS

BR123 would not create significant adverse effects on energy supplies or resources, nor would it require additional sources of energy supply or consume energy in a wasteful or inefficient manner. Staff therefore concludes that the project would present no significant adverse impacts upon energy resources.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

No Conditions of Certification are proposed.

REFERENCES

California Energy Commission (CEC). 2003a. Decision for CE Obsidian Energy's Salton Sea Geothermal Unit #6 Power Project Application for Certification, Docket No. 02-AFC-2, Imperial County, published on December 19, 2003.

California Energy Commission (CEC). 2003. Staff Assessment for Salton Sea Geothermal Unit #6 Power Project Application for Certification (02-AFC-2), Imperial County, California, published on August 5, 2003.

CE Obsidian Energy, LLC, (CE Obsidian/AECOM). 2009. Black Rock 1, 2, and 3 Geothermal Power Project (formerly Salton Sea Geothermal Unit #6 Power Project), Petition for License Amendment. Submitted to the California Energy Commission, March 13, 2009.

POWER PLANT RELIABILITY

Testimony of Shahab Khoshmashrab

INTRODUCTION

The proposed amendment would not yield significant reliability impacts. From the standpoint of power plant reliability, staff believes the proposed modifications to the Salton Sea Unit 6 Geothermal Power Project to become the Black Rock 1, 2 & 3 project (BR123) can be approved.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

No LORS apply to power plant reliability.

ANALYSIS

Staff has reviewed the petition for potential reliability effects. Based on this review, staff determines that BR123 would be built in accordance with typical industry norms for reliable power generation in relation to equipment availability, plant maintainability, fuel and water availability, and power plant reliability in relation to natural hazards.

CUMULATIVE IMPACTS

No projects have been identified that lie near enough to BR123 to create cumulative impacts. Therefore, staff concludes that no cumulative reliability impacts are possible.

CONCLUSIONS AND RECOMMENDATIONS

BR123 would be built and operated in a manner consistent with industry norms for reliable operation. This should provide an adequate level of reliability.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

No Conditions of Certification are proposed.

REFERENCES

California Energy Commission (CEC). 2003a. Decision for CE Obsidian Energy's Salton Sea Geothermal Unit #6 Power Project Application for Certification, Docket No. 02-AFC-2, Imperial County, published on December 19, 2003.

California Energy Commission (CEC). 2003. Staff Assessment for Salton Sea Geothermal Unit #6 Power Project Application for Certification (02-AFC-2), Imperial County, California, published on August 5, 2003.

CE Obsidian Energy, LLC, (CE Obsidian/AECOM). 2009. Black Rock 1, 2, and 3 Geothermal Power Project (formerly Salton Sea Geothermal Unit #6 Power Project), Petition for License Amendment. Submitted to the California Energy Commission, March 13, 2009.

TRANSMISSION SYSTEM ENGINEERING

Testimony of Sudath Edirisuriya and Mark Hesters

INTRODUCTION

The applicant, CE Obsidian Energy, LLC, is proposing to amend the currently effective license to allow for the construction of three smaller geothermal plants named Black Rock Units 1, 2, and 3 (BR123), which will produce clean, renewable energy. The original project Salton Sea Unit 6 (SSU6) was granted a license by the California Energy Commission in December 2003 for a net output of 185 MW. The 2003 license was amended in May, 2005 to enable the plant to increase its capacity to 215 MW. The proposed amendment would change the project to three 53 MW geothermal electric power plants producing a combined nominal output of 159 MW. The three units will be located on the same site as the original SSU6 project in the Southeast of the Salton Sea, Imperial County, California.

The project would be owned by CE Obsidian and operated by Cal Energy Operating Corporation. As with the originally licensed project, the amended project will require two new transmission lines: the “Midway” and “L” interconnection lines. The amended project will be interconnected to the Imperial Irrigation District (IID) grid via two 161kV single circuits. The proposed 16-mile single circuit L-line interconnection at the Banister switching station and the proposed 15-mile single circuit IID Midway interconnection would be a direct inter-tie between the Black Rock project and IID’s existing L-line and Midway substations. The configuration of these lines is unchanged from the originally licensed SSU6 project. The transmission lines will be constructed, owned, maintained and operated by IID. The proposed transmission lines are already licensed and will not be modified by the amended project. The detailed amended project description has been discussed in the applicant’s Petition to Amend in section 1.1 to 1.13 and Figure 1.1, 1.2, 1.3.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS) COMPLIANCE

The LORS that apply to the transmission facilities associated with the proposed Black Rock 1, 2, 3 Project are:

- California Public Utilities Commission (CPUC) General Order 95 (GO-95), *Rules for Overhead Electric Line Construction*, sets forth uniform requirements for the construction of overhead lines. Compliance with this Order ensures adequate service and the safety of the public and the people who build, maintain, and operate overhead electric lines.

- CPUC General Order 128 (GO-128), *Rules for Construction of Underground Electric Supply and Communications Systems*, sets forth uniform requirements and minimum standards for underground supply systems to ensure adequate service and the safety of the public and the people who build, maintain, and operate underground electric lines.

- The National Electric Safety Code, 2007, provides electrical, mechanical, civil, and structural requirements for overhead electric line construction and operation.
- The combined North American Electric Reliability Corporation/Western Electricity Coordinating Council (NERC/WECC) planning standards provide system performance standards for assessing the reliability of the interconnected transmission system. These standards require continuity of service and the preservation of interconnected operation as the first and second priorities, respectively. Some aspects of NERC/WECC standards are either more stringent or more specific than the either agency's standards alone. These standards are designed to ensure that transmission systems can withstand both forced and maintenance outage system contingencies while operating reliably within equipment and electric system thermal, voltage, and stability limits. They include reliability criteria for system adequacy and security, system modeling data requirements, system protection and control, and system restoration. Analysis of the WECC system is based to a large degree on Section I.A of WECC standards, *NERC and WECC Planning Standards with Table I and WECC Disturbance-Performance Table,* and on Section I.D, *NERC and WECC Standards for Voltage Support and Reactive Power.* The standards require that power flows and stability simulations verify defined performance levels. Performance levels are defined by specifying allowable variations in thermal loading, voltage and frequency, and loss of load that may occur during various disturbances. Performance levels range from no substantial adverse effects inside and outside a system area during a minor disturbance (such as the loss of load from a single transmission element) to a catastrophic loss level designed to prevent system cascading and the subsequent blackout of islanded areas and millions of consumers during a major transmission disturbance (such as the loss of multiple 500-kV lines along a common right-of-way, and/or of multiple large generators). While the controlled loss of generation or system separation is permitted under certain specific circumstances, a major uncontrolled loss is not permitted (WECC, 2002).
- NERC's reliability standards for North America's electric transmission system spell out the national policies, standards, principles, and guidelines that ensure the adequacy and security of the nation's transmission system. These reliability standards provide for system performance levels under both normal and contingency conditions. While these standards are similar to the combined NERC/WECC standards, certain aspects of the combined standards are either more stringent or more specific than the NERC performance standards alone. NERC's reliability standards apply to both interconnected system operations and to individual service areas (NERC, 2006).

ANALYSIS AND IMPACTS

SYSTEM RELIABILITY

Because the BR123 project would be located within IID's transmission system, a Transitional Cluster Study was conducted to analyze the potential effect of connecting the known proposed new power plants to the existing IID power system grid to determine the alternate and preferred interconnection facilities to the grid, downstream transmission system impacts and their mitigation measures in conformance with system performance levels, as required in utility reliability criteria, NERC planning standards, WECC reliability criteria. The study determines both positive and negative impacts, and for the reliability criteria violation cases (for the negative impacts) determines the alternate and preferred additional transmission facilities or other mitigation measures. The study is conducted with and without new cluster generation projects and their interconnection facilities by using the computer model base case for the year the generator projects will come on-line.

The cluster study normally includes a Load Flow study, Transient Stability study, Post-transient Load Flow study, and Short Circuit study. The cluster study is focused on thermal overloads, voltage deviations, system stability (excessive oscillations in the generators and transmission system, voltage collapse, loss of loads or cascading outages), and short circuit duties. The study must be conducted under the normal condition (N-0) of the system and also for all credible contingency/emergency conditions, which includes the loss of a single system element (N-1) such as a transmission line, transformer or a generator and the simultaneous loss of two system elements (N-2), such as two transmission lines or a transmission line and a generator. The study may also be conducted for credible simultaneous loss of multiple (more than two) system elements. In addition to the above analysis, the studies may be performed to verify whether sufficient active or reactive power margins are available in the area system or area sub-system to which the new generator project will be interconnected. The cluster study is followed by supplemental studies conducted by the participating transmission owner with details provided in a Detailed Interconnection Facility Study or a Facility Cost Report.

Any new transmission facilities, such as the power plant switchyard, the outlet line, and downstream facilities required for connecting a project to the grid, are considered part of the project and are subject to the full Energy Commission review process.

Scope of Transitional Cluster Study

The Cluster Study was performed by PDS Consulting, PLC at the request of IID to identify the transmission system impacts of cluster group projects on the IID 115/230/500 kV system. The study included power flow, short circuit studies, and transient and post-transient analyses. For cluster study purposes, projects were divided into four groups according to each project’s proposed commercial operating date. The output from all the generation projects in each group were dispatched and delivered as indicated in each project’s interconnection application. The study modeled the Black Rock project with a net output of 159 MW. The base case was developed from WECC’s 2012 heavy summer and 2013 light winter base case series and included all major IID transmission projects, and model all proposed higher-queued generation projects that will be operational by 2012 and 2013, respectively. The power flow studies were conducted with and without proposed group 2012 cluster projects, consisting of 11 projects totaling 948 MW, connected to the IID grid at each project’s interconnection switchyard, using 2012 heavy summer and 2013 light winter base cases. The detailed study assumptions are described in the study. The power flow study assessed the group 2012 Cluster projects impacts on thermal loading of the transmission lines and equipment. Transient and post-transient studies were conducted using the 2012 heavy summer base case to determine whether the 2012 project group would create instability in the system following certain selected outages. Short circuit studies were conducted to determine if 2012 group cluster projects would overstress existing substation facilities. (IID Transitional Cluster Study 2009a)

Transitional Cluster Study Results:

The Transitional Cluster Study identified pre-project overload criteria violations under both the 2012 Heavy Summer and 2013 Light Winter study conditions. Pre-project overloads are caused by either existing system conditions or by projects with higher positions in the IID's generator interconnection queue. The study concludes that the addition of the 2012 cluster of projects would cause a number of pre-existing normal and/or emergency overloads to increase and would cause some new normal and emergency overloads. The amended Black Rock project would represent about 13 percent of the 2012 cluster output and as such would likely be responsible for only a small portion the mitigation of the overloads. Because the Black Rock project represents such a small portion of the overall 2012 cluster, staff does not believe that transmission upgrades will be required for the reliable interconnection of the BR123 project, and therefore are not a reasonably foreseeable consequence of the project.

Detailed results of the Transitional Cluster Study are below. Where potential overloads are identified, mitigation is proposed that would eliminate the potential impact to reliability.

Heavy Summer Pre-Cluster (Pre-Project) overloads:

Normal conditions (N-0); The power flow study projected that the pre-cluster projects would cause no normal overloads. Therefore, there is no mitigation needed for N-0 conditions.

Contingency (N-1); The power flow study projected that the pre-cluster projects would cause two N-1 overloads. A summary of the transmission facility overloads is provided in Appendix C2, Table C2-1, of the Transitional Cluster Study.

Recommended Mitigation: Reconductor the existing Avenue 58 – Avenue 48 92 kV line with a 191 MVA, 900MCM ACSS conductor.

Contingency (N-2); The power flow study projected that the pre-cluster projects would cause one N-2 overload. A summary of the transmission facility overloads is provided in Appendix C2, Table C2-3, of the Transitional Cluster Study.

Heavy Summer Post-Cluster Base case overloads:

Normal condition (N-0); The power flow study projected that the project's 2012 cluster group would cause one normal overload during normal operating conditions.

Recommended Mitigation:

- New 8.5 mile, 230kV line from Midway to Hudson Ranch using 560 MVA, 2-1590 MCM ACSS bundled conductors.
- New 24 miles 230kV line from Hudson Ranch to banister using 560 MVA, 2-1590 MCM ACSS bundled conductors.

- Replace existing Avenue 58-El Centro section with 786 MVA, 2-1033MCM ACSR bundled conductors. Terminate one circuit at El Centro and extend the other circuit at Dixieland.
- Install 225 MVA, 230/161 kV transformer at Bannister.
- Interconnect Project A-8 to the new Banister 230kV substation
- Interconnect Project A-12 to the new Bannister – Dixieland 230kV line.
- Interconnect Project A-1 to the Hudson Ranch 230kV substation.

These transmission line and interconnection point upgrades help to mitigate the costly upgrade of the Avenue 58-El Centro 161 kV line. Additionally, these upgrades would enhance the reliability of the entire transmission system during the selected double element outages from Midway to SCE transmission system.

Contingency (N-1); The power flow study projected that the 2012 cluster group projects would cause four overloads under selected single element outages. Two out of the four transmission facility overloads are attributable to the integration of group 2012 cluster projects. A summary of the transmission facility overloads is provided in Appendix C2, Table C2-1 and Table C-4, of the Transitional Cluster Study.

Recommended Mitigation: Reconductor the existing Avenue 58-Avenue 48, 92 kV line with a 191MVA, 900 MCM ACSS conductor.

Rebuild the existing 8.5 miles long RTP3ANZA-RTAP2 92 kV line with a 191 MVA, 900 MCM ACSS conductor.

Contingency (N-2); The power flow study projected that the 2012 cluster group projects would cause four overloads under selected double element outages. Three out of the four transmission facility overloads are attributable to the integration of group 2012 cluster projects. A summary of the transmission facility overloads is provided in Appendix C2, Table C2-3 and Table C-5, of the Transitional Cluster Study.

Recommended Mitigation: Implement a Special Protection System (SPS) to trip generation at Midway.

Light Winter Pre-Cluster Base case overloads:

Normal condition (N-0); The power flow study projected that the pre-cluster projects would cause no overloads during normal operating conditions.

Contingency (N-1); The power flow study projected that the pre-cluster projects would cause two overloads during selected single element outages. A summary of the transmission facility overloads is provided in Appendix C2, Table C2-5, of the Transitional Cluster Study.

Contingency (N-2); The power flow study projected that the pre-cluster projects would cause no overloads under selected double element outages.

Light Winter Post-Cluster Base case overloads:

Normal condition (N-0); The power flow study projected that the project 2012 cluster group would cause no normal overload during normal operating conditions.

Contingency (N-1); The power flow study projected that the 2012 cluster group projects would cause three overloads under selected single element outages. Two out of the three transmission facility overloads are existing overloads that persisted following the integration of the group 2012 cluster projects. A summary of the transmission facility overloads is provided in Appendix C2, Table C2-5 and Table C-7, of the Transitional Cluster Study.

> **Recommended Mitigation**: Rebuild the existing 8.5 miles long RTP3ANZA-RTAP2 92 kV line with a 191 MVA, 900 MCM ACSS conductor.

Contingency (N-2); The power flow study projected that the 2012 cluster group projects would cause one overload under selected double element outages. The transmission facility overload is attributable to the integration of group 2012 cluster projects. A summary of the transmission facility overloads is provided in Appendix C2, Table C2-7 and Table C-8, of the Transitional Cluster Study.

> **Recommended Mitigation**: Rebuild the existing 8.5 miles long RTP3ANZA-RTAP2 92 kV line with a 191 MVA, 900 MCM ACSS conductor.

Transient Stability Analysis results:

Stable and adequately damped transient stability performances were achieved following all of the outages simulated using both the pre-and post-cluster base cases. The power flow studies of N-1 and N-2 contingencies showed that the project would not cause voltage drops of 5 percent or more from the pre-project levels or cause the IID system to fail to meet applicable voltage criteria. No transient frequency criteria violations were observed for all the contingencies simulated. The transient stability study projected that the transmission system's performance relative to the applicable reliability guidelines would not be adversely affected by the group 2012 cluster projects due to selected disturbances.

Post-Transient Stability Analysis results:

Post-transient stability analysis was performed on the heavy summer pre-and post cluster base cases. The study indicated that the reactive power margins at the N. Laquin 92 kV bus following the outage of the N. Laquin–Ave42 92kV line would be below the acceptable minimum reactive margins of the IID reactive power criteria standard. The integration of the group 2012 Cluster projects resulted in marginal reductions in the reactive power margins at most of the buses monitored.(the study results can be found in Appendix C3 of the IID Transitional Cluster Study).

Short Circuit Study Results:

Short circuit studies were performed to determine the degree to which the addition of group 2012 cluster projects would increase fault duties at IID's substations, adjacent utility substations, and the other 115 kV, 230 kV and 500 kV busses within the study area. For the buses at which faults were simulated, the maximum three-phase and single-line-to-ground fault currents, both with and without the project, and information on the breaker duties at each location are summarized in Table C-9, short circuit study results, on page 89 of the Transitional Cluster Study Report. The interconnection of the group 2012 cluster projects will cause the El Centro 92kV and the Coachella Switching station 92kV breakers to exceed their interruption capabilities by 649 Amps and 31 Amps respectively. Therefore, these two breakers should be replaced with 63,000 Amps and 40,000 Amps, respectively, higher interrupting capability breakers.

CONCLUSION AND RECOMMENDATIONS

- Some downstream upgrades would be required in the IID system for the reliable interconnection of the group 2012 cluster projects. The Black Rock project is a small (13-percent) part of the cluster, and therefore these upgrades are not considered a reasonably foreseeable consequence of the amended project. Therefore, staff determined that the study results and selected mitigation measures are acceptable.
- The proposed geothermal plants will enhance grid reliability and stability by continuously operating throughout the year. The continuous operation capability would be a distinct advantage of geothermal power as a renewable source of energy compared to solar and wind power.
- The proposed 16-mile single circuit L-line interconnection at the Banister switching station and the proposed 15-mile single circuit IID Midway interconnection would be a direct inter-tie between the Black Rock project and IID's existing L-line and Midway substation. The original transmission interconnection lines are adequate to carry the reduced nominal output of the project and will not be modified by the proposed amendment.
- Additionally, the proposed interconnection will not affect the Black Rock project ability to comply with all applicable Laws, Ordinances, Regulations and Standards (LORS). Therefore, staff proposes no changes to the Transmission System Engineering Conditions of Certification from the final decision of the Salton Sea Unit 6 project.

REFERENCES

IID (Imperial Irrigation District) 2009a, Imperial Irrigation District; Transitional Cluster Study submitted to the California Energy Commission.

NERC (North American Electric Reliability Council). 1998. NERC Planning Standards, September 1997.

WECC (Western Systems Coordinating Council) 2001. NERC/WSCC Planning Standards, June 2001.

California Energy Commission (CEC). 2003. Decision approving the Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Application for Certification, Docket No. 02-AFC-2, Imperial County, published on December 19, 2003.

California Energy Commission (CEC). 2003a. Staff Assessment for Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Application for Certification (02-AFC-2), Imperial County, California, published on August 5, 2003.

California Energy Commission (CEC). 2005. Decision approving the Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Petition to Amend, Docket No. 02-AFC-2, Imperial County, published on May 11, 2005.

California Energy Commission (CEC). 2005a. Staff Assessment for Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant Petition to Amend, (02-AFC-2), Imperial County, California, published on April 20, 2005.

CE Obsidian Energy, LLC (CE Obsidian/AECOM). 2004. Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant, Petition to Amend, to Modify Project to Add Binary Turbine and Increase Generating Capacity to 215 MW. Submitted to the California Energy Commission, December 14, 2004.

CE Obsidian Energy, LLC (CE Obsidian/AECOM). 2009. Salton Sea Geothermal Unit 6 (now Black Rock 1, 2, 3) Power Plant, Petition for License Amendment, to Modify Project to Allow Construction of Three 53 MW Units, totaling 159 MW. Submitted to the California Energy Commission, March 10, 2009.

BLACK ROCK 1, 2, AND 3 GEOTHERMAL PROJECT (02-AFC-2C)
STAFF ASSESSMENT to the AMENDMENT

PREPARATION TEAM

EXECUTIVE SUMMARY..Christine Stora

INTRODUCTION ....Christine Stora

PROJECT DESCRIPTION..Christine Stora

AIR QUALITY ....William Walters, P.E.

BIOLOGICAL RESOURCES..Rick York and Misa Milliron

CULTURAL RESOURCES ....Dorothy Torres

LAND USE..Jeanine Hinde

NOISE AND VIBRATION ....Shahab Khoshmashrab

PUBLIC HEALTH ....Obed Odoemelam, PhD

SOCIOECONOMIC RESOURCES ....Kristin Ford

SOIL AND WATER RESOURCES ....Paul Marshall and Abdel-Karim Abulaban, PE

TRAFFIC AND TRANSPORTATION ....James Adams

TRANSMISSION LINE SAFETY AND NUISANCE.................................Obed Odoemelam, PhD

VISUAL RESOURCES ....James Adams

WASTE MANAGEMENT ....Ellie Townsend-Hough

FACILITY DESIGN...Erin Bright

GEOLOGY AND PALEONTOLOGY ....Dal Hunter, Ph.D., C.E.G.

POWER PLANT EFFICIENCY ....Shahab Khoshmashrab

POWER PLANT RELIABILITY ....Shahab Khoshmashrab

TRANSMISSION SYSTEM ENGINEERING...................Sudath Arachchige and Mark Hesters

COMPLIANCE UNIT TECHNICIAN ....Marci Errecart

DECLARATION OF
Christine Stora

I, **Christine Stora**, declare as follows:

1. I am presently employed by The California Energy Commission in the **Siting, Transmission and Environmental Protection Division** as a Planner II.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on the **Executive Summary, Introduction, and Project Description,** for the **Black Rock 1, 2, and 3 Geothermal Power Project**, based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issues addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 7/20/10 Signed: Christine Stora

At: Sacramento, CA

CHRISTINE R. STORA
California Energy Commission
1516 Ninth St., MS-2000
Sacramento, California 95814
(916) 654-4745

EXPERIENCE SUMMARY

Over 7 years of project and staff management experience related to the development of energy projects in North America and other international locations. Technical focus on NEPA and CEQA compliance, planning, permitting, and post construction monitoring.

PROFESSIONAL EXPERIENCE AND EDUCATION

CALIFORNIA ENERGY COMMISSION PLANNER II
06/2010 to Present
Currently working as a Compliance Project Manager (CPM) for the California Energy Commission in the Compliance Unit of the Siting, Transmission and Environmental Protection Division. In this role, I am in charge of coordinating with Technical Staff and Applicants to process Amendment Petitions.

URS CORPORATION RENEWABLE ENERGY PROJECT AND STAFF MANAGER
11/2003 to 5/2010
As a Project Manager, I provided environmental planning services for international renewable energy clients through sitting, permitting, construction, and post construction, environmental monitoring and compliance. I coordinated multiple disciplines for NEPA and CEQA compliance documents (EISs/EIRs) and other environmental reports related to renewable energy development. I coordinated field surveys as the lead field technician (surveys included avian mortality studies for wind energy developments, wetland delineations, burrowing owl surveys, meteorological siting investigations, geotechnical investigations, and other technical disciplines). I also contributed to marketing and research efforts for the URS renewable energy marketing sector including attending conferences such as the annual Wind Power Conference held by the American Wind Energy Association (AWEA).

Professional awards and certifications include: URS Team Award for a Wind Energy Environmental Planning for a team I managed (February 2010), URS Monthly Outstanding Achievement Award for Marketing Efforts in the Renewable Energy Sector (December 2008), Individual Outstanding Achievement Award in Project Management (2007), URS Project Manager Certification (November 2007).

EDUCATION
Bachelor of Science Degree in Environmental Science from Humboldt State University (2003). Academic honors include Cum Laude Honors Humboldt State University (2003) and Fall Presidential Scholar Humboldt State University (2001).

DECLARATION OF
Will Walters, P.E.

I, Will Walters, declare as follows:

1. I am presently employed by Aspen Environmental Group, a contractor to the California Energy Commission, Systems Assessment and Facilities Siting Division, as a senior associate in engineering and physical sciences.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on **Air Quality** and the **Visible Plume Modeling Analysis – Appendix VR-2**, for the Black Rock 1, 2, and 3 Geothermal Power Project Amendment based on my independent analysis of the Petition for Amendment and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issues addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: November 5, 2010 Signed: ______________________

At: Agoura Hills, California

WILLIAM WALTERS, P.E.
Air Quality Specialist

ACADEMIC BACKGROUND
B.S., CHEMICAL ENGINEERING, 1985, CORNELL UNIVERSITY

PROFESSIONAL EXPERIENCE

Mr. Walters has over 20 years of technical and project management experience in environmental compliance work, including environmental impact reports, emissions inventories, source permitting, energy and pollution control research RCRA/CERCLA site assessment and closure, site inspection, and source monitoring.

Aspen Environmental Group — 2000 to present

Responsible as lead technical and/or project manager of environmental projects, including the following specific relevant recent (2000 and forward) responsibilities and projects:

- **Engineering and Environmental Technical Assistance to Conduct Application for Certification Review for the California Energy Commission:**
  - Preparation and project management of the air quality section of the Staff Assessment and/or Initial Study and the visual plume assessment for the following licensing projects: Hanford Energy Park; United Golden Gate, Phase I; Huntington Beach Modernization Project*; Woodland Generating Station 2; Ocotillo Energy Project, Phase I; Magnolia Power Project*; Colusa Power Project; Rio Linda/Elverta Power Plant Project; Roseville Energy Center; Henrietta Peaker Project; Tracy Peaking Power Plant Project*; Avenal Energy Project; San Joaquin Valley Energy Center*; Salton Sea Unit 6 Project*; Modesto Irrigation District Electric Generation Station*; Walnut Energy Center*; Riverside Energy Resource Center*; Pastoria Energy Facility Expansion; Bullard Energy Center; Panoche Energy Center; Starwood Power Plant; Riverside Energy Resource Center Units 3 and 4 Project; Colusa Generating Station*; Chula Vista Energy Upgrade Project*; Orange Grove Power Plant Project*; Carlsbad Energy Center Power Project*; Hydrogen Energy California (in process); Canyon Power Plant Project*; Imperial Valley Solar Project*; Beacon Solar Energy Project; Calico Solar Power (in process); Abengoa Mojave Solar Project; Genesis Solar Energy Project; Blythe Solar Power Project; Palen Solar Power Project (in process); Ridgecrest Solar Power Project; Rice Solar Energy Project (in process); Ivanpah Solar Electric Generating Station project.
  - Preparation and project management of the visible plume assessment for the following licensing projects: Metcalf Energy Center Power Project*; Contra Costa Power Plant Project*; Mountainview Power Project; Potrero Power Plant Project; El Segundo Modernization Project; Morro Bay Power Plant Project; Valero Cogeneration Project; East Altamont Energy Center*; SMUD Cosumnes Power Plant Project*; Pico Power Project; Blythe Energy Project Phase II; City of Vernon Malburg Generating Station; San Francisco Electric Reliability Project; Los Esteros Critical Energy Facility Phase II; Roseville Energy Park; City of Vernon Power Plant; South Bay Replacement Project; Walnut Creek Energy Park; Sun Valley Energy Project; Highgrove Power Plant; Colusa Generating Station; Russell City Energy Center; Avenal Energy Project; Community Power Project; San Gabriel Generating Station; Sentinel Energy Project; Victorville 2 Hybrid Power Project; City of Palmdale Hybrid Energy Project (in process); Chevron Richmond Power plant Replacement Project; Tracy Combined Cycle Power Plant; Lodi Energy Center; and San Joaquin Solar 1&2 Power Plant.
  - Assistance in the aircraft safety review of thermal plume turbulence for the Riverside Energy Resources Center; Russell City Energy Center Amendment*; Eastshore Energy Power Plant*; Carlsbad Energy Center (in progress), City of Palmdale Hybrid Energy Project; Riverside Energy Resource Center Units 3 and 4 Project; Victorville 2 Hybrid Power Project; Blythe Energy Project Phase II*, Tracy Power Plant; Avenal Energy Project; and Blythe Solar Energy Project siting cases. Assistance in the aircraft safety review of

* - Includes providing expert witness testimony.

thermal and visual plumes of the operating Blythe Energy Power Plant. Preparation of a white paper on methods for the determination of vertical plume velocity determination for aircraft safety analyses.

- **Other California Energy Commission and relevant project experience:**
  - Preparation and instruction of a visual water vapor plume modeling methodology class for the CEC.
  - Preparation and project management of the public health section of the Initial Study for the Woodland Generating Station 2 Energy Commission licensing project.
  - Preparation of project amendment or project compliance assessments, for air quality or visual plume impacts, for several licensed power plants, including: Metcalf Energy Center; Pastoria Power Plant; Elk Hills Power Plant; Henrietta Peaker Project; Tracy Peaker Project; Magnolia Power Project; Delta Energy Center; SMUD Cosumnes Power Plant; Walnut Energy Center; San Joaquin Valley Energy Center; City of Vernon Malburg Generating Station; Otay Mesa Power Plant; Los Esteros Critical Energy Facility; Pico Power Project; Riverside Energy Resource Center; Blythe Energy Project Phase II; Inland Empire Energy Center; Salton Sea Unit 6 Project; Black Rock 1, 2, and 3 Geothermal Power Project, and Starwood Power-Midway Peaking Power Plant.
  - Preparation of the air quality section of the staff paper "A Preliminary Environmental Profile of California's Imported Electricity" for the Energy Commission and presentation of the findings before the Commission.
  - Preparation of the draft staff paper "Natural Gas Quality: Power Turbine Performance During Heat Content Surge", and presentation of the preliminary findings at the California Air Resources Board Compressed Natural Gas Workshop and a SoCalGas Technical Advisory Committee meeting.
  - Preparation of the staff paper "Emission Offsets Availability Issues" and preparation and presentation of the Emission Offsets Constraints Workshop Summary paper for the Energy Commission.
  - Preparation of information request and data analysis to update the Energy Commission's Cost of Generation Model capital and operating cost factors for combined and simple cycle gas turbine projects. Additionally, performed a review of the presentation for the revised model as part of the CEC's 2007 Integrated Energy Policy Report workshops, and attended the workshop and answering Commissioner questions on the data collection and data analysis. Prepared an update to the Energy Commission's capital and operating cost factors for combined and simple cycle gas turbine projects within the Cost of Generation model as part of the 2009 Integrated Energy Policy Report process.
  - Preparation of the Air Quality Section, air quality emission calculations, or other technical studies, is support of the environmental documentation for renewable energy projects including; the Liberty Energy XXIII Renewable Energy Project; the Topaz Solar Farm, the Pacific Wind Energy Project, and the Pine Tree Wind Development Project.
  - Preparation of comments on the Air Quality, Alternatives, Marine Traffic, Public Safety, and Noise section of the Cabrillo Port Liquefied Natural Gas Deepwater Port Draft EIS/EIR for the City of Oxnard.

CERTIFICATION

- Chemical Engineer, California License 5973

AWARDS

- California Energy Commission Outstanding Performance Award 2001

DECLARATION OF
Richard York

I, **Richard York**, declare as follows:

1. I am presently employed by the California Energy Commission in the **Environmental Protection Office** of the **Energy Facilities Siting Division** as a **Planner III**.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **Biological Resources** for the Black Rock 123 project based on my independent analysis of the application and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: March 23, 2010 Signed: Richard York

At: Sacramento, California

RICHARD YORK

WORK EXPERIENCE SUMMARY

Experienced in biological resource assessment including endangered species surveys, field survey protocols, endangered species mitigation and monitoring, coordination with state and federal agencies, and wetland delineation. Educational background emphasized biological resources, plant identification and taxonomy, general ecology, and herbarium specimen curatorship.

WORK EXPERIENCE

1989 – to date

PLANNER II, California Energy Commission. I provide independent biological resource assessments of proposed energy facilities and review implementation of biological resource conditions of certification required by the Warren-Alquist Act and the California Environmental Quality Act. Once energy facilities are constructed and operating, I am responsible for making sure each facility operates in compliance with associated biological resources conditions of certification. These conditions of certification involve endangered species protection, habitat restoration and monitoring, off-site habitat compensation, and wildlife surveys.

I am also involved with various preserves in the San Joaquin Valley (Semitropic Ridge and Lokern) that were established with Energy Commission mitigation funds. Also, I edited the endangered species and sensitive biological resource policy paper for the California Energy Commission's Energy Facilities Siting and Environmental Protection Division.

1986 - 1989

BOTANIST, The Nature Conservancy. Collected, mapped and computerized rare plant location and ecological information for the California Natural Diversity Data Base while under contract to the California Department of Fish and Game. Required statewide coordination with many other botanists, some field work, and management of contracts.

1980 - 1986

BOTANIST, California Native Plant Society. Compiled and co-edited the 3rd edition of the California Native Plant Society's statewide *Inventory of Rare and Endangered Vascular Plants of California.* Work involved field surveys, attendance at public meetings and statewide board meetings, coordination and supervision of volunteers, data base management and quality control, endangered species regulatory review and comment, coordination with state and federal agencies, and writing special plant status reports.

1975 - 1980

BOTANIST/RANGE TECHNICIAN (Bureau Land Mgmt., Wyoming)
HERBARIUM ASSISTANT (Humboldt State University)
RESEARCH ASSISTANT (California Native Plant Society)
PARK AIDE (California Department of Parks and Recreation)
PRIVATE BOTANICAL CONSULTANT (Six Rivers Nat. Forest)

EDUCATION

- B. S. **BOTANY**, 1979, Humboldt State University, Arcata, California
- B. A. **PSYCHOLOGY**, 1979, Humboldt State University, Arcata, California

AWARDS

- 1992 RARE PLANT CONSERVATION AWARD – Calif. Native Plant Society

PROFESSIONAL AFFILIATIONS

- California Native Plant Society
- California Botanical Society
- The Nature Conservancy
- Interagency Botanists

DECLARATION OF
Misa Milliron, Senior Biologist

I, Misa Milliron, declare as follows:

1. I am presently employed by the California Energy Commission in the Environmental Office of the Siting, Transmission & Environmental Protection Division and the Energy Research Development, and Demonstration Division as a Senior Biologist.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on Biological Resources for the Black Rock 1, 2, and 3 Geothermal Power Project based on my independent analysis of the Amendment Petition and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 3/22/10 Signed: ______________________

At: Sacramento, California

MISA MILLIRON

EDUCATION

University of Georgia, Athens 2000

- M.S. Botany

California Polytechnic State University, San Luis Obispo 1997

- B.S. Biological Sciences, Botany Concentration, *Magna Cum Laude*

WORK EXPERIENCE

California Energy Commission

Research Development and Demonstration Division, Public Interest Energy Research Program

Technical Lead, Terrestrial Resources *September 2009 - Present*

Siting, Transmission and Environmental Protection Division

Senior Biologist, Technical Lead *May 2007 - Present*

Biologist *May 2006 - May 2007*

- Manage and develop projects for energy-related biological research.
- Develop and present oral and written testimony on energy-related environmental analyses and land use planning, natural resource management, energy facility siting issues and evaluate compliance with applicable local, state, and federal laws, ordinances, regulations, and standards.
- Identify, describe, and analyze policy, regulatory, electric transmission corridor planning, and biological resource issues related to construction and operation of electrical energy production facilities and associated electric transmission systems, alternative energy technologies including wind and geothermal facilities, and Commission programs.
- Conduct project management and team leadership, manage contract budgets, and coordinate work of contract personnel for the Order Instituting Informational proceeding pursuant to the California Public Resources Code on the Development of *California Guidelines for Reducing Impacts to Birds and Bats from Wind Energy Development.*
- Coordinate multi-agency input as well as write and edit sections for the *Guidelines*, which were identified as a priority policy issue in the Commission's 2005 *Integrated Energy Policy Report.*
- Consult with and advise Office Managers, Division Chiefs, Executive Office, and Commissioners and their advisers on electricity-related siting and planning subjects.
- Evaluate compliance with conditions of certification related to biological resources.
- Coordinate with biological resource protection and management agencies, environmental organizations, universities, and special interest groups to ensure input into Commission programs.
- Organize and conduct public workshops and meetings concerning Commission projects.
- Review information for *Environmental Performance Report* updates.
- Review job applications, develop interview questions, serve on interview panels, and make recommendations on potential new hires in the Biology Unit.
- Represent the Commission at college recruitment fairs.
- Serve as acting supervisor of Biology and Cultural Resources Unit as needed during supervisor's absences.
- Won Superior Accomplishment Award for outstanding performance and contribution in 2006.

California Native Plant Society (CNPS)

Rare Plant Botanist *March 2004 – June 2006*

- Provide leadership and project management equivalent to a Planner II – Energy Facilities Siting
- Manage Rare Plant Program's plant science activities and establish yearly, quarterly and daily priorities, including natural resource management activities
- Supervise and monitor work of consultants, volunteers, and interns
- Monitor species affected by development, including intra- and inter-state electric transmission corridors.
- Provide advice and data to consultants working for large electricity companies on utility transmission planning alternatives analysis and natural resource management.
- Conduct timely data entry and quality control of the CNPS rare plant database.

- Coordinate and expand interagency botanists group, network of local and regional rare plant experts, and consult with chapter Rare Plant Coordinators.
- Research status, nomenclature, distribution, abundance, and endangerment for the CNPS Inventory of Rare and Endangered Plants of California.
- Compile and disseminate concise technical reports on rare plants for public agencies, conservationists, consultants, researchers, media, and others.
- Develop oral presentations and write articles in CNPS publications regarding program activities.
- Organize meetings to facilitate yearly program evaluation.
- Serve on job search committee, screen applications, and interview references.
- Train interim, Program Assistant Rare Plant Botanist in key Program areas as described below.
- Consult on rare plant science activities, priorities, and data issues (2006-2007).

EDAW, Inc. *Sacramento Office* *October 2001 – April 2004*

Botanist

- Identify, describe, and analyze policy, regulatory, electric transmission corridor planning, and biological resource issues related to construction and operation of electrical energy production facilities and associated electric transmission systems, and alternative energy technologies including geothermal facilities as well as other major development.
- Apply knowledge of local, state, and federal laws, ordinances, regulations, and standards on biological resources.
- Authored numerous environmental impact analyses, rare plant survey reports, floristic inventories, restoration monitoring reports, and wetland delineations related to land use planning, natural resource management.
- Primary biologist responsible for analysis of wetlands on a large inter-state electric transmission corridor.
- Conduct alternatives analysis for utility transmission corridor planning and utility intertie projects.
- Conduct botanical surveys in a variety of habitats throughout California (and southern Oregon) to facilitate environmental planning for both public agency and private sector clients, including electric utility companies.
- Document and map rare plants and sensitive habitats using traditional field mapping or GPS.
- Determine potentially suitable habitat areas, perform jurisdictional wetland delineations, characterize plant communities and ecological processes/functions, and make impact assessments based on field data and previously reported information.
- Apply knowledge of existing laws on biological resources through CEQA/NEPA document and other report preparation.

Office of the Registrar *University of Georgia* *February 2000-October 2001*

Administrator and Web Content Manager

- Designed and created the first comprehensive on-line tutorial for the University's registration system.
- Facilitated the design of a new Registrar website and served as a technical writer and editor.
- Determined honors eligibility for combined degree students and coordinated commencement ceremony.
- Assisted in the reporting and organization of student statistics using the Registrar Systems database.

Botany Department *University of Georgia* *January 1999 - August 2000*

Plant Taxonomy Laboratory Instructor

- Coordinated course organization and content with lecture instructor and collected plant material for labs.
- Delivered lectures on plant morphology and identification, dichotomous key construction, field collection techniques and plant classification.
- Led field trips to greenhouses, state botanical gardens, and local natural areas.
- Composed keying and identification tests and graded graduate student plant collections and field notebooks.

Plant Anatomy Laboratory Instructor

- Prepared anatomical slide demonstrations using fresh plant material and delivered lectures.
- Authored, administered, and graded lab exams.
- Provided weekly written feedback on lab reports and developed study guides for exams.

Molecular Systematics Laboratory Instructor

- Demonstrated the use of current phylogenetic analysis software and web-based bioinformatics resources.
- Created lab exercises and user-friendly help documents for computer programs.
- Directed and evaluated graduate student class research projects.

Biological Sciences Department *Cal Poly, San Luis Obispo* *August 1996 - June 1997*

Field Botany Teaching Assistant (Volunteer)

- Identified and collected California native plants in diverse plant communities on extended field trips.
- Administered and graded exams in both field and lab settings.
- Led review field trips and prepared specimens for study.

Introductory Biology Teaching Assistant

- Designed, proctored and graded weekly lab practical exams.

Student Academic Services *Cal Poly, San Luis Obispo* *August 1994 - June 1997*

Biology of Plants and Fungi Supplemental Instructor

- Mediated student discussion sessions.
- Delivered brief review lectures and wrote practice exams.

Biology and Botany Study Group Leader

- Tutored introductory biology, botany, and plant taxonomy.
- Guided plant identification field trips.
- Taught study strategies and learning techniques.

Tutoring Program Assistant

- Assign students to appropriate study groups and tutors.
- Maintain database of students, tutors, and study groups.
- Answer questions related to academic assistance program.
- Completed data entry of student surveys for program evaluation statistics.

OTHER RELEVANT EXPERIENCE

Energy Commission- Sponsored Training *2006-2007*

- Applied Project Management
- Time Management and Organizing Skills
- Essential Facilitation
- Business Writing and Grammar Skills
- Management and Leadership Skills
- Expert Witness Training

Plants of the Tropics Course	*Fairchild Tropical Garden, FL*	*1999*
Tropical Plant Systematics Course	*Organization for Tropical Studies, Costa Rica*	*1998*
Wrigley Botanical Garden Internship	*Catalina Island, CA*	*1996*

RESEARCH AND PUBLICATIONS

The California Native Plant Society Rare Plant Program and Inventory. Poster presentation, Botany 2004 conference of the American Bryological and Lichenological Society, American Fern Society, American Society of Plant Taxonomists and Botanical Society of America.

Ward, M. and A. Howald. 2005. The California Native Plant Society's Rare Plant Program: 37 Years of Plant Science. *Fremontia*: 33(2): 17-23.

Rare Plants of the Ione Formation in California. Poster presentation on rare plant survey results, regulatory status, and natural history for the Botany 2003 Conference.

Ward, N.M. and R.A. Price. 2002. Phylogenetic Relationships of Marcgraviaceae: Insights from three chloroplast genes. *Systematic Botany* 27(1): 149-160.

Ward, N.M. 2000. Master's Thesis: Molecular Systematics and Evolution of Marcgraviaceae.

Werner, N.M. and R.A. Price. 2000. Phylogeny and morphological evolution of Marcgraviaceae: Insights from three chloroplast genes. *American Journal of Botany* 87(6 Suppl.): 183.

Werner, N.M. 1997. Undergraduate Thesis: A Plant Survey of Bitter Creek National Wildlife Refuge.

DECLARATION OF
Dorothy Torres

I, Dorothy Torres, declare as follows:

1. I am presently employed by the California Energy Commission in the Environmental Protection Office as a Retired Annuitant.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepared the cultural resources analysis in the Cultural Resource section for the Black Rock Units 1, 2, and 3, Staff Assessment based on my independent analysis of the Petition to Amend and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue(s) addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 3/24/10

Signed: Dorothy Torres

At: Sacramento, California

Dorothy E. Torres

EXPERIENCE:

February 2009- Present	**Retired Annuitant: Cultural Unit** Duties are the same as those required in the Planner II position.
September 2002- January 2009	**Planner II: Biology and Cultural Unit,** Facilities Siting Division, California Energy Commission. Duties: As a Planner II, I Identify, describe, and analyze complex cultural resources issues related to electrical energy production facilities, alternative energy technologies, energy research and development and Commission programs. This includes the preparation of sections of initial studies, environmental impact reports and Commission reports. In addition, I prepare independent assessments of the cultural resources aspects of Notices of Intention, Applications for Certification, and Small Power Plant Exemptions. The final analyses include the preparation and presentation of expert technical testimony, which is presented at Commission hearings. I also coordinate and work with federal, state, regional and local governments; cultural resources related agencies; environmental organization and universities; Native American or other ethnic groups; archaeological or historical professional organizations; and members of the general public regarding energy-related issues to assure their input into the Commission power plant siting process and other Commission programs. Moreover, I lead or participate in workshops and meetings concerning Commission projects, programs and policies, amongst and between project applicants, staff, other governmental agencies, private organizations, and the public. In addition, I examine and evaluate existing and proposed laws, ordinances, regulations, standards, and policies pertinent to the visual, cultural aspects of proposed energy facilities on Commission programs. After permitting, I evaluate the licensee's compliance with conditions of certification for power plant facilities.

April 2001-
August 2002

Planner I: Cultural, Socioeconomic and Visual Unit, Systems Assessment and Facilities Division, California Energy Commission. Duties: I gather, organize and analyze cultural resources data and identify issues, impacts and mitigation measures ensuring compliance with the California Environmental Quality Act. I provide oversight for consultants working on siting applications in the area of cultural resources. I participate in workshops and meetings concerning Energy Commission projects and programs. In addition, I Interact with Division technical staff and staff representing other Divisions, local and regional government staff/decision makers, federal and state agency representatives and consultants/experts in the areas of anthropology, archaeology, history and related fields. I prepare written assessments of energy related documents.

December 1998-
March 2001

Energy Analyst: Community and Cultural Resources Unit, Energy Facilities Siting and Environmental Protection Division, California Energy Commission. Duties: I assist in gathering, organizing and analyzing cultural resources data and identify issues, impacts and mitigation measures. I assist in coordinating with local governments, resource protection agencies, environmental organizations and business organizations. Furthermore, I participate in workshops and meetings concerning Energy Commission projects and programs. I evaluate existing and proposed laws, ordinances, regulations, standards, and policies pertinent to the cultural resource aspect of proposed energy facilities. I prepare written assessments of energy related documents.

EDUCATION:

Spring 1988 — M.A., Anthropology
California State University, Sacramento

Spring 1980 — B.A., Anthropology and History
California State University, Sacramento

Professional Organizations

Society for California Archaeology
Sacramento Archaeological Society

DECLARATION OF
Jeanine Hinde

I, **Jeanine Hinde**, declare as follows:

1. I am presently employed by the California Energy Commission in the Siting, Transmission, and Environmental Protection Division as a Planner I.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on **Land Use** for the Black Rock 1, 2, & 3 Geothermal Project based on my independent analysis of the application and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: July 19, 2010 Signed: Jeanine Hinde

At: Sacramento, California

JEANINE M. HINDE

Professional Experience

Planner II **February 2010–Present**
California Energy Commission, Sacramento, CA
Environmental Office of the Siting, Transmission, and Environmental Protection Division

Generalist skilled in research and analysis, and in preparing environmental assessments relating to the siting of a variety of power plant projects filed with the Energy Commission. Analyzes project-related impacts to land use, agricultural resources, and visual/aesthetic resources. Evaluates project conformance with applicable laws, ordinances, regulations, and standards. Recommends appropriate mitigation measures to reduce project effects on environmental resources. Prepared the land use analyses for a 159-megawatt (MW) geothermal power plant in Imperial County and a 174-MW electrical generating plant in Ceres. Prepared the visual resources analysis for an integrated gasification combined cycle project proposed for location on an approximately 470-acre site in western Kern County.

Environmental Analyst **2004–2009**
EDAW-AECOM, Sacramento, CA

Coordinated preparation of environmental studies to satisfy the California Environmental Quality Act (CEQA) and the National Environmental Policy Act and related permitting and regulatory requirements. Contributed to the preparation of regulatory compliance documents for projects that have addressed flood protection, wastewater management, water quality, habitat restoration, and urban development. As an assistant project manager, contributed to the preparation, technical review, and distribution of a variety of environmental compliance documents for projects that included a levee repair project on the Feather and Yuba Rivers, a levee seepage project on the San Joaquin River near the Sacramento-San Joaquin Delta (Delta), a wastewater treatment plant improvement project in Atwater, and a habitat restoration project adjacent to the middle Sacramento River. As an analyst, prepared environmental impact analyses for resource topics that included land use; agricultural resources; visual/aesthetic resources; public services, utilities and service systems; hazardous materials; recreation; and geology, soils, and mineral resources. Prepared mitigation monitoring and reporting program documents and assisted with fulfilling CEQA noticing and filing requirements.

Environmental Analyst **2003–2004**
Sackheim Consulting, Fair Oaks, CA

Researched and wrote the aesthetics analyses for the CEQA documents on related neighborhood electrical distribution projects in the Natomas and Elkhorn areas of Sacramento. Prepared a similar analysis for a project in Elk Grove. Assisted with the analyses addressing potential impacts to cultural resources and to hazards and hazardous materials.

Environmental Specialist II **1986–1997**
Jones & Stokes Associates, Sacramento, CA

Evaluated impacts to land use, visual resources, and recreation for several state and federal projects, including a water supply management program in the East Bay, a project addressing long-term management of resources in the Delta and Suisun Marsh, and a military operations project at Camp Roberts. Provided technical review and coordinated preparation of report sections prepared by staff, and assisted with research and documentation of required federal, state, and local permits and approvals for inclusion in regulatory compliance plans.

Education

B.A. Geography, California State University, Chico

DECLARATION OF
SHAHAB KHOSHMASHRAB

I, **SHAHAB KHOSHMASHRAB**, declare as follows:

1. I am presently employed by the California Energy Commission in the **ENGINEERING OFFICE** of the Facilities Siting Division as a **MECHANICAL ENGINEER**.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I participated in the preparation of the staff testimony on **Noise and Vibration** for the **Black Rock 123** project based on my independent analysis of the Major Amendment and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issues addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: March 29, 2010 Signed: [signature]

At: Sacramento, California

DECLARATION OF
SHAHAB KHOSHMASHRAB

I, **SHAHAB KHOSHMASHRAB**, declare as follows:

1. I am presently employed by the California Energy Commission in the **ENGINEERING OFFICE** of the Facilities Siting Division as a **MECHANICAL ENGINEER**.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I participated in the preparation of the staff testimony on **Power Plant Efficiency** for the **Black Rock 123** project based on my independent analysis of the Major Amendment and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issues addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: March 23, 2010 Signed: Shahab Khoshmashrab

At: Sacramento, California

DECLARATION OF
SHAHAB KHOSHMASHRAB

I, **SHAHAB KHOSHMASHRAB**, declare as follows:

1. I am presently employed by the California Energy Commission in the **ENGINEERING OFFICE** of the Facilities Siting Division as a **MECHANICAL ENGINEER**.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I participated in the preparation of the staff testimony on **Power Plant Reliability** for the **Black Rock 123** project based on my independent analysis of the Major Amendment and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issues addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: March 23, 2010 Signed: [signature]

At: Sacramento, California

Shahab Khoshmashrab
Mechanical Engineer

Experience Summary

Nine years experience in the Mechanical, Civil, Structural, and Manufacturing Engineering fields involving engineering and manufacturing of various mechanical components and building structures. This experience includes QA/QC, construction/licensing of electric generating power plants, analysis of noise pollution, and engineering and policy analysis of thermal power plant regulatory issues.

Education

- California State University, Sacramento-- Bachelor of Science, Mechanical Engineering
- Registered Professional Engineer (Mechanical), California

Professional Experience

2001-2004--Mechanical Engineer, Systems Assessment and Facilities Siting– California Energy Commission

Performed analysis of generating capacity, reliability, efficiency, noise and vibration, and the mechanical, civil/structural and geotechnical engineering aspects of power plant siting cases.

1998-2001--Structural Engineer – Rankin & Rankin

Engineered concrete foundations, structural steel and sheet metal of various building structures including energy related structures such as fuel islands. Performed energy analysis/calculations of such structures and produced structural engineering detail drawings.

1995-1998--Manufacturing Engineer – Carpenter Advanced Technologies

Managed manufacturing projects of various mechanical components used in high tech medical and engineering equipment. Directed fabrication and inspection of first articles. Wrote and implemented QA/QC procedures and occupational safety procedures. Conducted developmental research of the most advanced manufacturing machines and processes including writing of formal reports. Developed project cost analysis. Developed/improved manufacturing processes.

DECLARATION OF
Dr.Obed Odoemelam

I, **Obed Odoemelam** declare as follows:

1. I am presently employed by the California Energy Commission in the Facilities Siting, Transmission, and Environmental Protection Division as a Staff Toxicologist.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **Public Health** for Black Rock Geothermal Power Project based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 7/13/2010 Signed: O Odoemelam

At: Sacramento, California

DECLARATION OF
Dr.Obed Odoemelam

I, **Obed Odoemelam** declare as follows:

1. I am presently employed by the California Energy Commission in the Facilities Siting, Transmission, and Environmental Protection Division as a Staff Toxicologist.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **Transmission Line safety and Nuisance** for Black Rock Geothermal Power Project based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 7/13/2010 Signed: O. Odoemelam

At: Sacramento, California

RESUME

DR. OBED ODOEMELAM

EDUCATION:

1979-1981 University of California, Davis, California. Ph.D., Ecotoxicology

1976-1978 University of Wisconsin, Eau Claire, Wisconsin. M.S., Biology.

1972-1976 University of Wisconsin, Eau Claire, Wisconsin. B.S., Biology

EXPERIENCE:

1989
The Present: California Energy Commission. Staff Toxicologist.

Responsible for the technical oversight of staffs from all Divisions in the Commission as well as outside consultants or University researchers who manage or conduct multi-disciplinary research in support of Commission programs. Research is in the following program areas: Energy conservation-related indoor pollution, power plant-related outdoor pollution, power plant-related waste management, alternative fuels-related health effects, waste water treatment, and the health effects of electromagnetic fields. Serve as scientific adviser to Commissioners and Commission staff on issues related to energy conservation. Serve on statewide advisory panels on issues related to multiple chemical sensitivity, ventilation standards, electromagnetic field regulation, health risk assessment, and outdoor pollution control technology. Testify as an expert witness at Commission hearings and before the California legislature on health issues related to energy development and conservation. Review research proposals and findings for policy implications, interact with federal and state agencies and industry on the establishment of exposure limits for environmental pollutants, and prepare reports for publication.

1985-1989 California Energy Commission.

Responsible for assessing the potential impacts of criteria and noncriteria pollutants and hazardous wastes associated with the construction, operation and decommissioning of specific power plant projects. Testified before the Commission in the power plant certification process, and interacted with federal and state agencies on the establishment of environmental limits for air and water pollutants.

1983-1985 California Department of Food and Agriculture.

Environmental Health Specialist.

Evaluated pesticide registration data regarding the health and environmental effects of agricultural chemicals. Prepared reports for public information in connection with the eradication of specific agricultural pests in California.

DECLARATION OF
Kristin Ford

I, **Kristin Ford**, declare as follows:

1. I am presently employed by the California Energy Commission in the Siting, Transmission, and Environmental Protection Division as a Planner I.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on **Socioeconomics** for the Black Rock 1, 2, & 3 Geothermal Project based on my independent analysis of the application and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: April 26, 2010 Signed: ______________

At: Sacramento, California

Kristin S. Ford

Experience

Environmental Planner November 2009 to Present
California Energy Commission, Sacramento, California
- Conduct CEQA-equivalent environmental review for proposed and existing power plants.
- Write analysis for Socioeconomics, Traffic, Visual Resources and Land Use sections for staff assessments.
- Provide expert witness testimony on Socioeconomics, Traffic, Visual Resources and Land Use issues at Energy Commission hearings.

Assistant Planner June 2006 to July 2009
City of Sacramento, Environmental Planning Services, Sacramento, California
- Evaluated, prepared and supervised the preparation of a variety of environmental documents under the California Environmental Quality Act (CEQA); analyzed data and made recommendations on complex planning matters involving issues related to land use, traffic, utilities, aesthetics, noise, energy, historic preservation, air quality and biological resources.
- Prepared, researched and reviewed Mitigation Monitoring Plans per CEQA, the California State & Federal Endangered Species Acts (CESA & FESA), the Clean Water Act (CWA), the Migratory Bird Treaty Act (MBTA) and the Natomas Basin Habitat Conservation Plan.
- Conducted biological resources site assessments for proposed development projects. Determined the need for preparation and/or review of specific studies, such as Wetland Delineations, Nesting Raptor Surveys, and Arborist Reports, to identify resources and provide mitigation measures.
- Coordinated the release of the City of Sacramento's 2030 General Plan Draft/Final Environmental Impact Report between various City departments, the Planning Commission, City Council and the consultant team.

Environmental Coordinator August 2005 to June 2006
Nella Oil Company, Auburn, California
- Coordinated company-wide environmental regulatory compliance activities, including:
    - site investigations;
    - underground fuel-storage tank environmental compliance recommendations and subsequent tank upgrades; and
    - hazardous waste removal.
- Maintained and managed Air Quality Management District and Environmental Health Department permits for 60+ gas stations.

Student Assistant March 2005 to August 2005
California Energy Commission, Sacramento, California
- Conducted research and provided technical writing support to Biology and Water Departments for the annual Energy Policy Report impact analyses.
- Maintained and managed compliance files on power plant facilities.

Student Assistant June 2004 to March 2005
Central Valley Regional Water Quality Control Board, Sacramento, California
- Supported National Pollutant Discharge Elimination System (NPDES) staff by:
    - maintaining waste water treatment plant discharge self-monitoring reports and case files; and
    - analyzed (Amador, Sutter, Placer and Yolo county) wastewater treatment plant monthly monitoring reports for possible permit violations.

Education

2005 **Bachelor of Arts, Environmental Studies**, *California State University, Sacramento*
2001 **Associate of Arts, Liberal Studies**, *Allan Hancock College, Santa Maria, California*

DECLARATION OF
Paul Marshall

I, Paul Marshall, declare as follows:

1. I am presently employed by the California Energy Commission in the Siting, Transmission and Environmental Protection Division, as an Associate Civil Engineer.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on the Soil and Water Resources for the Black Rock 1, 2, and 3 project (02-AFC-2C) based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue(s) addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony, and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: December 01, 2010

Signed: Paul Marshall

At: Sacramento, California

Paul D. Marshall

EDUCATION

SAN DIEGO STATE UNIVERSITY, CALIFORNIA
Bachelor of Science Degree in Engineering Geology
Completed post-baccalaureate courses in Engineering Geology

FRESNO STATE UNIVERSITY, CALIFORNIA
Completed post-baccalaureate courses in Civil Engineering

LICENSES

California Registered Geologist, No. 5718
California Certified Engineering Geologist, No. 1817
California Certified Hydrogeologist, No. 468

EMPLOYMENT HISTORY

CALIFORNIA ENERGY COMMISSION
Siting, Transmission, and Environmental Protection Division – Supervisor, Soil, Water Resources, and Waste Management Unit/ January 2008 -Present
Supervise a multidisciplinary team of engineers and geologists responsible for analysis of potential environmental impacts from power plant construction and operation to soil and water resources and from waste management activities. Provide guidance and technical assistance to staff for complex analysis of power plant impacts on water supply, water quality, wastewater disposal, discharges to surface water and groundwater, development and utilization of groundwater, flood impacts and storm water management, and assessment of potential impacts on human health and the environment. Ensures staff work products are consistent with laws, regulations, and policies of the US EPA, US ACOE, SWRCB, RWQCB's, CDFG, DTSC, and other local ordinances. Contract with and direct the work of consultants conducting technical reviews of power plants. Schedule and confer with a multidisciplinary staff of planners, engineers, and scientists to ensure staff analyses are coordinated with other disciplines where there is overlap. Ensure product delivery in a timely manner. Hire and develop staff, complete probationary and performance reports, counsel and mentor staff. Take adverse actions when appropriate.

CALIFORNIA DEPARTMENT OF CONSERVATION
Office of Mine Reclamation – Supervisor, Compliance Unit/October 2006 – January 2008
Supervise a team of engineering geologists responsible for ensuring compliance with mine reclamation plans and specifications. Review and approve staff work conducted to ensure plans and specifications were adequate and enforceable. Direct staff responsible for enforcement actions and preparation of data and reports for presentation to the State Mining and Geology Board. Oversight of staff review of cost estimates for mine reclamation and conduct statewide workshops outlining requirements for mine reclamation cost estimates. Implement Lead Agency review and audit program.

STATE WATER RESOURCES CONTROL BOARD
Division of Financial Assistance – Chief, Project Implementation Unit/January 2001 – September 2006
Supervise a multidisciplinary team responsible for contract and project management associated with Prop 13, Prop 40, Prop 50, Water Bond 1986 and 1996, and the Federal Clean Water Act funding programs. Develop program policies and procedures for implementation and management of grant and loan programs and projects. Direct the work of staff and coordinate with state and federal agencies in the development of technical review criteria for selection of projects recommended for grant award. Direct the work of staff and contractors developing a Project Assessment and Evaluation Program used to evaluate program effectiveness. Provide guidance and technical support to stakeholders for project development. Represent SWRCB at public meetings and conduct training on program procedures. Ensure project integrity and compliance with State and Federal laws.

CALIFORNIA DEPARTMENT OF WATER RESOURCES

Division of Local Assistance - Senior Engineering Geologist/ July 2000 – January 2001

Manage multidisciplinary staff to identify and develop conjunctive water management programs throughout Southern California. Organize, guide, and support local stakeholder groups in development of conjunctive water management plans. Develop partnering opportunities with other local, state, and federal agencies to spread program benefits region-wide and implement CALFED goals and objectives. Write and review contract documents, task orders, grant applications, and provide input on program policy. Solicit and assist agencies with loan and grant applications for various Water Bond 2000 programs.

Division of Safety of Dams - Senior Engineering Geologist/October 1995 – June 2000

Serve as an engineering geology consultant to a staff of 47 design and field engineers performing regulatory oversight of dam construction and operation. Evaluate existing and proposed dam sites for geologic and seismic hazards; review and comment on geotechnical site assessments and construction plans and specifications; act as technical adviser to staff during construction; inspect and document geologic conditions. Communicate findings to staff, consultants, and owners through written reports, briefings, and meetings. Give presentations to DSOD Board of Consultants on development of state-of-the-art procedures. Develop information and monitor changes in the regional geologic environment.

Division of Local Assistance - Associate Engineering Geologist/November 1993 - October 1995

As a member of the Water Quality Assessment Program I independently performed surface and groundwater studies, and environmental site assessments for both DWR and federal and local government agencies. Negotiated contracts, authored task assignments, and oversaw the work of consultants. Authored reports with analysis of data from various types of exploration and sampling programs. Assembled a Department-wide Site Assessment Project Team and assisted in developing DWR policy for site assessments. Trained team members and gave staff presentations outlining program and team goals.

Division of Local Assistance - Associate Engineering Geologist/October 1992 - October 1993

Under the auspices of the Proposition 82 Water Conservation Bond Law of 1988, I directed the Department's technical, environmental, and economic review of ground water recharge and water supply loan applications. Performed independent technical review and certified feasibility and construction loan applications. Provided assistance to public water agencies regarding compliance with environmental and water rights regulations, and institutional and legal requirements for project development. Coordinated Department's technical review and comment on various CEQA documents.

KLEINFELDER, INC.

Project Geologist - 4 years

Worked in regional offices throughout Central and Southern California, Western Arizona and Southern Nevada performing geotechnical investigations and environmental site characterizations. Supervised field exploration activities throughout the Central Valley and Central Coast of California. Directed water resource, groundwater recharge, geotechnical, and environmental site characterization studies. Marketed clients, determined scope of services, and prepared cost proposals. Monitored project schedules and billing. Briefed clients and supervisors on project status. Authored reports providing geotechnical recommendations for various federal, state, municipal, and commercial projects. Inspected remediation and stabilization projects. Other responsibilities included compilation of data using spreadsheets and databases, conducting literature and aerial photograph review, and writing reports.

EARTH SYSTEMS, INC.

Staff Geologist - 3 years

Designed and supervised installation of monitoring well arrays, extraction wells, drains, dewatering, and slope monitoring equipment throughout central and southern California. Directed subsurface exploration using various drilling and geophysical techniques. Conducted liquefaction, fault rupture hazard, and coastal bluff stability studies. Conducted special inspections of excavations, deep foundations, reinforced earth, and concrete. Performed numerical analyses for slope stability, liquefaction, and earthquake ground motion studies. Authored reports containing cross-sections, maps, and graphs presenting various types of water resource and geotechnical data.

DECLARATION OF
AbdelKarim Abulaban

I, AbdelKarim Abulaban, declare as follows:

1. I am presently employed by the California Energy Commission in the Siting, Transmission and Environmental Protection Division, as an Associate Civil Engineer.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on the **Soil and Water Resources** for the **Rice Solar Energy** project (09-AFC-10) based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue(s) addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony, and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: December 01, 2010

Signed: A Abulaban

At: Sacramento, California

AbdelKarim Abulaban

Education

Ph.D. Civil Engineering,University of Minnesota (*Hydrology and Water Resources).*
Thesis title: Modeling the transport of sorbing chemicals in heterogeneous porous media.
B.S. and M.S. Civil Engineering, Yarmouk University, Jordan *(Water Resources).*

Registration:

Registered Professional Engineer (Civil) with the stae of California (Lic. No. 76030)

Employment

June 2010-Present: Associate Civil Engineer

CA Energy Commission, Sacramento, CA.

Reviewing and evaluating the construction, operation, and maintenance of energy facilities and power plants for water supply, wastewater disposal, waste, water quality, and stormwater to assess the potential impacts to human health and the environment. Also, reviewing sensitive project sites that may have issues involoving flooding and stormwater management, discharges to impaired water bodies, depleted groundwater and surface water resources, and wastewater management and disposal methods, in addition to responding to soils or water resources issues that may arise regarding power plant operations, and conducting investigations to determine if any violations of the program's regulations, the Energy Commission's conditions of certification, or the CA Environmental Quality Act (CEQA) have occurred.

Dec. 2006-May 2010: **Water Resources Engineer**
CA Dept. of Water Resources, Fresno, CA.
In charge of hydraulic modeling and sediment transport for the San Joaquin River restoration project. Perform 1- and 2-D hydraulic analysis to support restoration of the San Joaquin River for the purpose of improving spawning/rearing habitat, enhancing floodplain connectivity, and improving riparian corridor.

Dec. 2001-Dec. 2006: **Retained Hydrologist**
J.L. Nieber & Associates, Hydrologic Consultants, Lindstrom, Minnesota, USA.
Hydrologic analysis and assessment of environmental impact of comtamination incidents on ground water resources, as well as design of remediation plans. Contaminants analyzed included hydro-carbons, chlorinated solvents, as well as agrichemicals.

Dec. 90 – Dec. 93: **Retained Hydrologist.**
BAUMGARTNER ENVIRONICS, INC, Olivia, Minnesota, USA.
Assessment of the environmental impact of contamination incidents on groundwater resources, and design of action plans.

Sep. 2003-Sep. 2005:
Assistant Professor, Hashemite University, Zarqa, Jordan.
Taught general and spcialized courses in the civil engineering department: Water and Wastewater Treatment Mehods; Wastewater Engineering; Statics; Engineering Drawing; Visual Communication. rs

June – August, 96, 97, 98, 2000:
Army High Performance Computing Research Center, Minneapolis, Minnesota.
Taught and helped teach the Summer Insitute course in hydrology and transport in porous media. The Summer Institute is a summer course offered to promising upper class students from member institutions. The ground water flow and transport group normally has about 4 students from different backgrounds. I was involved in training the students to use a particle tracking solute transport code which I developed, and also to use the DoD's Ground Water Modeling System, GMS; however, in the summer of 2000 I was in charge of the whole group consisting of four students.

August, 1997:
University of Minnesota, Minneapolis, Minnesota, USA.
Taught a short course on the application of the Department of Defense's Ground Water Modeling System, GMS, offered by the American Society of Agricultural Engineers and attended by about 40

professionals and academicians from around the United States as well as several countries around the world.

Research

i- Ground Water Flow and Transport:

Oct. 93-Mar. 2002: **Research Associate**

Biosystems and Agricultural Engineering Department, University of Minnesota, USA.

Modeling single and multi-phase flow and multicomponent transport in variably saturated heterogeneous porous media with chemical transformation such as adsorption and biodegradation. A computer model based on the Random Walk Particle Tracking technique was successfully developed and applied for this purpose. Because of the large memory and CPU time requirements, the model was developed and implemented using on a **supercomputer platform** through several grants from the Minnesota Supercomputer Center. This work was continued in a joint effort between the Biosystems and Agricultural Engineering Department and the Army High Performance Computing Research Center through a grant from the US Army Corps of Engineers Waterways Experiment Station, Vicksburg, MS. I also was involved in the modeling of flow and transport through preferential flow paths caused by unstable wetting fronts. Sample results for a simple scenario can be found on the World Wide Web by visiting http://www.arc.umn.edu/education/SummerInst/1996/

ii- Surface Water Hydrology:

Oct. 93- Jun. 95: **Post-Doctorate Associate**

Department of Biosystems and Agricultural Engineering, University of Minnesota, Saint Paul, Minnesota, USA.

Analysis of the impact of and best management practices of surface tile inlets on the water quality in the Minnesota River basin.

Sep. 84 - Jun. 87: **Research Assistant**

Civil Engineering Dept., Yarmouk University, Irbid, Jordan.

Development of Intensity-Duration-Frequency (IDF) Curves for design rain storms in Irbid Region. This research was supported by a grant from Yarmouk University.

Sample Publications

Hamasha, S.; Abu Allaban, M; **Abulaban A.** (2008). Modeling Atmospheric Turbidity at Zarqa Area Using Meteorological Data. JJP, 1:(1), 53-60.

Munjed Al-Sharif, J. Abu Ashour, **A. Abulaban**, and S. Al-Shar'a, (2007), Effect of Soil-Water Seperation Technique on the Estimation of Bacterial Adsorption onto Soil, Jordan Journal of Civil Engineering, Vol.(1), No. 2. pp. 295-302.

Peters, J.F., Howington, S.E., Maier, R.S., ***Abulaban, A.***, and Nieber, J.L (2002). *Imbedding velocity autocorrelation into simulators for constituent transport through porous media.* Computational Methods in Water Resources: Proceedings of the Xivth International Conference on Computational Methods in Water ResourceProceedings, Delft, The Netherlands, pp.405-412.

Abulaban, A. and J.L. Nieber (2000). *Modeling plume behavior of non-linearly sorbing solutes in saturated heterogeneous porous media. Advances in Water Resources,* **23**, pp. 893-905.

Abulaban, A., J.L. Nieber, and D. Misra (1998). *Modeling plume behavior of non-linearly sorbing solutes in saturated homogeneous porous media. Advances in Water Resources,* **21** (6) pp. 487-498.

Nguyen, H.V., J.L. Nieber, and **A. Abulaban** (1998). *An improved method to model gravity-driven unstable flow in porous media.* International Workshop 'Soil Water Repellency: Origins, Assessment, Occurrence, Consequences, Modeling, and Amelioration', Wageningen, The Netherlands, September 2-4, 1998.

DECLARATION OF
JAMES S. ADAMS

I, James S. Adams, declare as follows:

1. I am presently employed by the California Energy Commission in the Siting, Transmission, and Environmental Protection Division as a Planner II.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the Traffic and Transportation and Visual Resources sections for the Black Rock Power Plant Staff Assessment based on my independent analysis of the Petition for Amendment and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue(s) addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 1/4/10

Signed: James Adams

At: Sacramento, California

James S. Adams
Environmental Office
Siting, Transmission and Environmental Protection Division
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814-5504
PH (916) 653-0702, FAX (916) 651-8868
jadams@energy.state.ca.us

5/1999
Present **Environmental Planner II**

Review applications for certification to acquire permits from the California Energy Commission to build electric generating power plants. Specific technical fields include traffic and transportation, land use and visual resources. Provide technical analysis when requested for the Energy Commission's Integrated Energy Policy Report.

11/1997
Present **Energy and Resource Consultant**

Provide clients with technical expertise on various issues related to natural resource use and development. Recent activities include providing expert testimony before the California Public Utilities Commission regarding decommissioning issues concerning Humboldt Bay, Diablo Canyon and San Onofre nuclear reactors.

9/1994--
10/1997 **Senior Analyst - Safe Energy Communication Council (SECC)**

Responsible for developing and/or implementing campaigns on various energy issues involving the promotion of energy efficiency and renewable energy and advocating less reliance on nuclear power. Managed educational outreach efforts to newspaper editorial writers throughout the U.S. to encourage coverage of energy issues. Participated in meetings and negotiations with key Clinton administration officials, members of Congress and staff, national coalitions, and grassroots organizations on important energy issues (e.g. U.S. Department of Energy Budget for Fiscal Years 1996-1998). Successfully raised $140,000 from private foundations to support SECC activities.

6/1978--
12/1992 **Principal Consultant - Redwood Alliance**

Provided consulting services to the Alliance; a renewable energy/political advocacy organization. Major responsibilities included managing and/or participating in several interventions/appearances before the California Public Utilities Commission, California Energy Commission, California Legislature, U.S. Congress and the U.S. Nuclear Regulatory Commission. Issues included electric utility planning options, greater reliance on energy efficiency and renewable energy, nuclear power economic analyses, decommissioning cost estimates, and nuclear waste management and disposal.

2/1983--
8/1986 **<u>Natural Resource Specialist</u>**

Assisted private consulting, firms, non-profit corporations and government agencies in various projects related to the enhancement and protection of national forests in Northern California and Southern Oregon. This included contracts with the U.S. Forest Service, Fish and Wildlife Service, National Park Service, the California Coastal Conservancy, and private landowners.

6/1978--
present <u>Consultant/Journalist/Paralegal/Lobbyist</u>

Throughout the period of work outlined above, I have written a considerable amount of news articles and reports connected to ongoing-projects and issues of personal interest. The legal/administrative interventions have required extensive paralegal work to support attorneys, and technical expertise to identify and assist consultants. In addition, many of the projects required consulting services and lobbying, at the local, state and federal level whenever necessary, as well as working with the print and television media as appropriate.

From 1978 through 1984 1 served on the Board of Directors for two locals non-profit agencies devoted to sustainable community development, Redwood Community Development Council and Redwood Community Action Agency (RCAA). I also was hired on staff at RCAA as a natural resource specialist which is explained more fully above. I am proficient with computers, printers, fax machines and related equipment.

EDUCATION

M.A. Social Science. Political science and natural resources emphasis. California State University at Humboldt. Graduated December 1988.

B.A. Political Science. Political and economic aspects of natural resource development, with a particular emphasis in forest ecology and appropriate technology. California State University at Humboldt. Graduated June 1978.

Academic
Honors. Member of PI GAMMU MU Honor Society since 1986.

MILITARY SERVICE

7/1969--
9/1975 U.S. Navy. Air Traffic Controller.
Honorable Discharge.

DECLARATION OF
Ellen Townsend-Hough

I, **Ellen Townsend-Hough** declare as follows:

1. I am presently employed by the California Energy Commission in the Engineering Office of the Siting Transmission& Environmental Protection Division as an Associate Mechanical Engineer.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on Waste Management for the Black Rock 1, 2, and 3 Geothermal Power Project Amendment based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 3/29/10 Signed: Ellen Townsend-Hough

At: Sacramento, California

Ellen Townsend-Hough

SUMMARY

I am a chemical engineer with 27 years of experience. My professional career has afforded me many unique growth and development opportunities. I have a working knowledge of the California Environmental Quality Act. My strengths are in analyzing and performing complex environmental engineering analyses, in areas such as Waste Management, Hazardous Materials Management, Worker Safety, and Water Resources. I worked as a policy advisor to a California Energy Commissioner for three years. I am also an US Environmental Protection Agency Environmental Justice trainer.

PROFESSIONAL EXPERIENCE

Writing

- Write letters, memos, negative declarations, environmental impact reports that require technical evaluation of mechanical engineering and environmental aspects of pollution control systems, environmental impacts, public health issues and worker safety.

Technical Analysis and Presentation

- Performs mechanical engineering analysis of designs for complex mechanical engineering analysis of designs for systems such as combustion chambers and steam boilers, turbine generators, heat transfer systems, air quality abatement systems, cooling water tower systems, pumps and control systems

- Review and process compliance submittals in accordance with the California Environmental Quality Act, the Warren Alquist Act, the Federal Clean Air Act and the California and Federal Occupational Health and Safety Acts to assure compliance of projects

- Provides licensing recommendations and function as an expert witness in regulatory hearings.

- Provide public health impact analysis to assess the potential for impacts associated with project related air toxic/non-criteria pollutant emissions.

- Evaluate the potential of public exposure to pollutant emissions during routine operation and during incidents due to accidents or control equipment failure

- Provide an engineering analysis examining the likelihood of compliance with the design criteria for power plants and also examine site specific potential significant adverse environmental impacts

Technical Skills

- Establish mitigation that reduces the potential for human exposure to levels which would not result in significant health impact or health risk in any segment of the exposed population.

- Assist with on-site audits and inspection to assure compliance with Commission decisions.

- Review and evaluate the pollution control technology applied to thermal power plants and other industrial energy conversion technologies.

- Work with the following software applications: WORD, Excel, and PowerPoint.

Policy Advisor

- Provided policy, administrative and technical advice to the Commissioner Robert Pernell. My work with the Commissioner focused on the policy and environmental issues related to the Commission's power plant licensing, research and development and export programs.

- Track and provide research on varied California Energy Commission (CEC) programs. Prepare analysis of economic, environmental and public health impacts of programs, proposals and other Commission business items.

- Represent Commissioner's position in policy arenas and power plant siting discussions.

- Write and review comments articulating commission positions before other regulatory bodies including Air Resources Board, California Public Utilities Commission, and the Coastal Commission.

- Wrote speeches for the Commissioner's presentations.

EMPLOYMENT HISTORY

2002-Present	Associate Mechanical Engineer	California Energy Commission (CEC) Sacramento CA
1999-2002	Advisor to CEC Commissioner	CEC Sacramento CA
1989-1999	Associate Mechanical Engineer	CEC Sacramento CA
1992-1993	Managing Partner	EnvironNet Sacramento CA
1988-1989	Sales Engineering Representative	Honeywell Inc Commerce CA
`1987-1988	Chemical Engineer	Groundwater Technology Torrance CA
1985-1986	Technical Marketing Engineer	Personal Computer Engineers Los Angeles CA
1985-1985	Energy Systems Engineer	Southern California Gas Company Anaheim CA
1980-1985	Design Engineer	Southern California Edison Rosemead CA
1975-1980	Student Chemical Engineer	Gulf Oil Company Pittsburgh PA

EDUCATION

Bachelor of Science, Chemical Engineering
Drexel University, Philadelphia Pennsylvania

<u>Continuing Education</u>

Hazardous Material Management Certificate, University California Davis
Urban Redevelopment and Environmental Law, University of California Berkley
Analytical Skills, California Department of Personnel Administration (DPA) Training Center
Legislative Process/Bill Analysis, DPA Training Center
Federally Certified Environmental Justice Trainer

DECLARATION OF
Erin Bright

I, Erin Bright, declare as follows:

1. I am presently employed by the California Energy Commission in the Engineering Office of the Siting, Transmission and Environmental Protection Division as a Senior Mechanical Engineer.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on **Facility Design** for the **Black Rock Amendment** based on my independent analysis of the Petition for Amendment and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issues addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: March 30, 2010 Signed:

At: Sacramento, California

Erin Bright
Mechanical Engineer

Experience Summary

Two years of experience in the electric power generation field, including analysis of noise pollution, construction/licensing of electric generating power plants, and engineering and policy analysis of thermal power plant regulatory issues. One year of experience in the alternative energy field, including analysis of alternative fuel production and use.

Education

- University of California, Davis--Bachelor of Science, Mechanical Engineering and Materials Science
- University of California, Davis Extension Program--Renewable Energy Systems

Professional Experience

2007 to Present-- Mechanical Engineer, Energy Facilities Siting Division - California Energy Commission

Performed analysis of generating capacity, reliability, efficiency, noise, and the mechanical, civil/structural and geotechnical engineering aspects of power plant siting cases.

2006 to 2007--Energy Analyst, Fuels & Transportation Division - California Energy Commission

Performed analysis of use potential and environmental effects of emerging non-petroleum fuels, including compressed natural gas, biomass, hydrogen and electricity, in heavy and light duty transportation vehicles. Contributor to Energy Commission's alternative fuels plan.

DECLARATION OF
Dal Hunter, Ph.D., C.E.G.

I, **Dal Hunter**, declare as follows:

1. I am presently employed as a subcontractor to Aspen Environmental Group, a contractor to the California Energy Commission, Systems Assessment and Facilities Siting Division, as an engineering geologist.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on **Geology and Paleontology**, for the **Black Rock 1, 2, and 3 Geothermal Power Project Major Amendment** based on my independent analysis of the Petition for Amendment and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issues addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: March 23, 2010 Signed: ______

At: Reno, Nevada

REGISTERED GEOLOGIST
ROBERT DALTON HUNTER
No. 1411
CERTIFIED ENGINEERING GEOLOGIST
STATE OF CALIFORNIA

exp 3.31.11

Robert D. Hunter, Ph.D., C.E.G.
Engineering Geologist
Vice President

Education

- Ph.D. – Geology – 1989 – University of Nevada, Reno
- M.S. – Geology – 1976 – University of California - Riverside
- B.S. – Earth Science – 1972 – California State University, Fullerton

Registrations

- Professional Geological Engineer – Nevada
- Registered Geologist – California
- Certified Engineering Geologist – California

Experience

1997 to Present: Black Eagle Consulting, Inc.; Vice President. Dr. Hunter is in charge of all phases of geochemical, geological, and geotechnical projects and is responsible for conducting, coordinating, and supervising geotechnical investigations for public and private sector clients. He is very familiar with design specifications and state and federal requirements.

Dr. Hunter has also provided geological, geotechnical, and paleontological review and written and oral testimony for California Energy Commission (CEC) power plant projects including:

- El Segundo Power Redevelopment Project (Coastal, including testimony and compliance monitoring)
- Magnolia Power Project (including compliance monitoring
- Ocotillo Energy Project (Wind Turbines)
- Vernon-Malburg Generating Station
- Inland Empire Energy Center (including testimony and compliance monitoring)
- Palomar Energy Project
- Henrietta Peaker Project
- East Altamont Energy Center
- Avenal Energy Center
- Teayawa Energy Center monitoring
- Walnut Energy Center (including compliance monitoring
- Riverside Energy Resource Center
- Salton Sea Unit 6 (Geothermal Turbines)
- National Modoc Power Plant
- Pastoria Energy Center
- Sun Valley Energy Project
- El Centro Unit 3 Repower Project
- AES Highgrove Project
- South Bay Replacement Project
- Vernon Power Plant

- Humboldt Bay Repowering Project
- Victorville Power Project
- Carlsbad Energy Center
- San Gabriel Generating Station
- Orange Grove
- Chula Vista Energy Upgrade
- Carrizo (Solar)
- Kings River
- Canyon Power Plant
- Otay Mesa Generating Project (compliance monitoring)
- Montainview Power Plant Project (compliance monitoring)
- Consumes Power Plant (compliance monitoring)
- Sunrise Power Project (compliance monitoring)
- Niland Power Project (compliance monitoring)
- Panoche Power Plant (compliance monitoring)

Attended Expert Witness Training Sponsored by CEC.

1978 to 1997: SEA, Incorporated; Geotechnical Manager, Engineering Geologist. Dr. Hunter was in charge of all phases of geotechnical projects for SEA, including project coordination and supervision, field exploration, geotechnical analysis, slope stability analysis, soil mechanics, engineering geochemistry, mineral and aggregate evaluations, and report preparation. Numerous investigations were undertaken on military, commercial, industrial, airport, residential, and roadway projects. He worked on many geothermal power plants, providing expertise in foundations design, slope stability, seismic assessment, geothermal hazard evaluation, expansive clay, and settlement problems. Project types included high-rise structures, airports, warehouses, shopping centers, apartments, subdivisions, storage tanks, roadways, mineral and aggregate evaluations, slope stability analyses, and fault studies.

1977 to 1978: Fugro (Ertec) Incorporated Consulting Engineers and Geologists; Staff Engineering Geologist; Long Beach, California.

Affiliations

- Association of Engineering Geologists

Publications

- Hunter, 1988, *Lime Induced Heave in Sulfate Bearing Clay Soils*, Journal of Geotechnical Engineering, ASCE, Vol. 14, No. 2, pp. 150-167.

- Hunter, 1989, *Applications of Stable Isotope Geochemistry in Engineering Geology*: Proceedings of the 25th Annual Symposium on Engineering Geology and Geotechnical Engineering.

- Hunter, 1993, *Evaluation of Potential Settlement Problems Related to Salt Dissolution in Foundation Soils*: Proceedings of the 29th Annual Symposium on Engineering Geology and Geotechnical Engineering.

DECLARATION OF
Sudath Edirisuriya

I, Sudath Edirisuriya declare as follows:

I am presently employed by the California Energy Commission in the Engineering Office of the Systems Assessments and Facilities Siting Division as an Associate Electrical Engineer.

A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

I helped prepare the staff testimony on Transmission System Engineering for the Black Rock Unit 1,2 and 3 amendment based on my independent analysis and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue(s) addressed therein.

I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Sudath Edirisuriya

Date: March 23, 2010. Signed: Sudath Edirisuriya

At: Sacramento, California

Sudath A. Edirisuriya
1916 Ackleton Way
Roseville CA 95661 Phone 916-654-4851

EDUCATION:
Bachelor of Science in Electrical Engineering at California State University Fullerton

ATTAINMENTS:
Member of the Professional Engineers in California Government
Vice President Electrical Engineering Society-California State University Fullerton.

EXPERIENCE:

November-2001 to Present: - Associate Electrical Engineer, System Assessment and Facilities Siting Division, California Energy Commission.
Working in the Transmission System Engineering unit on licensing generation projects. Work involves evaluating generation interconnection studies (SIS and FS), their reliability and environmental impacts on transmission system, preparing staff assessment reports, presenting testimony. Perform reliability studies and coordinating data and technical activities with utilities, California ISO and other agencies. Conduct and perform planning studies and contingency analysis including power flow, short-circuit, transient, and post-transient analysis to maintain reliable operation of the power system. Understanding of regulatory and reliability guidelines, WECC and NERC planning and operation criteria, CPUC and FERC requirements. Review technical analyses for WECC/CA ISO/PTO transmission systems and proposed system additions; and provide support for regulatory filings.

June-1998 to November-2001: - Project Electrical Engineer, Design Electrical Engineering Section, Department of Transportation, California.
Electrical Engineering knowledge and skills in the design, construction and maintenance of California state work projects involving all the public work areas; contract administration, construction management, plan checking, field engineering and provide liaison with consultants, developers, and contractors. Plan review in facility constructions, highway lighting, sign lighting, rest area lighting, preparation of project reports, cooperative agreements, review plans for compliance of construction and design guide lines for national electrical code, standards and ordinance. Review process included breaker relay coordination, detail wiring diagrams, layout details, service coordination, load, conductor sizes, derated ampacity, voltage drop calculations, harmonic and flicker determination.

June-1993 to May-1998:- Substation Electrical Engineer, City of Anaheim, California.
Performed protective relay system application, design and setting determination in Transmission & Distribution Substation. Understanding of principles of selective coordination system protection and controls for Electric Utility Equipment. Understanding of Power theory and Analysis of symmetrical components. Ability to review engineering plans, specifications, estimates and computation for Electrical

Utility Projects. Practices of Electrical Engineering design, to include application of Electro-mechanical and solid state relays in Electrical Power Systems. Software skills in RNPDC (Fuse Coordination Program), Capacitor Bank allocation program, and GE Load Flow Program. Design projects using CAD, Excel spread sheets including cost estimates, wiring diagrams, material specifications and field coordination.

Performed underground service design 12kV and 4kV duct banks; pole riser; getaway upgrade; voltage drop calculation, ampacity calculation and wiring diagrams. Design and maintenance of substations in City Electrical Utility System. Upgrade Station Light and power transformers; upgrade capacitor banks; replacement of 12kV-4kV power circuits; Breakers at Metal Clad Switchgear. Design one-line diagrams; three line diagrams; grounding circuits; schematics; coordination of relay settings; conduit and material list preparation. Calculation of derated ampacity; inrush current, short circuit current.

DECLARATION OF
Mark Hesters

I, **Mark Hesters**, declare as follows:

1. I am presently employed by The California Energy Commission in the **Siting, Transmission and Environmental Protection Division** as a Senior Electrical Engineer.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on **Transmission System Engineering**, for the **Black Rock 1, 2, and 3 Geothermal Power Project**, based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issues addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 7/12/10 Signed:______________________

At: Sacramento, CA________________

Mark Hesters
Associate Electrical Engineer

Mark Hesters has fourteen years of experience in electric power regulation. He worked in the Engineering Office of the California Energy Commission's Energy Facilities Siting & Environmental Protection Division since 1998 providing analysis of California transmission systems and testimony on transmission systems in several Commission power plant certification processes. Prior to that Mark worked in the CEC's Electricity Analysis Office providing lead analysis on Southern California Edison resource issues and modeling support for all areas of California. He holds a B.S. degree from the University of California at Davis in Environmental Policy Analysis and Planning.