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STATE OF CALIFORNIA

Energy Resources Conservation
And Development Commission

In the Matter of: Application for Certification For the Blythe Solar Power Project Palo Verde Solar, LLC	Docket No. 09-AFC-6

Energy Commission Staff's Final Transmission System Engineering Analysis and Attachments

The Blythe Solar Power Project Committee held evidentiary hearings on July 15 and 16, 2010, for the purpose of receiving evidence concerning the Blythe Solar Power Project's conformance with laws, ordinances, regulations and standards and its potential to result in significant adverse environmental impacts. At that time Energy Commission staff had not yet received the California Independent System Operator's Phase II analysis and, thus, could not reach a conclusion in the technical area of Transmission System Engineering. The Committee left the evidentiary record open for receipt of this analysis. In late July, staff received the necessary study and has completed its analysis, which is attached, along with the Phase II study and an analysis of the potential environmental impacts resulting from the construction of the Red Bluff substation and subsequent loop in of the second circuit of the Colorado River – Devers 500 kV transmission line, which has been identified as a necessary element for the interconnection of BSPP. Please mark this filing as exhibit 217. If the parties do not object, staff stipulates to entering this testimony into the record by declaration.

DATED: August 6, 2010

Respectfully submitted,

/s/ Lisa M. Decarlo

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D.5 - TRANSMISSION SYSTEM ENGINEERING

Testimony of Laiping Ng and Mark Hesters

D.5.1 SUMMARY OF CONCLUSIONS

The proposed interconnecting facilities including the Blythe Solar Power Project (BSPP) 230 kV switchyard, two 230 kV overhead generator tie-lines and its termination at the proposed Southern California Edison (SCE) Colorado River 230 kV Substation are acceptable and would comply with applicable laws, ordinances, regulations and standards (LORS). The project interconnection to the grid would require additional downstream transmission facilities (other than those proposed by the applicant) that require California Environmental Quality Act (CEQA) review. The CEQA review of the downstream transmission facilities has been included as attachment to this document.

The California Independent System Operator's (California ISO) Transition Cluster Phase II Study Report – Group Report in SCE's Eastern Bulk System (Phase II Group Study) indicates the reliable interconnection and delivery of projects in the Eastern bulk system, which includes the BSPP, would require the following upgrades to the existing or planned SCE transmission system:

- Replacement or upgrade of many circuit breakers at substations in the SCE system. Circuit breaker replacement generally occurs within the fence line of existing substation facilities.

- Construction of the Red Bluff substation and looping the 2nd Colorado River – Devers 500kV transmission line into the proposed Red Bluff substation. The environmental analysis of this approximately 2 miles of new transmission facilities and the Red Bluff substation has been included as Appendix B of this document. This appendix contains an environmental analysis of the Red Bluff Substation and other improvements identified in the Phase II study and was originally written for use in the Palen Solar Power Project staff assessment, but is equally applicable here due to BSPP's reliance on this same infrastructure.

- The use of new or expanded Special Protection Systems (SPS). These are essentially operating procedures that reduce the output of generators under specific conditions in order to avoid overloading transmission equipment.

- Expansion of the proposed Colorado River substation. The interconnection of the BSPP and other generators in the region to the licensed, but not built Colorado River Substation, would require the size of the substation to increase by approximately 48 acres. The environmental analysis of the substation expansion was provided in the Supplemental Staff Assessment Transmission System Engineering Appendix A.

- The reconductoring and relocation of four 220 kV transmission lines west of the Devers substation. These upgrades, called the West of Devers upgrades, have been identified in SCE transmission plans for several years starting in 2007 as needed to reliably serve future loads in the SCE area and would therefore be needed to maintain system reliability even if the Eastern Bulk System generators were not constructed.

- Reconductor of the drops of the Mira Loma – Vista 220 kV transmission line at the Vista substation. The "drops" are the portion of the line that comes into the substation and would not require environmental analysis.

Staff's proposed Condition of Certification TSE -5 requires the submittal of the executed Large Generator Interconnection Agreement (LGIA) and that the design, construction, and operation of the proposed transmission facilities conform to all applicable LORS prior to the start of construction of transmission facilities.

D.5.2 INTRODUCTION

D.5.2.1 STAFF ANALYSIS

This Transmission System Engineering (TSE) analysis examines whether this project's proposed interconnection conforms to all LORS required for safe and reliable electric power transmission. Additionally, under California Environmental Quality Act (CEQA), the California Energy Commission (Energy Commission) must conduct an environmental review of the "whole of the action," which may include facilities not licensed by the Energy Commission (California Code of Regulations, title 14, §15378). The Energy Commission must therefore identify the system impacts and necessary new or modified transmission facilities downstream of the proposed interconnection that are both required for interconnection and represent the "whole of the action."
Energy Commission staff relies upon the interconnecting authority, in this case the California ISO, for the analysis of impacts on the transmission grid from the proposed interconnection, as well as the identification and approval of new or modified facilities downstream that could be required for mitigation.

The proposed BSPP would connect to the SCE transmission system and require both analysis by SCE and approval by the California ISO.

D.5.2.2 SOUTHERN CALIFORNIA EDISON'S ROLE

SCE is responsible for ensuring electric system reliability on its transmission system with the addition of proposed transmission modifications, and determines both the standards necessary to ensure reliability and whether the proposed transmission modifications conform to existing standards. The California ISO has provided an analysis in its Phase I Study and will provide analysis in its Phase II Study, and its approval for the facilities and changes required in its system for addition of the proposed transmission modifications.

D.5.2.3 CALIFORNIA ISO'S ROLE

The California ISO is responsible for dispatching generating units in California, establishing the order in which electricity will be used, ensuring electric system reliability for all participating transmission owners and is also responsible for developing the standards and procedures necessary for system reliability. The California ISO will review SCE's studies to ensure the adequacy of the proposed BSPP transmission interconnection. The California ISO will also determine the reliability impacts of the proposed transmission modifications on SCE's transmission system in accordance with all applicable reliability criteria. According to the California ISO Tariff, it will determine the need for transmission additions or upgrades downstream from the interconnection point to ensure reliability of the transmission grid. The California ISO will, therefore, perform the Phase I Interconnection Study, provide its analysis, conclusions, and recommendations, and issue a preliminary approval or concurrence letter to SCE. On completion of the Phase II Interconnection Study, the California ISO will provide its conclusions and recommendations, and issue a final approval/disapproval letter for the interconnection of the proposed generation project. If necessary, the California ISO will provide written and verbal testimony on its findings at the Energy Commission hearings.

D.5.3 LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

- The North American Electric Reliability Council's (NERC) Reliability Standards for the bulk electric transmission systems of North America provide national policies, standards, principles and guides to assure the adequacy and security of the electric transmission system. The NERC planning standards provide for system performance levels for both normal and contingency conditions. With regard to power flow and stability simulations, while these Standards are similar to NERC/Western Electric Coordinating Council (WECC) Planning Standards, certain aspects of the NERC/WECC standards are either more stringent or more specific than the NERC standards for Transmission System Contingency Performance. The NERC's planning standards apply not only to interconnected system operation but to individual service areas as well (NERC 2006).
- NERC/WECC Planning Standards: The WECC Planning Standards are merged with the NERC Reliability Standards to provide the system performance standards used to assess the reliability of the interconnected system. These standards require the uninterrupted continuity of service as their first priority, and the preservation of interconnected operation as their secondary priority. Some aspects of NERC/WECC standards are more stringent or specific than NERC standards alone. These standards include the 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 upon Section I.A of the standards, *NERC and WECC Planning Standards with Table I and WECC Disturbance-Performance Table* and on Section I.D, *NERC and WECC Standards for Voltage Support and Reactive Power.* These standards require that the results of power flow and stability simulations verify defined performance levels. Performance levels are defined by specifying allowable variations in thermal loading, voltage and frequency, and the loss of load that could occur on systems during various disturbances. Performance levels range from no significant adverse effects inside and outside a system area during a minor disturbance (loss of load or a single transmission element out of service) to a level that seeks to prevent system cascading and the subsequent blackout of islanded areas during a major disturbance (such as the loss of either multiple 500 kV lines along a common right-of-way, and/or the loss of multiple generators). While controlled loss of generation or load or system separation is permitted under certain circumstances, uncontrolled loss is not permitted (WECC 2002).

- California Public Utilities Commission (CPUC) General Order 95 (GO-95*), Rules for Overhead Electric Line Construction,* sets forth uniform requirements for the construction of overhead lines. Compliance with this order ensures both adequate service and the safety of both the public and the people who build, maintain, and operate overhead electric lines.
- CPUC General Order 128 (GO-128), *Rules for Construction of Underground Electric* Supply *and Communications Systems*, sets forth uniform requirements and minimum standards for underground supply systems to ensure adequate service and the safety of both the public and the people who build, maintain, and operate underground electric lines.
- National Electric Safety Code, 1999, provides electrical, mechanical, civil, and structural requirements for overhead electric line construction and operation.
- California ISO Planning Standards also provide standards and guidelines that assure the adequacy, security and reliability during the planning process of the California ISO's electric transmission facilities. The California ISO Planning Standards incorporate both NERC and WECC Planning Standards. With regard to power flow and stability simulations, the California ISO's Planning Standards are similar to those of the NERC and WECC and to the NERC Planning Standards for transmission system contingency performance. However, the California ISO's standards also provide additional requirements that are not found in the NERC, WECC, or NERC planning standards. The California ISO standards apply to all participating transmission owners that interconnect to both the California ISO-controlled transmission grid and to neighboring grids not operated by the California ISO (California ISO 2002a).
- California ISO and Federal Energy Regulatory Commission (FERC) electric tariffs provide guidelines for the construction of all transmission additions and upgrades (projects) within the California ISO-controlled grid. The California ISO also determines the "need" for the proposed project where it will promote economic efficiency and maintain system reliability. The California ISO also determines the cost responsibility of the proposed project and provides operational review for all facilities that are to be connected to the California ISO grid (California ISO 2003a).

D.5.4 PROJECT DESCRIPTION

D.5.4.1 SETTING AND EXISTING CONDITIONS

The applicant has proposed to interconnect the 1,000 megawatt (MW) BSPP to the SCE's planned Colorado River Substation. The BSPP would be located approximately two miles north of U.S. Interstate 10 and eight miles west of the City of Blythe in Riverside County, California. The proposed project would be developed in four phases or units. The proposed commercial operation dates are second quarter 2013, fourth quarter 2013, second quarter 2015, and second quarter 2016 for units 1 through 4, respectively.

The BSPP would be a solar thermal project which would use a solar parabolic trough technology to generate electricity. Arrays of parabolic mirrors collect heat from the sun and heat up the fluid in the solar field piping. Through a series of heat exchangers, heat is released to generate high pressure steam. The steam is then fed to a steam turbine generator (STG) to generate electricity.

The BSPP project would consist of four identical generating units (unit 1 to unit 4). Each unit would have its own solar field and power block. Each power block consists of a heat transfer fluid system, solar steam generator, a steam turbine generator, air-cooled condenser, and auxiliary equipment. Units 1 and 2 would each occupy 1,600 acres and units 3 and 4 would each occupy 1,200 acres. Each unit is expected to generate at a normal output of 250 MW. The total of four steam turbine generators is expected to generate 1,000 MW.

Each STG is rated at 300 MVA with a power factor of 0.90. The STG would be connected through a 24 kV 12,000-ampere disconnect switch and a 10,000-ampere generator circuit breaker via a short 12,000-ampere isolated phase bus duct to the low side of its dedicated 210/280/350 MVA generator step-up (18/230 kV) transformer. The 30 MW parasitic load for each unit would be provided through its dedicated back-fed transformer (18/6.9 kV) which is connected between the STG circuit breaker and the low side of the step-up transformer through 12,000-ampere disconnect switches and via a short 12,000-ampere isolated phase bus duct. The high side of the transformer would be connected through a 230 kV 3,000-ampere disconnect switch to the generator tie bus in the project switchyard (Solar Millennium 2009a, section 1.0, section 2.5.7, Solar Millennium 2010b, Figure 2-9).

D.5.4.2 SWITCHYARDS AND INTERCONNECTION FACILITIES

Units 1 and 2 would be connected to the first generator tie bus in the project switchyard by 230 kV overhead conductors 4,800-foot long and 14,200-foot long respectively, then through 230 kV 3,000-ampere disconnect switches. Units 3 and 4 would be connected to the second generator tie bus in the project switchyard by 230 kV overhead conductors 10,300-foot long and 7,400-foot long respectively then through 230 kV 3,000-ampere disconnect switches.

The BSPP switchyard would be connected from the two generator tie buses to SCE’s proposed Colorado River Substation via two new 230 kV overhead generator tie-lines, approximately 9.8 miles long, through 3,000-ampere disconnect switches and 3,000-ampere circuit breakers. Each 230 kV overhead generator tie-line would be built with single bundled 2156 kcmil (Bluebird) conductors. The generator tie-lines together could carry the full capacity of the 1,000 MW BSPP. The two generator tie-lines would be supported by 90-foot to 145-foot height single and double circuit towers. The applicant has proposed breaker-and-a-half bus work in the Colorado River Substation to accommodate the BSPP. Three 230 kV 3,000-ampere circuit breakers and six 230 kV 3,000-amperes disconnect switches would be needed at the Colorado River Substation for the interconnection of the BSPP. Power would be distributed to the SCE grid via transmission lines from the Colorado River Substation.

The applicant changed its original proposed interconnection voltage of 500 kV to 230 kV. Instead of a single 500 kV generator tie-line, the applicant proposed to use two separate 230 kV generator tie-lines. The California ISO accepted the changes prior to the Phase II Study (Solar Millennium 2010b, Solar Millennium 2010c).

The interconnection of the BSPP and other generators in the region to the licensed but not built Colorado River Substation would require the size of the substation to increase by approximately 48-acres. The analysis of the impacts of the substation expansion was provided in a Supplemental Staff Assessment as Appendix A to the Transmission System Engineering analysis.

The configuration of the BSPP 230 kV switchyard, the two 230 kV overhead generator tie-lines to the proposed SCE Colorado River Substation and its termination at the proposed substation would be adequate and in accordance with industry standards and good utility practices, and are acceptable to staff. The proposed Conditions of Certification TSE-1 through TSE-7 ensure that the proposed facilities are designed, built and operated in accordance with good utility practices and applicable LORS.

D.5.4.3 ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

For the interconnection of a proposed generating unit or transmission facility to the grid, the interconnecting utility and the control area operator are responsible for ensuring grid reliability. For the BSPP, SCE and the California ISO are responsible for ensuring grid reliability.

The California ISO's generator interconnection study process is in transition from a serial process to an interconnection window cluster study process. The BSPP was studied under the window cluster process and the transmission reliability impacts of the proposed project are studied in the Phase I and Phase II Interconnection Studies. The Phase I Interconnection Study is similar to the former System Impact Study except it is now performed for a group of projects in the same geographical area of a utility that apply for interconnection in the same request window. The Phase II Interconnection Study is performed after generators in each cluster meet specific milestones required to stay in the generator interconnection queue. The Phase II Interconnection Study is then performed based on the number of generators left in each cluster.

The Phase I Studies for projects in the transition cluster were conducted to determine the preferred and alternative generator interconnection methods and to identify any mitigation measures required to ensure system conformance with utility reliability criteria, NERC planning standards, WECC reliability criteria, and California ISO reliability criteria. Staff relies on the studies and any review conducted by the responsible agencies to determine the effect of the projects on the transmission grid and to identify any necessary downstream facilities or indirect project impacts required to bring the transmission network into compliance with applicable reliability standards (NERC2006, WECC 2006, California ISO 2002a, 2007a & 2009a).

The Phase I Study analyzes the grid with and without the generator or generators in a cluster under conditions specified in the planning standards and reliability criteria. The standards and criteria define the assumptions used in the study and establish the thresholds by which grid reliability is determined. The studies must analyze the impact of the projects for their proposed first year(s) of operation and thus are based on a forecast of loads, generation and transmission. Load forecasts are developed by the interconnected utility, which would be SCE in this case. Generation and transmission forecasts are based on the interconnection queue. The studies are focused on thermal overloads, voltage deviations, system stability (excessive oscillations in generators and transmission system, voltage collapse, loss of loads or cascading outages), short circuit duties and substation evaluation.

Under the new Large Generator Interconnection Procedures (LGIP), generators are able to choose between either “full capacity” or “energy only” depending on whether or not the generator wants to have the right to generate energy 24-hours per day. A generator that chooses the full capacity option will be required to pay for transmission network upgrades that are needed to allow the generator to operate under virtually any system conditions and as such could sign contracts that allowed them to provide capacity to utilities. Energy only generators would not pay for network transmission upgrades, and essentially would have access to as available transmission capacity, and would likely not be able to sign capacity contracts.

If the studies show that the interconnection of the project or cluster of projects causes the grid to be out of compliance with reliability standards, the studies will then identify mitigation alternatives or ways in which the grid could be brought into compliance with reliability standards. If the interconnecting utility determines that the only feasible mitigation includes transmission modifications or additions which require CEQA review as part of the “whole of the action,” the Energy Commission must analyze those modifications or additions according to CEQA requirements. Where the Phase I Study identifies transmission modifications required for the reliable interconnection of a cluster of generators, staff will analyze the proposed generating project’s impact on individual reliability criteria violations to determine whether or not the identified mitigation measures are a reasonably foreseeable consequence of the proposed project.

D.5.4.4 SCOPE OF TRANSITION CLUSTER PHASE I AND PHASE II INTERCONNECTION STUDIES

The July 28, 2009, Transition Cluster Phase I Interconnection Study was prepared by the California ISO in coordination with SCE. Fifteen queue generation projects, including the proposed 500 MW BSPP in the Eastern Riverside County area with a total of 9,690 MW net generation output, were included in this cluster study. As of December 4, 2009 only five projects (2,200 MW) of the original 15 projects remained in the interconnection queue. Reducing the size of the cluster by 10 projects and over 7,000 MW meant the Phase I Study results for the cluster were not a reasonable forecast of the reliability impacts of the proposed project.

Generally staff relies on the California ISO Phase I/SIS to determine whether or not the proposed generation project will likely comply with reliability and to identify the transmission facilities required for reliable interconnection. For the Transition Cluster projects, the Phase I Study did not provide an accurate forecast of impacts of the BSPP on the SCE transmission grid. Therefore, staff has relied on the Phase II Study that was completed on July 8, 2010 and received on July 23, 2010, to determine the BSPP impact on grid reliability and identify transmission upgrades for reliable interconnection.

The changes between the Transition Cluster Phase I and Phase II Group Studies for the Eastern Bulk System included the withdrawal of ten generation projects totaling 7,490 MW, changing the point of interconnection of one generation project, and a reduction of 350 MW of generation from two projects. For study purposes, five generation projects totaling a maximum output of 2,200 MW were included in the SCE Transition Cluster base cases. Three of these projects, BSPP, the Palen Solar Power Project and the Genesis Solar Energy Project are currently seeking licenses from the California Energy Commission.

The Phase II Group Study modeled the Blythe project with a net output of 1,000 MW. The base case was developed from WECC's 2013 Peak load and 2013 Off-Peak load base case series and included all major SCE transmission projects, and all proposed higher queued generation projects that will be operational by 2013. The Phase II Group Study pre-project base cases were modeled to include the Devers-Colorado River project (DCR), which is the California portion of Devers-Palo Verde 2 (DPV2), and the proposed 500 kV switchyard at Colorado River substation. The power flow studies were conducted with and without the proposed Transition Cluster Phase II projects connected to the SCE grid at each project's interconnection switchyard. The detailed study assumptions were described in the study. The power flow study assessed the Transition Cluster Phase II projects' impact on thermal loading of the transmission lines and equipment. Transient and post-transient studies were conducted using the Peak load full loop base case to determine whether the Transition Cluster Phase II projects would create instability in the system following certain selected outages. Short circuit studies were conducted to determine if the Transition Cluster Phase II projects would overstress existing substation facilities. (Transition Cluster Phase II Interconnection Study Report, SCE's Eastern Bulk System)

PHASE II STUDY RESULTS FOR TRANSITION CLUSTER PROJECTS

Power Flow Study Results and Mitigation Measures

The Phase II Group Study identified pre-project overload criteria violations under 2013 Summer Peak and Off-Peak study condition. Pre-project overloads are caused by either existing system conditions or by projects with higher positions in the SCE's generator interconnection queue. The study concluded that the addition of the Phase II Transition Cluster projects would cause a number of pre-existing normal and /or emergency overloads to increase and would cause some new normal and emergency overloads.(CalISO 2010a)

Results of the Phase II Group Study are detailed below. Where potential overloads were identified, mitigation was proposed to eliminate the potential reliability impact.

Normal Overloads (N-0): The power flow study indicated that the Phase II Transition Cluster projects would cause three normal overloads under 2013 Peak load conditions and Off-Peak load conditions. The predicted overload facilities were the same for both Peak and Off-Peak load conditions.

Overloaded Transmission Facilities:

- Devers-San Bernardino 230 kV No. 1 line
- Devers-San Bernardino 230 kV No. 2 lines
- Devers-Vista 230 kV No. 1 line

Recommended Mitigation:

A combination of congestion management for base case and contingency overloads, the West-of-Devers upgrade projects, and the looping the 2nd Colorado River –Devers 500 kV transmission line into the Red Bluff substation are required to mitigate the power flow impacts caused by the project. The detailed electrical facilities needed to mitigate the overload criteria violations have been addressed and selected in the group report in SCE's Eastern Bulk System.

Category B (N-1): The power flow study indicated that the Phase II Transition Cluster projects would cause four N-1 overloads under 2013 Peak load conditions and Off-Peak load conditions. The predicted overload facilities were the same for both Peak and Off-Peak load conditions.

Overloaded Transmission Facilities:

- Devers-San Bernardino 230 kV No. 1 line
- Devers-San Bernardino 230 kV No. 2 line
- Devers-Vista 230 kV No. 1 line
- Devers-Vista 230 kV No. 2 line

Recommended Mitigation:

A combination of congestion management for base case and contingency overloads, the West-of-Devers upgrade project, and the looping the 2nd Colorado River –Devers 500 kV transmission line into the Red Bluff substation are required to mitigate the power flow impacts caused by the project. The detailed electrical facilities needed to mitigate the overload criteria violations have been addressed and selected in the group report in SCE's Eastern Bulk System.

Category C (N-2): The power flow study indicated that the Phase II Transition Cluster projects would cause five new N-2 overloads under 2013 Peak load conditions and Off-Peak load conditions. The three predicted overload facilities were the same for both Peak and Off-Peak load conditions. Additionally one new overload was revealed.

Overloaded Transmission Facilities:

- Devers-San Bernardino 230 kV No. 1 line
- Devers-San Bernardino 230 kV No. 2 line
- Devers-Vista 230 kV No. 1 line
- Devers-Vista 230 kV No. 2 line
- Mira Loma-Vista 230 kV No. 2 line

Recommended Mitigation:
A combination of congestion management, the West-of-Devers upgrade project, and the looping the 2nd Colorado River –Devers 500 kV transmission line into the Red Bluff substation are required to mitigate the power flow impacts caused by the project. The detailed electrical facilities needed to mitigate the overload criteria violations have been addressed and selected in the group report in SCE's Eastern Bulk System.

Short Circuit Study Results, Mitigation Measures and Substation Evaluation

Short Circuit studies were performed to determine the degree to which the addition of the Phase II Transition Cluster projects increases fault duties at SCE's substations, adjacent utility substations, and the other 115 kV, 230 kV and 500 kV busses within the study area. The fault duties were calculated with and without the Phase II Transition Cluster projects to identify any equipment overstress conditions. All bus locations where the Phase II Transition Cluster projects increased the short circuit duty by 0.1 kA or more and where the short circuit duty was in excess of 60% of the minimum breaker nameplate rating are listed in Appendix H of the Transition Cluster Phase II Interconnection Study Report, SCE's Eastern Bulk System. With the addition of the Transition Cluster Phase II projects, the following overstressed circuit breakers were identified at the following substations:

- Vincent 500 kV Substation: replace seven circuit breakers and upgrade four circuit breakers
- Kramer 220 kV Substation: replace five circuit breakers
- Windhub 220 kV Substation: sectionalize 220 kV bus
- Antelope 66 kV Substation: operating procedure to reduce short circuit duty

To interconnect the BSPP to the Colorado River Substation and deliver the power generated by the BSPP, the substation would require expansion to include a new 500/230 kV transformer and installation of the required interconnection equipment. Detailed substation upgrades are listed in the Transition Cluster Phase II Interconnection Study Report, Appendix A, Section 11.

Transient Stability Study Results and Mitigation Measures

Transient stability studies were conducted using the full loop base cases to ensure that the transmission system remained in operating equilibrium, as well as operating in a coordinated fashion, through abnormal operating conditions after the Phase II Transition Cluster projects became operational. Disturbance simulations were performed for a study period of 10 seconds to determine whether the Phase II Transition Cluster projects would create any system instability during line and generator outages. All outage cases were evaluated with the assumption that existing Special Protection Systems (SPS) or Remedial Action Schemes (RAS) would operate as designed. The most critical single contingency and double contingency outage conditions in the east and west of Devers area within the overall SCE Eastern Bulk System were evaluated. The transient study identified system instability during the Category C (N-2) outages.

Therefore, an SPS has been proposed as a mitigation measure that will curtail the 1,400 MW of generation of the Phase II Transition Cluster projects. The proposed BSPP project has been included in rearming the SPS. (Transition Cluster Phase II Interconnection Study Report, SCE's Eastern Bulk System, Appendix F Dynamic Stability Plots)

<u>Reactive Power Deficiency Analysis Results</u>

Reactive power deficiency analysis was performed to determine the system performance according to the NERC/WECC planning criteria. The reactive power deficiency analysis included power flow sensitivity analysis in the Eastern Bulk System. The study found no reactive deficiency from this PSPP project to the SCE bulk system.

D.5.4.5 CEQA LEVEL OF SIGNIFICANCE

Generally staff relies on the California ISO Phase I /System Impact Study to determine whether or not the proposed generation project will likely comply with reliability and to identify the transmission facilities required for reliable interconnection. For the Transition Cluster projects, the Phase I Interconnection Study did not provide an accurate forecast of impacts of the BSPP on the SCE transmission grid. Therefore, staff relied on the Phase II Study that was completed on July 8, 2010 and received on July 23, 2010, to determine the PSPP impact on grid reliability, identify transmission upgrades for reliable interconnection, and mitigation measures to this SA. In order to ensure compliance with reliability LORS, Condition of Certification TSE-5 requires the executed Large Generator Interconnection Agreement (LGIA) prior to the start of construction of transmission facilities.

D.5.4.5.1 DOWNSTREAM FACILITIES

The Phase II Study determined that several downstream reliability upgrades outside the existing substation fence lines will be needed to accommodate Eastern Bulk System cluster of projects which includes the proposed BSPP. Many of the downstream upgrades would be constructed within the fence line of an existing substation and would require little or no environmental licensing while other upgrades would require environmental permitting and analysis by the California Public Utilities Commission (CPUC) and relevant federal agencies.

In summary, to reliably interconnect and deliver the power generation of the Eastern Bulk System generators, including the BSPP, the following network upgrades are required:

- Replacement and upgrade of circuit breakers at the Vincent, Kramer, Windhub and Antelope substations. Circuit breaker replacement or upgrades generally occur within the fence lines of existing facilities and do not require CEQA analysis.
- Construction and/or expansion of the Red Bluff Substation and the looping in of the Colorado River-Devers 500 kV No. 2 transmission line into the Red Bluff Substation. The environmental analysis of the Red Bluff substation and the loop in of the Colorado River – Devers 500 kV transmission line was completed for the Palen Solar Power Project and has been provided in Transmission System

Engineering Appendix B. This appendix contains an environmental analysis of the Red Bluff Substation and other improvements identified in the Phase II study and was originally written for use in the Palen Solar Power Project staff assessment, but is equally applicable here due to BSPP's reliance on this same infrastructure. These facilities will require a full CEQA analysis and license from the CPUC and an Environmental Impact Statement from Bureau of Land Management.

- The expansion of the Colorado River Substation. The interconnection of the BSPP and other generators in the region to the licensed, but not built Colorado River Substation, would require the size of the substation to increase by approximately 48 acres. The environmental analysis of the substation expansion was provided in the Supplemental Staff Assessment for the Blythe Solar Power Project as Appendix A to the Transmission System Engineering analysis. The expansion of the proposed Colorado River Substation is required for all of the Easter Bulk System projects and the environmental analysis is the same.
- Replacement of the drops on Mira Loma-Vista 230 kV No. 2 transmission at Vista Substation. The drops are the segment of the line that enters the substation and do not require environmental analysis.
- Development of SPS which would drop generation under certain contingency conditions.
- The West of Devers 230 kV Line Upgrades project. The West of Devers project consists of the reconductoring and relocation of two 35-mile 220 kV circuits between the Devers and San Bernardino substations and two 37-mile 220 kV circuits between the Devers and Vista substations. The West of Devers project has been included in the SCE/California ISO Transmission Plan for several years because it is needed to reliably serve loads in southern California. Because the West of Devers project is a previously planned project that would be required for the SCE system to meet reliability standards even if the Eastern Bulk System generators were not operating staff does not believe transmission upgrade should be considered a reasonably foreseeable consequence of the BSPP.

D.5.5 RECONFIGURED ALTERNATIVE

The Reconfigured Alternative would be a 1,000 MW solar facility that would retain use of the proposed solar Units 1, 2, and 4 (the two northern solar fields, and the southeastern solar field) at their proposed locations as shown on Figure DR-ALT-43-1. The proposed Unit 3 (the southwestern solar field) would be relocated approximately 0.8 miles south of its proposed location. This alternative is analyzed because (1) it would retain the 1,000 MW generation capacity defined for the proposed project and the engineering is defined by Solar Millennium as feasible, and (2) it minimizes impacts to state waters and desert dry wash woodlands, a vegetation community classified as sensitive by the Bureau of Land Management (BLM) and California Department of Fish and Game (CDFG). Approximately 480 acres of the Reconfigured Alternative would be outside of the right-of-way (ROW) application area but the alternative would remain entirely within BLM-managed lands. The Reconfigured Alternative is shown in **Alternatives Figure 1**.

D.5.5.1 SETTING AND EXISTING CONDITIONS

This alternative includes Units 1, 2, and 4 as proposed for the BSPP as well as a reconfigured Unit 3. The setting for Units 1, 2, and 4 would not change from that for the proposed project. Unit 3 would be relocated approximately 0.8 miles south of the proposed location. The relocated Unit 3 includes the use of 480 acres of BLM land immediately south of the proposed ROW.

Similar to the proposed project, the Reconfigured Alternative would transmit the same amount of power output to the grid through the Colorado River Substation. It would require the same infrastructure as the proposed project, including transmission line and switchyard. The transmission line would remain approximately the same length as for the proposed project. The required linear facility routes may require minor adjustments.

D.5.5.2 ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

This alternative would require the same solar fields and power blocks, and would generate the same output as the proposed option. It would require the same distribution and substation facilities to be built within the project site. No additional potential downstream transmission upgrades are required. The Reconfigured Alternative would not cause significantly different impacts from the proposed option which would require different mitigation.

D.5.5.3 CEQA LEVEL OF SIGNIFICANCE

This alternative would require the same distribution and transmission facilities to be built on the project site. Because this option retains the 1,000 MW project output and the proposed interconnection to the Colorado River Substation, no additional potential downstream transmission upgrades would be required. This option would not cause additional environmental impacts which would require additional CEQA analysis.

D.5.6 REDUCED ACREAGE ALTERNATIVE

The Reduced Acreage Alternative would essentially be Units 1, 2, and 4 of the proposed project, and would be a 750 MW solar facility located within the boundaries of the proposed project as defined by Solar Millennium. This alternative is analyzed for two major reasons: (1) it eliminates about 25 percent of the proposed project area so all impacts are reduced, and (2) by removing the southwestern solar field, which is located on flowing desert washes, this alternative minimizes impacts to state waters and to desert dry wash woodlands, a vegetation community classified as sensitive by the BLM and CDFG, and to wildlife movement corridors. The boundaries of the Reduced Acreage Alternative are shown in **Alternatives Figure 2**.

D.5.6.1 SETTING AND EXISTING CONDITIONS

This alternative is located entirely within the boundaries of the proposed project. It eliminates effects to the southwestern 250 MW solar field (1,200 acres). As a result, the environmental setting consists of the northern and eastern portions of the proposed project, as well as the area affected by the linear project components.

The Reduced Acreage Alternative would retain 75 percent of the proposed project's generating capacity of approximately 750 MW and the project footprint would occupy approximately 4,750 acres of land. Units 1, 2, and 4 each include their own solar field and power blocks, heat transfer fluid systems, solar steam generators, and steam turbine generators, air-cooled condensers, and auxiliary equipment.

Similar to the proposed project, the Reduced Acreage Alternative would transmit power to the grid through the Colorado River Substation. It would require infrastructure including a transmission line and switchyard. The transmission line would remain approximately the same length as for the proposed project. The required linear project components could require minor adjustment to accommodate the smaller configuration.

D.5.6.2 ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

This alternative would require fewer solar fields and power blocks, heat transfer fluid system, solar steam generator, steam turbine generator, air-cooled condenser, and various auxiliary equipment. It would require fewer distribution and substation facilities to be built within the project site. Additionally, this alternative would require fewer transmission system upgrades of the SCE grid.

D.5.6.3 CEQA LEVEL OF SIGNIFICANCE

This alternative would require fewer distribution and transmission facilities to be built in the project site. Therefore, installation of fewer transformers, collector distribution feeders and other electrical components would contribute less environmental impacts.

D.5.7 NO PROJECT/NO ACTION ALTERNATIVES

The No Project Alternative under CEQA or the No Action Alternative under NEPA defines the scenario that would exist if the proposed BSPP were not constructed. The CEQA Guidelines state that "the purpose of describing and analyzing a 'no project' alternative is to allow decision makers to compare the impacts of approving the proposed project with the impacts of not approving the proposed project" (Cal. Code Regs., tit. 14 § 15126.6(i)). The No Project analysis in this SA/DEIS considers existing conditions and "what would be reasonably expected to occur in the foreseeable future if the project were not approved…" (Cal. Code Regs, tit. 14 § 15126.6(e)(2)). Under NEPA, the No Action Alternative is used as a benchmark of existing conditions by which the public and decision makers can compare the environmental effects of the proposed action and the alternatives.

If the No Project/No Action Alternative were selected, the construction and operational impacts of the BSPP would not occur. There would be no grading of the site, no loss of resources or disturbance of approximately 9,400 acres of desert habitat, no impacts to cultural resources, and no installation of power generation and transmission equipment. The No Project/No Action Alternative would also eliminate contributions to cumulative impacts on a number of resources and environmental parameters in Riverside County and in the Colorado Desert as a whole.

In the absence of the BSPP, however, other power plants, both renewable and non-renewable, would have to be constructed to serve the demand for electricity and to meet RPS. If the No Project/No Action Alternative were chosen, other utility-scale solar power facilities may be built, and the impacts to the environment may be similar to those of the proposed project because these technologies require large amounts of land like that required for the Blythe Project. The No Project/No Action Alternative may also lead to siting of other non-solar renewable technologies to help achieve the California RPS.

Additionally, if the No Project/No Action Alternative were chosen, it is likely that additional gas-fired power plants would be built or that existing gas-fired plants could operate longer. If the proposed project were not built, California would not benefit from the reduction in greenhouse gases that this facility would provide, and SCE would not receive the 1,000 MW contribution to its renewable state-mandated energy portfolio.

D.5.8 CUMULATIVE IMPACT ANALYSIS

Staff has reviewed the lists of existing and foreseeable projects as presented in the Cumulative Scenario section of the BSPP RSA. Staff's review considers whether the interconnection of BSPP to SCE's transmission system along with other existing and foreseeable generation projects would conform to all LORS required for safe and reliable electric power transmission. The analysis described above under the heading Scope of the Transition Cluster Phase I and Phase II Interconnection Studies is conducted in coordination with the California ISO to consider existing and proposed generator interconnections to the transmission grid and the potential safety and reliability impacts under a number of conservative contingency conditions.

The cumulative marginal impacts to the safe and reliable operation of the transmission system due to the BSPP project, as identified in the pending Phase II Study, would be mitigated with the Energy Commission's incorporation of the mitigation measures and Conditions of Certification set forth in this section.

D.5.9 COMPLIANCE WITH LORS

The proposed interconnecting facilities including the BSPP 230 kV switchyard, the double circuit 230 kV overhead generator tie-lines, and termination to the new Colorado River Substation are adequate in accordance with industry standards and good utility practices, and are acceptable to staff. Staff proposed conditions of certification TSE-1 through TSE-7 would help ensure that construction and operation of the transmission facilities for the proposed BSPP would comply with applicable LORS.

D.5.10 PROPOSED CONDITIONS OF CERTIFICATION

TSE-1 The project owner shall provide the Compliance Project Manager (CPM) and the Chief Building Official (CBO) with a schedule of transmission facility design submittals, a master drawing list, a master specifications list, and a major equipment and structure list. The schedule shall contain both a description and a list of proposed submittal packages for design, calculations, and specifications for major structures and equipment. To facilitate audits by

Energy Commission staff, the project owner shall provide designated packages to the CPM when requested.

Verification: Prior to the start of construction, the project owner shall submit the schedule, a master drawing list, and a master specifications list to both the CBO and the CPM. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment (see a list of major equipment in **Table 1: Major Equipment List** below). Additions and deletions shall be made to the table only with both CPM and CBO approval. The project owner shall provide schedule updates in the monthly compliance report.

Table 1: Major Equipment List
Breakers
Step-up transformer
Switchyard
Busses
Surge arrestors
Disconnects
Take-off facilities
Electrical control building
Switchyard control building
Transmission pole/tower
Grounding system

TSE-2 Before the start of construction, the project owner shall assign to the project an electrical engineer and at least one of each of the following:

a) a civil engineer;

b) a geotechnical engineer or a civil engineer experienced and knowledgeable in the practice of soils engineering;

c) a design engineer who is either a structural engineer or a civil engineer and fully competent and proficient in the design of power plant structures and equipment supports; or

d) a mechanical engineer (Business and Professions Code Sections 6704 et seq. require state registration to practice as either a civil engineer or a structural engineer in California).

The tasks performed by the civil, mechanical, electrical, or design engineers may be divided between two or more engineers as long as each engineer is responsible for a particular segment of the project, e.g., proposed earthwork, civil structures, power plant structures, or equipment support. No segment of the project shall have more than one responsible engineer. The transmission line may be the responsibility of a separate California registered electrical engineer. The civil, geotechnical, or civil and design engineer, assigned as required by Facility Design Condition **GEN-5**, may be responsible for design and review of the TSE facilities.

The project owner shall submit to the CBO, for review and approval, the names, qualifications, and registration numbers of all engineers assigned to the project. If any one of the designated engineers is subsequently reassigned or replaced, the project owner shall submit the name, qualifications, and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer. This engineer shall be authorized to halt earth work and require changes if site conditions are unsafe or do not conform with the predicted conditions used as the basis for design of earth work or foundations.

The electrical engineer shall:

1. be responsible for the electrical design of the power plant switchyard, outlet, and termination facilities; and
2. sign and stamp electrical design drawings, plans, specifications, and calculations.

Verification: Prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, the names, qualifications, and registration numbers of all the responsible engineers assigned to the project. The project owner shall notify the CPM of the CBO's approvals of the engineers within five days of the approval.

If the designated responsible engineer is subsequently reassigned or replaced, the project owner has five days in which to submit the name, qualifications, and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.

TSE-3 If any discrepancy in design and/or construction is discovered in any engineering work that has undergone CBO design review and approval, the project owner shall document the discrepancy and recommend corrective action (2001 California Building Code, Chapter 1, section 108.4, approval required; Chapter 17, section 1701.3, *Duties and Responsibilities of the Special Inspector;* Appendix Chapter 33, section 3317.7, *Notification of Noncompliance*). The discrepancy documentation shall become a controlled document and shall be submitted to the CBO for review and approval and refer to this condition of certification.

Verification: The project owner shall submit a copy of the CBO's approval or disapproval of any corrective action taken to resolve a discrepancy to the CPM within 15 days of receipt. If disapproved, the project owner shall advise the CPM, within five days, the reason for the disapproval, along with the revised corrective action required to obtain the CBO's approval.

TSE-4 For the power plant switchyard, outlet line and termination, the project owner shall not begin any construction until plans for that increment of construction have been approved by the CBO. These plans, together with design changes and design change notices, shall remain on the site for one year after completion of construction. The project owner shall request that the CBO inspect the installation to ensure compliance with the requirements of applicable LORS. The following activities shall be reported in the monthly compliance report:

a) receipt or delay of major electrical equipment;

b) testing or energization of major electrical equipment; and

c) the number of electrical drawings approved, submitted for approval, and still to be submitted.

Verification: Prior to the start of each increment of construction, the project owner shall submit to the CBO for review and approval the final design plans, specifications and calculations for equipment and systems of the power plant switchyard, and outlet line and termination, including a copy of the signed and stamped statement from the responsible electrical engineer verifying compliance with all applicable LORS, and send the CPM a copy of the transmittal letter in the next monthly compliance report.

TSE-5 The project owner shall ensure that the design, construction, and operation of the proposed transmission facilities will conform to all applicable LORS, and the requirements listed below. The project owner shall submit the required number of copies of the design drawings and calculations, as determined by the CBO.

a) The power plant outlet line shall meet or exceed the electrical, mechanical, civil, and structural requirements of CPUC General Order 95 or National Electric Safety Code (NESC); Title 8 of the California Code and Regulations (Title 8); Articles 35, 36 and 37 of the *High Voltage Electric Safety Orders*, California ISO standards, National Electric Code (NEC) and related industry standards.

b) Breakers and busses in the power plant switchyard and other switchyards, where applicable, shall be sized to comply with a short-circuit analysis.

c) Outlet line crossings and line parallels with transmission and distribution facilities shall be coordinated with the transmission line owner and comply with the owner's standards.

d) The project conductors shall be sized to accommodate the full output of the project.

e) Termination facilities shall comply with applicable SCE interconnection standards.

f) The project owner shall provide to the CPM:

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

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

   iii) A copy of the executed LGIA signed by the California ISO and the project owner.

Verification: Prior to the start of construction of transmission facilities, the project owner shall submit to the CBO for approval:

1. Design drawings, specifications, and calculations conforming with CPUC General Order 95 or National Electric Safety Code (NESC); Title 8 of the California Code and Regulations (Title 8); Articles 35, 36 and 37 of the *High Voltage Electric Safety Orders*, CA ISO standards, National Electric Code (NEC) and related industry standards, for the poles/towers, foundations, anchor bolts, conductors, grounding systems, and major switchyard equipment;
2. For each element of the transmission facilities identified above, the submittal package to the CBO shall contain the design criteria, a discussion of the calculation method(s), a sample calculation based on "worst case conditions"[1] and a statement signed and sealed by the registered engineer in responsible charge, or other acceptable alternative verification, that the transmission element(s) will conform with CPUC General Order 95 or National Electric Safety Code (NESC); Title 8 of the California Code and Regulations (Title 8); Articles 35, 36 and 37 of the *High Voltage Electric Safety Orders*, California ISO standards, National Electric Code (NEC), and related industry standards;
3. Electrical one-line diagrams signed and sealed by the registered professional electrical engineer in charge, a route map, and an engineering description of the equipment and configurations covered by requirements **TSE-5** a) through f), above;
4. The Special Protection System (SPS) sequencing and timing if applicable shall be provided concurrently to the CPM;
5. A letter stating that the mitigation measures or projects selected by the transmission owners for each reliability criteria violation, for which the project is responsible, are acceptable;
6. The final Phase II Interconnection Study, including a description of facility upgrades, operational mitigation measures, and/or special protection system sequencing and timing if applicable; and
7. A copy of the executed LGIA signed by the California ISO and the project owner.

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

TSE-6 The project owner shall provide the following Notice to the California Independent System Operator (California ISO) prior to synchronizing the facility with the California Transmission system:

1. At least one week prior to synchronizing the facility with the grid for testing, provide the California ISO a letter stating the proposed date of synchronization; and
2. At least one business day prior to synchronizing the facility with the grid for testing, provide telephone notification to the California ISO Outage Coordination Department.

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

Verification: The project owner shall provide copies of the California ISO letter to the CPM when it is sent to the California ISO one week prior to initial synchronization with the grid. The project owner shall contact the California ISO Outage Coordination Department, Monday through Friday, between the hours of 0700 and 1530 at (916) 351-2300 at least one business day prior to synchronizing the facility with the grid for testing. A report of conversation with the California ISO shall be provided electronically to the CPM one day before synchronizing the facility with the California transmission system for the first time.

TSE-7 The project owner shall be responsible for the inspection of the transmission facilities during and after project construction, and any subsequent CPM and CBO approved changes thereto, to ensure conformance with CPUC GO-95 or NESC, Title 8, CCR, Articles 35, 36 and 37 of the, "High Voltage Electric Safety Orders", applicable interconnection standards, NEC and related industry standards. In case of non-conformance, the project owner shall inform the CPM and CBO in writing, within 10 days of discovering such non-conformance and describe the corrective actions to be taken.

Verification: Within 60 days after first synchronization of the project, the project owner shall transmit to the CPM and CBO:

1. "As built" engineering description(s) and one-line drawings of the electrical portion of the facilities signed and sealed by the registered electrical engineer in responsible charge. A statement attesting to conformance with CPUC GO-95 or NESC, Title 8, California Code of Regulations, Articles 35, 36 and 37 of the, "High Voltage Electric Safety Orders", and applicable interconnection standards, NEC, related industry standards.

2. An "as built" engineering description of the mechanical, structural, and civil portion of the transmission facilities signed and sealed by the registered engineer in responsible charge or acceptable alternative verification. "As built" drawings of the electrical, mechanical, structural, and civil portion of the transmission facilities shall be maintained at the power plant and made available, if requested, for CPM audit as set forth in the "Compliance Monitoring Plan".

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

D.5.11 CONCLUSIONS

The proposed interconnecting facilities including the proposed Blythe Solar Power Project (BSPP) 230 kV switchyard, two 230 kV overhead generator tie-lines and its termination at the proposed Southern California Edison (SCE) Colorado River 230 kV Substation are acceptable and would comply with applicable laws, ordinances, regulations and standards (LORS).

The Phase II Study identified six mitigation measures required to allow for the reliable operation and delivery of power from the BSPP. Where the mitigation had the potential for significant environmental impacts staff has provided an environmental analysis in Appendix A and Appendix B of this Transmission System Engineering Testimony. Facilities identified in Appendices A and B may require license or approval from the CPUC and/or the Bureau of Land Management.

Staff's recommended Conditions of Certification TSE 1 to TSE-7 would help ensure that the BSPP transmission facilities comply with applicable LORS.

D.5.12 REFERENCES

California ISO 1998a – California ISO tariff scheduling protocol posted April 1998, Amendments 1,4,5,6, and 7 incorporated

California ISO 1998b – California ISO dispatch protocol posted April 1998

California ISO 2002a – California ISO Grid Planning Standards, February 2002

California ISO 2003a - California ISO, FERC Electric Tariff, First Replacement Vol. No. 1, March 11, 2003.

California ISO 2009a - California Independent System Operator, Large Generator Interconnection Procedures, dated 8/18/2009.

Cal ISO2010a- Cal ISO (tn:57823). Redacted Phase II Study, dated 7/8/2010

NERC (North American Electric Reliability Council) 2006. Reliability Standards for the Bulk Electric Systems of North America, May 2 2006

Solar Millennium 2009a – Solar Millennium (tn: 52937). Application for Certification Vol 1 & 2, dated 8/24/2009.

Solar Millennium 2009b – Solar Millennium (tn: 54007). Data Adequacy Supplement, dated 10/26/2009.

Solar Millennium 2010b – Solar Millennium (tn: 54130). Response to Queries, dated 2/1/2010.

Solar Millennium 2010c – Solar Millennium (tn: 54213). Response to January 15 and 20, 2010 CEC Email Query from CEC staff, Additional Information regarding Transmission System Engineering., dated 2/3/2010.

WECC (Western Electricity Coordinating Council) 2002. NERC/WECC Planning Standards, August 2002

D.5.13 DEFINITION OF TERMS

AAC All aluminum conductor

ACSR Aluminum conductor steel-reinforced

ACSS Aluminum conductor steel-supported

Ampacity Current-carrying capacity, expressed in amperes, of a conductor at specified ambient conditions, at which damage to the conductor is nonexistent or deemed acceptable based on economic, safety, and reliability considerations

Ampere The unit of current flowing in a conductor

Bundled Two wires, 18 inches apart

Bus Conductors that serve as a common connection for two or more circuits

Conductor The part of the transmission line (the wire) that carries the current.

Congestion Management A scheduling protocol that ensures dispatched generation and transmission loading (imports) will not violate criteria

Double Contingency Also known as emergency or N-2 condition, occurs when a forced outage of two system elements occurs -- usually (but not exclusively) caused by one single event. Examples of an N-2 contingency include loss of two transmission circuits on single tower line or loss of two elements connected by a common circuit breaker due to the failure of that common breaker

Emergency Overload See Single Contingency condition. This is also called an N-1.

Kcmil or KCM Thousand circular mil. A unit of the conductor's cross sectional area; when divided by 1,273, the area in square inches is obtained.

Kilovolt (kV) A unit of potential difference, or voltage, between two conductors of a circuit, or between a conductor and the ground

Loop An electrical cul de sac. A transmission configuration that interrupts an existing circuit, diverts it to another connection, and returns it back to the interrupted circuit, thus forming a loop or cul de sac

Megavar One megavolt ampere reactive

Megavars Mega-volt-ampere-reactive. One million volt-ampere-reactive. Reactive power is generally associated with the reactive nature of motor loads that must be fed by generation units in the system

Megavolt Ampere (MVA) A unit of apparent power, equals the product of the line voltage in kilovolts, current in amperes, the square root of 3, divided by 1,000

Megawatt (MW) A unit of power equivalent to 1,341 horsepower

N-0 Condition See Normal Operation/Normal Overload, below

Normal Operation/ Normal Overload (N-0) When all customers receive the power they are entitled to without interruption and at steady voltage, and no element of the transmission system is loaded beyond its continuous rating

N-1 Condition See Single Contingency, below

N-2 Condition See Double Contingency, above

Outlet Transmission facilities (circuit, transformer, circuit breaker, etc.) linking generation facilities with the main grid

Power Flow Analysis A power flow analysis is a forward-looking computer simulation of essentially all generation and transmission system facilities that identifies overloaded circuits, transformers, and other equipment and system voltage levels

Reactive Power Reactive power is generally associated with the reactive nature of motor loads that must be fed by generation units in the system. An adequate supply of reactive power is required to maintain voltage levels in the system

Remedial Action Scheme A remedial action scheme is an automatic control provision that, as one example, will trip a selected generating unit when a circuit overloads

SF6 Sulfur hexafluoride is an insulating medium

Single Contingency Also known as emergency or N-1 condition, occurs when one major transmission element (circuit, transformer, circuit breaker, etc.) or one generator is out of service

Solid Dielectric Cable Copper or aluminum conductors that are insulated by solid polyethylene type insulation and covered by a metallic shield and outer polyethylene jacket

Special Protection Scheme/System Detects a transmission outage (either a single or credible multiple contingency) or an overloaded transmission facility and then trips or runs back generation output to avoid potential overloaded facilities or other criteria violations

Switchyard A power plant switchyard is an integral part of a power plant that is used as an outlet for one or more electric generators

Thermal Rating See ampacity.

TSE Transmission System Engineering

Tap A transmission configuration that creates an interconnection through a short single circuit to a small or medium-sized load or generator. The new single circuit line is inserted into an existing circuit by utilizing breakers at existing terminals of the circuit, rather than installing breakers at the interconnection in a new switchyard.

Undercrossing A transmission configuration where a transmission line crosses below the conductors of another transmission line, generally at 90 degrees.

Underbuild A transmission or distribution configuration where a transmission or distribution circuit is attached to a transmission tower or pole below (under) the principle transmission line conductors.

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 **Blythe Solar Power Plant**, 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: 8/6/2010 Signed: ______

At: Davis, CA______

DECLARATION OF
LAIPING NG

I, Laiping Ng declare as follows:

1. I am presently employed by the California Energy Commission in the Strategic Transmission Planning Office of the Siting, Transmission & Environmental Protection Division as an Associate 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 Blythe Solar 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 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: 8/6/2010 Signed: Laiping Ng

At: Sacramento, California

APPENDIX B

TRANSMISSION SYSTEM ENGINEERING

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Testimony of Suzanne Phinney, D.Env.

1.0 INTRODUCTION AND PURPOSE

This Transmission System Engineering Appendix for the Palen Solar Power Project (PSPP) supplements information provided in staff's Revised Staff Assessment (RSA). It identifies and evaluates those actions necessary to provide power from the PSPP to the electricity grid.

The Energy Commission has the exclusive authority to certify the construction and operation of thermal electric power plants 50 MW or larger and associated facilities. The Energy Commission's licensing authority extends up to the first point of interconnection for transmission facilities. Under the California Environmental Quality Act (CEQA), the Energy Commission must conduct an environmental review of the "whole of the action," which may include facilities beyond the first point of interconnection and therefore not licensed by the Energy Commission. Transmission–related facilities comprising the "whole of the action" include the following:

1. Constructing the proposed Red Bluff Substation
2. Looping the existing Devers-Palo Verde 1 (DPV1) 500-kV transmission line into the Red Bluff Substation and creating two new 500-kV lines (Colorado River-Red Bluff and Devers-Red Bluff)
3. Modifying existing 220 kV structures
4. Constructing an overhead distribution line for substation light and power
5. Installing telecommunications support between the Red Bluff Substation and other communications centers
6. Relocating a segment of the existing Eagle Mountain-Blythe 161-kV line that lies within the PSPP footprint.
7. Connecting the PSPP 220-kV generation interconnection transmission line (gen-tie) to the Red Bluff Substation
8. Installing telecommunications support between the Red Bluff Substation and the PSPP and

These actions in total comprise the PSPP transmission/telecommunications actions project. The first six elements would allow Southern California Edison (SCE) to interconnect multiple solar development projects in the Desert Center area of the Mojave Desert and therefore are reasonably foreseeable actions common to all the projects. The last two elements are specific to the PSPP project.

Construction of the Red Bluff Substation, transmission line looping, 220 kV line modifications, overhead distribution line and substation telecommunications are considered reasonably foreseeable actions and are currently being permitted as elements of the Desert Sunlight Solar Farm and a Draft Plan Amendment (PA)/Environmental Impact Statement (EIS) is expected to be released later in 2010. Staff has reviewed information being developed for the PA/EIS and believes it accurately describes environmental impacts.

The California Public Utilities Commission (CPUC) would be the CEQA lead agency for these six elements. The Bureau of Land Management (BLM) would be the National Environmental Policy Act (NEPA) lead agency for permitting and licensing of all the transmission/telecommunication-related facilities on BLM lands.

The Energy Commission is the CEQA lead agency for the gen-tie connection and telecommunications support between the PSPP and the Red Bluff Substation.

This appendix describes all the transmission/telecommunication-related facilities identified above. It evaluates those actions for which the Energy Commission is the CEQA lead agency. In addition, this appendix evaluates the relocation of the 161-kV line given its location within the PSPP footprint.

SCE proposes to design, construct and operate the Red Bluff Substation. SCE has provided a project description for the substation construction and transmission/telecommunications actions (SCE, 2010, Solar Millennium 2010n). This project description is a planning level description and site-specific engineering and design documents will be prepared at a later date. Therefore this CEQA analysis provides as detailed an analysis as possible with the information available for the project at this time.

The purpose of staff's analysis is to inform the Energy Commission, interested parties and the general public of the potential environmental and public health effects caused by the approval of the PSPP. The analysis draws conclusions as to the likelihood that the PSPP transmission/telecommunications actions could be accomplished with no significant environmental impacts, and identifies mitigation measures that could be enacted to ensure that the actions would not cause significant impacts. The analysis discusses environmental issues that generally reflect the CEQA checklist (Appendix G), but does not include sections specific to power plant operations (Facility Design, Power Plant Efficiency, Power Plant Reliability, and Transmission Line Safety and Nuisance). The construction-related analysis and proposed mitigation measures in those sections of the RSA for the PSPP project provide a general understanding of the potential impacts in those areas that could possibly, but not likely, be caused by the PSPP transmission/telecommunications actions.

2.0 DESCRIPTION OF TRANSMISSION/TELECOMMUNICATION-RELATED FACILITIES

The proposed SCE Red Bluff Substation near Desert Center in Riverside County, California would allow for interconnection of the proposed PSPP in the Desert Center area of the Mohave Desert to SCE's existing Devers-Palo Verde (DPV) Transmission Line. This would create the Colorado River-Red Bluff and Devers-Red Bluff 500 kV Transmission Lines. Although two alternate sites were originally proposed for the Red Bluff Substation, the eastern location has recently been selected as the proposed site (see Figure 1).

The PSPP, under joint developers Solar Millennium, LLC and Chevron Energy Solutions, would consist of two identical 250-megawatt (MW) (total capacity 500 MW) solar parabolic trough technology energy generating farms. The proposed project would be constructed on a relatively flat, largely undeveloped portion of the Colorado Desert (a subdivision of the Sonoran Desert) in the Chuckwalla Valley between the Palen Mountains and U.S. Interstate 10 (I-10) (Corn Springs Road exit) in Riverside County, California. The PSPP would be located about ten miles northeast of Desert Center. The site is dominated by Sonoran creosote brush scrub that has several desert dry wash and unvegetated ephemeral dry wash areas. High voltage electric lines cross the area.

The following sections summarize the transmission/telecommunications components using information provided by SCE and the applicants (SCE 2010, Solar Millennium 2010n).

2.1 COMPONENTS COMMON TO MULTIPLE SOLAR PROJECTS

2.1.1 Red Bluff Substation

The Red Bluff Substation would be located approximately 5 miles east of California State Highway 177 along the south side of Interstate I-10 in the County of Riverside. The substation would be located on BLM land and would be generally located in the center of the parcel. The approximate center of the substation would be at 33.697 degrees North and 115.325 degrees West.

The substation site would be reached (see Figure 1) from I-10 via the Corn Springs Road exit. This access would include heading east along an existing 3,800-foot long paved portion of Chuckwalla Valley Road. At this point the access would turn south over a 1,100 foot portion of Corn Springs Road. At the intersection of the existing unimproved pipeline patrol road, the substation access turns west over a distance of approximately 25,000 feet. The final leg of the access would be a new road segment approximately 1,400 feet long that would connect to the substation's southern boundary.

Construction of the Red Bluff Substation is expected to start in the second quarter of 2011 and would proceed for two years. The projected substation operating date is in the third quarter of 2013. Once constructed, the Red Bluff Substation would be unstaffed, and electrical equipment within the substation would be remotely monitored. SCE personnel would visit for routine maintenance purposes. Routine maintenance would include equipment testing, monitoring, and repair. SCE personnel would generally visit the substation three to four times per month.

The substation site would require substantial grading to incorporate the proposed approximately 1,450-foot by 2,200-foot enclosed facility (containing approximately 75 acres) and to provide diversion means to channel the existing surface drainage around the facility. The surface area occupied by the slopes and channels would be anticipated at approximately 30 acres.

Extensive improvements along the 25,000 foot pipeline road would be required in order to provide 24-hour access to the Red Bluff Substation. Included in these improvements would be widening to a minimum width of 24 feet, leveling or installation of culverts over the numerous eroded gully crossings, diversion berms along portions of the south (upslope) edge to prevent erosion of the road, and the placement of a compacted layer of base gravel to form a firm drivable surface.

Because the Red Bluff Substation site is located down-slope from the Chuckwalla Mountains, surface runoff in the form of several eroded channels (designated as Blue-line streams) traverse the site. It is anticipated that alteration of three of these channels would be required in order to protect the substation's southern exposure from flooding. Drainage improvements would disturb an area approximately 20 acres.

Internal surface runoff would be directed towards detention basins occupying approximately one-half acre and located within or directly adjacent to the enclosed substation.

Additional temporary land disturbance (up to approximately 10 acres) adjacent to the site may be necessary for temporary equipment storage and material staging areas associated with construction efforts.

Following completion of construction activities, SCE would also restore all areas that were temporarily disturbed by construction of the Project to as close to preconstruction conditions as possible, or, where applicable, to the conditions agreed upon between the landowner and SCE. In addition, all construction materials and debris would be removed from the area and recycled or properly disposed of off-site at local authorized waste management facilities. SCE would conduct a final inspection to ensure that cleanup activities were successfully completed.

2.1.2 Transmission Line Looping/Construction

The proposed Red Bluff Substation would be connected to the existing DPV 500 kV transmission source line via a loop-in line, which would dissect the existing line and change it into two line segments: the Colorado River-Red Bluff and the Devers-Red Bluff 500 kV transmission lines. The new piece of each line segment into the Red Bluff Substation would be approximately 1,000 feet long.

The new 500 kV line segments would be constructed using approximately eight transmission structures - six of which are expected to be single-circuit lattice steel tower

(LST) or tubular steel pole (TSP) and two of which are expected to be modified double-circuit LSTs. The double-circuit LSTs would be approximately 40 feet taller than the single circuit towers but would have a smaller footprint.

The new transmission line segments would require an approximately 600 foot wide right of way along that portion of the loop-in lines between SCE's existing ROW and the new Red Bluff Substation site. Other transmission structures would be within SCE's existing ROW. Three dead-end structures would be required for each line segment to reach the edge of the Red Bluff Substation site.

A temporary staging area (approximately 0.5 to 1.5 acres) would be established within the substation site to support transmission line looping/construction. Additional temporary areas may be required for crew "show up" yards and would be used for temporary parking. Land disturbed at the temporary equipment and material staging area would be restored to preconstruction conditions following the completion of construction.

Similar to rehabilitation of existing roads, all new road alignments would first be cleared and grubbed of vegetation. Roads would be blade-graded to remove potholes, ruts, and other surface irregularities, fill material would be deposited where necessary, and roads would be re-compacted to provide a smooth and dense riding surface capable of supporting heavy construction equipment.

2.1.3 220 kV Transmission Line Structure Modifications/Replacement Design

Looping of the 500 kV lines would require crossing over the Florida Power and Light (FPL) Buck-Julian Hinds 220 kV line. It may be necessary to modify the FPL structures, either lowered or otherwise reconfigured. Additional towers may be required. Modifications to the FPL line cannot be known until further engineering work and studies are completed.

Transmission line facilities to be removed include existing 500 kV transmission structures and associated hardware. SCE may temporarily transfer the existing 500 kV conductor to temporary structures during the removal and replacement of the existing 500 kV structures. Upon completion of the construction of the 500 kV replacement structures and dismantling of the existing 500 kV structure to a level below the conductor attachment height, the existing conductor would be transferred over from the temporary structures and attached to the new 500 kV structures.

The new 500kV and 220kV structure locations would first be graded and/or cleared of vegetation as required to provide a reasonably level and vegetation-free surface for footing and structure construction. Site preparation for the temporary laydown area required for the assembly of the 500 kV and 220 kV structures would also be cleared of vegetation and graded. Erection of the structure would require an erection crane to be set up adjacent to and 60 feet from the centerline of the structure. A crane pad would be located within the laydown area used for structure assembly. The structures would require drilled, poured-in-place, concrete footings that would form the structure foundation. Guard structures[1] would be installed at the FPL Buck-Julian Hinds 220 kV transmission crossing and at any other facilities in the area requiring protection.

2.1.4 Distribution System for Station Light and Power

Providing for substation light and power would require rebuilding the Desert Center 12-kV circuit overhead along the south frontage of the I-10 freeway approximately 20,000 feet to upgrade the circuit from single-phase to three-phase construction and then extending approximately 1,000 feet underground (south) towards the substation. This rebuild would require the replacement of approximately 100 poles, assuming an average span of 200 feet.

Distribution line work could follow the new/upgraded access road that would likely be required to support the rebuilt overhead distribution lines from existing circuitry to the Red Bluff Substation site. A laydown area within the substation site may be required to store any materials needed during construction.

2.1.5 Telecommunications Support between Red Bluff Substation and Other Centers

A telecommunication system would be required in order to provide monitoring and remote operation capabilities of the electrical equipment at the Red Bluff Substation, and transmission line protection. Components common to multiple solar projects include line protection, SCADA and telecommunications circuits from Red Bluff Substation to Devers Substation and Colorado River Substation.

SCE would build these circuits using some existing infrastructure, as well as the following new infrastructure:

- An optical system between the solar developers' substation and the Red Bluff Substation
- A microwave system between Red Bluff Substation and a new Desert Center Communications Site
- A microwave system between a new Desert Center Communications Site and the existing Chuckwalla Mountain Communications Site.

These components include both reasonably-foreseeable telecommunications actions and project-specific telecommunications actions.

[1] Guard structures are temporary facilities designed to stop the movement of a conductor should it momentarily drop below a conventional stringing height.

Equipment and Installation

SCE would install the following equipment for the reasonably-foreseeable actions:

- New microwave equipment in a new 25 foot by 40 foot communications room inside the MEER at Red Bluff Substation.
- A new 185 foot microwave tower at Red Bluff Substation. This tower would be located near the communications room inside the MEER. The tower base would be a square with 35 foot sides. The concrete tower anchors would be about 6 foot in diameter.
- A new Desert Center Communications Site which would have a tower identical to the one at Red Bluff Substation. It would have microwave equipment and dishes for paths to Red Bluff Substation and Chuckwalla Communications Site. The microwave repeater station would be located along Airport Access Road approximately 600 feet east of Rice Road and encompassing an area approximately 100 feet by 50 feet. The area would a12 feet by 30 feet communication room, a 185 foot tall lattice steel microwave tower and two 8-foot diameter microwave antennas.
- Microwave equipment and a dish at Chuckwalla Communications Site.

The project-specific telecommunications actions are described in Section 2.2.3.

2.2 COMPONENTS SPECIFIC TO THE PSPP

2.2.1 Generation Tie Line Connection

A single circuit 230 kV transmission line originating at each power block would terminate at the PSPP Central Switchyard. Construction of the 220 kV generation tie line (gen-tie) structure would be the responsibility of the developers. SCE would connect the PSPP gen-tie into the Red Bluff Substation by installing the last span of conductor (one single-circuit lattice steel tower or tubular steel pole) between the 220 kV switchrack and the first developer-built 220 kV transmission line structure north of the substation.

Wire Stringing of 230 kV Conductor

Wire stringing of 220 kV conductor includes the installation of primary conductor and overhead ground wire (OHGW), vibration dampeners, weights, spacers, and suspension and dead-end hardware assemblies. Insulators and stringing sheaves (rollers or travelers) are typically attached during the steel erection process.

Wire-stringing activities would be conducted in accordance with SCE specifications, which is similar to process methods detailed in Institute of Electrical and Electronics Engineers Standard (IEEE) 524-2003, Guide to the Installation of Overhead Transmission Line Conductors. To ensure the safety of workers and the public, safety devices such as traveling grounds, temporary grounding grid/mats around stringing equipment, guard structures, and radio equipped public safety roving vehicles and linemen would be in place prior to the initiation of wire-stringing activities.

The following four steps describe the wire installation activities utilized by SCE:

- **Step 1**: Sock Line, Threading: Typically, a lightweight sock line is passed from structure to structure, which would be threaded through the wire rollers in order to engage a camlock device that would secure the pulling sock in the roller. This threading process would continue between all structures through the rollers of a particular set of spans selected for a conductor pull.
- **Step 2**: Pulling: The sock line would be used to pull in the conductor pulling cable. The conductor pulling cable would be attached to the conductor using a special swivel joint to prevent damage to the wire and to allow the wire to rotate freely to prevent complications from twisting as the conductor unwinds off the reel. A piece of hardware known as a running board would be installed to properly feed the conductor into the roller; this device keeps the bundle conductor from wrapping during installation.
- **Step 3**: Splicing, Sagging, and Dead-ending: After the conductor is pulled in, the conductor would be sagged to proper tension and dead-ended to structures.
- **Step 4**: Clipping-in, Spacers: After the conductor is dead-ended, the conductors would be secured to all tangent structures; a process called clipping in. Once this is complete, spacers would be attached between the bundled conductors of each phase to keep uniform separation between each conductor.

SCE estimates that an area of 150 feet by 500 feet (1.72 acres) would be optimal for tensioning equipment setup sites. An area of 150 feet by 300 feet (1.03 acres) would be optimal for pulling and equipment set-up sites; however, crews can work from within slightly smaller areas when space is limited. Each stringing operation would include one puller positioned at one end and one tensioner and wire reel stand truck positioned at the other end.

An OHGW for shielding would be installed on the transmission line. The OHGW would be installed in the same manner as the conductor and in conjunction with installation of the conductor.

Land Disturbance

Table 1 provides an estimate of temporary and permanent land disturbance areas related to connection of the PSPP gen-tie. The numbers presented in **Table 1** are preliminary and may change as the result of detailed engineering.

Table 1. PSPP Gen-Tie Connection – Land Disturbance

	Site Quantity	Disturbed Acreage Calculation	Acres Disturbed During Construction	Acres Temporarily Disturbed	Acres Permanently Disturbed
Install New 220 kV Gen-Tie Span to Switchrack (1)	1	150' x 300'	1.03	1.03	0.00
Total Estimated Disturbed Acres (2)			**1.03**	**1.03**	**0.00**
Notes to Table 1					
1. Structure construction work, including foundation installation, structure assembly & erection is the responsibility of the Developer, and is therefore not described here. All disturbance herein is solely for the installation of the final SCE-owned span between the final structure and the substation 220kV switchrack. This work would require only temporary disturbance area to set up wire stringing and pulling equipment.					
2. The disturbed acreage calculations are estimates based upon SCE's preferred area of use for the described project feature, the width of the existing right-of-way, or the width of the proposed right-of-way and, they do not include any new access/spur road information; they are subject to revision based upon final engineering and review of the project by SCE's Construction Manager and/or Contractor awarded project.					
Note: All data provided in this table is based on planning level assumptions and may change following completion of more detailed engineering, identification of field conditions, availability of material, and equipment, and any environmental and/or permitting requirements.					

Source: Solar Millennium 2010n

Construction Labor and Equipment

Table 2 identifies the equipment and workforce needed to connect the PSPP gen-tie to the Red Bluff Substation. The numbers presented in **Table 2** are preliminary and may change as the result of detailed engineering.

Table 2. Construction Equipment and Workforce Estimates by Activity to Install PSPP 220 kV Gen-Tie[2]

Work Activity				Activity Production			
Primary Equipment Description	Estimated Horse-Power	Probable Fuel Type	Primary Equipment Quantity	Estimated Workforce	Estimated Schedule (Days)	Duration of Use (Hrs/Day)	Estimated Production Per Day
1-Ton Crew Cab Truck, 4x4	300	Diesel	2		2	8	
Wire Truck/Trailer	350	Diesel	2		2	2	
Dump Truck (Trash)	350	Diesel	1		2	2	
Rough Terrain Crane	350	Diesel	1		2	2	
22-Ton Manitex	350	Diesel	2		2	8	0.37 Mile/Day
30-Ton Line Truck	350	Diesel	4		2	6	
Static Truck/ Tensioner	350	Diesel	1		2	6	
Sock Line Puller	300	Diesel	1		1	6	
Bull Wheel Puller	525	Diesel	1		1	6	
580 Case Backhoe	120	Diesel	1		2	2	
Lowboy Truck/Trailer	500	Diesel	2		2	2	

Crew Size Assumptions: #1 Conductor & GW Installation = one 20-man crew

[2] This table is based on data provided by SCE for the Blythe and Genesis Solar Power Projects.

2.2.2 Telecommunications Support between Red Bluff Substation and PSPP

Project-specific actions required to provide monitoring and remote operation capabilities of the electrical equipment at the Red Bluff Substation for protection of the PSPP gen-tie line would include:

- Installation of optical ground wire (OPGW) on the PSPP interconnection generation tie-line terminating inside the PSPP central switchyard.
- Construction of a redundant telecom line from the PSPP to the Red Bluff Substation
- Construction of a duct bank from the Red Bluff Substation mechanical-electrical equipment room (MEER) building to one of the new transmission towers of the solar developer's 220kV generator tie line. The duct bank from the MEER building would contain one five inch duct. The trench would be dug 36 inches deep and 18 inches wide. The conduit would be laid in and then covered with slurry. The slurry would be covered with soil that came out the excavation. The total length of the duct would be approximately 1,000 feet.
- Final terminations to associated communications equipment installed inside both SCE's Red Bluff Substation and the PSSP central switchyard.
- Construction of two duct banks from the Red Bluff Substation MEER building to two of the new transmission towers of the Devers – Red Bluff and Colorado River – Red Bluff 500kV transmission lines. Duct characteristics would be as described above.

The proposed PSPP gen-tie line would carry fiber optic cable. The gen-tie route would start at the PSPP central switchyard metering point located near the northern boundary of the Unit #2 solar field centerline and then would run north approximately ¼ mile until it exits the site boundary. At that point it jogs west-northwest for about a mile, then runs due west for about a ¼ mile, and then southwest for about a ½ mile. From there it proceeds due west for approximately 2 ½ miles where it reaches a point approximately ¾ mile north of the proposed Red Bluff Substation location. The gen-tie would approach the substation from the east and would tie-in to the 230-kV bus from the eastern end of the substation. The alignment of this route would total approximately 5 ¼ miles (see **Figure 1**).

The redundant telecom line would exit the project site buried in the right-of-way for the site access road, cross under I-10 west of the Corn Springs Road interchange and proceed to a microwave repeating tower approximately 700 feet south of the freeway. The line would be trenched and buried approximately 30 inches deep in the drainage ditch under the freeway. The redundant telecommunications line to the Red Bluff Substation would then be hung on the existing 12.47 kV SCE line that feeds the microwave tower and carried to the Red Bluff Substation. The underground line would be in 5 inch PVC conduit. No construction details are available at this time. See **Figure 1** for the redundant telecom line route.

Land Disturbance

Table 3 provides a preliminary estimate of temporary and permanent land disturbance related to connection of the telecommunication system between the PSPP and the Red Bluff Substation. The numbers presented in **Table 3** are preliminary and may change as the result of detailed engineering.

Table 3. PSPP Telecommunication System Connection – Estimated Land Disturbance

Construction Activity	Acres Temporarily Disturbed	Acres Permanently Disturbed
Duct from Red Bluff MEER to first 220kV tower outside station[1]	0.03	-
Two ducts from Colorado River Substation telecom vault to first 220kV tower outside station[1]	0.06	-
Above ground telecom line[2]	-	-
Underground telecom line[3]	5.01	-
Total Acres Disturbed	5.10	-

[1] 1,000 feet long by 1.5 feet wide trench

[2] No additional land disturbance over that associated with gen-tie construction (see PSPP RSA)

[3] Solar Millennium 2010n

Construction Labor and Equipment

Table 4 identifies the equipment and workforce needed to connect the proposed telecommunications facilities at the Red Bluff Substation. Labor associated with the redundant telecom line is assumed to be included in the PSPP RSA as part of PSPP construction. The numbers presented in **Table 4** are preliminary and subject to change as the result of detailed engineering.

Table 4. Telecommunication System Connection Construction Equipment and Workforce Estimates by Activity

Construction Activity	Number of Personnel	Number of Work Days	Equipment Requirements
Trench Construction	5	12	2-crew trucks (gas/diesel) 1-backhoe (diesel) 1-stakebed truck (diesel) 1-concrete mixer (diesel)
Underground Fiber Cable Installation	5	3	1-crew trucks (gas/diesel) 2-line trucks (diesel)
Telecommunications Installation Crew	2	20	2-vans (gas)

Source: SCE, 2010

2.2.3 Eagle Mountain-Blythe 161-kV Transmission Line Relocation

SCE's existing Eagle Mountain-Blythe 161-kV transmission line crosses the southwest portion of the PSPP (**Figure 2**). In order to maximize the development of the solar field, PSPP's joint developers have requested that SCE relocate approximately 6,000 feet of the Eagle Mountain-Blythe 161-kV transmission line.

Line relocation would be accomplished by installing approximately eighteen 65-foot H-Frame structures (each structure is composed of 2 poles for a total of 36 poles), three 65-foot Three-Pole structures, approximately 8,000 circuit feet of conductor, and all associated hardware and guying. The new structures would be set approximately 8.5 feet deep; the new span lengths would range from 350 to 450 feet depending on line direction.

Approximately 6,000 feet of transmission line would be removed. Components requiring removal include: seven 65-foot H-Frame structures (each structure is composed of 2 poles for a total of 14 poles), one 65 foot Three-Pole structure (3 poles), approximately 6,200 circuit feet of 336.4 ACSR 30/7 conductor, and all associated hardware and guy wire.

Table 5 provides an estimate of temporary and permanent land disturbance areas related to line relocation.

Table 5. Land Disturbance for Transmission Line Relocation

	Site Quantity	Disturbed Acreage Calculation (L x W)	Acres Disturbed During Construction	Acres Temporarily Disturbed	Acres Permanently Disturbed
Guard Structures	4	50' x 75'	0.3	0.3	0.0
161kV Conductor Removal Setup Area - Tensioner (3)	2	500' x 100'	2.3	2.3	0.0
Remove Existing Wood 3 Pole Structure (1)	1	100' x 50'	0.1	0.1	0.0
Construct New Wood H-Frame Pole (2)	18	100' x 50'	2.1	0.8	1.3
Construct New Wood 3 Pole Structure (1)	3	100' x 50'	0.3	0.3	0.0
161kV Conductor & OPGW Stringing Setup Area - Tensioner (3)	2	500' x 100'	2.3	2.3	0.0
161 kV Conductor Pulling Site	2	300’ X 100’	1.38	1.38	0.0
161kV Conductor Splicing Setup Areas (3)	4	150' x 100'	1.4	1.4	0.0
New Access Roads (4)	1.4	linear miles x 14’ wide	2.4	0.0	2.4
TOTAL ESTIMATED (5)			**14.9**	**8.9**	**3.6**
Notes to Table 5:					
1. Includes the removal of existing conductor, teardown of existing structure, and removal of foundation 2' below ground surface.					
2. Includes structure assembly & erection, conductor & OPGW installation. Area to be restored after construction. Portion of R/W within 25' of the Tubular Steel Pole and within 10' of Light Weight Steel Pole, and H-Frame to remain cleared of vegetation. Permanently disturbed areas for TSP=0.06 acre, LWS=0.05 acre, and H-Frame=0.06 acre.					
3. Based on 9,000’ conductor reel lengths, number of circuits, and route design.					
4. Based on approximate length of road in miles x road width of 14’.					
5. The disturbed acreage calculations are estimates based upon SCE’s preferred area of use for the described project feature, the width of the existing right-of-way, or the width of the proposed right-of-way and, they do not include any new access/spur road information; they are subject to revision based upon final engineering and review of the project by SCE's Construction Manager and/or Contractor awarded project.					
Footing/Base Volume and Area Calculations: Average Wood H-Frame & Wood 3 Pole Structure depth 12ft deep, 2.5ft diameter, qty 2 per H-Frame: earth removed for pole base = 4.4 cu. yds.; surface area = 9.8 sq. ft.					

Source: SCE, 2010

Staging Areas

A separate marshalling yard would be required for the removal and relocation actions. The size and location of the temporary equipment and material staging area would be dependent upon a detailed site inspection. An area of approximately 20 acres would likely be required. Land disturbed at the temporary equipment and material staging area would be allowed to naturally return to preconstruction conditions following the completion of construction.

Transmission Line Access and Spur Roads

Existing public roads and existing transmission line roads would be used wherever feasible. It is expected that some new roads would be needed to access the new transmission line segments and structure locations.

Rehabilitation work may be necessary in some locations along the existing transmission line roads to accommodate construction activities. As required, these roads could be cleared of vegetation, blade-graded to remove potholes, ruts, and other surface irregularities, or recompacted to provide a smooth and dense riding surface capable of supporting heavy construction equipment. The graded road would have a minimum drivable width of 14 feet with 2 feet of shoulder on each side but may be wider depending on final engineering requirements and field conditions.

Existing road rehabilitation and new road construction would require removal of vegetation. Roads would be bladegraded to remove potholes, ruts, and other surface irregularities. Fill material would be deposited on the roads where necessary, and roads would be re-compacted to provide a smooth and dense riding surface capable of supporting heavy construction equipment. The graded road would have a minimum drivable width of 14 feet with 2 feet of shoulder on each side but may be wider depending on final engineering requirements and field conditions. New road gradients would be leveled so that any sustained grade does not exceed 12 percent. All curves would have a curvature radius of not less than 50 feet measured at the center line of the usable road surface. The new spur roads would usually have turnaround areas near the structure locations.

Construction of New 161 kV Transmission Structures

The new structure locations would first be graded and/or cleared to provide a reasonably level and vegetation-free surface for footing construction. Sites would be graded such that water would run toward the direction of the natural drainage. In addition, drainage would be designed to prevent ponding and erosive water flows that could cause damage to the base of the poles. The graded area would be compacted to at least 90 percent relative density, and would be capable of supporting heavy vehicular traffic.

Assembly and erection of the wood pole structures typically would require a temporary laydown area of approximately 150 feet by 75 feet. In locations where the terrain in the laydown area is already reasonably level (for example, at an existing pole location), only vegetation removal would occur to prepare the site for construction. In locations where a level surface is not present (for example, a new pole site), both vegetation clearing and grading would be necessary to prepare the laydown area for construction.

The Eagle Mountain-Blythe line would utilize wood poles. The wood would be direct buried in boreholes approximately 2 to 4 feet in diameter and 8 to 10 feet deep, and are typically installed using a line truck. Once the wood poles are set in place, bore spoils (material from holes drilled) would be used to backfill the hole. If the bore spoils are not suitable for backfill, imported clean fill material, such as clean fill dirt and/or pea gravel, would be used. Excess bore spoils would be distributed at each pole site and used as backfill for the holes left after removal of existing structures or disposed of off-site in accordance with all applicable laws.

Pole installation would begin by transporting the poles by flatbed trucks and pole trailers from the staging area and laying the individual poles on the ground at each new structure location. While on the ground, the top section would be pre-configured with the necessary insulators and wire-stringing hardware. A line truck (with a boom on it) would be used to position each pole into previously augured holes. When each pole for a structure is secured, the top section would be framed out.

After construction is completed, the transmission structure site would be graded such that water would run toward the direction of the natural drainage. In addition, drainage would be designed to prevent ponding and erosive water flows that could damage the structure footing. The graded area would be compacted and capable of supporting heavy vehicular traffic.

Wire Stringing of 161kV Conductors

Wire-stringing activities would include those described in Section 2.2.1.

The dimensions of the area needed for the stringing setups associated with wire installation are variable and depend upon terrain. The preferred minimum area needed for tensioning equipment set-up sites requires approximately 500 feet by 100 feet (1.15 acres). The preferred minimum area needed for pulling equipment set-up sites requires approximately 300 feet by 150 feet (1.03 acres). Crews though can work from within slightly smaller areas when space is limited. Each stringing operation would include one puller positioned at one end and one tensioner and wire reel stand truck positioned at the other end.

Stringing equipment that cannot be positioned at either side of a dead-end transmission structure would require installation of temporary field snubs (i.e., anchoring and dead-end hardware) to sag conductor wire to the correct tension.

The puller and tensioner set-up locations would require level areas to allow for maneuvering of the equipment. When possible, these locations would be located on existing level areas and existing roads to minimize the need for grading and cleanup. The final number and locations of the puller and tensioner sites would be determined during detailed engineering based on the construction methods chosen by SCE or its Contractor.

An overhead ground wire (OHGW) for shielding would be installed on the transmission line. The OHGW would be installed in the same manner as the conductor. The OHGW is typically installed in conjunction with the conductor, depending upon various factors including line direction, inclination, and accessibility.

Removal of Existing 161 kV Transmission Structures

Transmission line facilities to be removed include existing 161 kV transmission structures located on the portion of the existing Eagle Mountain-Blythe 161kV transmission line that crosses the PSSP and associated hardware (i.e., insulators, vibration dampeners, suspension clamps, ground wire clamps, shackles, links, nuts, bolts, washers, cotters pins, insulator weights, and bond wires).

Existing access roads would be used to reach structure sites. Some rehabilitation work on these roads may be necessary before removal activities begin. In addition, grading may be necessary to establish a temporary laydown area adjacent to the existing structure for equipment and material staging during the structure removal. The laydown area would be approximately 100 feet by 50 feet (0.10 acre).

Each structure would require a crane truck or rough terrain crane to support the structure during dismantle and removal. A crane pad would be located within the laydown area used for structure assembly. If the existing terrain is not suitable to support crane activities, a temporary 50 feet by 50 feet (0.06 acre) crane pad would be constructed. The existing structure footings would be removed to a depth of approximately 2 feet below ground level. Holes would be filled, compacted, and the area would be smoothed to match surrounding grade.

Construction Site Cleanup

Damage to existing roads as a result of construction would be repaired once construction is complete. All areas that are temporarily disturbed by project activities (including equipment and material staging yard, pull and tension sites, and structure laydown and assembly sites) would be restored to preconstruction conditions following the completion of construction. Restoration may include grading and restoration of sites to original contours and reseeding where appropriate. In addition, all construction materials and debris would be removed from the area and recycled or properly disposed of at an off-site disposal facility in accordance with all applicable laws. A final inspection would be conducted to ensure that cleanup activities are successfully completed.

Labor and Equipment

Transmission line relocation construction would be performed by SCE crews or contract personnel with SCE responsible for project administration and inspection. The estimated number of persons and types of equipment required for each phase of transmission line construction is shown in **Table 6** below.

Operation and Maintenance

Following the completion of project construction, operation and maintenance of the new relocated line would commence. Operation, inspection, and maintenance activities would occur at least once per year in compliance with CPUC General Order No. 165. The frequency of inspection and maintenance activities would depend upon weather effects and any unique problems that may arise due to such variables as substantial storm damage or vandalism.

Table 6. Construction Equipment and Workforce Estimates by Activity to Relocate Transmission Line

WORK ACTIVITY				ACTIVITY PRODUCTION			
Primary Equipment Description	**Estimated Horse-Power**	**Probable Fuel Type**	**Primary Equipment Quantity**	**Estimated Workforce**	**Estimated Schedule (Days)**	**Duration of Use (Hrs/Day)**	**Estimated Production Per Day**
Survey (1)				**4**	**3**		**1.2 Miles**
1/2-Ton Pick-up Truck, 4x4	200	Gas	2		3	8	1 Mile/Day
Marshalling Yard (2)				**4**			
1-Ton Crew Cab,4x4	300	Diesel	1			2	
30-Ton Crane Truck	300	Diesel	1			2	
10,000 lb Rough Terrain Fork Lift	200	Diesel	1		Duration of Project	5	
Water Truck	350	Diesel	2			8	
Truck, Semi, Tractor	350	Diesel	1			1	
Road & Landing Work (3)				**5**	**3**		**1.2 miles**
1-Ton Crew Cab, 4 x 4	300	Diesel	1		1	2	2 Miles/Day
Road Grader	350	Diesel	1		1	4	
Backhoe/Front Loader	350	Diesel	1		1	6	
Drum Type Compactor	250	Diesel	1		1	4	
Track Type Dozer	350	Diesel	1		1	6	
Excavator	300	Diesel	1		1	6	
Lowboy Truck/Trailer	500	Diesel	1		2	2	
Remove Existing Conductor (4)				**14**	**5**		**1.2 circuit miles**
1-Ton Crew Cab, 4 x 4	300	Diesel	4		5	8	0.5 Mile/Day
Sleeving Truck	300	Diesel	1		3	4	
30-Ton Crane Truck	300	Diesel	1		3	4	
80ft. Hydraulic Manlift/Bucket Truck	350	Diesel	3		3	8	
Bull Wheel Puller	500	Diesel	1		3	6	

WORK ACTIVITY				ACTIVITY PRODUCTION			
Primary Equipment Description	**Estimated Horse-Power**	**Probable Fuel Type**	**Primary Equipment Quantity**	**Estimated Workforce**	**Estimated Schedule (Days)**	**Duration of Use (Hrs/Day)**	**Estimated Production Per Day**
Hydraulic Rewind Puller	300	Diesel	1		3	6	
40' Flat Bed Trailer	N/A	N/A	3		3	2	
Truck, Semi, Tractor	350	Diesel	1		3	1	
Wood H-Frames / Poles Removal (5)				**6**	**3**		**7 H-Frame Poles/ 1 Three Pole Structures**
1-Ton Crew Cab, 4 x 4	300	Diesel	2		1	5	9 H-Frames or Poles/Day
10,000 lb. Rough Terrain Forklift	200	Diesel	1		1	4	
30-Ton Crane Truck	300	Diesel	1		1	6	
Compressor Trailer	120	Diesel	1		1	6	
Flat Bed Truck/Trailer	350	Diesel	1		1	8	
Install Wood H-Frames / Poles (5)				**6**	**6**		**18 H-Frame Poles/ 3 Three Pole Structures**
1-Ton Crew Cab, 4 x 4	300	Diesel	2		6	5	4 H-Frames or Poles/Day
10,000 lb. Rough Terrain Forklift	200	Diesel	1		3	4	
30-Ton Crane Truck	300	Diesel	1		6	6	
Compressor Trailer	120	Diesel	1		5	6	
Flat Bed Truck/Trailer	350	Diesel	1		3	8	
Install Conductor (6)				**16**	**11**		**3.1 Circuit Miles**
3/4-Ton Truck, 4 x 4	300	Gas	4		11	8	0.37 Mile/Day
1-Ton Crew Cab Truck, 4 x 4	300	Diesel	6		11	8	
Wire Truck/Trailer	350	Diesel	4		7	2	
Dump Truck (Trash)	350	Diesel	1		9	2	
Bucket Truck	350	Diesel	2		11	8	
20,000 lb. Rough Terrain Fork Lift	350	Diesel	1		9	2	
22-Ton Manitex	350	Diesel	2		9	8	

WORK ACTIVITY				ACTIVITY PRODUCTION			
Primary Equipment Description	**Estimated Horse-Power**	**Probable Fuel Type**	**Primary Equipment Quantity**	**Estimated Workforce**	**Estimated Schedule (Days)**	**Duration of Use (Hrs/Day)**	**Estimated Production Per Day**
Splicing Rig	350	Diesel	1		3	6	
Splicing Lab	300	Diesel	1		3	6	
Static Truck/Tensioner	350	Diesel	1		6	6	
3 Drum Straw Line Puller	300	Diesel	1		6	6	
Lowboy Truck/Trailer	500	Diesel	1		4	2	
Restoration (7)				**7**	**1**		**1.2 Miles**
1-Ton Crew Cab, 4 x 4	300	Diesel	2		1	2	1 Mile/Day
Road Grader	350	Diesel	1		1	6	
Backhoe/Front Loader	350	Diesel	1		1	6	
Drum Type Compactor	250	Diesel	1		1	6	
D8 Cat	300	Diesel	1		1	6	
Lowboy Truck/Trailer	500	Diesel	1		1	3	

Crew Size Assumptions:
#1 Survey = one 4-man crew
#2 Marshalling Yards = one 4-man crew
#3 Roads & Landing Work = one 5-man crew
#4 Remove Existing Conductor = one 14-man crew
#5 Remove/Install Existing Wood H-Frames/Wood Poles = one 6-man crew
#6 Conductor Installation = two 8-man crews
#7 Restoration = one 7-man crew

Source: SCE, 2010

2.3 BEST MANAGEMENT PRACTICES AND DESIGN MEASURES

Conditions of Certification, Best Management Practices (BMPs) and design measures included in the Staff Assessment and Revised Staff Assessment (RSA) for the PSPP may be applicable to the RBS substation construction and transmission/telecommunications facilities. Staff recommends that these measures be considered by SCE. Further environmental analysis conducted by other agencies pursuant to CEQA and NEPA may identify additional measures. SCE as the builder of the proposed facilities would be expected to operate under these standard SCE BMPs along with project specific mitigation.

Air Quality

AIR-1 The construction activities would be in compliance with AQMD requirements, as applicable to the project.

Aesthetics and Visual Resources

AES-1 LSTs and TSPs would be galvanized steel with a dulled grey finish that minimizes reflected light.

AES-2 Insulators that minimize reflection of light would be utilized.

AES-3 Substation equipment would have materials that minimize reflective light.

AES-4 If chain link fence is used, it would have a dulled-finish.

AES-5 The substation lighting would be designed to be manually operated for non-routine nighttime work.

Biological Resources

BIO-1 Preconstruction biological clearance surveys would be conducted to identify special-status plants and wildlife.

BIO-2 SCE would prepare a Worker Environmental Awareness Program (WEAP). All construction crews and contractors would be required to participate in WEAP training prior to starting work on the project.

BIO-3 All transmission and subtransmission towers and poles would be designed to be avian-safe in accordance with the suggested practices for Avian Protection on Power Lines: the State of the Art in 2006 (Avian Power Line Interaction Committee 2006).

Cultural Resources

CR-1 A cultural resource inventory of the project area would be conducted for cultural resources prior to any disturbance. All surveys would be conducted and documented as per applicable laws, regulations, and guidelines.

CR-2 To the extent feasible, all ground-disturbing activities shall be sited to avoid or minimize impacts to cultural resources listed as, or potentially-eligible for listing as, unique archaeological sites, historical resources, or historic properties.

CR-3 A protective buffer zone would be established and maintained around each recorded archaeological site within or immediately adjacent to the ROW.

Paleontology Resources

PALEO-1 A paleontologist would conduct a pre-construction field survey of the project area.

PALEO-2 Prior to construction, a certified paleontologist would supervise monitoring of construction excavations.

Geology and Soils

GEO-1 Prior to final design of substation facilities, and transmission and, be conducted to identify site-specific geologic conditions and potential geologic hazards in sufficient detail to support sound engineering practices.

GEO-2 For new substation construction, specific requirements for seismic design would be followed based on the Institute of Electrical and Electronic Engineers' 693 "Recommended Practices for Seismic Design of Substations."

GEO-3 New access roads, where required, would be designed to minimize ground disturbance during grading.

GEO-4 Cut and fill slopes would be minimized by a combination of benching and following natural topography where feasible.

GEO-5 Any disturbed areas associated with temporary construction would be returned to preconstruction conditions (to the extent feasible) after the completion of project construction.

Hazards and Hazardous Waste

HAZ-1 A Phase I ESA would be performed at each new or expanded substation location and along newly acquired transmission subtransmission line ROWs.

HAZ-2 SCE would implement standard fire prevention and response practices for the construction activities.

HAZ-3 As applicable, SCE would follow fire codes per Cal Fire Power Line Fire Prevention Fire Guide requirements for vegetation clearance during construction of the project to reduce the fire hazard potential.

HAZ-4 Hazardous materials and waste handling would be managed in accordance with the following SCE plans and programs:

- *Spill Prevention, Countermeasure, and Control Plan (SPCC Plan).* In accordance with Title 40 of the CFR, Part 112, SCE would prepare a SPCC for proposed and/or expanded substations, as applicable.
- *Hazardous Materials Business Plans (HMBPs).* Prior to operation of new or expanded substations, SCE would prepare or update and submit, in accordance with Chapter 6.95 of the CHSD, and Title 22 CCR, an HMBP, as applicable.
- *Storm Water Pollution Prevention Plan (SWPPP):* A project-specific construction SWPPP would be prepared and implemented prior to the start of construction of the transmission line and substation.
- *Health and Safety Program:* SCE would prepare and implement a health and safety program to address site-specific health and safety issues.
- *Hazardous Materials and Hazardous Waste Handling:* A project specific hazardous materials management and hazardous waste management program would be developed prior to initiation of the project. Material Safety Data Sheets would be made available to all Project workers
- *Emergency Release Response Procedures:* An Emergency Response Plan detailing responses to releases of hazardous materials would be developed prior to construction activities. All construction personnel, including environmental monitors, would be aware of state and federal emergency response reporting guidelines.

HAZ-5 Hazardous materials would be used or stored and disposed of in accordance with Federal, State, and Local regulations.

HAZ-6 The substation would be grounded to limit electric shock and surges that could ignite fires.

HAZ-7 All construction and demolition waste would be removed and transported to an appropriately permitted disposal facility.

Hydrology and Water Quality

HYDRO-1 Construction equipment would be kept out of flowing stream channels as feasible.

HYDRO-2 Towers would be located to avoid active drainage channels, especially downstream of steep hill slope areas, to minimize the potential for damage.

Land Use

LAND USE-1 SCE shall provide 14 days of advance notice of the start of construction to property owners located within 300 feet of construction-related activities.

Noise

NOISE-1 SCE would comply with local noise ordinances.

Transportation and Traffic

TRANS-1 Traffic control services would be used for equipment, supply delivery, and conductor stringing, as applicable.

TRANS-2 Construction traffic would be scheduled for off-peak hours to the extent feasible and would not block emergency equipment routes.

TRANS-3 If work requires modifications or activities within local roadway and railroad ROWs, appropriate permits would be obtained prior to the commencement of construction activities.

3.0 ANALYSIS OF TRANSMISSION/TELECOMMUNICATIONS ACTIONS

This section examines the potential impacts of project-specific transmission system engineering (TSE) actions required for the operation of the PSPP. The project-specific elements analyzed include connecting the PSPP gen-tie line to the Red Bluff Substation, installing redundant telecommunications support between the Red Bluff Substation and the PSPP substation, and relocating the Eagle Mountain-Blythe 161-kV line.

Constructing the Red Bluff Substation, looping of existing 500 kV lines, modification of the existing 200-kv line, constructing a light and power distribution line and installing telecommunications support with other centers would be fully evaluated in the Desert Sunlight PA/EIS.

The purpose of this analysis is to inform the Energy Commission and interested parties, and the general public of the potential environmental and public health effects that may result from other actions related to the PSPP.

3.1 AIR QUALITY

Environmental Setting

PSPP transmission/telecommunications actions would occur at the Red Bluff Substation location, along the eastern access road to the substation, and at the PSPP site. All locations are within the Mojave Desert Air Basin (MDAB), in an area administered by the South Coast Air Quality Management District (SCAQMD). The Riverside County portion of the MDAB is nonattainment for the State ozone and particulate matter (PM) 10 standards. Additional information regarding the MDAB and SCAQMD, including meteorological data and ambient air quality data, can be found in the environmental setting section C.1.4.1 of the RSA. Laws, ordinances, regulations and standards (LORS) are also described in the RSA.

Local air quality is based on proximity of sensitive air quality receptors to local air pollution sources (e.g., traffic-congested roadways and intersections). Sensitive air quality receptors include structures that house children, the elderly, and persons with preexisting respiratory or cardiovascular illness (i.e., schools, hospitals, and nursing homes). The nearest sensitive receptors are a residence located approximately 25 feet from the northwest corner of the PSPP project right-of-way boundary and a residence located approximately 3,500 feet northwest of the PSPP site boundary. However, these residences are over a mile away from the southwestern corner of the site where transmission relocation activities would occur. Additional sensitive receptors include and residences about 4 miles to the northwest of the Red Bluff Substation and Eagle Mountain Elementary School approximately 10 miles west of the PSPP in the City of Blythe.

Potential Impacts of Transmission/Telecommunications Actions

The PSPP transmission/telecommunication components (i.e., generation tie line connection, telecommunication system and transmission line relocation) would generate air pollutant emissions, almost exclusively from facilities construction. Operation and maintenance of the constructed facilities would generate very minor emissions.

Construction activities would generate temporary (short-term) emissions as fugitive dust emissions (particulate matter) from earth-moving activities and as exhaust emissions from the operation of construction equipment and vehicles. Exhaust emissions may include carbon monoxide (CO); ozone (O3) precursors; nitrogen dioxide (NO2); sulfur dioxide (SO2); lead (Pb); and particulate matter, which is subdivided into two classes based on particle size: fine particles (PM2.5) and inhalable particles (PM10).

Operations would generate minor stationary and mobile exhaust emissions from operation and maintenance of the proposed facilities (i.e., substation and fiber optic lines).

Since PSPP transmission/telecommunication components would be largely located away from sensitive air quality receptors, the diesel PM emissions generated from construction equipment and mobile sources are not anticipated to subject sensitive receptors to adverse levels of diesel PM or other emissions. Impacts of trenching with respect to sensitive receptors would be less than significant.

Gen-Tie Line Connection

Connecting the gen-tie line to the Red Bluff Substation would include the installation of primary conductor and OHGW, vibration dampeners, weights, spacers, and suspension and dead-end hardware assemblies.

The air emissions would consist of exhaust emissions from heavy-duty diesel construction equipment use, diesel and gasoline fueled on-road delivery trucks, and fugitive dust (particulate matter) emissions from construction activities and from vehicle travel on unpaved road. The gen-tie line connection would be temporary and short-term, approximately 2 days. Due to the nature of short-term construction, the construction emissions would be minimal and would be less than significant.

Telecommunication System

In order to provide monitoring and remote operation capabilities of the electrical element at the Project substation, a telecommunication system is required, which would include line protection, installation of Supervisory Control and Data Acquisition (SCADA) and telecommunications circuit from the PSPP Substation to the Red Bluff Substation on an optical system utilizing OPGW on the 220 kV gen-tie line. The redundant telecom line from the PSPP to the RBS would be installed underground within the PSPP and Red Bluff Substation access road ROW and then above ground on an existing distribution line within SCE right of way.

Air emissions would consist of exhaust emissions from use of a backhoe, diesel and gasoline fueled on-road trucks, and fugitive dust (particulate matter) emissions from construction activities and from vehicle travel on unpaved road. Based on the expected short construction duration and the minimal number of construction equipment, the construction emissions would be minimal and would be less than significant.

Transmission Line Relocation

The existing Eagle-Mountain-Blythe 161 kV line would be relocated from within the PSPP site to just outside the site. Removal of poles, construction of new poles and stringing of conductor would require use of diesel equipment over a one to two month period (see **Table 6**).

Transmission line relocation emissions would principally consist of exhaust emissions from heavy-duty diesel and gasoline-powered construction equipment and particulate matter (fugitive dust) from construction activities (grading, excavation, etc.) and travel on unpaved surfaces. Exhaust emissions and fugitive dust emissions would also be caused by workers commuting to and from the work sites, from trucks hauling poles, transformers, conductor, and other equipment and supplies, and crew trucks.

Based on the expected short construction duration, the construction emissions would be minimal and would be less than significant.

Impact Minimization Measures

Construction phase emissions are generally short-term in duration. Effective and comprehensive control measures would be needed to reduce equipment emissions to the extent feasible. Implementing appropriate fugitive dust control measures, such as those described in staff recommended conditions **AC-SC3** and **AC-SC4** would substantially reduce potential fugitive dust emissions during project construction.

Implementing appropriate off-road equipment emission control measures, such as those described in **AC-SC5** would substantially reduce potential off-road equipment tailpipe emissions potential during project construction.

The project would be required to comply with South Coast Air Quality Management District rules and District/ARB portable equipment rules, which would dictate how certain equipment could be operated during construction and would dictate the emergency power generator engine control and testing requirements.

The short-term nature of the construction activities would not create a significant cumulative impact.

Conclusions

Staff concludes that with effective and comprehensive control measures such as those recommended for the proposed PSPP, fugitive dust and equipment exhaust criteria pollutant emission impacts could likely be reduced to a less than significant level.

3.2 BIOLOGICAL RESOURCES

The Biological Resources section of the PSPP RSA provides an analysis of potential impacts of construction and operation of the proposed Eagle Mountain-Blythe 161-kV transmission line relocation, the portion of the redundant telecommunication line that would be placed underground between the PSPP and the existing microwave repeating tower, and the optical ground wire that would be collocated on the PSPP gen-tie towers. As such, these proposed components are not analyzed in this Appendix; refer to PSPP RSA Section C.2.

Environmental Setting

Biological survey data is not available for the proposed telecommunication/transmission interconnection components. The following general description of the environmental setting is inferred from reviewing aerial imagery and biological resource survey data provided by Solar Millennium for the area surrounding the PSPP offsite linears (Solar Millennium 2010k; Solar Millennium 2010n), which encompasses a small portion of the redundant telecom line and an area north of the gen-tie connection.

Vegetation Communities

The majority of the habitat within the proposed telecommunication/transmission interconnection area appears to be sonorant creosote bush scrub, which is the dominant vegetation community in the region. Species typically associated with this community include creosote bush (*Larrea tridentata*), burro bush (*Ambrosia dumosa*), boxthorn (*Lycium* sp.), brittlebush (*Encelia farinosa*), indigo bush (*Psorothamnus* spp.), and cheesebush (*Hymenoclea salsola*).

Ephemeral desert washes occurring in the project area are likely to be considered waters of the State. These resources support vegetative cover ranging from desert dry wash woodland to unvegetated ephemeral dry wash. Desert dry wash woodland is a sensitive vegetation community recognized by the CNDDB and BLM (CDFG 2003, BLM CDD 2002). This community is typically an open to densely covered, drought-deciduous, microphyll (small-leaved) riparian scrub woodland, often supported by braided wash channels that change patterns and flow directions following every surface flow event (Holland 1986). Dominant tree species include blue palo verde (*Parkinsonia florida*), honey mesquite (*Prosopis glandulosa*), ironwood (*Olneya tesota*), and smoke tree (*Psorothamnus spinosus*) with an understory of big galleta grass (*Pleuraphis rigida*), desert starvine (*Brandegea bigelovii*) and intermixed with creosote scrub and Russian thistle (*Salsola tragus*).

These vegetation communities provide value to various species of wildlife in the form of food, cover, dispersal, and refuge habitat.

Special Status Species

Special-status species are plant and wildlife species that have been afforded special recognition by federal, state, or local resource agencies or organizations. Listed and special-status species are of relatively limited distribution and typically require unique habitat conditions.

Table 7 lists special-status species that would likely occur in the project area and vicinity, based on a preliminary desktop habitat assessment and nearby records of species occurrence. There are additional species with low to moderate potential to occur and potentially others that may be identified during focused surveys and field investigations. As described above, survey data is not available for the gen-tie connection and the majority of the redundant telecom line. Loggerhead shrike (*Lanius ludovicianus*), a California species of special concern, was the only special-status species observed in the small portion of the proposed redundant telecommunication line covered by PSPP biological resource surveys.

Table 7. Special-Status Species Potentially Occurring in the Project Area

PLANTS		
Common Name	**Scientific Name**	**Status State/Fed/CNPS/BLM/ Global Rank/State Rank**
Harwood's milk-vetch	*Astragalus insularis var. harwoodii*	__/__/2.2/__/G5T3/S2.2?
Crucifixion thorn	*Castela emoryi*	__/__/2.3/__/G3/S2.2
Las Animas colubrina	*Colubrina californica*	__/__/2.3/__/G4/S2S3.3

PLANTS		
Common Name	**Scientific Name**	**Status State/Fed/CNPS/BLM/ Global Rank/State Rank**
Foxtail cactus	*Coryphantha alversonii*	__/__/4.3/__/G3/S3.2
Ribbed cryptantha	*Cryptantha costata*	__/__/4.3/__/G4G5/S3.3
California ditaxis	*Ditaxis serrata var. californica*	__/__/3.2/__/G5T2T3/S2.2
Cottontop cactus	*Echinocactus polycephalus var. polycephalus*	__/__/__/__/__/__
Harwood's eriastrum	*Eriastrum harwoodii*	__/__/1B.2/BLM/G2/S2
Desert unicorn plant	*Proboscidea althaeifolia*	__/__/4.3/__/G5/S3.3
WILDLIFE		
Common Name	**Scientific Name**	**Status State/Federal/BLM**
Reptiles/Amphibians		
Desert tortoise	*Gopherus agassizii*	ST/FT/__
Birds		
Western burrowing owl	*Athene cunicularia hypugaea*	CSC/BCC/BLM
Golden eagle	*Aquila chrysaetos*	CFP/__/BLM
Ferruginous hawk	*Buteo regalis*	WL/__BLM
Swainson's hawk	*Buteo swainsoni*	ST/__/__
Prairie falcon	*Falco mexicanus*	WL/__/__
Vaux's swift	*Chaetura vauxi*	CSC/__/__
Northern harrier	*Circus cyaneus*	CSC/__/__
California horned lark	*Eremophila alpestris actia*	WL/__/__
Loggerhead shrike	*Lanius ludovicianus*	CSC/BCC/__
Purple martin	*Progne subis*	CSC/__/__
Le Conte's thrasher	*Toxostoma lecontei*	WL/BCC/ BLM
Mammals		
Burro deer	*Odocoileus hemionus eremicus*	__/__/__
Chuckwalla	*Sauromalus obesus*	__/__/__

PLANTS		
Common Name	**Scientific Name**	**Status State/Fed/CNPS/BLM/ Global Rank/State Rank**
American badger	*Taxidea taxus*	CSC/__/__
Desert kit fox	*Vulpes macrotis arsipus*	__/__/__

(Sources: CEC2010k; Solar Millennium 2010k , Solar Millennium 2010n; CDFG 2010)

***Status Legend (State/Fed/CNPS/BLM/Global Rank/State Rank)**:
FE = Federally listed Endangered; **FT** = Federally listed Threatened; **BCC** = USFWS Bird of Conservation Concern; **SE** = State listed Endangered**; ST** = State listed Threatened; **CSC** = California Species of Concern; **SFP** = State Fully Protected; **WL** = State Watch List; **List 1B** = Rare or Endangered in California and elsewhere; **List 2** = Rare, threatened, or endangered in California but more common elsewhere; **List 4** = Limited distribution – a watch list; **.1** = Seriously threatened in California (high degree/immediacy of threat); **.2** = Fairly threatened in California (moderate degree/immediacy of threat)

Global Rank/State Rank
G1 or S1 = Critically imperiled; Less than 6 viable element occurrences (EOs) OR less than 1,000 individuals; G2 or S2 = Imperiled; 6-20 EOs OR 1,000-3,000 individuals; G3 or S3 = Rare, uncommon or threatened, but not immediately imperiled; 21-100 EOs OR 3,000-10,000 individuals; G4 or S4 = Not rare and apparently secure, but with cause for long-term concern; G5 or S5= Demonstrably widespread, abundant, and secure. **Threat Rank** .1 = very threatened; .2 = threatened; .3 = no current threats known

Potential Impacts of Transmission/Telecommunications Actions

Generation Tie Line Connection

Impacts to biological resources from construction of an additional transmission support structure to connect the gen-tie are similar to impacts resulting from construction of the remainder of the gen-tie, which are described in Section C.2.4.2 of the PSPP RSA. Creosote scrub and desert wash woodland habitat as well as jurisdictional waters of the State would be temporarily and permanently impacted by construction of the gen-tie connection. In addition, special-status wildlife species and plant species could be crushed, disturbed, or otherwise directly impacted by construction activities.

Although the transmission support structure and construction equipment could possibly be sited to avoid direct impacts to special-status species and sensitive habitat, indirect impacts would likely occur. Indirect impacts may include increased predation by ravens, habitat modification and degradation, and proliferation of non-native invasive plant species.

Telecommunications System

The redundant telecom line would be collocated with the existing 12.47-kV distribution line between the microwave tower and the Red Bluff Substation on existing towers. New or replacement structures would not be required. Therefore, potential impacts to biological resources would be temporary and limited to construction. Construction equipment could be sited to avoid direct impacts to sensitive habitat and special-status species. Indirect impacts could include introduction of non-native invasive plant species by construction equipment and workers.

Cumulative Impacts

Cumulative impacts resulting from the proposed telecommunication/transmission components would be similar to the PSPP albeit at a much reduced level; refer to Section C.2.9 of the RSA. In the PSPP RSA, staff concluded that implementation proposed conditions of certification would mitigate biological resource impacts to biological resources below the level of significance, thereby eliminating the projects contribution to cumulatively considerable impacts. It is anticipated that with implementation of similar measures, the telecommunication/transmission components could also adequately mitigate potential cumulative effects.

Impact Minimization Measures

Assuming that avoidance of sensitive biological resources is possible, the proposed telecommunication/transmission components are not likely to result in significant direct, indirect and cumulative impacts to biological resources. To this end, Staff recommends implementation of the measures similar to the following conditions of certification presented in the PSPP RSA:

- General impact avoidance and minimization measures (**BIO-8**). Confine work to delineated areas, control standing water, adhere to speed limits, dispose of trash, etc.
- Desert tortoise clearance surveys and fencing (**BIO-9**). Conduct clearance surveys and install exclusion fencing ensure no desert tortoises are within the project area during construction.
- Raven management plan (**BIO-13**). Minimize raven subsidies, implement a project Raven Plan.
- Weed management plan (**BIO-14**). Inspect and clean construction equipment, eradicate and monitor weed populations, quickly restore temporarily disturbed areas.
- Pre-construction nest surveys (**BIO-15**). Conduct pre-construction nest surveys and implement impact avoidance measures including establishing no-disturbance buffers around nests.
- American badger and desert kit fox avoidance and minimization measures (**BIO-17**). Conduct pre-construction clearance surveys and passively relocate individuals.
- Burrowing owl impact avoidance and minimization measures (**BIO-18**). Conduct pre-construction clearance surveys, passive relocation, burrow construction;
- Special-status plant impacts avoidance and minimization measures (**BIO-19**). Conduct pre-construction surveys, flag and avoid plant populations, control herbicide drift, implement erosion control measures.
- Golden eagle inventory and monitoring (**BIO-25**). Conduct golden eagle inventory and monitoring and develop and implement a territory-specific management plan to avoid disturbance.
- Revegetation of temporarily disturbed areas (**BIO-27**). Restore temporarily disturbed areas to pre-construction conditions and conduct monitoring to ensure effectiveness.

Provision of qualified personnel (Designated Biologist and Biological Monitors; e.g., **BIO-1** through **BIO-5**), worker training (e.g., **BIO-6**), and monitoring and reporting (e.g., **BIO-7**) are recommended to ensure that any impact avoidance and minimization measures, such as those listed above, are effectively implemented.

Conclusions

It is anticipated that, with implementation of impact avoidance and minimization measures, particularly identification and avoidance of sensitive biological resources, connection of the gen-tie line to the Red Bluff Substation and installation of the redundant telecommunication line on existing structures would result in less than significant impacts to biological resources. However, analysis of focused, site-specific biological survey results of the project area is needed to substantiate this. Staff does not currently have that project-specific information and therefore cannot address the feasibility of implementing effective avoidance measures as a means of reducing impacts below the level of significance.

3.3 CULTURAL RESOURCES

The cultural resources analysis of the transmission/telecommunications actions is based on applicant-provided cultural resource information presented in the PSPP AFC (Solar Millennium 2009a) and PSPP SA/DEIS (CEC 2010k) and associated with the Desert Sunlight Solar Farm Revised Preliminary Draft PA/EIS analysis. Site specific information for the TSE project area was not available. The TSE actions and potentially resultant impacts to cultural resources will undergo an independent, site specific analysis pursuant to CEQA and NEPA in permitting by the BLM.

Environmental Setting

The environmental setting for cultural resources is common to the proposed gen-tie connection, telecommunication system and transmission line relocation areas. The prehistoric and historic setting of this region is described in detail in Section C.3 of the PSPP RSA.

Regional Setting

The proposed project area is located in Chuckwalla Valley, along the southwest edge of Palen Dry Lake. This area is part of the Mojave Desert, a sub-region of the Lower Sonoran Life Zone. The project vicinity has two main vegetation types: Sonoran creosote bush scrub and stabilized and partially stabilized sand dunes. Humans have inhabited this region for the last 10,000 years, with the population ebbing and flowing primarily in response to several climatic shifts. Within the Chuckwalla Valley, prehistoric sites are clustered around springs, wells, and other obvious important features/resources. Sites include villages with cemeteries, occupation sites with and without pottery, large and small concentrations of ceramic sherds and flaked stone tools, rock art sites, rock shelters with perishable items, rock rings/stone circles, geoglyphs, and cleared areas, a vast network of trails, markers and shrines, and quarry sites. The Chuckwalla Valley does not appear to be associated clearly with any historic

Native American group (Singer 1984, pp. 36-38). However, seven groups - Chemehuevi, Serrano, Cahuilla, Mojave, Quechan, Maricopa, and Halchidhoma - claim territory nearby or describe this region in their oral history. The trails, rock art, geoglyphs and other prehistoric features are still of religious importance to many of these Native American groups.

The major historical themes for the Mojave Desert region and PSPP vicinity are the establishment of transportation routes, water access, mineral exploitation, agriculture, and military uses. Military uses of the region are primarily associated with Gen. Patton's World War II Desert Training Center/California-Arizona Maneuver Area (DTC/C-AMA), which was in operation from 1942-1944. The remains of the DTC/C-AMA areas consist of rock features, faint roads, structural features, concertina wire, tank tracks, footprints of runway and landing strips, foxholes and bivouacs, concrete defensive positions, refuse, and trails (Bischoff 2000).

Existing Resources

Although cultural resources surveys for the proposed gen-tie connection, telecommunication system and transmission line relocation areas have been conducted, staff did not have access to site-specific information for the project components. Staff based the following discussion on general information about the nature and density of cultural resources in the region using the PSPP AFC, the PSPP SA/DEIS and the Desert Sunlight Draft PA/EIS.

In general, the previous research in the Chuckwalla Valley suggests that prehistoric archaeological sites are typically located near water (specifically, near springs), on terraces near the shore of the dry lake beds, and in areas where natural resources were utilized. Prehistoric site types in the PSPP site footprint and vicinity include artifact scatters, habitation sites, quarries, rock art sites, and trail segments. The vicinity of Palen Dry Lake and the Chuckwalla Mountains appear to be areas of particular sensitivity for cultural resources. These areas are associated with three BLM Areas of Critical Environmental Concern for cultural resources (Alligator Rock, Corn Springs, and Palen Dry Lake), two National Register of Historic Places Districts (North Chuckwalla Petroglyph District [CA-Riv-1383] and North Chuckwalla Mountains Quarry District [CA-Riv-1814], and one location listed in the Sacred Lands database of the Native American Heritage Commission (NAHC).

Historical archaeological sites in the region are primarily associated with transportation, DTC/C-AMA and Desert Strike military maneuvers, mining, and ranching. Historical archaeological site types for the area include road segments, wells, refuse scatters with domestic and/or military discards, tank tracks, and other isolates.

Staff has grouped sites associated with prehistoric trails and those associated with historic military maneuvers into two groups which staff has defined as cultural landscapes. A cultural landscape consists of "geographic area, including both natural and cultural resources, associated with a historic event, activity or person" (NPS 1996). Cultural landscapes can be determined eligible and nominated for inclusion on the NRHP as either sites or districts (Evans et al. 2001).

Staff has proposed the Prehistoric Trails Network Cultural Landscape, which is a noncontiguous cultural landscape (historic district) that incorporates prehistoric archaeological sites associated with the Halchidhoma Trail (CA-Riv-0053T). This landscape consists of important destinations in the Colorado Desert near Blythe, California, the network of trails that tie them together, and the features and sites associated with the trails. Energy Commission staff considers the resources that make up the PTNCL to be significant under NRHP Criterion A (CRHR Criteria 1), for their ties to important events in American history. These sites are also considered register-eligible under Criterion D/4 for their ability to yield information important in history and prehistory.

Staff has also proposed the creation of the Desert Training Center California-Arizona Maneuver Area (DTC/C-AMA) Cultural Landscape (DTCCL) a contiguous cultural landscape (historic district) that incorporates historical archaeological sites associated with General Patton's Desert Training Center (Bischoff 2000). Energy Commission staff recommends that DTCCL is eligible for listing on the NRHP under Criterion D (CRHR Criterion 4). Most property types associated with the DTC/C-AMA, across the full extent of the resource, exist today as archaeological resources, such as refuse deposits, tank tracks, foxholes, and bivouacs.

These landscapes extend beyond the boundaries of a single project. Possible contributors have been identified within the PSPP, Desert Sunlight Solar Farm, Genesis Solar Energy Project, Rice Solar Energy Project, and Blythe Solar Power Project site foot prints and linear corridors. As many contributing elements to both of these landscapes are often considered not to be significant in their own right, staff expects that previously identified cultural resources will need to be re-evaluated.

Potential Impacts of Transmission/Telecommunications Actions

Direct, indirect and cumulative impacts would be similar for the gen-tie connection, transmission line relocation, and the telecommunication systems; therefore, impacts from all three project elements are discussed jointly below.

Direct Impacts

Direct impacts to cultural resources would potentially occur from ground disturbance during the construction of the gen-tie line connection, the telecommunication system, and the transmission line relocation.

The gen-tie line connection will be built adjacent to the proposed Red Bluff Substation. A number of additional towers associated with new transmission lines are planned, but only a single tower is analyzed here. One single-circuit lattice steel tower or tubular steel pole between the 230 kV switchrack and the first developer-built 230 kV transmission line structure north of the substation is proposed.

The proposed telecommunication system will consist of a fiber-optic line strung along the 220 kV gen-tie line transmission towers north of I-10, and a redundant line following the proposed Red Bluff Substation access road south of I-10. While some of the redundant line would be buried, most would be strung on an existing SCE distribution line. Impacts associated with the installation of the fiber-optic line would be primarily associated with the construction of the gen-tie transmission towers; analysis of the gen-tie line is presented in the RSA. Staff does not believe that the stringing of the fiber-optic line alone would result in significant direct impacts to cultural resources. Similarly, stringing of cable on the distribution line would not significantly impact cultural resources. However, that portion of the line that would be buried would contribute to ground disturbance planned along the substation access road. This access road and other road improvements would be analyzed in the Desert Sunlight PA/EIS.

The applicant proposes to relocate approximately 6,000 feet of the Eagle Mountain-Blythe 161kV transmission line around the edge of the southwest corner of the PSPP site footprint. Line relocation would be accomplished by installing approximately eighteen 65-foot H-Frame structures. Other ground disturbance associated with this relocation would be the creation of a 20 acre staging area, the construction of new spur roads, the improvement of existing roads, and extensive grading in preparation for the use of equipment to remove, install and string new poles.

Staff concludes that the construction of the transmission/telecommunications components is likely to result in direct impacts to cultural resources. Cultural resources located within the proposed project area are expected to be completely destroyed by this ground disturbance. The number and type of these resources will need to be identified by future CPUC and BLM analyses. However, previous research suggests that many of them will be contributing elements of the PTN and DTC Cultural Landscapes. Some of these sites may have been determined ineligible for the CRHR and NRHP during previous archaeological surveys. However, the establishment of two new cultural landscapes would require that these resources be re-evaluated to determine their role in the context of these landscapes.

Indirect Impacts

Indirect impacts to cultural resources can have both physical and cultural or spiritual components. While construction of the proposed transmission/telecommunications components are unlikely to result in increased visitation to nearby archaeological sites, and in turn result in erosion and vandalism, they are part of a larger project with that potential. Alternatively, the historical integrity of nearby ethnographic resources (or TCPs) could be visually degraded by the proposed project. Impacts to the integrity of ethnographic resources can only be identified by members of the community who value the resources culturally and/or spiritually, in this case Native Americans. BLM is currently in the process of consulting with local Native American groups regarding impacts and potential mitigation for the PSPP project area. Previous research suggests that the project area is one of high ethnographic sensitivity. Unidentified Traditional Cultural Properties may be present.

Cumulative Impacts

Cumulative impacts resulting for the PSPP TSE actions would be similar to the PSPP Project. The proposed project impacts, when combined with impacts from past, present, and reasonably foreseeable projects, contribute in a small but significant way to the cumulatively considerable adverse impacts for cultural resources at both the local I-10 Corridor and regional levels. This analysis, presented in detail in the PSPP RSA, estimates that more than 800 sites within the I-10 Corridor, and 17,000 sites within the Southern California Desert Region, would potentially be destroyed. Staff concludes that mitigation can reduce the impact of this destruction, but not to a less-than-significant level.

Impact Minimization Measures

Staff concludes that the most appropriate impact minimization measures for construction of the proposed transmission/telecommunications components are a selection of the cultural resources conditions of certification proposed in the PSPP RSA. The primary reason for this conclusion stems from the fact that these conditions were designed for particular prehistoric and historic site types common to the PTN and DTC Cultural Landscapes. Newly identified sites should be accommodated by the existing conditions. Finally, this decision is consistent with staff's decision to coordinate the mitigation of all impacts to PTNCL and DTCCL potential contributors by developing shared conditions of certification for the three solar projects proposed by NextEra and Solar Millennium for areas north of the I-10 corridor between Blythe and Desert Center: Genesis Solar Energy Project, Blythe Solar Power Project, and PSPP. The conditions relevant to the proposed project are summarized below, and presented in detail in PSPP RSA Section C.3.

- **CUL-1** and **CUL-2** would fund programs to define, document, and nominate to the NRHP two cultural landscapes that the proposed project shares with PSPP and two other nearby solar projects, identifying specialists who would be hired to supervise the mitigation of the proposed projects cumulative impacts to these resources and establishing a fund, to which multiple project owners will contribute, to hire these specialists. While the implementation of these conditions would reduce the proposed projects cumulative impacts to the greatest extent possible, they would still be cumulatively considerable.
- **CUL-3** and **CUL-4** are administrative conditions that set out who the people would be who will implement the balance of the conditions, what are their qualifications and roles would be, and the information the project owner would supply them to help them fulfill those roles.
- **CUL-5** provides for the preparation and implementation of the Cultural Resources Monitoring and Mitigation Plan (CRMMP), which would structure and govern the implementation of the broader treatment program.
- **CUL-7** and **CUL-8** are treatment conditions for direct impacts to historic-period and prehistoric resources that would reduce the severity of the proposed project impacts to less-than-significant.

- **CUL-9** would provide training of project personnel to identify, protect, and provide appropriate notice about known and new potential cultural resources in the project construction area.
- **CUL-10** and **CUL-11** would provide construction monitoring and cultural resources discovery protocols.
- **CUL-12** provides for the preparation of a final report to analyze, interpret, and document the ultimate results of the project cultural resources management program.

Conclusions

Staff was not provided any site specific cultural resources information regarding the proposed PSPP gen-tie connection, telecommunication system, or transmission line rerouting. However, the results of previous research indicate that construction of the TSE is likely to result in direct and indirect impacts to cultural resources. Project impacts when combined with impacts from past, present, and reasonably foreseeable projects, would contribute in a small but significant way to the cumulatively considerable adverse impacts for cultural resources at both the local I-10 Corridor and regional levels. Future cultural resources surveys and analyses conducted by the CPUC and BLM as part of their compliance with CEQA, NEPA, and Section 106 of the National Historic Preservation Act (NHPA) would need to address potential impacts to cultural resources in the PSPP TSE project footprint.

3.4 GEOLOGY AND PALEONTOLOGY

Environmental Setting

Geology

The proposed transmission/telecommunications components are located in the southeastern portion of the Mojave Desert geomorphic province (CGS 2002a), in the Mojave Desert of Southern California. This physiographic province is delineated by the northeast-striking Garlock Fault on the northwest side and the northwest-striking San Andreas Fault on the southwestern boundary. The topography and structural fabric in the Mojave Desert is predominately southeast to northwest, and is associated with faulting oriented similar to the San Andreas Fault. A secondary east to west orientation correlates with structural trends in the Transverse Ranges geomorphic province.

The transmission/telecommunications actions would be situated on a broad alluvial plain within the northwest-trending Chuckwalla Valley. Overall the project area and vicinity slopes at very shallow grade toward the local topographic low at Palen Dry Lake. Quaternary age alluvial, lacustrine and eolian sedimentary deposits are mapped within and proximate to the project area.

Geologic Hazards

The area in which the proposed transmission/telecommunications components would be constructed is not crossed by any known active faults or designated Alquist-Priolo Earthquake Fault Zones (CGS 2002b). There are no major faults (i.e., Type A or B) within approximately 20 miles of the project area. The distance from seismically active areas suggests a low to moderate probability of intense ground shaking. Also, the transmission/telecommunications project area is located on flat to gently sloping ground and is therefore not susceptible to landslides.

The proposed transmission/telecommunications project area is located within an area with low to moderate level of liquefaction potential as per Riverside County Land Information System (RCLIA 2010). However, the estimated depth to ground water based on measured values in boreholes and wells near the project area is greater than 60 feet below existing grade (Solar Millennium 2009a). In addition, the typical medium dense to very dense nature of the coarse grain soils encountered in the borings (Kleinfelder 2009) indicates that there is no liquefaction potential. Consequently, the potential for lateral spreading during seismic events would also be negligible.

The Riverside County Land Information System designates the area as being susceptible to subsidence (RCLIA 2010); however, no localized or regional subsidence has been recorded and no petroleum or natural gas withdrawals are taking place in the vicinity of the proposed transmission/telecommunications project area. Therefore, the potential for local or regional subsidence is considered to be very low.

Mineral Resources

The proposed project components are located within Mineral Resource Zone 4, which denotes “areas of no known mineral occurrences where geological information does not rule out either the presence or absence of significant mineral resources” (CDMG 1994); however, the project area is not currently used for mineral production, nor is it under claim, lease, or permit for the production of locatable, leasable, or salable minerals. Many inactive mines and mineral prospects are hosted by in metamorphic and intrusive basement rocks within 10 miles of the proposed project. These have produced a number of precious and base metals and minerals, including iron (magnetite), gold, silver, copper, uranium, and pyrophyllite, several borrow pits are present along Interstate 10. No mines are known to have existed in the proposed project area (USGS 2008).

Paleontology

In the PSPP RSA, which included an analysis of sediments also present within the transmission/telecommunications action area, staff concludes that the paleontological resource sensitivity of Quaternary age sediments varies from low in Holocene age younger alluviual, lacustrine and eolian deposits at shallow depths to high as Pleistocene age older alluvium and lacustrine deposits are encountered at deeper depths. The paleontological sensitivity map produced by the Riverside County Land

Information System (2010) designates the project area as having low and undetermined paleontological sensitivity.

The probability for significant paleontological resources to be encountered during construction activities is considered to be low in Holocene age deposits. However, grading and trenching may penetrate underlying Pleistocene age soils at undetermined depths. Overall, the potential for exposure of paleontological resources during trenching is considered to be high, until determined otherwise by a qualified professional paleontologist.

Potential Impacts of Transmission/Telecommunications Actions

Impacts to geological and paleontological resources would potentially occur from ground disturbance during construction. Ground disturbance from excavation for tower footings for the gen-tie connection and transmission line relocation would result in similar impacts to geological and paleontological resources; therefore, impacts from all project elements are discussed jointly below.

Geologic Hazards

It is standard practice, and a requirement of Section 1802A of the 2007 California Building Code, to conduct a geotechnical study of the project area, prior to the start of construction. This study evaluates the depth to the water table, evidence of faulting, liquefaction potential, physical properties of subsurface soils, soil resistivity, slope stability, and the presence of hazardous materials. The results of the geotechnical investigations would then be applied to the project's engineering design to ensure that potential impacts to geology are avoided or minimized.

There are no known active faults in the immediate vicinity of the proposed project area. As such, the hazard of direct surface displacement by faulting of any portion of the proposed components is not expected. As described above, the project would be located in an area of minimal seismicity and would only be susceptible to groundshaking in the event of a significant earthquake on any of the regional active faults. The project facilities would be engineered to withstand potential ground shaking in accordance with the CPUC's General Order 95 and would meet relevant seismic requirements. Proper design would reduce the threat of damage to the proposed facilities from the potential maximum ground acceleration to less than significant levels.

The susceptibility of a site to liquefaction is a function of the depth, density, and water content of the granular sediments and the magnitude and frequency of earthquakes in the surrounding region. As described above, the project area has low to moderate liquefaction potential and is susceptible to subsidence. Despite the presence of potentially liquefiable alluvial sediments, anticipated seismic groundshaking is not expected to be of sufficient frequency or intensity to cause liquefaction of these sediments. A properly designed facility would reduce the minor threat of damage to the proposed facilities as a result of lateral spreading, subsidence, liquefaction, or collapse to less than significant levels. The project is located on relatively level ground and thus no impact is expected from landslides.

Construction would occur in relatively flat terrain and the geologic investigation described above would identify the affected soils and their site-specific erosion potential. Erosion control best BMPs would be used where excavation and grading occurs as would be required by the project National Pollution Discharge Elimination System (NPDES) permits and the SWPPP (see the Soils and Water Resources section of this Appendix). With proper construction practices there should be no notable erosion or transport of sediment from the site. Considering these factors, there should be little or no impact due to erosion or loss of topsoil. Potential impacts would be less than significant and no mitigation is recommended.

Paleontology

Ground disturbances associated with construction of the telecommunications facilities could disturb significant paleontological resources potentially located within the project area. Indirect impacts to paleontological resources may include erosion of features due to channeling of runoff or damage to outcrop areas due to earth-shaking activities associated with drilling, trenching, or grading activities. Impacts to paleontological resources, if present, would be potentially significant.

Minerals

Since there are no known mining operations identified in the project area, construction of the project is unlikely to interfere with daily ongoing or planned mining operations. No impacts would occur and no mitigation is recommended.

Cumulative Impacts

Cumulative impacts resulting from the proposed Project would be similar to the PSPP Project albeit at a much reduced level; refer to Section D.2.9 of the RSA. Implementation of the conditions of certification recommended below would mitigate potential geological and paleontological impacts below the level of significance, thereby eliminating the projects contribution to cumulatively considerable impacts.

Impact Minimization Measures

As described above, soils and rock testing should be conducted and analyzed by a professional, licensed geotechnical engineer or geologist to determine existing foundation conditions, as described in conditions of certification **GEN-1, GEN-5,** and **CIVIL-1** in the Facility Design section of the PSPP RSA. The results of the geotechnical investigation would then be applied to the project's engineering design and this would ensure that potential impacts to geology are avoided or minimized.

Implementation of a worker education program in conjunction with monitoring of earthwork activities by qualified professional paleontologists (paleontological resource specialist, or PRS) would mitigate potential unforeseen impacts to less than significant. Recommended paleontology mitigation requirements are described in conditions of certification **PAL-1** to **PAL-7** in the Geology, Paleontology, and Minerals section of the

PSPP RSA. Earthwork would be halted any time potential fossils are recognized by either the paleontologist or the worker. For finds deemed significant by the PRS, earthwork cannot restart until all fossils in that strata, including those below the design depth of the excavation, are collected. When properly implemented, the conditions of certification would yield a net gain to the science of paleontology since fossils that would not otherwise have been discovered can be collected, identified, studied, and properly curated. A paleontological resource specialist would be retained, for the project by the applicant, to produce a monitoring and mitigation plan, conduct the worker training, and provide the monitoring.

Implementation of staff’s recommended conditions of certification as presented in the PSPP RSA, or similar measures would reduce potential direct, indirect, and cumulative impacts to geological and paleontological resources to less than significant.

Conclusions

Impacts to geologic resources would potentially occur from ground disturbance during construction. Direct surface displacement by faulting of any portion of the proposed facility is not expected. The components would be engineered to withstand potential ground shaking in accordance with the CPUC’s General Order 95 and would meet relevant seismic requirements. The project is located on relatively level ground and in an area of low seismicity. No impact is expected from landslides. With proper construction practices there should be no notable erosion or transport of sediment from the site. Impacts to paleontological resources, if present, would be potentially significant. No impacts to mining would occur. The proposed Project would not result in cumulative impacts. Mitigation measures would reduce potential geological and paleontological impacts below the level of significance.

3.5 LAND USE

Environmental Setting

This land use analysis focuses on the consistency of the PSPP transmission/telecommunications actions with existing land use resources, land use plans, ordinances, regulations, policies, and the project’s compatibility with existing or reasonably foreseeable land uses.

The proposed PSPP would be constructed on a relatively flat, largely undeveloped portion of the Colorado Desert (a subdivision of the Sonoran Desert) in the Chuckwalla Valley between the Palen Mountains and I-10 (Corn Springs Road exit) in Riverside County, California.

The solar facility would be located on land within the California Desert Conservation Area (CDCA) Plan area. The project area is in the “Multiple-Use Class M” land use category, except for a 40 acre parcel in private ownership. The CDCA Multiple Use classification provides for electrical generation plants in accordance with state, federal, and local laws. The Red Bluff Substation and access road would be on land designated

BLM Multiple Use Class L (Limited Use) and are within a CDCA utility corridor. The CDCA LU classification states that new transmission facilities are allowed only in designated utility corridors areas.

The proposed PSPP transmission/telecommunications components would require the BLM's approval of an Amendment to the CDCA Plan and issuance of a Right of Way grant. With the BLM's approval, the project would be consistent with the CDCA Plan.

The proposed project area is within the Northern and Eastern Colorado Desert Coordinated Management Plan (NECO) area. The NECO is an update amendment to the CDCA Plan to make it compatible with Desert tortoise conservation and recovery. The NECO is a landscape-scale planning effort for most of the California portion of the Sonoran Desert ecosystem that promotes desert tortoise conservation and recovery. The project area is within the Desert tortoise Eastern Colorado Recovery Unit.

The nearest sensitive receptors would be located a mile to the north of the transmission line relocation area. There are no schools, day-care facilities, convalescent centers, or hospitals within the immediate vicinity of the proposed substation site. The proposed PSPP and Red Bluff Substation sites are not used for agriculture, nor are they located within a range allotment or herd management area.

The California desert, including the NECO planning area, offers multiple recreational opportunities such as casual vehicle touring, nature studies, hiking, camping, and lakebed activities. The nearest designated wilderness areas are the Palen/McCoy Wilderness Area, approximately 2 miles to the north-northeast of the PSPP site, and the Chuckwalla Mountain Wilderness, approximately 3 miles south of the PSPP site. The Palen/McCoy Wilderness Area involves approximately 236,488 acres. Hunting, fishing, and non-commercial trapping are allowed. The Chuckwalla Mountains Wilderness is approximately 99,500 acres and is available for recreational purposes. Hunting, fishing, and non-commercial trapping are allowed under state and local laws. Camping is permitted within both wilderness areas for up to 14 days (BLM 2010a). The Corn Springs Campground is located approximately six miles south of the Red Bluff Substation in a canyon of the Chuckwalla Mountains, and supports abundant wildlife and is an important stopping place for migratory birds. Corn Springs was a major occupation site of prehistoric Native American Indian groups and contains petroglyphs. They display a wide variety of elements and cover a long time span, with the earliest petroglyphs dating as far back as 10,000 years. Corn Spring Campground has nine camp sites.

Potential Impacts of Transmission/Telecommunications Actions

Land use impacts of the PSPP transmission/telecommunications actions would be less than significant and would comply with applicable land use plans, ordinances, regulations, policies and reasonably foreseeable land uses. The gen-tie connection and redundant telecom line would be located within an existing utility corridor, adjacent to an existing 500 kV transmission line. These uses are consistent with a utility corridor, so would not change existing or planned land uses. The utility corridor is an established land use and therefore the proposed construction of the gen-tie connection and redundant telecom line is not expected to conflict with applicable LORS, including the

General Plan of Riverside County. Relocation of the transmission line would be consistent with the PSPP land classification of Multiple Use.

Project construction activities would create a number of temporary nuisances that would temporarily diminish the recreational value of adjacent areas. For example, the noise, dust, and construction traffic generated during construction activities could create short-term impacts to a visitor's enjoyment of these recreation areas. However, due to the numerous designated open routes in the Chuckwalla Valley and the size of the Chuckwalla Mountains Wilderness, it is assumed that recreationists would not be precluded from those activities.

The TSE components would not create a cumulative land use impact. However, as noted in Section C.6 of the RSA, the incremental effect of the proposed PSPP, combined with the effects of the other projects would substantially reduce a scenic and biological important resource of value, and may substantially reduce an important cultural resource of value.

Impact Minimization Measures

No additional minimization measures are recommended beyond the proposed PSPP project's compliance with all applicable land use LORS for both operation and construction.

Conclusions

Land use impacts of the proposed transmission/telecommunications components would be less than significant. The project would comply with applicable land use plans, ordinances, regulations, policies and reasonably foreseeable land uses. The project would not impact any agriculture or rangelands, recreation and wilderness areas, areas designated by BLM as Herd Areas or Herd Management Areas or divide an existing community. Although the PSPP project may combine with other past and reasonably foreseeable future projects to reduce scenic values and biological and cultural resources in the Chuckwalla Valley and southern California desert region and therefore, would result in a significant and unavoidable cumulative land use impact in this regard, the contribution to this cumulative impact from the TSE components would be minimal.

3.6 NOISE AND VIBRATION

Environmental Setting

The environmental setting for the PSPP transmission/telecommunication components is shared among each of the project components. The PSPP site is located 0.5 mile north of Interstate I-10 at the Corn Springs Road intersection. The Red Bluff Substation site is located approximately 5 miles east of California State Highway 177 along the south side of Interstate I-10. Both sites are in Riverside County in a remote area of primarily undeveloped land. The environmental setting would be essentially as described and analyzed in Section C.7 (Noise and Vibration) of the PSPP RSA.

The small community of Desert Center is located approximately 10 miles west of the site, along I-10.The predominant noise source in proximity to the project site is vehicular traffic on I-10. There is one residence located approximately 25 feet from the northwest corner of the PSPP project right-of-way boundary. Another residence is located approximately 3,500 feet northwest of the PSPP site boundary. However, these residences are over a mile away from the southwestern corner of the site where transmission relocation activities would occur. There are residences about 4 miles to the northwest of the Red Bluff Substation. Eagle Mountain Elementary School is approximately 10 miles to the east in the City of Blythe.

Potential Impacts of Transmission/Telecommunications Actions

Construction of the PSPP transmission/telecommunication components would generate noise above ambient levels. Construction noise would include the operation of construction equipment and vehicles at the proposed construction sites, and the transport of construction materials and workers as vehicle trips to and from the project sites. Construction would generate temporary noise levels from equipment and vehicles during site grading activities, trench construction, and surface paving. Connection of the PSPP gen-tie and construction along the telecommunication route would be temporary and short term. Transmission line relocation activities would occur over a slightly longer timeframe but would also be temporary.

Noise impacts from construction are a function of the noise generated by equipment, the location and sensitivity of nearby land uses, and the timing and duration of the noise-generating activities. Potential impacts to noise-sensitive receptors from construction noise would be limited to receptors in proximity to PSPP and Red Bluff Substation facilities and the telecommunication system route.

Construction of the project would require short-term use of heavy-duty equipment such as trenchers, excavators, backhoes, cranes, and trucks. In general, construction work within 200 feet of any location would cause noise levels averaging around 65 dBA, with intermittent peaks up to about 88 dBA. This would be a noticeable (more than five dBA) temporary increase in the ambient noise levels near the work that would fade into quiet background noise at distances over one-quarter mile. There are no sensitive receptors within one-quarter of PSPP transmission/telecommunication components. As such, impacts from construction noise are not expected.

Riverside County Code 847 limits noisy construction activity to daylight hours when construction activities occur within one quarter mile of noise-sensitive receptors. Given the distance between construction activities and noise-sensitive receptors, this limit does not apply. Because there are no noise sensitive receptors in the proposed project vicinity, noise impacts from construction and operation of the TSE components would be less than significant.

Equipment needed for the proposed project construction is not likely to create vibration impacts that would be perceived at the nearest noise-sensitive receptor. No impact from vibration would occur.

Operational noise impacts from occasional maintenance of the PSPP transmission/telecommunication components would be insignificant. Cumulative impacts are analyzed in Section C.7.8 of the PSPP RSA and it was determined that no cumulative noise impact would result from the proposed PSPP Project. Similarly, no cumulative impacts would be expected from the PSPP TSE components.

SCE would be required to protect construction, operation and maintenance workers from noise hazards per applicable LORS.

Impact Minimization Measures

Noise levels from project construction and operation would attenuate to an acceptable level to the nearest noise-sensitive receptors. In the event that actual construction noise should annoy sensitive receptors, implementation of measures similar to condition of certification **NOISE-1** and **NOISE-2** as described in the Noise and Vibration section of the PSPP RSA, would establish a public notification process to notify nearby residents of the project construction and operation, and a Noise Complaint Process that would require the applicant to resolve any complaints regarding project noise. To ensure that construction, operation and maintenance workers are adequately protected, condition of certification **NOISE-3** (noise control program), as described in Section C.7 of the PSPP RSA, would reduce noise impacts to workers. In addition, implementation of a minimization measure similar to **NOISE-6** (construction restrictions), would ensure compliance with the Riverside County Noise Ordinance 847 by requiring the noisy construction activities occur during certain daylight hours.

Conclusions

Staff concludes that the PSPP transmission/telecommunication components would comply with all applicable noise and vibration LORS and would produce no significant direct or cumulative adverse noise impacts on people within the project area, directly, indirectly, or cumulatively.

3.7 SOCIOECONOMICS

Environmental Setting

The proposed PSPP transmission/telecommunication components are located in the Southern California inland desert on federal land managed by the BLM, approximately 10 miles east of Desert Center, in eastern Riverside County. Research shows that workers may commute as much as two hours each direction from their communities rather than relocate (EPRI 1982). Therefore, the local and regional study area is considered to be Riverside County, CA; San Bernardino County, CA; and La Paz County, AZ.

Population data for the PSPP Project is considered applicable to the transmission/telecommunications components. The total population within a six-mile radius of the proposed PSPP Project is 17 persons and the total minority population is 10 persons or 58.8 percent of the total population. The total below-poverty-level population is 0.00 percent within the 6-mile radius. The current vacancy rates for the cities of Blythe, CA and Ehrenberg, AZ are 16.1 and 34.9 percent, respectively (PSPP RSA Section 5.8).

Potential Impacts of Transmission/Telecommunications Actions

Socioeconomic impacts could result from long-term employment of people from regions outside the study area as a result of relocations and population influx; however, no significant adverse socioeconomics impacts would occur as result of the construction or operation of the transmission/telecommunications components given that no socioeconomic impacts were identified for the PSPP Project.

It is anticipated that the construction period for the transmission/telecommunications components would occur over a 1-2 month period. There would be at most 20 construction workers on any given day, depending on the work required. Laborers would consist of craftspeople and supervisory, support, and construction management personnel on site during construction. As evaluated in the Section C.8.4 of the PSPP RSA, there is more than adequate local availability of construction workforce within the Riverside/San Bernardino/Ontario MSA alone for the PSPP. As such, the additional 20 workers needed for the proposed transmission/telecommunications components would not create a significant impact on the local workforce.

Should some construction workers from within the study area choose to stay temporarily at a local area motel or hotel close to the proposed PSPP Project site, there is ample transient housing available. There are approximately 630 hotel/motel rooms and suites among 11 different establishments in the Blythe area. As noted above, the current vacancy rates for the cities of Blythe, CA and Ehrenberg, AZ are 16.1 and 34.9 percent, respectively. Staff concludes that inducement of substantial population growth either directly or indirectly by the transmission/telecommunications actions would not be significant or adverse and construction activities would not encourage people to permanently relocate to the area.

Operation

Operation of the proposed project components would not require any addition to the current workforce. The transmission/telecommunication components would not permanently or significantly increase the population in the area and therefore would not result in significant demands on law enforcement or medical services, schools nor parks or recreation. No populations, high-minority, low-income, or otherwise, would be affected by the proposed project.

Cumulative Impacts

The cumulative impacts of construction and operation of the proposed PSPP Project ancillary facilities, which include the transmission line and its associated infrastructure was analyzed in the PSPP RSA. Staff concluded that the local and regional labor force would adequately serve construction and operation of the proposed PSPP and it would not contribute to cumulative increases in population that would generate an increase in demand for local housing and public services. Staff concludes that construction and operation of the proposed transmission/telecommunication components would not contribute to adverse cumulative socioeconomic impacts.

Impact Minimization Measures

Construction of the proposed transmission/telecommunications components would not cause a significant adverse direct, indirect, or cumulative impact to the study area's population, housing, schools, law enforcement, emergency services, hospitals, and utilities. In addition, because there would be no adverse project-related socioeconomic impacts, minority and low-income populations would not be disproportionately impacted. No impact minimization measures are recommended.

Conclusions

The proposed transmission/telecommunications components would not cause a significant adverse direct, indirect, or cumulative impact to the study area's population, housing, schools, law enforcement, emergency services, hospitals, and utilities. No minority and low-income populations would be disproportionately impacted.

3.8 SOIL AND WATER RESOURCES

Environmental Setting

The PSPP TSE components are located within the Mojave Desert Geomorphic Province, which is a broad interior region of isolated mountain ranges separated by expanses of desert plains/valleys. It has an interior enclosed drainage and many playas, but no perennial streams or permanent natural bodies of water. Standing water may persist for short periods in dry lakes and low areas after heavy rainfall events. Several ephemeral desert washes extending from mountain ranges to playas traverse the project area.

Project components located within the Colorado River Basin, within the Chuckwalla Valley Drainage Basin. There are no perennial streams in Chuckwalla Valley. Chuckwalla Valley is an internally drained basin, and all surface water flows to Palen Dry Lake in the western portion of the valley and Ford Dry Lake in the eastern portion of the valley.

The ground surface in the region generally slopes gently downward to the southeast. Soil types on the PSPP plant site include VIIe and VIIIc Capability Subclasses, indicating that the soils have very severe limitations that make them unsuitable for cultivation and commercial crop production. The PSPP RSA describes soils on site as consisting of sandy material and classified as poorly graded sand with silt. Across most of the subject property, the soils would be expected to range from silty sand to poorly graded sand with silt.

The proposed PSPP site is crossed by a series of small distributary alluvial fan channels, and two large wash complexes formed by concentrated drainage under I-10. There are three eroded channels associated with the proposed Red Bluff Substation. These channels would require alteration in order to protect the Substation from potential flooding impacts. The 25,000 foot pipeline road would traverse numerous eroded gully crossings and Blue-line streams and would require leveling or installation of culverts over the gully crossings and diversion berms along portions of the south (upslope) edge to prevent erosion of the road.

The only perennial surface water resources in the eastern portion of Chuckwalla Valley are McCoy Spring, at the foot of the McCoy Mountains approximately 19 miles northeast of the site, and Chuckwalla Spring, approximately 16 miles south of the site at the foot of the Chuckwalla Mountains.

Potential Impacts of Transmission/Telecommunications Actions

Potential direct and indirect impacts to soil and water resources are primarily related to drainage, erosion, and sedimentation control during construction and operation. Most of the potential impacts would be expected to occur during construction. Potential impacts resulting from ground disturbance would be similar for all proposed PSPP transmission/telecommunication elements and are discussed jointly below.

Although there are no perennial water resources, the area shows evidence of surface storm water runoff. Construction of the Red Bluff Substation would alter existing drainage channels. Construction of a channel to route flows around the substation and construction of the detention basis south of the substation would mitigate potential surface water and drainage impacts, and potential erosion or siltation. Connection of the PSPP gen-tie would not create additional water resource impacts.

Soil related issues in the project area include a high potential for wind and water erosion of soils disturbed during construction. Disturbed soils lack their normal, although limited, natural vegetative cover. If ephemeral drainages are present, erosion of disturbed areas could transport/deposit sediment downstream within an ephemeral drainage, which would result in a significant adverse impact to water quality. Further, inadvertent construction-related discharges of petroleum hydrocarbons or other contaminants could potentially result in significant impacts to water quality in surface flow if improperly contained.

The proposed area is not located within a 100-year floodplain and therefore would not exacerbate flood conditions or substantially impede flood flows. Groundwater would not be utilized in construction of the TSE components and no impacts would occur.

Impacts from the proposed transmission/telecommunications elements would not contribute significantly to cumulative impacts, as discussed in Section C.9.9 of the PSPP RSA.

Impact Minimization Measures

The **Soil and Water Resources** section of the PSPP RSA discusses mitigation measures that are designed to avoid and reduce the amount of soil loss due to wind and water erosion. These mitigation measures include implementation of a construction Storm Water Pollution Prevention Plan (SWPPP) or Drainage Erosion and Sedimentation Control Plan (DESCP), as described in Condition of Certification **Soil & Water-1**. The Clean Water Act (CWA) (33 U.S.C. Section 1251 *et seq*.), regulates discharges through the National Pollutant Discharge Elimination System (NPDES) permit process (CWA Section 402). Pursuant to NPDES permit requirements, SCE would be required to prepare and adhere to a SWPPP that would include temporary and permanent Best Management Practices (BMPs) to reduce or prevent construction pollutants from leaving the site in storm water runoff and minimize construction erosion. The content of a DESCP is very similar to a SWPPP, but the DESCP covers both construction and operation in one document whereas separate SWPPPs are prepared for construction and operation.

Examples of BMPs and approaches to erosion control that should be implemented as described in Condition of Certification **Soil & Water-1** include:

- Minimizing initial land disturbance and clearing within the working area;
- Segregating topsoil, stockpiling and replacing;
- Applying temporary and permanent erosion control measures; and
- Restoration of disturbed areas.

If drainage of the existing site is altered, as described above, staff recommends that SCE submit a Project Drainage Report/Plan for review and approval by the appropriate licensing authority (e.g., BLM and CPUC) in coordination with the Colorado River Basin Regional Water Quality Control Board (CRBRWQCB). The project drainage plan, when completed and implemented consistent with the requirements of Condition of Certification **Soil & Water-10** in the PSPP RSA would adequately protect the facility from significant damage due to flooding and mitigate impacts to soils related to water erosion.

SCE must comply with all applicable LORS and incorporate all related requirements of other responsible agencies, potentially including, but not limited to CPUC, BLM, the State Water Resources Control Board/CRBRWQCB, California Department of Fish and Game, Metropolitan Water District, and Riverside County. With implementation of the recommended Conditions of Certification or similar measures, staff anticipates that there would not be any significant adverse direct, indirect, or cumulative impacts to soil and water resources resulting from construction of the PSPP transmission/telecommunication components.

Conclusions

The proposed transmission/telecommunications components are not located within a 100-year floodplain and therefore would not exacerbate flood conditions or substantially impede flood flows. Impacts to groundwater would be less than significant and no mitigation is recommended. Impacts would not be cumulatively considerable. Construction could create wind and water erosion of soils and impact drainages. Mitigation measures would reduce potential soil and water resources impacts below the level of significance, thereby eliminating the projects contribution to cumulatively considerable impacts.

3.9 TRAFFIC & TRANSPORTATION

Environmental Setting

The proposed PSPP site is located in Riverside County, California along I-10, approximately 10 miles east of the small community of Desert Center and halfway between the cities of Indio and Blythe. Site access would be from an extension of Corn Springs Road at the I-10 interchange. Corn Springs Road currently runs north-south across I-10 and terminates just north of the I-10 overpass. From this dead-end, Corn Springs Road would be extended about 1,350 feet to the north to connect with a new access road running east into the project site.

The proposed Red Bluff Substation would be located approximately 5 miles east of California State Highway 177 along the south side of I-10 in the County of Riverside. The substation site would be reached from I-10 via the Corn Springs Road exit. This access would include heading east along an existing 3,800-foot long paved portion of Chuckwalla Valley Road. At this point the access would turn south over a 1,100 foot portion of Corn Springs Road. At the intersection of the existing unimproved pipeline patrol road, the substation access turns west over a distance of approximately 25,000 feet. The final leg of the access would be a new road segment approximately 1,400 feet long that would connect to the substation's southern boundary.

In the project area, the I-10 speed limit is 70 miles per hour and the road is fully improved to freeway status with two lanes in each direction, each direction experiencing an Average Annual Daily Traffic (AADT) volume of 21,400 vehicles in 2008 (the most recent year for which Caltrans figures are available). Corn Springs Road is a relatively short road that runs north toward the project site, as well as south, where it intersects with Chuckwalla Valley Road. Chuckwalla Valley Road is a minor local access road running in an east-west direction just south of I-10 in the vicinity of the project site. It is a two-lane frontage road extending from the southern part of the Corn Springs Road interchange to the Ford Dry Lake Road interchange approximately 10 miles to the east.

Bicycle and pedestrian activity in the vicinity of the PSPP site is minimal-to-none.

Potential Impacts of Transmission/Telecommunications Actions

Based on the descriptions provided by SCE, staff anticipates a maximum of 20 construction personnel on any given day. In contrast, Section C.10.4.2 of the RSA projects approximately 1,140 daily workers for construction of the PSPP site. The transmission/telecommunication project components would add a minor volume of trips and would not affect I-10 Level of Service (LOS) “A” or capacity in the vicinity. In addition, SCE would repair any construction-related damage to existing roads upon completion of construction, in accordance with local agency requirements.

Impact Minimization Measures

Given the short-term (1-2 months) and the minimal number of daily workers (20), no mitigation measures are identified beyond those routinely used by SCE (see Section 2.3).

Conclusions

Construction of the PSPP transmission/telecommunications components would add a minor amount of vehicles to I-10 and would not impact the highway’s capacity nor add cumulatively to the traffic or transportation impacts.

3.10 VISUAL RESOURCES

The visual resources analysis of the TSE is based on applicant-provided visual resource information for the PSPP (Solar Millennium 2009a) and the RSA Visual Resources Assessment for the PSPP project. In the PSPP RSA, staff employed a combination of the standard visual assessment methodology developed by California Energy Commission staff and BLM's Visual Resources Management (VRM) Methodology. The setting for visual resources is shared by the proposed Red Bluff Substation, gen-tie connection and substation access road (location of redundant telecom line). The overhead fiber-optic telecommunication system line would be co-located with the PSPP gen-tie line.

Environmental Setting

The proposed project is located within the Mojave Desert, a sub-region of the Sonoran Desert. The Mojave Desert is a landscape typical of the basin and range physiographic province of which it is part, with small, rocky mountain ranges with jagged peaks alternating with talus slopes and desert floor. Flat basins form broad flat expanses of barren plains typified by low scrub vegetation and expansive views. Dark browns and garnets are the dominant mountain hues, although blues and purples prevail as viewing distance increases. In contrast, lighter brown and tan soils dominate the desert floor, sparsely dotted with the grey-green of Sonoran creosote bush and golden bursage scrub vegetation.

The project site is located adjacent and to the north of I-10 in Chuckwalla Valley, approximately 10 miles east of Desert Center in eastern Riverside County. The Chuckwalla Valley is a broad, flat desert plain that includes scattered dry lakes and rolling sand dunes and is bordered by a number of rugged mountain ranges including the Eagle Mountains to the west and north, the Coxcomb and Granite Mountains to the north, the Palen Mountains to the northeast and the Chuckwalla Mountains to the south.

The TSE project area is located on, and is surrounded by, land managed by BLM as part of the California Desert Conservation Area (CDCA). This designation imparts a High rating for Viewer Sensitivity, using the BLM system, for all lands within the CDCA. Nearby areas that are especially visually sensitive include: to the north – Palen Dry Lake and Sand Dunes Area, Desert Lily Sanctuary Area of Critical Environmental Concern (ACEC), and Joshua Tree Wilderness; to the northeast – Palen McCoy Wilderness; to the east – Palen Dry Lake ACEC and Ford Dry Lake OHV Area; to the south – Chuckwalla Mountains Wilderness; and to the west – Alligator Rock ACEC and Desert Center. This portion of Chuckwalla Valley offers panoramic views of a desert plain landscape that appears relatively visually intact except for the presence of I-10 to the immediate south and two transmission lines. I-10 is the main travel corridor between Southern California and Phoenix, Arizona.

The project site is presently undeveloped and consists mainly of desert scrub, lakebed, and dune landscapes and is predominantly intact on the broad, Chuckwalla Valley floor. A wood-pole, H-frame 161-kV transmission line passes through the southwestern corner of the PSPP site and several BLM 4-wheel drive roads provide recreational access to Palen Dry Lake, the Palen Sand Dunes Area, Palen Dry Lake ACEC, and the Palen McCoy Wilderness. The view of the PSPP project from I-10 looking north reveals a primarily natural setting comprised of a mosaic of sparse, shrubby vegetation of darker greens and tans, low-growing grasses and light-colored soils, rocks and desert pavement openings. Views from the site are panoramic, encompassing the open Chuckwalla Valley and the various mountain ranges that define the valley. The rugged ridges, angular forms and bluish hue of the Palen Mountains to the immediate east of the project site provide a contrast of visual interest to the flat, light-colored horizontal landform of the Chuckwalla Valley floor and project site. The area surrounding the project site is very lightly populated. The project visual setting is described in detail in the PSPP RSA.

The gen-tie line connection would be located just to the east of the proposed Red Bluff Substation, which is immediately south of I-10 along the northern edge of the Chuckwalla Mountains. The buried telecommunications line would follow the substation access road east until it crosses I-10 at the Corn Springs Exit. This area is located adjacent to an area of interesting rock formations known as Alligator Rock Area of Critical Environmental Concern (ACEC), just south of Desert Center. The foreground landform of the valley floor is horizontal with the prominent, angular form and jagged line of the steeply rising Chuckwalla Mountains providing a backdrop of added visual interest. Landform colors are tan to lavender and bluish hues for the more distant mountains. The views of this region also include the DPV1 500 kV transmission line and the Blythe Energy Project Transmission Line. These built structural features appear geometric and complex (lattice towers) to simple linear (conductors) in form with vertical and diagonal lines for the structures and curvilinear lines for the conductors.

In spite of the influence of the nearby transmission lines, the nearby mountains provide features of considerable visual variety that enhance the visual quality of the site and surroundings. Therefore, visual quality would be moderate. Viewer concern would be high, from both I-10 and the Alligator Rock ACEC and viewer exposure would also be high given the site's close proximity to I-10. Overall visual sensitivity would be moderate-to-high.

The overhead fiber optic line would be strung along the 220 kV gen-tie line transmission towers north of I-10. From I-10 at Desert Center looking east, the transmission line would converge on and then parallel I-10, approximately 0.3 mile to the north of the freeway. The foreground to middleground terrain is flat and supports sparse desert scrub vegetation. Although there are a number of built facilities in the vicinity of Desert Center, the existing landscape is predominantly natural in appearance. The project would be prominently visible in the foreground of views from eastbound I-10. In the background are the Palen Mountains to the east, the Granite Mountains to the northeast, and the Coxcomb Mountains to the north. The mountain ranges add visual interest and contribute to the low-to-moderate rating for visual quality.

As the landscapes along the I-10 corridor become more and more industrialized with the addition of built features with industrial character, opportunities for expansive views of natural appearing desert landscapes are rapidly diminishing. Combined with the high volume of travelers on I-10 and viewer expectations of observing higher quality landscape features while traveling through a designated conservation area (CDCA), travelers would be highly sensitive to the introduction of additional industrial character to this predominantly naturally appearing landscape, which would be perceived as an adverse visual change. Therefore, overall viewer concern is rated high. Site visibility is high in that the view of the transmission line route from I-10 is unobstructed at a foreground viewing distance. The number of viewers is high and the view duration for motorists on I-10 would be extended with uninterrupted sightlines to the transmission line from I-10 for several miles of travel distance. The high visibility and numbers of viewers and extended duration of view would result in high viewer exposure.

For viewers looking east from I-10, the low-to-moderate visual quality combined with high viewer concern and viewer exposure results in an overall moderate-to-high visual sensitivity of the visual setting and viewing characteristics.

The applicant proposes to relocate approximately 6,000 feet of the Eagle Mountain-Blythe 161kV transmission line around the edge of the southwest corner of the PSPP site footprint. Line relocation would be accomplished by installing approximately eighteen 65-foot H-Frame structures.

From I-10 looking northeast the foreground to middleground terrain is flat and supports sparse desert scrub vegetation. The existing landscape appears predominantly natural in appearance and is absent any built features except for the rough-hewn vertical wood poles of the Eagle Mountain-Blythe line. Featured prominently in the background are the angular forms of the Palen Mountains. The mountain range adds visual interest and contributes to the low-to-moderate rating for visual quality. Overall viewer concern is rated high, as opportunities for recreational activities with expansive views of desert landscapes are rapidly diminishing. The high visibility, high numbers of viewers and short duration of view would result in moderate-to-high viewer exposure. The low-to-moderate visual quality combined with high viewer concern and moderate-to-high viewer exposure result in an overall moderate-to-high visual sensitivity of the visual setting and viewing characteristics.

Potential Impacts of Transmission/Telecommunications Actions

Connection of the PSPP gen-tie line to the Red Bluff Substation would not be expected to create visual impacts given the surrounding substation structure and transmission lines. Construction of the gen-tie connection and telecom line would be short-term and visual impacts from construction equipment would be minor compared to construction of the Red-Bluff substation and PSPP Project. The buried redundant fiber optic line would not be visible and the overhead portion of the line would not be distinguishable from other wire and conductor hung from the poles.

Staff has determined that the gen-tie towers themselves (analyzed in Section C.12 of the PSPP RSA) would result in a substantial adverse impact to existing scenic resource values in the project vicinity. These impacts could not be mitigated to less than significant levels and would thus result in significant and unavoidable impacts under CEQA. However, the fiber optic cables, which constitute the overhead telecom line portion of the proposed TSE project, consist of a very minor aspect of this impact.

The relocation of the 161kV transmission line would re-arrange but not qualitatively change the already existing view. Despite the prominence of the poles in the foreground for viewers from I-10 the dramatic, dominant views of the solar arrays and other project features would distract from the change associated with the relocation.

Transmission line relocation would not be expected to create visual impacts given the surrounding substation structure and transmission lines.

Cumulative Impacts

The contribution of the proposed PSPP to the visible industrialization of the desert landscape would constitute a significant visual impact when considered with existing and future foreseeable projects, both within the immediate project viewshed and in a broader context that encompasses the whole of the California Desert Conservation Area. Staff concludes that the proposed mitigation, would reduce cumulative visual impacts, but not to a less than significant level. The proposed PSPP transmission/telecommunications components would not significantly add to this cumulative effect.

Impact Minimization Measures

With the inclusion of the following recommended mitigation measures or similar, potential visual impacts related to proposed PSPP transmission/telecommunications components would be less than significant:

- **VIS-1 Surface Treatment of Project Structures and Buildings:** to lower color contrast of the proposed transmission poles and blend with the visual background;
- **VIS-2 Revegetation of Disturbed Soil Areas:** to minimize the visual prominence of the proposed construction to travelers on I-10;
- **VIS-3 Temporary and Permanent Exterior Lighting:** low glare, not visible from a distance;
- **VIS-5 Project Design:** use applicable design principles to reduce the visual contrast of the project with the characteristic landscape.

Conclusions

Connection of the PSPP gen-tie line to the Red Bluff Substation would not be expected to create visual impacts given the surrounding substation structure and transmission lines. No visual impacts from the buried telecom line or overhead line would remain after construction. Anticipated cumulative operational impacts of past and foreseeable future region-wide projects in the southern California desert are considered cumulatively considerable and potentially significant when combined with impacts of the PSPP.

3.11 WASTE MANAGEMENT/HAZARDOUS MATERIALS

Environmental Setting

Waste streams generally include solid waste, including excavated soil that could not be backfilled, vegetation and sanitation waste as well as empty cable reels and cut-off pieces of fiber optic cable. All waste streams are regulated and discharges or disposal of any waste material either requires specific permitting, or disposal at a permitted facility based on the type of waste. Both solid and liquid waste streams can be either hazardous or non hazardous, depending on the constituents in the waste stream and the characteristics (e.g., ignitability, reactivity, toxicity, and corrosivity) of the waste. The status of the waste stream determines both the storage options for the material, and the disposal method for the material.

As identified in the PSPP AFC (Solar Millennium 2009a), there are six Class III waste disposal facilities in Riverside County that could potentially take non-hazardous waste generated by the project. They have a combined remaining capacity of 160 million cubic yards. However, the nearest is the Desert Center Landfill, which has a remaining capacity of only 23 thousand cubic yards. Hazardous waste landfills include Clean Harbors' Buttonwillow in Kern County and Chemical Waste Management's Kettleman Hills Landfill in Kings County.

Hazardous materials – in the form of contaminated soil and unexploded ordnance – may be present. A Phase 1 Environmental Site Assessment (ESA) conducted for the PSPP location likely includes land encompassed by the transmission line relocation and access road. A Phase 1 ESA would be required for the Red Bluff Substation and pipeline patrol road (redundant telecom line follows the road), and any subject areas not encompassed in the Phase 1 ESA conducted for the PSPP.

Potential Impacts of Transmission/Telecommunications Actions

The PSPP transmission/telecommunication components (i.e., generation tie line connection, telecommunication system and transmission line relocation) would generate non-hazardous and hazardous wastes, primarily from facilities construction. In addition, construction would require soil and vegetation removal, requiring additional disposal. The total waste quantity would be expected to be much less than that for PSPP construction.

Construction of the components would result in the generation of various waste materials that can be recycled and salvaged (e.g., cable, poles). Waste items and materials would be collected by construction crews and separated at the materials staging area. All waste materials that are not recycled would be categorized by SCE in order to assure appropriate final disposal. Nonhazardous waste would be transported to local authorized waste management facilities. Given the 160 million cubic yard remaining capacity of all Class III landfills in Riverside County, the project's non-hazardous waste disposal would not create a significant environmental impact.

Hazardous materials would likely include small amounts of fuels, lubricants, and cleaning solvents. All hazardous materials would be stored, handled and used in accordance with applicable regulations. Storage locations would be designated in the Storm Water Pollution Prevention Plan (SWPPP) prepared for the Red Bluff Substation and PSPP projects. The SWPPP would also include protective measures, notifications, and cleanup requirements for any incidental spills or other potential releases of hazardous materials. Material Safety Data Sheets would be made available at the construction site for all crew workers.

At the conclusion of construction, SCE would conduct a final inspection to ensure that all work areas are brought to the original conditions (e.g., free of trash, litter etc).

Cumulative impacts resulting for the PSPP transmission/telecommunication components would be similar to the PSPP project, as detailed in the Waste Management section of the PSPP RSA. Impacts of the PSPP TSE would combine with impacts of past, present, and reasonably foreseeable projects to result in a contribution to local and regional cumulative impacts related to waste management. The amount of non-hazardous and hazardous wastes generated from the proposed components would add to the total quantity of hazardous and non-hazardous waste generated in Riverside County. However, sufficient capacity is available at treatment and disposal facilities to handle the volumes of wastes that would be generated by the project. Therefore, staff concludes that waste generation not result in significant adverse cumulative waste management impacts, under CEQA, either locally or regionally.

Impact Minimization Measures

Under SCE's mitigation measure HAZ-1, a Phase I ESA would be performed at the Red Bluff substation location and along any newly acquired transmission and subtransmission line ROWs. This would reduce the potential for trenching and excavation to expose contaminated soil to construction workers. In addition, SCE's HAZ-2 through HAZ-7 would implement standard fire prevention, waste handling, storage, and disposal measures.

Measure **WASTE-1** in the Waste Management section of the PSPP RSA includes steps for UXO identification, training, and reporting. **WASTE-3** further discusses procedures in the event that contamination is identified during assessment of the project site. **WASTE-4** requires preparation of a Construction Waste Management Plan and goals for recycling and minimization of site preparation (soil and vegetation) and construction waste.

Conclusions

No impacts are expected from the use of hazardous materials or from waste generation. Compliance with LORS would ensure proper handling and disposal of materials. There is sufficient capacity at approved disposal facilities to accept waste generated from PSPP TSE components. Mitigation measures would reduce impacts if UXO or existing contamination is present.

3.12 WORKER AND PUBLIC SAFETY

Environmental Setting

Industrial facilities generally pose worker safety concerns. These include exposure to loud noises, moving/falling equipment, trenches, confined space entry and egress, chemical spills, hazardous waste, fires, explosions, and electrical sparks and electrocution. Workers may experience falls, trips, burns, lacerations, and other injuries.

The PSPP transmission/telecommunication components would be located in the vicinity of the Red Bluff Substation (5 miles east of SR-177 along the south side of I-10) and the PSPP site (10 miles east of Desert Center along I-10, via Corn Springs Road exit) in the County of Riverside, California.

Although proximate to 1-10, little to no opportunity for public exposure exists. There is one residence located approximately 25 feet from the northwest corner of the PSPP project right-of-way boundary. Another residence is located approximately 3,500 feet northwest of the PSPP site boundary. However, these residences are over a mile away from the southwestern corner of the site where transmission relocation activities would occur. There are residences about 4 miles to the northwest of the Red Bluff Substation.

Eagle Mountain Elementary School is approximately 10 miles to the east in the City of Blythe.

Fire support services would be under the jurisdiction of the Riverside County Fire Department (RCFD). RCFD fire stations have full-time staff with a minimum of three personnel, including paramedics. The nearest stations are #49 Lake Tamarisk in Desert Center and #45 Blythe Air Base, with estimated response times of 14 minutes and 30 minutes, respectively (CEC 2010k).

Construction workers may be at risk of exposure to Coccidiodomycosis (known as Valley Fever). Soil disturbance (primarily of previously undisturbed lands) could release the spores of the fungus Coccidiodes immitis, which can be inhaled and affect the lungs with potentially severe consequences. Riverside County has approximately 50 cases of Valley Fever per year, with nine reported deaths between 2005 and 2008. This compares to Kern County with a recent average of 1,000 cases per year.

The site also has the potential to contain unexploded ordnance (UXO) and soil contaminated with hazardous materials.

Potential Impacts of Transmission/Telecommunications Actions

Workers could be exposed to hazardous materials that are already present (i.e. contaminated soil and UXO) or that are used in construction. Soil excavation for substation grading and trenching for the telecom cable have the potential to release the fungus that causes Valley Fever.

Hazardous materials used during construction would be stored, handled and used in accordance with applicable regulations. Material Safety Data Sheets would be made available at the construction site for all crew workers. Also, safety devices such as traveling grounds, temporary grounding grid/mats around stringing equipment, guard structures, and radio equipped public safety roving vehicles and linemen would be in place prior to the initiation of wire-stringing activities.

Due to the scale of the proposed components, a significant impact on emergency and fire response is not expected.

As noted above, the proposed transmission/telecommunications elements are unlikely to impact services. Nor are they likely to contribute significantly to cumulative impacts. However, the RCFD may not be adequately equipped to respond in a timely manner to fire, hazmat, rescue, and EMS emergencies for the PSPP and other large solar projects. Construction and operation of these projects would present short and long-term adverse impacts on services. The Worker Safety and Fire Protection section in the PSPP RSA discusses that the significant impact could be mitigated under measures to increase resources for the fire department.

Impact Minimization Measures

SCE mitigation measure HAZ-1 and PSPP RSA condition **WASTE-1** reduce the potential for worker exposure to hazardous materials and UXO, respectively. The PSPP RSA section on Worker Safety and Fire Protection includes **WORKER SAFETY-10**, to minimize construction workers to Valley Fever exposure. These measures would protect the public as well.

SCE measures HAZ-2 through HAZ-5 contain steps for fire prevention and response, and hazardous waste and materials handling. Under HAZ-6, the substation would be grounded to limit electric shock and surges that could ignite fires. The PSPP RSA Worker Safety and Fire Protection section also includes measures that would mitigate any impacts to worker (and public) safety to less than significant.

Conclusions

Worker safety and public health impacts would be reduced to less than significant levels through compliance with LORS and implementation of mitigation measures, including measures relating to Valley Fever and UXO. The Riverside County Fire Department may not be adequately equipped to respond in a timely manner to fire, hazmat, rescue, and EMS emergencies for the proposed PSPP TSE components in addition to the PSPP and other large solar projects. Construction and operation of these projects would present short and long-term adverse impacts on services but could be mitigated with measures as described in the PSPP RSA.

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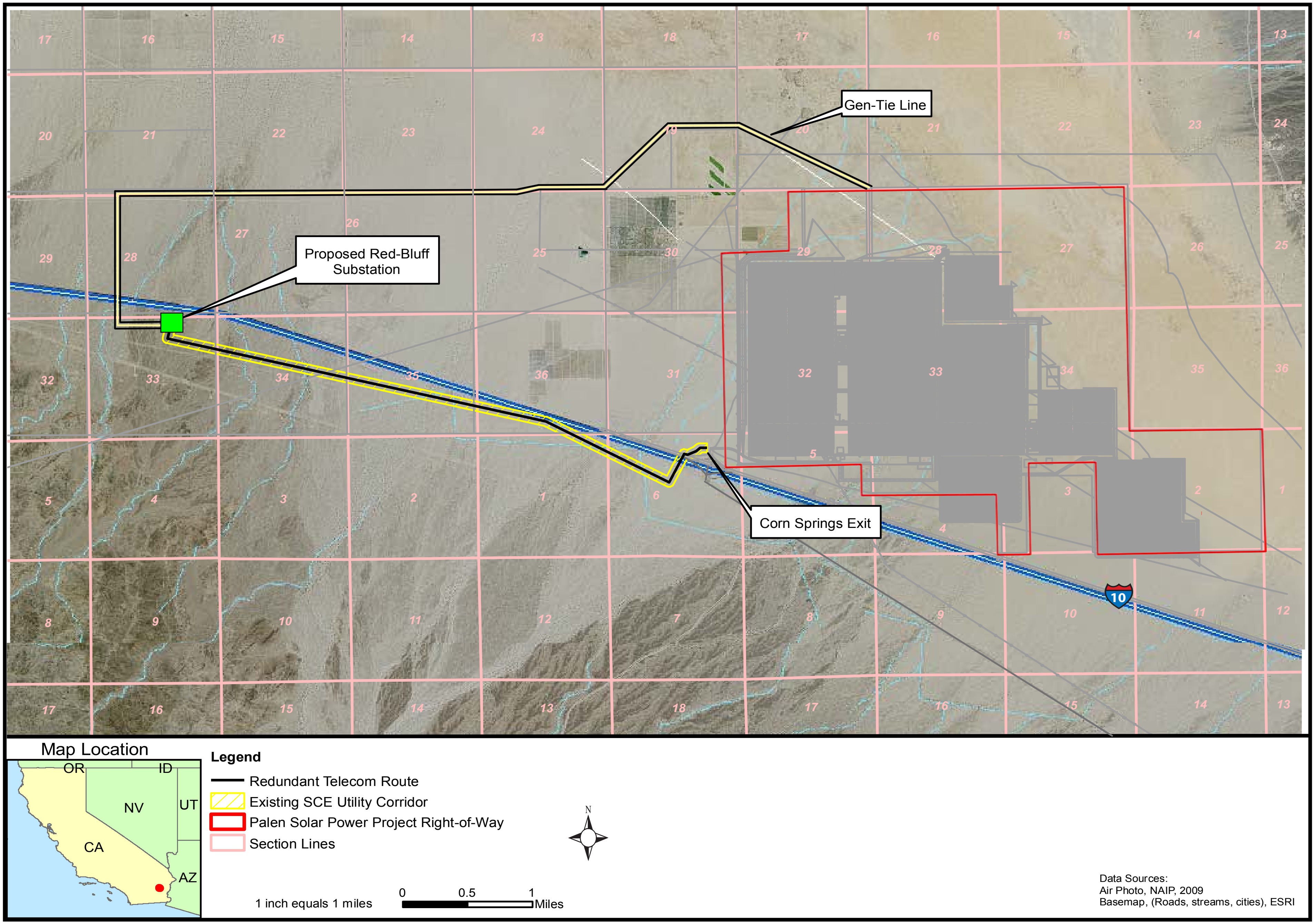
Insert Figure 1

Insert Figure 2.

TSE Appendix B Figure 1 - Gen-Tie and Redundant Telcom Routes

Palen Solar Power Project

July 2010



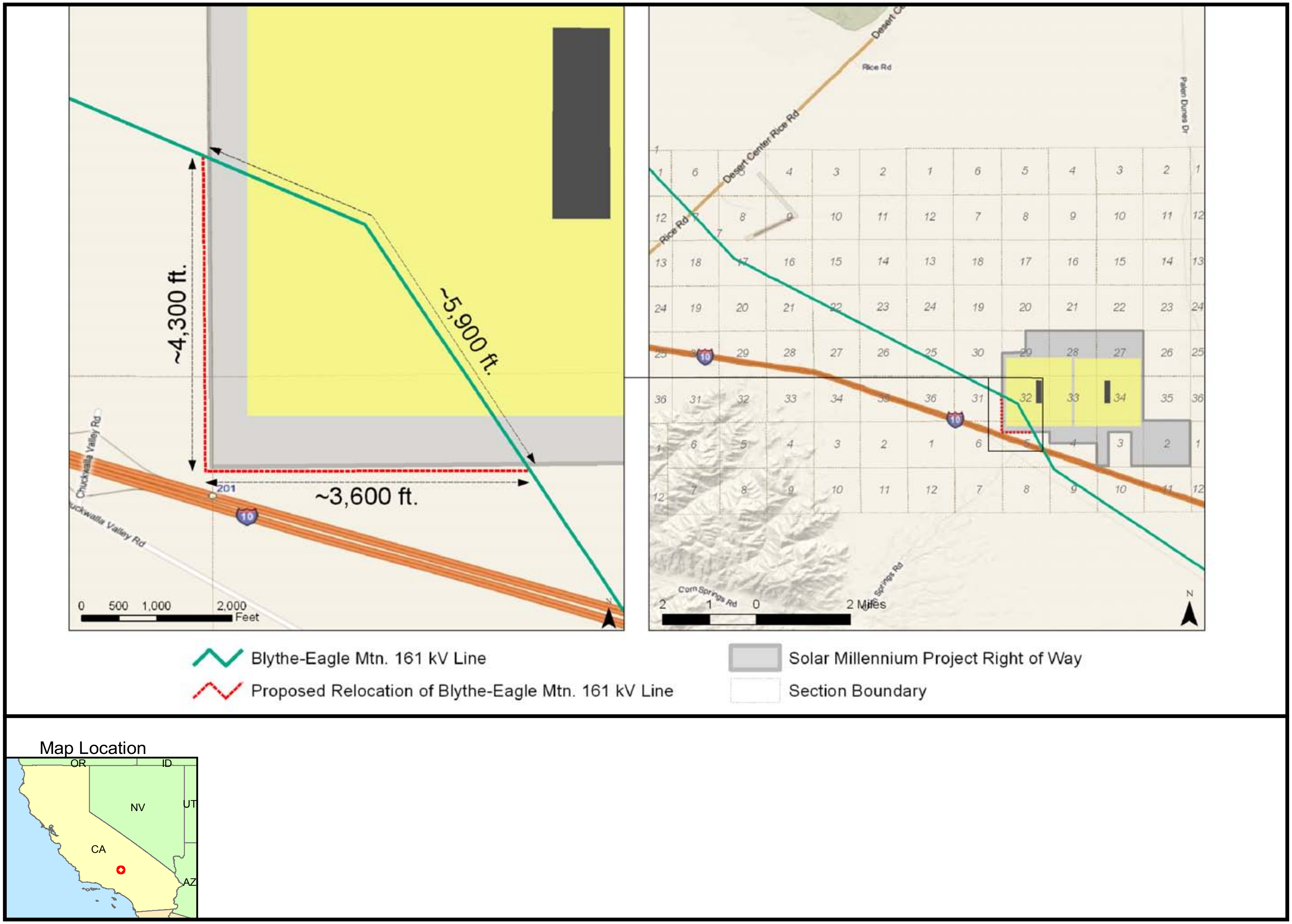
TRANSMISSION SYSTEM ENGINEERING

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, JULY 2010

SOURCE: AECOM 2010i

TSE Appendix B Figure 2 - 161 kV Line Relocation

Palen Solar Power Project



SOURCE: AECOM 2010i

Transition Cluster Phase II Interconnection Study Report

Group Report in SCE's Eastern Bulk System

Final Report

California ISO
Your Link to Power

July 08, 2010

This study has been completed in coordination with SCE per CAISO Tariff Appendix Y Large Generator Interconnection Procedures (LGIP) for Interconnection Requests in a Queue Cluster Window

Table of Contents

Appendices:

Definitions

AVR	Automatic Voltage Regulation
Borrego Cluster	Group of Transition Cluster projects located in the Borrego area
CAISO	California Independent System Operator Corporation
COD	Commercial Operation Date
Deliverability Assessment	CAISO's Deliverability Assessment
EO	Energy Only Deliverability Status
FC	Full Capacity Deliverability Status
FERC	Federal Energy Regulatory Commission
IC	Interconnection Customer
IID	Imperial Irrigation District
LADWP	Los Angeles Department of Water and Power
LFBs	Local Furnishing Bonds
LGIA	Large Generator Interconnection Agreement
LGIP	Large Generator Interconnection Procedures
Pmax	Maximum generation output
NERC	North American Electric Reliability Corporation
NQC	Net Qualifying Capacity as modeled in the Deliverability Assessment.
PG&E	Pacific Gas and Electric Company
Phase I Study	Transition Cluster Phase I Study
Phase II Study	Transition Cluster Phase II Study
PTO	Participating Transmission Owner
RAS	Remedial Action Scheme (also known as SPS)
POI	Point of Interconnection
POS	Plan of Service
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SPS	Special Protection System (also known as RAS)
SVC	Static VAr Compensator
TC	Transition Cluster
TPP	CAISO's Transmission Planning Process
WECC	Western Electricity Coordinating Council

1. Executive Summary

In accordance with the Federal Energy Regulatory Commission (FERC) approved Large Generator Interconnection Procedures (LGIP) for Interconnection Requests in a Queue Cluster Window (CAISO Appendix Y), this Transition Cluster Phase II Study was initiated to determine the combined impact of all the Transition Cluster projects on SCE's electrical system, including that portion of SCE's electrical system that is part of the CAISO Controlled Grid.

There are thirty-five generation projects in the Transition Cluster in SCE's service territory for the Phase II Study. Four general groups are formed based on the electrical impact among the generation projects: Northern Bulk System, Eastern Bulk System, East of Lugo Bulk System and Metro System. This study report provides the following:

1. Transmission system impacts caused by the addition of five Transition Cluster projects requesting interconnection in the Eastern Bulk System;

2. System reinforcements necessary to mitigate the adverse impacts of the five Transition Cluster projects requesting interconnection in the Eastern Bulk System under various system conditions; and

3. The responsibility for financing the cost of necessary system reinforcements and interconnection facilities, and a good faith estimate of the time required to permit, engineer, design, procure, construct, and place into operation these necessary system reinforcements and interconnection facilities.

To determine the system impacts caused by Transition Cluster projects, the following studies were performed:

- Steady State Power Flow Analyses
- Short Circuit Duty Analyses
- Transient Stability Analyses
- Reactive Power Deficiency Analyses
- Deliverability Assessment
- Operational Studies

The results of above studies indicated that Transition Cluster projects are responsible for the overloading of several transmission facilities and overstressing of several circuit breakers at a number of substations in the

SCE service territory. Network Upgrades[1] to mitigate identified problems corresponding to the five Transition Cluster projects requesting interconnection in the Eastern Bulk System have been proposed in this report. The following tables show a summary of the proposed Network Upgrades and Distribution Upgrades along with an estimated cost.

Table A – Plan of Service Reliability Network Upgrades

1	Various (see individual Appendix A reports)	
	TOTAL	[redacted]

Table B – Reliability Network Upgrades

1	Loop the Colorado River-Devers 500 kV #2 line into Red Bluff Sub	
2	Upgrade Line Drop on Mira Loma-Vista 220 kV #2 Line at Vista Substation	
3	Colorado River Sub Expansion -- #1 AA Bank	
4	New SPS to Trip 1400 MW Phase II projects by Loss of Devers-Red Bluff 500 kV #1 and #2 Lines	
5	New SPS to Trip 500 MW Phase II projects by Loss of one of AA Bank at Colorado River Sub	
TOTAL		[redacted]

Table C – Delivery Network Upgrades

1	West of Devers 220 kV Upgrades Project	
2	Colorado River Sub Expansion -- #2 AA Bank	
TOTAL		[redacted]

Table D – Distribution Upgrades

1	None	
TOTAL		[redacted]

These upgrades do not include Interconnection Facilities which are the obligation of each Interconnection Customer to finance. Interconnection facilities relating to each individual project are discussed in the corresponding Appendix A. Distribution Upgrades identified in Table D are not Network Upgrades and are non-refundable.

Given the magnitude of the above upgrades, a good faith estimate of the time required to engineer, license, procure, and construct all facilities identified in the above tables could be up to 84 months from LGIA execution. Timelines required to engineer, license, procure, and construct facilities necessary for

[1] The additions, modifications, and upgrades to the CAISO Controlled Grid required at or beyond the Point of Interconnection to accommodate the interconnection of the Generating Facility to the CAISO Controlled Grid. Network Upgrades shall consist of Delivery Network Upgrades and Reliability Network Upgrades.

interconnection and/or delivery of each individual project are discussed in Appendix A.

2. Transition Cluster Interconnection Information

A total of five generation projects totaling a maximum output of 2,199.5 MW are included in the SCE Transition Cluster. Table 2.1 lists all the generator projects with essential data obtained from the CAISO Generation queue.

Table 2.1: SCE Transition Cluster Projects (Eastern Bulk System)

CAISO Queue	Point of Interconnection	Full Capacity Energy Only	Fuel	Max MW	Proposed On-Line Date (as requested by IC)
193	Colorado River 220 kV	FC	Solar	500	07/01/2013
421	Blythe-Eagle Mountain 161 kV Line	FC	Solar	49.5	02/01/2012
294	Colorado River 220 kV	FC	Solar	1,000	07/01/2013
365	Red Bluff 220 kV	FC	Solar	500	07/01/2013
431	Colorado River 220 kV	FC	Solar	150	07/01/2014
Total Phase II Transition Cluster Generation				**2,199.5**	

Note that significant changes occurred between Phase I and Phase II in the Transition Cluster queue for the Eastern Bulk System including:

- Withdrawal of 10 projects (7,490 MW)
- Change in POI for Q294 (moved from Colorado River 500 kV to Colorado River 220 kV for Phase II Study)
- Q365 reduced from 750 MW to 500 MW
- Q431 reduced from 250 MW to 150 MW

3. Study Objectives

This Phase II Interconnection Study was performed in accordance with Section 7.1 of Appendix Y of the CAISO tariff, which states:

"The Phase II Interconnection Study shall:

(i) update, as necessary, analyses performed in the Phase I Interconnection Studies to account for the withdrawal of Interconnection Requests,

(ii) identify final Reliability Network Upgrades needed to physically interconnect the Large Generating Facilities,

(iii) assign responsibility for financing the identified final Reliability Network Upgrades,

(iv) identify, following coordination with the CAISO's Transmission Planning Process, final Delivery Network Upgrades needed to interconnect those Large Generating Facilities selecting Full Capacity Deliverability Status;

(v) assign responsibility for financing Delivery Network Upgrades needed to interconnect those Large Generating Facilities selecting Full Capacity Deliverability Status;

(vi) identify for each Interconnection Request final Point of Interconnection and Participating TO's Interconnection Facilities;

(vii) provide a +/-20% estimate for each Interconnection Request of the final Participating TO's Interconnection Facilities;

(viii) optimize in-service timing requirements based on operational studies in order to maximize achievement of the Commercial Operation Dates of the Large Generating Facilities; and

(ix) if it is determined that the Delivery Network Upgrades cannot be completed by the Interconnection Customer's identified Commercial Operation Date, provide that operating procedures necessary to allow the Large Generating Facility to interconnect as an energy-only resource, on an interim-only basis, will be developed and utilized until the Delivery Network Upgrades for the Large Generating Facility are completed and placed into service.

This same section continues and further states that the Phase II Interconnection Study shall:

(x) specify and estimate the cost of the equipment, engineering, procurement and construction work, including the financial impacts (i.e., on Local Furnishing Bonds), if any, and schedule for effecting remedial measures that address such financial impacts, needed on the CAISO Controlled Grid to implement the conclusions of the updated Phase II Interconnection Study technical analyses in accordance with Good Utility Practice to physically and electrically connect the Interconnection Customer's Interconnection Facilities to the CAISO Controlled Grid; and

(xi) also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Participating TO's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities.

The Phase II Study analysis was performed to identify the Interconnection Facilities, Plan of Service Reliability Network Upgrades, Reliability Network Upgrades, Delivery Network Upgrades and Distribution Upgrades necessary to safely and reliably interconnect the Transition Cluster projects into the CAISO Controlled Grid. An estimated cost and construction schedule for these facilities has also been provided in this report.

4. Study Assumptions

4.1 Power flow base cases

The Phase II Study used four power flow base cases; two for Deliverability Assessment and two for Reliability Assessment, representing 2013 peak load and 2013 off-peak system conditions. These base cases included all CAISO approved transmission projects, as well as higher queue serial generation projects with associated Network Upgrades and Special Protection Systems.

4.2 Load and Import

The Deliverability Assessment On-Peak case modeled a 26243 MW load (1-in-5 load forecast) in SCE system with an import target as shown in Table 4.2. The Off-Peak case modeled a 16082 MW load in SCE system.

Table 4.2: On-Peak Deliverability Assessment Import Target

Branch Group (BG) Name	BG Import Direction	Net Import MW	Import Unused ETC MW
Lugo_victrville_BG	N-S	1047	523
COI_BG	N-S	3770	548
BLYTHE_BG	E-W	106	0
CASCADE_BG	N-S	23	0
CFE_BG	S-N	-154	0
ELDORADO_BG	E-W	935	0
IID-SCE_BG	E-W	268	0
IID-SDGE_BG	E-W	-174	163
INYO_BG	E-W	0	0
LAUGHLIN_BG	E-W	0	0
MCCULLGH_BG	E-W	-15	316
MEAD_BG	E-W	539	516
MERCHANT_BG	E-W	425	0
N.GILABK4_BG	E-W	-170	168
NOB_BG	N-S	1449	0
PALOVRDE_BG	E-W	2984	233
PARKER_BG	E-W	66	52
SILVERPK_BG	E-W	9	0
SUMMIT_BG	E-W	-32	15
SYLMAR-AC_BG	E-W	-351	471
Total		**10726**	**3005**

The Reliability Assessment 2013 peak load case modeled a 26,262 MW load (1-in-10 load forecast). The off-peak load case represented about 60% of peak load.

While it is impractical to study all combinations of system load and generation levels during all seasons and at all times of the day, the base cases were developed to represent stressed scenarios of loading and generation conditions for the study group area.

4.3 Generation Dispatch

Generation assumptions for SCE's Eastern Bulk System are shown in Table 4.3.1 (existing) and 4.3.2 (active queued ahead serial).

Generation dispatch assumptions in Deliverability Assessment can be found at http://www.caiso.com/1c44/1c44b5c31cce0.html. In the on-peak Deliverability Assessment, the Summer Peak Qualified Capacity for proposed Full Capacity generation projects is set to 64% of the requested PMax for wind generation and 100% of the requested PMax for Solar generation.

In the Reliability Assessment, the generation is dispatched at PMax as listed in Tables 4.3.1 and 4.3.2..

Table 4.3.1
Existing Eastern Bulk Generation

Locations	Type	Size (MW)
Devers Area	Wind	873
East of Devers Area	N-Gas	520
Eastern Bulk	QF	472

Table 4.3.2
Eastern Bulk Serial Interconnection Requests

CAISO Queue Position	Type	Project Size (MW)
1	Wind	16.5
3	N-Gas	850
17	N-Gas	520
49	Wind	100.5
72	Hydro	500
136	N-Gas	300
138	Wind	150
146	Solar	150
147	Solar	400
219	N-Gas	50
	Total	**3,037**

4.4 New Transmission Projects

This Phase II Study included the modeling of all CAISO-approved transmission projects in the Eastern Bulk System base cases. In addition, a number of transmission upgrades are needed to support queued ahead serial generation projects in the Eastern Bulk System were modeled in order to determine if additional facilities would be needed to support the Transition Cluster projects.

The Transition Cluster Phase II Study pre-project base cases assume for modeling purposes that the California Portion of DPV2, namely Devers-Colorado River project (DCR) including the proposed 500kV Switchyard at Colorado River, has been constructed and placed in service by SCE. Based on this modeling assumption, DCR costs have not been included in this Phase II Study nor has any portion of DCR been allocated to the Transition Cluster Phase II Study Projects. However, if required regulatory approvals are not granted, modeling assumption will need to be re-examined.

- Devers – Mirage Split Project

SCE's Devers and Mirage 115 kV systems are operated in parallel with the local 220 kV systems. Such configuration caused peak time overloads on the 115 kV systems.

Reconfiguring the Devers 115 kV and Mirage 115 kV systems to be operated radial from the 220 kV system will mitigate the identified overloads and increase local reliability to serve load. The Devers-Mirage Split Project has received final approval from the CPUC.

- The Red Bluff 500/220 kV Substation

  There are two-(2) solar projects in the Serial Group, totaling 550 MW, which proposed to interconnect in SCE/MWD's J. Hinds and Eagle Mountain area. This injection capacity would result in overloading MWD's 220kV system and would cause costly system upgrades and interruption of the MWD's pump services during the construction of the system upgrades.

  Based on the mutual agreement among CAISO, SCE, and affected Interconnection Customers (the ICs), the Red Bluff Substation was proposed to interconnect these projects directly into SCE's existing Palo Verde – Devers 500 kV line (DPV1 Line) by looping-in the Red Bluff Substation 2 miles East of the CA series caps on the DPV1 line (final substation location is subject to regulatory approvals).

- Devers – Colorado River Project

  Construct a 500 kV Colorado River switchyard. Construct a new 125.4 mile 500kV T/L from the proposed Colorado River switchyard to Devers Substation. Construct a new 42 miles 500 kV T/L between Devers Substation and Valley Substation.

- West-of-Devers SPS (Temporary)
- Blythe I Generation SPS
- MWD Cross Tripping SPS

4.5 Other SPSs and Operator Actions

4.5.1 All new SPSs and modifications to existing ones are subject to review by affected parties and members of the WECC Remedial Action Scheme Reliability Subcommittee (RASRS).

- LEAPS Generation Dynamic SPS

4.5.2 Operating Procedures

Operating procedures, which may include curtailing the output of the Transition Cluster projects during planned or extended forced outages may be required for reliable operation of the transmission system. These procedures, if needed, will be developed before the projects' Commercial Operation Date.

4.6 Queued Ahead Triggered Circuit Breaker Upgrades, Replacement or Mitigation Requirements

This TC Phase II Study assumed that all previously triggered short-circuit duty impacts would be mitigated by the corresponding triggering project. Consequently, this study evaluated the incremental impacts associated with the addition of the Transition Cluster projects, including appropriate transmission upgrades as identified in this study, in an effort to cost allocate the incremental upgrades associated with the addition of the Transition Cluster projects. However, it should be clear that for reliability reasons it may be necessary to implement mitigation upgrades previously triggered by queued ahead generation projects prior to allowing interconnection of Transition Cluster generation projects.

A determination of such mitigation upgrade needs will be based on the study results of the Operational Studies undertaken for each of the Transition Cluster generation projects. Should an impact to circuit breakers be identified in the Operational Study to require the implementation of mitigation upgrades, such upgrades will need to be advanced by the corresponding projects in Operational Queue order to enable interconnection.

The following provide the mitigation details of all previously triggered short-circuit duty impacts.

Upgrade the following three 500 kV circuit breakers at Lugo Substation from 50 kA to 63 kA by installing Transient Recovery Voltage (TRC) Capacitors:

4.6.1 Lugo 500 kV

Upgrade the following three 500 kV circuit breakers at Lugo Substation from 50 kA to 63 kA by installing Transient Recovery Voltage (TRC) Capacitors:

- Lugo CB762
- Lugo CB922
- Lugo CB852

4.6.2 Mira Loma 500 kV

Upgrade the following six 500 kV circuit breakers at Mira Loma Substation from 40 kA to 50 kA by recertifying breaker capability:

- Mira Loma CB712 and CB812
- Mira Loma CB822
- Mira Loma CB742 and CB942
- Mira Loma CB962

4.6.3 Vincent 500 kV

Upgrade the following four 500 kV circuit breakers at Vincent Substation from 40 kA to 50 kA by recertifying breaker capability:

- Vincent CB812 and CB912
- Vincent CB852
- Vincent CB862

4.6.4 Antelope 220 kV

Upgrade or replace the following eleven 40 kA 220 kV circuit breakers at Antelope Substation to 63 kA:

- Antelope CB61X2 (Replace with 63kA)
- Antelope CB4022 (Replace with 63kA) and CB6022 (Replace with 63kA)
- Antelope CB4032 (Install TRV) and CB6032 (Replace with 63kA)
- Antelope CB4042 (Replace with 63kA) and CB6042 (Replace with 63kA)
- Antelope CB4062 (Replace with 63kA) and CB6062 (Replace with 63kA)
- Antelope CB4072 (Replace with 63kA)
- Antelope CB4082 (Replace with 63kA)

4.6.5 Chino 220 kV

Upgrade the following 220 kV circuit breaker at Chino Substation from 50 kA to 63 kA by installing Transient Recovery Voltage (TRC) Capacitors:

- Chino CB6072

4.6.6 Devers 220 kV

Upgrade or replace the following nine 220 kV circuit breakers at Devers Substation to 63 kA:

- Devers CB42X2 (Replace with 63 kA) and CB62X2 (Replace with 63 kA)
- Devers CB5022 (Replace with 63 kA) and CB6022 (Replace with 63 kA)
- Devers CB4032 (Install TRV Caps)

- Devers CB4082 (Replace with 63 kA) and CB6082 (Install TRV Caps)
- Devers CB4092 (Replace with 63 kA) and CB6092 (Replace with 63 kA)

4.6.7 Etiwanda 220 kV

Implement mitigation measures to address impacts on the following twenty-four 220 kV circuit breakers at the Etiwanda Substation:

- Etiwanda CB43E2 and Etiwanda CB63E2
- Etiwanda CB4022 and Etiwanda CB6022
- Etiwanda CB41E2 and Etiwanda CB42E2
- Etiwanda CB45E2 and Etiwanda CB61E2
- Etiwanda CB62E2 and Etiwanda CB65E2
- Etiwanda CB4032 and Etiwanda CB6032
- Etiwanda CB4042 and Etiwanda CB6042
- Etiwanda CB4052 and Etiwanda CB6052
- Etiwanda CB4092 and Etiwanda CB6092
- Etiwanda CB4102 and Etiwanda CB6102
- Etiwanda CB4072 and Etiwanda CB6072
- Etiwanda CB4082 and Etiwanda CB6082

4.6.8 Mesa 220 kV

Upgrade the following two 220 kV circuit breakers at Mesa Substation from 50 kA to 63 kA by installing Transient Recovery Voltage (TRC) Capacitors:

- Mesa CB4132 and CB6132

4.6.9 Mira Loma East 220 kV

Implement mitigation measures to address impacts on the following twelve 220 kV circuit breakers at the Mira Loma Substation East Section:

- Mira Loma CB4102, CB6102 and CB4172
- Mira Loma CB4142, CB4152 and CB4162
- Mira Loma CB5142, CB5152 and CB5162
- Mira Loma CB6142, CB6152 and CB6162

4.6.10 Villa Park 220 kV

Upgrade the following two 220 kV circuit breakers at Villa Park Substation from 50 kA to 63 kA by installing Transient Recovery Voltage (TRV) Capacitors:

- Villa Park CB4N062
- Villa Park CB4062

4.6.11 Vincent 220 kV

Implement mitigation measures to address impacts on the following twenty-one 220 kV circuit breakers at the Vincent Substation:

- Vincent CB41X2, CB51X2 and CB61X2
- Vincent CB412, CB512 and CB612
- Vincent CB422, CB522 and CB622
- Vincent CB432, CB532 and CB632
- Vincent CB452 and CB652
- Vincent CB462, CB562 and CB662
- Vincent CB472, CB572 and CB672
- Vincent CB682

4.6.12 Devers 115 kV

Replace the following fourteen 115 kV circuit breakers at Devers Substation to 40 kA:

- Devers CB3N, CB3S and CB3T
- Devers CB4N and CB4S
- Devers CB6N and CB6S
- Devers CB7N and CB7S
- Devers CB10N and C10S
- Devers CB11N and C11S
- Devers CB CAP4

4.6.13 Inyokern 115 kV

Replace the following two 115 kV circuit breakers at Inyokern Substation to 40 kA:

- Inyokern CB13 and CB14

4.6.14 Terawind 115 kV

Replace the following 115 kV circuit breaker at Terawind Substation to 40 kA:

- Terawind CB1

4.6.15 Antelope 66 kV

Replace the following thirty-eight 66 kV circuit breaker at Antelope Substation to 40 kA:

- Antelope CB1E and CB1W
- Antelope CB2E and CB2W
- Antelope CB3E and CB3W
- Antelope CB4E and CB4W
- Antelope CB5E and CB5W
- Antelope CB7E and CB7W
- Antelope CB8E and CB8W
- Antelope CB9E and CB9W
- Antelope CB10E and CB10W
- Antelope CB12E and CB12W
- Antelope CB14E and CB14W
- Antelope CB18E and CB18W

- Antelope CB20E and CB20W
- Antelope CB22E and CB22W
- Antelope CB23E and CB23W
- Antelope CB24E and CB24W
- Antelope CB25E and CB25W
- Antelope CB26E and CB26W
- Antelope CB CAP1
- Antelope CB CAP3

4.6.16 Ellis 66 kV

Replace the following forty-five 66 kV circuit breaker at Ellis Substation to
40 kA:

- Ellis CB1XN and CB1XS
- Ellis CB1N and CB1S
- Ellis CB2N and CB2S
- Ellis CB4N and CB4S
- Ellis CB5N and CB5S
- Ellis CB6N and CB6S
- Ellis CB7N and CB7S
- Ellis CB8N and CB8S
- Ellis CB9N and CB9S
- Ellis CB10N and CB10S
- Ellis CB11N and CB11S
- Ellis CB12N and CB12S
- Ellis CB14N and CB14S
- Ellis CB15N and CB15S
- Ellis CB23N and CB23S
- Ellis CB24N and CB24S
- Ellis CB25N and CB25S
- Ellis CB26N and CB26S
- Ellis CB27N and CB27S
- Ellis CB28N and CB28S
- Ellis CB30N and CB30S
- Ellis CB CAP1
- Ellis CB CAP2
- Ellis CB CAP4

4.6.17 Hinson 66 kV

Replace the following thirty-one 66 kV circuit breaker at Hinson Substation to
40 kA:

- Hinson CB2N, CB2S and CB2T
- Hinson CB3N and CB3S
- Hinson CB4N, CB4S and CB4T
- Hinson CB5N, CB5S and CB5T
- Hinson CB6N, CB6S and CB6T
- Hinson CB7N and CB7S
- Hinson CB8N, CB8S and CB8T

- Hinson CB13N, CB13S and CB13T
- Hinson CB14N, CB14S and CB14T
- Hinson CB16N and CB16S
- Hinson CB CAP1
- Hinson CB CAP2
- Hinson CB CAP3
- Hinson CB CAP4

4.6.18 Neenach 66 kV

Replace the following two 66 kV circuit breakers at Neenach Substation to 40 kA:

- Neenach CB2 and CB3

4.6.19 San Bernardino 66 kV

Replace the following eighteen 66 kV circuit breakers at the San Bernardino Substation to 40 kA:

- San Bernardino CB7N, CB7S and CB7T
- San Bernardino CB8S and CB8T
- San Bernardino CB10N and CB10S
- San Bernardino CB13N, CB13S and CB13T
- San Bernardino CB15N and CB15S
- San Bernardino CB16N and CB16S
- San Bernardino CB19N and CB19S
- San Bernardino CB CAP1
- San Bernardino CB CAP2

4.6.20 Saugus 66 kV

Implement mitigation measures to address impacts on the following thirty-eight 66 kV circuit breakers at the Saugus Substation:

- Saugus CB1E and CB1W
- Saugus CB2E, CB2W and CB2T
- Saugus CB3E and CB3W
- Saugus CB4E, CB4W and CB4T
- Saugus CB5E, CB5W and CB5T
- Saugus CB6E, CB6W and CB6T
- Saugus CB8E and CB8W
- Saugus CB9E, CB9W and CB9T
- Saugus CB10E, CB10W and CB10T
- Saugus CB11E, CB11W and CB11T
- Saugus CB12E and CB12W
- Saugus CB13E and CB13W
- Saugus CB14E and CB14W
- Saugus CB CAP1
- Saugus CB CAP3
- Saugus CB CAP4
- Saugus CB CAP5
- Saugus CB CAP7

4.6.21 Vista "A" 66 kV

Replace the following twelve 66 kV circuit breakers at the Vista "A" Substation to 40 kA:

- Vista "A" CB3XE, CB3XW and CB3XT
- Vista "A" CB4XE, CB4XW and CB4XT
- Vista "A" CB5XE and CB5XW
- Vista "A" CB0BE and CB0BW
- Vista "A" CAP 4
- Vista "A" CAP 6

4.6.22 Vista "C" 66 kV

Replace the following twelve 66 kV circuit breakers at the Vista "C" Substation to 40 kA:

- Vista "C" CB9E and CB9W
- Vista "C" CB10E and CB10W
- Vista "C" CB17E and CB17W
- Vista "C" CB19E and CB19W
- Vista "C" CAP 1
- Vista "C" CAP 2
- Vista "C" CAP 3
- Vista "C" CAP 5

5. Study Criteria and Methodology

The applicable reliability criteria, which incorporate the Western Electricity Coordinating Council (WECC) , the North American Electric Reliability Council (NERC) planning criteria, and the CAISO Planning Standards were used to evaluate the impact of Transition Cluster projects on the CAISO Controlled Grid.

5.1 Steady State Study Criteria

5.1.1 Normal Overloads

Normal overloads are those that exceed 100 percent of normal facility ratings. The CAISO Controlled Grid Reliability Criteria requires the loading of all transmission system facilities be within their normal ratings. Normal overloads refer to overloads that occur during normal operating conditions (no contingency).

5.1.2 Emergency Overloads

Emergency overloads are those that exceed 100 percent of emergency ratings. Emergency overloads refer to overloads that occur during single element contingencies (Category “B”) and multiple element contingencies (Category “C”).

5.1.3 Voltage Violations

Voltage violations will occur if voltage deviations exceed +/-7% of the pre-disturbance level for Category B contingencies and +/ -10% for Category C contingencies.

5.1.4 Contingencies

The contingencies used in this analysis are provided in Appendix C. Various categories of contingencies are summarized in Table 5-1:

Table 5-1: Power flow contingencies

Contingencies	Description
CAISO Category "A" (No contingency)	All facilities in service – Normal Conditions
CAISO Category "B"	• B1 - All single generator outages. • B2 - All single transmission circuit outages. • B3 - All single transformer outages. • Selected overlapping single generator and transmission circuit outages.
CAISO Category "C"	• C1 - SLG Fault, with Normal Clearing: Bus outages (60-230 kV) • C2 - SLG Fault, with Normal Clearing: Breaker failures (excluding bus tie and sectionalizing breakers) at the same bus section above. • C3 - Combination of any two-generator/transmission line/transformer outages. • C4 - Bipolar (dc) Line • C5 - Outages of double circuit tower lines (60-230 kV) • C6 - SLG Fault, with Delayed Clearing: Generator • C7 - SLG Fault, with Delayed Clearing: Transmission Line • C8 - SLG Fault, with Delayed Clearing: Transformer • C9 - SLG Fault, with Delayed Clearing: Bus Section

Although most of the CAISO Category "C" contingencies were considered as part of this study, it is impractical to study all possible combinations of any two elements throughout the system. Therefore, as allowed under NERC standard TPL-003-0 R1.3.1, only selected critical Category C contingencies (C1 – C9) that were deemed most severe were evaluated in this study.

5.2 Short Circuit Duty Criteria

Short circuit studies are performed to determine the maximum fault duty on the adjacent buses to the Transition Cluster projects in the SCE service territory. This study determines the impact of increased fault current resulting from Transition Cluster projects. Short circuit results will allocate costs for overstressed breakers to each cluster, which are formed from generation projects with a fault contribution above a threshold value. The Computer Aided Protection Engineering (CAPE) software is used to conduct the detailed short circuit studies with three phase (3PH) and single-line-to-ground (SLG) faults.

To determine the impact on short-circuit duty within SCE's electrical system, after inclusion of the Transition Cluster generation projects, the study calculated the maximum 3PH and SLG short-circuit duties. Generation, transformer, and generation tie-line data provided by each Transition Cluster Interconnection Customer was utilized. Bus locations where short-circuit duty is increased with the proposed Transition Cluster projects by at least 0.1 kA and the duty is in excess of 60% of the minimum breaker nameplate rating are flagged for further review. Upon completion of the detailed circuit breaker review, circuit breakers exposed to fault currents in excess of 100 percent of their interrupting capacities will need to be replaced or upgraded, whichever is appropriate. It should be noted that other WECC entities may request specific information within the WECC process to evaluate potential impact within their respective systems of this project addition.

5.3 Transient Stability Criteria

Transient stability analysis is a time-based simulation that assesses the performance of the power system during (and shortly following) a contingency. Transient stability studies are performed to ensure system stability following critical faults on the system.

The system is considered stable if the following conditions are met:

1. All machines in the WECC interconnected system must remain in synchronism as demonstrated by relative rotor angles (unless modeling problems are identified and concurrence is reached that a problem does not really exist).

2. A stability simulation will be deemed to exhibit positive damping if a line defined by the peaks of the machine relative rotor angle swing curves tends to intersect a second line connecting the valleys of the curves with the passing of time.

3. Corresponding lines on bus voltage swing curves will likewise tend to intersect. A stability simulation, which satisfies these conditions, will be defined as stable.

4. Duration of a stability simulation run will be ten seconds unless a longer time is required to ascertain damping.

5. The transient performance analysis will start immediately after the fault clearing and conclude at the end of the simulation.

6. A case will be defined as marginally stable if it appears to have zero percent damping and the voltage dips are within (or at) the WECC Reliability Criteria limits.

Performance of the transmission system is measured against the WECC Reliability Criteria and the NERC Planning Standards.

Table 5.3 illustrates the NERC/WECC Reliability Criteria. The reliability and performance criteria are applied to the entire WECC transmission system.

Table 5.3

WECC Disturbance-Performance Table of Allowable Effects on Other Systems (in addition to NERC requirements)

NERC and WECC Categories	Outage Frequency Associated with the Performance Category (Outage/Year)	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post-Transient Voltage Deviation Standard (See Note 2)
A	Not Applicable	Nothing in Addition to NERC		
B	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6 Hz** for 6 cycles or more at a load bus	Not to exceed **5%** at any bus (see Note 3)
C	0.033 – 0.33	Not to exceed 30% at any bus. Not to exceed **20% for more than 40 cycles** at load buses.	Not below **59.0 Hz** for 6 cycles or more at a load bus	Not to exceed **10%** at any bus
D	< 0.033	Nothing in Addition to NERC		

Note 2: As an example in applying the WECC Disturbance-Performance Table, Category B disturbance in one system shall not cause a transient voltage dip in another system that is greater than 20% for more than 20 cycles at load buses, or exceed 25% at load buses or 30% at non-load buses at any time other than during the fault.

Note 3:SCE applies a 7% post-transient criteria for Category "B" disturbances on the SCE system.

5.4 Post-Transient Voltage Stability Criteria

The last column of the above Table 5.3 illustrates the Post-Transient Voltage Stability Criteria. For some large generator contingencies, the governor power flow is utilized to test for the post-transient voltage deviation criteria.

5.5 Reactive Margin Criteria

Table 5.5 summarizes the voltage support and reactive power criteria in the NERC/WECC Planning Standards.

The system performance will be evaluated according to the NERC/WECC planning criteria.

Table 5.5: Reactive Margin Analysis Criteria Summary

Performance Level/Category	Disturbance	Reactive Power Deficiency Criteria
B	Generator One Circuit One Transformer DC Single Pole Block	Governor power flow to reach convergence at 105% of load level or operational transfer capability
C	Two Generators Two Circuits DC Bipolar Block	Governor power flow to reach convergence at 102.5% of load level or operational transfer capability

5.6 Power Factor Criteria

Table 5.6 summarizes the power factor criteria per the CAISO tariff. The voltage at the POI must be within criteria under normal and contingency conditions. Additional requirements may also be imposed by the CAISO Tariff or by the SCE Interconnection Handbook.

Table 5.6: Power Factor Analysis Criteria Summary

Generation Type	Power Factor Criteria
Wind Generator	0.95 lagging to 0.95 leading at the POI
All other Generator Types	0.90 lagging to 0.95 leading at Generator terminals

6. Deliverability Assessment

This assessment is comprised of on-peak and off-peak deliverability assessments for the Transition Cluster projects in the Eastern Bulk System. Both SCE system and SDG&E bulk system were monitored for any adverse impacts.

6.1 On-Peak Deliverability Assessment

The assessment was performed following the on-peak Deliverability Assessment methodology (http://www.caiso.com/23d7/23d7e41c14580.pdf). The study results are summarized in Table 6.1.

Table 6.1: On-Peak Deliverability Assessment for Eastern Bulk System

Contingency	Overloaded Facilities	Rating	Max Flow
Devers – Valley 500 kV #1 and #2	Devers – TOT185HS 230 kV #1	1150 Amps	1258 Amps/ 109%
	Devers –El Casco 230 kV #1	1150 Amps	1693 Amps/ 147%
	Devers-VSTA 230 kV #2	1240 Amps	1485 Amps / 120%
	Devers-SANBRDNO 230 kV #1	796 Amps	1286 Amps / 162%
Basecase	Colorado River 500/230 kV transformers #2	1120 MVA	1948 MVA

The Colorado River substation is originally triggered by a project in the Serial Group and only a 500 kV switchyard is required. For the TC Phase II projects, it is needed to expand the Colorado River switchyard to a 500/230 kV substation with two transformers.

There are multiple contingencies that cause West of Devers 230kV lines (as shown in Table 6.1) overloaded. The Devers – Valley 500 kV N-2 is the most critical contingencies for this overload.

6.2 Off-Peak Deliverability Assessment

There is no off-peak deliverability assessment is required by the Deliverability Assessment methodology (http://www.caiso.com/23d7/23d7e41c14580.pdf) for the Eastern Bulk area since there are all solar projects in this area.

7. Steady State Assessment

This assessment is comprised of Power Flow Analysis and Reactive Power Deficiency Analysis.

Power flow analysis was performed to ensure that SCE's transmission system remains in full compliance with North American Reliability Corporation (NERC) reliability standards TPL-001, 002, 003 and 004 with the proposed interconnection. The results of these power flow analyses will serve as documentation that an evaluation of the reliability impact of new facilities and their connections on interconnected transmission systems is performed. If a NERC reliability problem exists as a result of this interconnection, it is SCE's responsibility to identify the problem and develop an appropriate corrective action plan to comply with NERC reliability standards and the CAISO's responsibility to review and approve such corrective action plan.

As part of SCE's obligations with NERC as the registered Transmission Owner for the SCE transmission system, the study results for this interconnection will be communicated to the CAISO, or other neighboring entities that may be impacted, for coordination and incorporation of its transmission assessments. Input from the CAISO and other neighboring entities are solicited to ensure coordination of transmission systems.

While it is impractical to study all combinations of system load and generation levels during all seasons and at all times of the day, the base cases were developed to represent stressed scenarios of loading and generation conditions for the study group area. The CAISO and SCE cannot guarantee that Transition Cluster projects can operate at maximum rated output 24 hours a day, year round, without adverse system impacts, nor can the CAISO and SCE guarantee that these projects would not have adverse system impacts during the times and seasons not studied in the Transition Cluster Phase II Study.

The following power flow base cases were used for the analysis in the Phase II Study:

- **On-Peak Full Loop Base Case:**

  Power flow analyses were performed using SCE's summer peak full loop base case (in General Electric Power Flow format). This base case was developed from base cases that were used in the SCE annual transmission expansion plan studies. It has a 1-in-10 year adverse weather load level for the SCE service territory.

- **Off-Peak Full Loop Base Case:**

  Power flow analyses were also performed using the off-peak full loop base case in order to evaluate system performance due to the addition of Transition Cluster generation projects during light load conditions. The spring load was modeled at about 60% of the summer peak load.

The base cases modeled all CAISO approved SCE transmission projects. The base cases also modeled all proposed generation projects that were higher than the Transition Cluster projects in the CAISO generation queue. These generation projects were modeled along with their identified transmission upgrades necessary for their interconnection and/or delivery.

The detail power flow study results were discussed in the sections below. Table 7-1 and 7-2 listed the overloaded lines under studied contingencies:

7.1 Study Results

The overloads caused by Transition Cluster Group projects and associated power flow plots are shown in Appendix D.

1. Normal Overloads (Category "A")

   Under projected 2013 peak load conditions, Phase II projects caused two (2) Category "A" normal overloads. Under projected off-peak load conditions, Phase II projects caused the same two (2) normal overloads which are also found in the peak load conditions.

   All identified base case overloads occurred on the two (2) 220 kV lines in the West of Devers Area.

2. Emergency Overloads (Category "B")

   Under projected 2013 peak load conditions, Phase II projects caused three (3) Category "B" overload. Under projected 2013 off-peak load conditions, Phase II projects caused the same three (3) Category "B" overloads.

   All identified N-1 overloads occurred on the three (3) 220 kV lines in the West of Devers Area.

3. Emergency Overloads (Category "C")

   Under the projected 2013 peak load conditions, Phase II projects caused four (4) new Category "C" overload. Under the projected 2013 off peak load conditions, Phase II projects caused total of four (4) Category "C" overloads: the same three (3) overloads as in the peak case and one (1) new overload.

   The identified base case overloads occurred on the four (4) 220 kV lines in the West of Devers Area.

Table 7-1 Peak Load Load, Category “A”, “B", and “ C” Overloads

Overload Facility	Rating	Loading (Amps)		Contingency
		Pre	Post	
San Bernardino – Devers 230 kV line No. 1	796 Amp (N) 796 Amp (E)	769	896	Base Case
Devers – El Casco 230 kV line No. 1	1150 Amp (N) 1150 Amp (E)	1143	1282	Base Case
Devers – Vista 230 kV line No. 2	1240 Amp (N) 1240 Amp (E)	1207	1388	Cabawind – Vista 230 kV line No. 1
San Bernardino – Devers 230 kV line No. 1	796 Amp (N) 796 Amp (E)	896	1042	DEVERS 230.0 to VSTA 230.0 Circuit 2
Devers – El Casco 230 kV line No. 1	1150 Amp (N) 1150 Amp (E)	1279	1439	DEVERS 230.0 to VSTA 230.0 Circuit 2
San Bernardino – Devers 230 kV line No.1	1150 Amp(N) 1150 Amp(E)	1361	1692	Devers – Valley 500kV lines No. 1 and No. 2
Devers – Vista 230 kV line No. 2	1150 Amp(N) 1150 Amp(E)	1617	1982	Devers – Valley 500kV lines No. 1 and No. 2
Devers – El Casco 230 kV line No. 1	1150 Amp(N) 1150 Amp(E)	1783	2156	Devers – Valley 500kV lines No. 1 and No. 2
San Bernardino – El Casco 230 kV line No. 1	1150 Amp (N) 1150 Amp (E)	917	1248	Devers – Valley 500kV lines No. 1 and No. 2

Table 7-2: Off Peak Load, Category “A”, “B", and “C” Overloads

Overload Facility	Rating	Loading (Amps)		Contingency
		Pre	Post	
Devers – San Bernardino 230kV line No. 1	796 Amp (N) 796 Amp (E)	755	952	Base Case
Devers – El Casco 230 kV line No. 1	1150 Amp(N) 1150 Amp(E)	1049	1265	Base Case
Devers – Vista 230 kV line No. 2	1240 Amp (N) 1240 Amp (E)	1142	1384	Vista – San Bernardino 230 kV line No. 2
Devers – El Casco 230 kV line No. 1	1150 Amp(N) 1150 Amp(E)	1193	1447	DEVERS 230.0 to VSTA 230.0 Circuit 2
Devers – San Bernardino 230kV line No. 1	1150 Amp (N) 1150 Amp (E)	890	1123	DEVERS 230.0 to VSTA 230.0 Circuit 2
Devers – San Bernardino 230kV line No. 1	1150 Amp(N) 1150 Amp(E)	719	917	DEVERS 230.0 to MIRAGE 230.0 Circuit 1, DEVERS 230.0 to MIRAGE
Devers – Vista 230 kV line No. 2	1240 Amp(N) 1240 Amp(E)	1465	1791	ETIWANDA 230.0 to SANBRDNO 230.0 Circuit 1, VSTA 230.0 to SANBRDNO
Devers – El Casco 230 kV line No. 1	1240 Amp(N) 1240 Amp(E)	1420	1746	DEVERS to VSTA 230 ck 2, SANBRDNO to DEVERS 230 ck 1
Mira Loma – Vista 230kV line No. 2	2299 Amp (N) 3110 Amp (E)	2693	3214	Etiwanda – San Bernardino 230 kV line No. 1 & Etiwanda – Vista 230 kV line

8. Short Circuit Duty Assessment

Short circuit studies were performed to determine the impact on circuit breakers with the interconnection of Transition Cluster Phase II projects to the transmission system. The fault duties were calculated before and after Phase II projects to identify any equipment overstress conditions. Three-phase (3PH) and single-line-to-ground (SLG) faults were simulated without the Phase II projects and with the Phase II projects including the identified Reliability and Delivery Network Upgrades from the power flow analysis.

8.1 SCD Results

All bus locations where the Transition Cluster Phase II Projects increased the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are listed in

Appendix H. These values have been used to determine if any *additional* equipment, beyond what has previously been identified to be overstressed due to queued ahead serial projects, is triggered with the addition of the Transition Cluster Phase II interconnections and corresponding network upgrades. The Transition Cluster Phase II breaker evaluation identified the following additional overstressed circuit breakers which are triggered by the Transition Cluster Projects:

8.1.1 Vincent 500 kV Substation

The study identified that the addition of the Transition Cluster projects results in increasing SCD at SCE's Vincent 500 kV Substation beyond the breaker capabilities. Such duty increases were identified to impact a total of eleven 500 kV circuit breakers including four circuit breakers (see Section 4.6.3) which were previously identified to be triggered by serial interconnection projects but whose upgrade did not create sufficient capacity to accommodate the Transition Cluster Projects.

- Vincent 500 kV CB712, CB812 and CB912
- Vincent 500 kV CB722 and CB822
- Vincent 500 kV CB752, CB852 and CB952
- Vincent 500 kV CB762, CB862 and CB962

8.1.2 Kramer 220 kV Substation

The study identified that the addition of the Transition Cluster projects results in increasing SCD at SCE's Kramer 220 kV Substation beyond the breaker capabilities. Such duty increases were identified to impact a total of five 220 kV circuit breakers.

- Kramer 220 kV CB6012
- Kramer 220 kV CB4022 and CB6022
- Kramer 220 kV CB4082
- Kramer 220 kV CB4102

8.1.3 Windhub 220 kV Substation

The study identified that the addition of the Transition Cluster projects results in increasing SCD at SCE's Windhub 220 kV Substation beyond the breaker capabilities with the Windhub Substation operating with four 500/220 kV transformer banks in parallel. Such duty increases were identified to impact a total of nine 220 kV circuit breakers.

- Windhub 220 kV CB4102 and CB6102
- Windhub 220 kV CB4122 and CB6122
- Windhub 220 kV CB4112 and CB6112
- Windhub 220 kV CB2132, CB4132 and CB6132

8.1.4 Antelope 66 kV Substation

The study identified that the addition of the Transition Cluster projects results in increasing SCD at SCE's Antelope 66 kV Substation. Such duty increases were identified to impact a total of forty 66 kV circuit breakers including thirty-eight circuit breakers which were previously identified to be triggered by serial interconnection projects (see Section 4.6.19). The incremental duty contributions will result in duty which is in excess of the previous mitigation for the thirty-eight circuit breakers previously identified. As a result, mitigation for all identified forty circuit breakers will be required.

- Antelope CB1E and CB1W
- Antelope CB2E and CB2W
- Antelope CB3E and CB3W
- Antelope CB4E and CB4W
- Antelope CB5E and CB5W
- Antelope CB7E and CB7W
- Antelope CB8E and CB8W
- Antelope CB9E and CB9W
- Antelope CB10E and CB10W
- Antelope CB12E and CB12W
- Antelope CB14E and CB14W
- Antelope CB18E and CB18W
- Antelope CB20E and CB20W
- Antelope CB21E and CB21W
- Antelope CB22E and CB22W
- Antelope CB23E and CB23W
- Antelope CB24E and CB24W
- Antelope CB25E and CB25W
- Antelope CB26E and CB26W
- Antelope CB CAP1
- Antelope CB CAP3

8.2 SCD Mitigation Measures

To mitigate these identified overstressed circuit breakers, the following upgrades are recommended:

- Replace seven CBs and upgrade four CBs to achieve 63 kA rating on overstressed Vincent 500 kV CBs
- Replace five CBs to achieve 50 kA rating on overstressed Kramer 220 kV CBs
- Sectionalize Windhub 220 kV bus

- Operating procedure[2] to reduce Antelope 66 kV SCD

The responsibility to finance short circuit related Reliability Network Upgrades identified through a Group Study shall be assigned to all Interconnection Requests in that Group Study pro rata on the basis of the maximum megawatt electrical output of each proposed new Large Generating Facility or the amount of megawatt increase in the generating capacity of each existing Generating Facility. The pro rata allocation of each Transition Cluster Project to the circuit breaker upgrades listed above is provided in each individual report (Appendix A).

9. Transient Stability Analysis

Transient stability analysis was conducted using both the summer peak and spring full loop base cases to ensure that the transmission system remains stable with the addition of Transition Cluster generation projects. The generator dynamic data used for the study is confidential in nature and is provided with each individual project report

9.1 Transient Stability Study Scenarios

Disturbance simulations were performed for a study period of 10 seconds to determine whether the Transition Cluster projects will create any system instability during a variety of line and generator outages. For SCE's Eastern Bulk System, selected line and generator outages within the Eastern Bulk System were evaluated. The outages were consistent with Category B and Category C requirements (single element and multiple element outages).

9.2 Transient Stability Results

The study identified total of 39 SCE buses showing poor performance in the on-peak cases for the worst contingency of N-2 of Devers-Red Bluff 500 kV line #1 and #2. After implementing the proposed system upgrades, the results showed acceptable system stability with no criteria violations.

The study results of the off-peak load condition showed lower EOR and WOR path flow may be needed to achieve acceptable system stability performance with all proposed system upgrades.

Transient stability plots for on-peak and off-peak conditions and spring load conditions are provided in Appendix F.

[2] SCE anticipates that the appropriate long-term mitigation of the Antelope 66 kV SCD problem involves sectionalization of the Antelope 66 kV bus, but may also involve pre-Transition Cluster system SCD mitigation for Vincent 220 kV and Mira Loma 220 kV SCD problems. As an interim mitigation measure until the appropriate upgrades can be identified, an operating procedure to de-loop or de-energize sufficient transmission facilities to keep Antelope 66 kV SCD below 40 KA will be required.

10. Post-Transient Voltage Stability Analysis

The post-transient voltage stability results indicate no criteria violations by adding Phase II projects. The study concluded that the Phase II projects would not cause the transmission system to go unstable under Category "B" and Category "C" outages.

11. Mitigation of Transition Cluster Project Impacts

The mitigation requirements triggered by Transition Cluster projects, based on the results described in Sections 6-10 above, are as follows.

11.1 Plan of Service Reliability Network Upgrades

Plan of Service Reliability Network Upgrades for Transition Cluster projects in the Eastern Bulk System are discussed in detail in each individual project report (Appendix A).

11.2 Reliability Network Upgrades

Assumed scope for the Reliability Network Upgrades for Transition Cluster projects in the Eastern Bulk System are listed below.

11.2.1 Loop the Colorado River – Devers 500 kV No. 2 Transmission Line into Red Bluff Substation

Devers – Colorado River No.2 500kV Transmission Line
Loop the proposed line into Red Bluff Substation and form the two new Devers – Red Bluff no.2 and Colorado River – Red Bluff No.2 500kV T/Ls.

This work requires the installation of approximately 1 Circuit Mile of 2-2156KCMIL ACSR Conductors and OPGW, four Dead End 500kV Lattice Steel Structures and thirty Insulator / Hardware Assemblies.

Red Bluff 500/220kV Substation
Install two new Double Breaker Line Positions within the existing 500kV Switchyard to terminate the two new Colorado River No.2 and Devers No.2 500kV T/Ls.

Existing Control Room
Install the following Protection Relays:

500kV Transmission Lines

- Four GE C60 Breaker Management Relays
- Two G.E. D60 Distance Relay (Digital Communication

Channel)

- Two G.E. L90 Current Differential Relay (Digital Communication Channel)
- Two SEL-421 Current Differential Relay with RFL 9780 on PLCC.
- Two additional RFL 9780 Direct Transfer Trip on PLCC
- Two RFL 9745 Direct transfer trip on PLCC

11.2.2 Colorado River Substation Expansion – No. 1 AA-Bank

Expand the existing station, presently configured as a 500kV Switchyard, to a 1120MVA 500/220kV Substation by installing one 1120MVA 500/220kV Transformer Bank with corresponding 500kV and 220kV Bank Positions and installing a new 220kV Switchyard.

Scope Detail:
Install the following equipment:

- One 500kV Double Breaker Bank Position to connect the No.1AA Tr. Bk.
- One additional 500kV Circuit breaker and two Disconnect Switches on existing 500kV Two-Breaker Position connect the No.2AA Tr. Bk.
- Two 1120MVA 500/220kV No.1AA and No.2AA Transformer Banks consisting of seven 373MVA Single-Phase Units (Includes one spare unit)
- Two 220KV Operating Buses covering eight positions
- One 220kV Double Breaker Bank Position to connect the No.1AA Tr. Bk.
- One 220kV Double Breaker Bank Position to connect the No.2AA Tr. Bk.

500kV Switchyard:
Position 3
Install the following equipment for a Double Breaker Bank Position on a Breaker-and a-Half Configuration to connect the No.1AA 500/220kV Tr. Bk.:

- One 108 Ft. High by 90 Ft. Wide Dead-End Structure
- Two 500kV – 4000A – 50kA Circuit Breakers
- Four 500kV Horizontal-Mounted Group-Operated Disconnect Switches – One of them equipped with Grounding Attachments.
- Fifteen 500kV Bus Supports
- 2-1590KCMIL ACSR Conductors

500/220kV Transformer Bank:
Install one 1120MVA 500/161-220kV Transformer Banks as follows:

- Four 373MVA 500/161-220kV Single-Phase units, including one spare unit.

- Three 500kV Surge Arresters
- Three 220kV Surge Arresters
- One standard seven-position transformer structure with all the required 500kV and 220kV bus-work to allow for the Grounded Wye / Delta connection of the Single-Phase units and placement of the spare unit.
- One 13.8kV Tertiary Bus equipped as follows:
- Five 13.8kV – 2000A – 17kA Circuit Breakers
- Fifteen 13.8kV Hook-Stick Disconnect Switches
- Five 13.8kV 45MVAR Reactors
- One Ground Bank Detector (3 - 5kVA 14400-120/240V Transformers)
- One 14400-120V Voltmeter Potential Transformer
- One Voltmeter
- Three 40E Standard Size 4 S&C Type Fuses
- Approximately 700 Circuit Ft. of 2-1590KCMIL ACSR Conductors for the 500kV and 220kV Transformer Leads

220kV Switchyard:
Operating Buses

Install the following equipment required for a new 220kV Switchyard:

- Six 60 Ft High x 90 Ft Wide Bus Dead End Structures
- Twenty four Bus Dead-End Insulator Assemblies
- Six 220kV Potential Devices
- Approximately 920 Circuit Ft. of 21590KCMIL ACSR Bus Conductors

Position 5:

Install the following equipment for a Double Breaker Bank Position on a Breaker-and-a-Half Configuration to connect the No.1AA 500/220kV Tr. Bk.:

- One 80 Ft. High by 50 Ft, Wide Dead-End Structure
- Two 220kV 3000A – 50kA Circuit Breakers
- Four 220kV 3000A – 80kA Horizontal-Mounted Group-Operated Disconnect Switches
- One Grounding Switch Attachment
- Eighteen 220kV Bus Supports with associated steel pedestals
- 2-1590KCMIL ACSR Conductors

Existing Control Room

Install the following Protection Relays:

500/220kV Transformer Banks

- Four GE C60 Breaker Management Relays
- One GE T60 Bank Differential Relay
- One SEL-387 Bank Differential Relay
- Four GE C30 Sudden Pressure Aux Relay

- Five GE F60 Reactor Bank Relays (one per reactor)
- Two SEL-351 Ground Detector Bank Relay
- Twelve GE SBD11B 220kV Bus Differential Relays

11.2.3 Upgrade Mira Loma – Vista No.2 220 kV T/L Line Drops at Vista Substation to Emergency Rating of 3,500 A or Higher

Vista Substation:
Replace the existing 2-1033KCMIL ACSR Conductors (N – 2 Rating of 3,150A) on the Mira – Loma No.2 220kV line Position at Vista Substation with new 2-1590KCMIL ACSR Conductors (N – 2 Rating of 4,100A)

11.2.4 New SPS to Trip up to 1,400 MW of Generation Under the Devers – Red Bluff No.1 and No.2 Double Contingency

Red Bluff Substation

Install the following SPS Relays <u>at each location:</u>

- Two N60 relays (One each for SPS A and B) for Line Monitoring
- One SEL – 2407 Satellite Synchronized Clock.

Colorado River Bluff Substation

Install the following SPS Relays:

- Four N60 relays (Two each for SPS A and B) for Logic Central Processing and sending of tripping signals to Generators.
- One SEL – 2407 Satellite Synchronized Clock.

Telecommunications
Install the following equipment and channels to support the SPS:

- Devers Substation: Two Channel Banks (One each for SPS A and B)

Power System Control
Install Dual RTU's for SPS arming, control and status and alarm indications at Colorado River Substation.

Expand existing RTU's Devers and Red Bluff Substations to install additional points required to support the SPS.

11.2.5 New SPS to Trip up to 500 MW of Generation Connected to Colorado River Substation Under Either No.1AA or No.2AA Transformer Bank Single Contingency

Colorado River Bluff Substation
Install the following SPS Relays:

- Four N60 relays (Two each for SPS A and B) for Banks Monitoring

The four N60 relays for Logic Central Processing and sending of tripping signals to Generators installed for SPS described on Item 11.2.3 will also support this additional SPS.

Telecommunications
No additional equipment required.
All equipment installed for SPS described on Item 3 will also support this additional SPS.

Power System Control
Also expand existing RTU's Devers and Red Bluff Substations to install additional points required to support the SPS.

11.3 Delivery Network Upgrades

Details of the scope for the Delivery Network Upgrades of the Phase II projects in the Eastern Bulk System are listed below.

11.3.1 West of Devers Upgrades

Upgrade the following 220kV transmission Lines to 3,000A Rating by replacing all existing conductors with new 2-1590KCMIL ACSR conductors per phase and replacing all substations terminal equipment with 3,000A rated elements:

- Devers – San Bernardino No.1 220kV T/L – 43 Circuit Miles
- Devers – San Bernardino No.2 220kV T/L – 43 Circuit Miles
- Devers – Vista No.1 220kV T/L – 45 Circuit Miles
- Devers – Vista No.2 220kV T/L – 45 Circuit Miles
- Devers Substation: Upgrade four 220kV line Positions
- San Bernardino G.S.: Upgrade two 220kV line Positions
- Vista Substation: Upgrade two 220kV line Positions

Note:

Prior to this upgrade the existing Devers – San Bernardino No.2 220kV T/L will be looped into the new El Casco Substation forming the two new Devers – El Casco and El Casco – San Bernardino 220kV T/Ls.

After this line re-configuration the existing Devers – San Bernardino No.1 220kVT/L will be re-named Devers – San Bernardino 220kV T/L.

The Devers and San Bernardino 220kV Line Positions at the new El Casco Substation will be rated 3,000A and would not require any upgrades.

11.3.2. Colorado River Substation Expansion – No. 2 AA Bank

Increase the 500/220kV station capacity from 1120MVA to 2240MVA by installing an additional No.2AA 1120MVA 500/220kV Transformer Bank with corresponding 500kV and 220kV Bank Positions.

Scope Detail:
500 kV Switchyard:

Position 5:
Install the following equipment on the existing 2-CB Line Position to expand to a 3-CB Line / Bank Position as required to connect the No.2AA Tr. Bk.:

- One 108 Ft. High by 90 Ft. Wide Dead-End Structure
- One 500kV 4000A – 50kA Circuit Breaker
- Two 500kV 4000A – 80kA Horizontal-Mounted Group-Operated Disc. Switches
- One Grounding Switch Attachments
- Also remove twelve 500kV Bus Supports and corresponding steel pedestals and foundations.

500/220 kV Transformer Bank:
Install one 1120MVA 500/161-220kV Transformer Bank as follows:

- Three 373MVA 500/161-220kV Single-Phase units.
- Three 500kV Surge Arresters
- Three 220kV Surge Arresters
- One 13.8kV Tertiary Bus equipped as follows:
- Five 13.8kV – 2000A – 17kA Circuit Breakers
- Fifteen 13.8kV Hook-Stick Disconnect Switches
- Five 13.8kV 45MVAR Reactors
- One Ground Bank Detector (3 - 5kVA 14400-120/240V Transformers)
- One 14400-120V Voltmeter Potential Transformer
- One Voltmeter

- Three 40E Standard Size 4 S&C Type Fuses
- Approximately 700 Circuit Ft. of 2-1590KCMIL ACSR Conductors for the 500kV and 220kV Transformer Leads

220kV Switchyard:
Position 7:
Install the following equipment for a Double Breaker Bank Position on a Breaker-and-a-Half Configuration to connect the No.2AA 500/220kV Tr. Bk.:

- One 80 Ft. High by 50 Ft, Wide Dead-End Structure
- Two 220kV 3000A – 50kA Circuit Breakers
- Four 220kV 3000A – 80kA Horizontal-Mounted Group-Operated Disconnect Switches
- One Grounding Switch Attachment
- Eighteen 220kV Bus Supports with associated steel pedestals
- 2-1590KCMIL ACSR Conductors

Existing Control Room
Install the following Protection Relays:

500/220kV Transformer Banks
- Four GE C60 Breaker Management Relays
- One GE T60 Bank Differential Relay
- One SEL-387 Bank Differential Relay
- Three GE C30 Sudden Pressure Aux Relays
- Five GE F60 Reactor Bank Relays (one per reactor)
- Two SEL-351 Ground Detector Bank Relay

12. Environmental Evaluation / Permitting

12.1 CPUC General Order 131-D

The California Public Utilities Commission's (CPUC) General Order 131-D (GO 131-D) sets for the permitting requirements for certain electrical and generation facilities. GO 131-D was established by the CPUC to be responsive to: the requirements of the California Environmental Quality Act (CEQA); the need for public notice and the opportunity for affected parties to be heard by the CPUC; and the obligations of the utilities to serve their customers in a timely and efficient manner.

Electric facilities between 50 and 200 kV are subject to the CPUC's Permit to Construct (PTC) review specified in GO 131-D, Section III.B. For facilities subject to PTC review, or for over 200 kV electric facilities subject to Certificate of Public Convenience and Necessity (CPCN) requirements specified in GO 131-D, Section III.A, the CPUC reviews utility PTC or CPCN applications pursuant to CEQA and serves as Lead Agency under CEQA. Section IX of GO 131-D discusses the requirements for PTC and CPCN applications.

Generally, SCE takes approximately a minimum of 6-18 months to assemble a CPCN or PTC application, the majority of which time is involves by developing a required Proponent's Environmental Assessment (PEA). The CPUC review of such applications may take anywhere from 8 – 36 months depending on the specific.

12.2 CPUC General Order 131-D – Permit to Construct/Exemptions

GO 131-D provides for certain exemptions from the CPUC PTC requirements for facilities between 50 and 200 kV. For example, Exemption f of GO 131-D (Section III.B.1.f) exempts from CPUC PTC permitting requirements power lines or substations between 50 - 200 kV to be constructed or relocated that have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA document (Environmental Impact Report or Negative Declaration) finds no significant unavoidable environmental impacts caused by the proposed line or substation. Note, GO 131-D, Section III.B.2, discusses the conditions under which PTC exemption shall not apply (consistent with CEQA Guidelines).

After lead agency approval of the final CEQA document which confirms there are no significant environmental impacts associated with the SCE scope of work, SCE may be eligible to use Exemption f, and in doing so would follow certain limited public noticing requirements, including filing an informational Advice Letter at the CPUC, posting the project site/route, providing notice to the local jurisdicition(s) planning director and the executive director of the California Energy Commission (CEC), and advertising the project notice, for once a week for two weeks successively in a local newspaper. As part of an agreement with the CPUC Energy Division, SCE informally provides a copy of the final CEQA document to the CPUC Energy Division for reference when the Advice Letter is pending before the CPUC.

Note, the CPUC rules for Advice Letters consider an Advice Letter to be in effect on 30th calendar day after the date filed, and GO 131-D specifies a minimum period of 45-days between advertising the notice for the project and when construction can occur.

Typically, SCE may proceed with construction 45-days after it has filed its Advice Letter and has posted and advertised the project notice unless a protest is filed and/or CPUC staffs suspend the Advice Letter. If protests are filed, they must address whether SCE has properly claimed the exemption. SCE has 5 business days to respond to the protest and the CPUC will typically take a minimum of 30 days to review the protest and SCE's response, and either dismiss the protests or require SCE to file a Permit to Construct. SCE has no control over the time it takes the CPUC to respond when issues arise. If the protest is granted, SCE may then need to apply for a formal permit to construct the project (i.e., Permit to Construct).

If SCE facilities are not included in the larger project's CEQA review, or if the project does not qualify for the exemption due to significant, unavoidable environmental impacts, or if the exemption is subject to the "override" provision in GO 131-D, Section III.B.2, SCE may need to seek approval from the CPUC (i.e., Permit to Construct) taking as much as 18 months or more since the CPUC would need to conduct its own environmental evaluation (i.e., Mitigated Negative Declaration or Environmental Impact Report).

Note, for projects undergoing no CEQA review but instead only undergoing a review under the National Environmental Policy Act (NEPA) due to the lead agency being a federal agency (such as the BLM), GO 131-D technically does not allow for the use of Exemption f when the environmental review is conducted only pursuant to NEPA and does not have a CEQA component. As such, SCE would need to review such projects on a case-by-case basis with the CPUC to determine if the CPUC would allow the project to proceed under Exemption f or instead allow SCE to proceed under an "expedited" PTC application by attaching the NEPA document in lieu of a PEA.

For projects that are not eligible for Exemption f, but have already undergone CEQA or NEPA review, SCE may be able to file an "expedited" PTC application, which typically takes the CPUC approximately 4-6 months to process.

12.3 CPUC General Order 131-D – Certificate of Public Convenience & Necessity (CPCN) Exceptions

When SCE's transmission lines are designed for immediate or eventual operation at 200 kV or more, GO 131-D requires SCE to obtain a Certificate of Pubic Convenience and Necessity (CPCN) from the CPUC unless one of the following exceptions applies: the replacement of existing power line facilities or supporting structures with equivalent facilities or structures, the minor relocation of existing facilities, the conversion of existing overhead lines (greater than 200 kV) to underground, or the placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built.

Unlike Exemption f relating to the exemptions allowed from a Permit to Construct for electric facilities between 50 – and 200 kV, no such exemption exists for electric facilities over 200 kV transmission lines that have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA document finds no significant unavoidable environmental impacts caused by the proposed line or substation. Accordingly, SCE would need to consult on a case-by-case basis with the CPUC for such projects CPUC would allow the project to proceed "exempt" or instead allow SCE to proceed under an "expedited" CPCN application by attaching the final CEQA document in lieu of a SCE Proponent's Environmental Assessment. Such an expedited CPCN with the environmental review already completed by the lead agency that permitted the Interconnection Customer's generator project, typically may take from only 4-6 months for the CPUC to process.

12.4 CPUC General Order 131-D – General Comments Relating to Environmental Review of SCE Scope of Work as Part of the Larger Generator Project

For the benefits and reasons stated above, It is assumed that the Interconnection Customer will include SCE's Interconnection Facilities and Network Upgrades work scope (including facilities to be constructed by others and deeded to SCE) in the Interconnection Customer's environmental reports/applications submitted to the lead agency permitting the Interconnection Customer's larger generator project (e.g., California Energy Commission or applicable local, state or federal permitting agency, such as the Bureau of Land Management), and that such agencies will review the potential environmental impacts associated with SCE's work scope in any environmental document issued. This may enable SCE to proceed "exempt" from CPUC permitting requirements or under an "expedited" PTC or CPCN. However, depending on certain circumstances, the CPUC may still require SCE to undergo a standard PTC or CPCN for the generator tie line and Network Upgrades work associated with the Interconnection Customer's Project. SCE may also be required to obtain other authorizations for its interconnection facilities and network upgrades. Hence, the SCE's facilities needed for the project interconnection could require an additional two years, or more, to license and permit. The cost for obtaining any of this type of permitting is not included in the cost estimates.

Please see General Order 131-D. This document can be found in the CPUC's web page at:

http://www.cpuc.ca.gov/PUBLISHED/GENERAL_ORDER/589.htm

12.5 CPUC Section 851

Because SCE is subject to the jurisdiction of the CPUC, it must also comply with Public Utilities Code Section 851. Among other things, this code provision requires SCE to obtain CPUC approval of leases and licenses to use SCE property, including rights-of-way granted to third parties for Interconnection Facilities. Obtaining CPUC approval for a Section 851 application can take several months, and requires compliance with the California Environmental Quality Act (CEQA). SCE recommends that Section 851 issues be identified as early as possible so that the necessary application can be prepared and processed. As with GO 131-D compliance, SCE recommends that the project proponent include any facilities that may be affected by Section 851 in the lead agency CEQA review so that the CPUC does not need to undertake additional CEQA review in connection with its Section 851 approval.

12.6 SCE scope of work NOT subject to CPUC General Order 131-D

Certain SCE facilities and scope of work may not be subject to CPUC's G.O. 131-D. In such instances, SCE will follow the requirements of all applicable environmental laws and regulations and issue an in-house environmental clearance before commencement of construction activities.

13. Upgrades, Cost and Time to Construct Estimates

The cost estimates are based on initial engineering scope as described in Section 11 of this report. Costs for each generation project are confidential and are not published in the main body of this report. Each IC is receiving a separate report, specific only to that generation project, containing the details of the IC's cost responsibilities.

Regardless of the requested Commercial Operating Date, the actual Commercial Operation Dates of the generation projects in the Transition Cluster are dependent on the completed construction and energizing of the identified Network Upgrades. Without these upgrades, the new generators may be subject to CAISO's congestion management, including generation tripping. Based on the needed time for permitting, design, and construction, it may not be feasible to complete all the upgrades needed for this cluster before the requested Commercial Operation Dates.

The estimated cost of **Reliability Network Upgrades** identified in this Group Study is assigned to all Interconnection Requests in that Group Study pro rata on the basis of the maximum megawatt electrical output of each proposed new Large Generating Facility or the amount of megawatt increase in the generating capacity of each existing Generating Facility as listed by the Interconnection Customer in its Interconnection Request.

The estimated cost of all **Delivery Network Upgrades** identified in the Deliverability Assessment are assigned to all Interconnection Requests selecting Full Capacity Deliverability Status based on the flow impact of each such Large Generating Facility on the Delivery Network Upgrades as determined by the generation distribution factor methodology.

The estimated cost of all **Interconnection Facilities and Plan of Service Reliability Upgrades** is assigned to each Interconnection Request individually. The cost estimates for the Interconnection Facilities **and Plan Service Reliability Upgrades** are all site specific and details are provided in each individual project report.

The estimated costs of **Distribution Upgrades** and **non-CAISO transmission upgrades, if applicable,** are assigned to all Interconnection Requests in that Group Study pro rata on the basis of the maximum megawatt electrical output of each proposed new Large Generating Facility or the amount of megawatt increase in the generating capacity of each existing Generating Facility as listed by the Interconnection Customer in its Interconnection Request. Distribution Upgrades and non-CAISO transmission upgrades are non-refundable.

Table 13.1 Upgrades, Estimated Costs, and Estimated Time to Construct Summary

Type of Upgrade	Upgrade	Description	Estimated Cost x 1,000	Estimated Time to Construct
Plan of Service Reliability Network Upgrades	Plan of Service Reliability Network Upgrades for TC Phase II projects in the Eastern Bulk System are discussed in detail in each individual project report (Appendix A).		[redacted]	See Appendix A
Reliability Network Upgrades	Loop the Colorado River – Devers 500 kV No. 2 Transmission Line into Red Bluff Substation	Loop the Colorado River – Devers 500 kV No. 2 line into Red Bluff Substation and form the two new Devers – Red Bluff No.2 and Colorado River – Red Bluff No.2 500kV T/Ls. Install two new Double Breaker Line Positions within the existing 500kV Switchyard to terminate the two new Colorado River No.2 and Devers No.2 500kV T/Ls.	[redacted]	36 months
	Colorado River Substation Expansion – No. 1 AA Bank	Expand the existing station, presently configured as a 500kV Switchyard, to a 1120MVA 500/220kV Substation by installing one 1120MVA 500/220kV Transformer Banks with corresponding 500kV and 220kV Bank Positions and installing a new 220kV Switchyard.		
	Upgrade Mira Loma – Vista No.2 220 kV T/L Line Drops at Vista Substation to Emergency Rating of 3,500 A or Higher	Replace the existing 2-1033KCMIL ACSR Conductors (N – 2 Rating of 3,150A) on the Mira – Loma No.2 220kV line Position at Vista Substation with new 2-1590KCMIL ACSR Conductors (N – 2 Rating of 4,100A)		
	New SPS To Trip up to 1,400 MW of Generation Under the Devers – Red Bluff No.1 and No.2 Double Contingency	Trip Generation under the Double Contingency caused by the simultaneous outages of Devers – Red Bluff No.1 and No.2 500kV T/Ls.		
	New SPS to Trip up to 500 MW of Generation Connected to Colorado River Substation Under Either No.1AA or No.2AA Transformer Bank Single Contingency	Trip Generation under the Single Contingency caused by the individual outage of either one of the Colorado River No.1AA or No.2AA Transformer Bank.		
Delivery Network Upgrades	West of Devers 220 kV Upgrades	Upgrade the following 220kV transmission Lines to 3,000A Rating by replacing all existing conductors with new 2-1590KCMIL ACSR conductors per phase and replacing all substations terminal equipment with 3,000A rated elements: Devers – San Bernardino No.1 220kV T/L – 35 Circuit Miles Devers – San Bernardino No.2 220kV T/L – 35 Circuit Miles Devers – Vista No.1 220kV T/L – 37 Circuit Miles Devers – Vista No.2 220kV T/L – 37 Circuit Miles Devers Substation: Upgrade four 220kV line Positions San Bernardino G.S.: Upgrade two 220kV line Positions Vista Substation: Upgrade two 220kV line Positions	[redacted]	84 months
	Colorado River Substation Expansion – No. 2 AA Bank	Increase the 500/220kV station capacity from 1120MVA to 2240MVA by installing an additional No.2AA 1120MVA 500/220kV Transformer Bank with corresponding 500kV and 220kV Bank Positions		
Distribution Upgrades	None		[redacted]	N/A
Total			[redacted]	**84 Months**

The non-binding construction schedule to engineer and construct the facilities identified in this report will be project-specific and will be based upon the assumption that the environmental permitting obtained by the IC is adequate for permitting all SCE activities.

It is assumed that the IC will include the SCE's Interconnection Facilities and Network Upgrades work scope, as they apply to work within public domains, in its environmental impact report to the CPUC. However, note that CPUC may still require SCE to obtain a Permit to Construct (PTC) or a Certificate of Public Convenience and Necessity (CPCN) for the Interconnection Facilities and Network Upgrades work associated with the project. Hence, the facilities needed for the project interconnection could require an additional two to three years to complete. The cost for obtaining any of this type of permitting is not included in the above estimates.

14. Coordination with Affected Systems

ISO LGIP tariff Appendix Y section 3.7 requires coordinating with any affected systems that have any potential impact of Transition Cluster projects. CAISO will coordinate the review of the Phase II reports with potentially Affected Systems, such as: MWD, IID, WAPA, APS…, etc to verify the conclusions and recommendations of this Phase II report. Depending on the outcome of such review, it may be necessary for the Interconnection Customer to enter into separate study agreements with the potentially affected system owner(s), at the cost of the Interconnection Customer, to analyze the impacts to the affected system(s). Any such analysis may identify additional upgrades on the affected system(s) for which mitigation would be the responsibility of the Interconnection Customer.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
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APPLICATION FOR CERTIFICATION FOR THE *BLYTHE SOLAR POWER PLANT PROJECT*

Docket No. 09-AFC-6

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(Revised 8/5/10)

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DECLARATION OF SERVICE

I, Rhea Moyer, declare that on August 6, 2010, I mailed hard copies of the attached Energy Commission Staff's Final Transmission System Engineering Analysis and Attachments, dated August 6, 2010. The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at:
[http://www.energy.ca.gov/sitingcases/solar_millennium_blythe]

The documents have been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

(*Check all that Apply*)

FOR SERVICE TO ALL OTHER PARTIES:

_X__ sent electronically to all email addresses on the Proof of Service list;

_____ by personal delivery;

_X__ by delivering on this date, for mailing with the United States Postal Service with first-class postage thereon fully prepaid, to the name and address of the person served, for mailing that same day in the ordinary course of business; that the envelope was sealed and placed for collection and mailing on that date to those addresses NOT marked "email preferred."

AND

FOR FILING WITH THE ENERGY COMMISSION:

_X__ sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below (*preferred method*);

OR

______ depositing in the mail an original and 12 paper copies, as follows:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 09-AFC-6
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.state.ca.us

I declare under penalty of perjury that the foregoing is true and correct.

______/s/ Rhea Moyer_______