Appendix A - Q #365

Solar Millennium, LLC

Palen Solar Power Plant Project

DOCKET	
09-AFC-7	
DATE	JUL 08 2010
RECD.	JUL 28 2010

Final Report

California ISO

Your Link to Power

July 08, 2010

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

Table of Contents

1. Executive Summary 1
2. Project and Interconnection Information 2
3. Study Assumptions 3
4. Power Flow Analysis 5
   - 4.1 Overloaded Transmission Facilities 5
   - 4.2 Power Flow Non-Convergence 5
   - 4.3 Recommended Mitigations 5
5. Short Circuit Analysis 6
   - 5.1 Short Circuit Study Input Data 6
   - 5.2 Results 6
   - 5.3 Preliminary Protection Requirements 7
6. Reactive Power Deficiency Analysis 7
7. Transient Stability Evaluation 7
   - 7.1 Transient Stability Study Scenarios 7
   - 7.2 Results 8
8. Deliverability Assessment 8
   - 8.1 On Peak Deliverability Assessment 8
   - 8.2 Off- Peak Deliverability Assessment 8
9. Operational Studies 8
   - 9.1 IC Proposed Project Timelines 8
   - 9.2 System Upgrade Timelines 8
   - 9.3 Conclusion 11
10. Environmental Evaluation/Permitting 12
11. Upgrades, Cost Estimates and Construction schedule estimates 12
12. Items not covered in this study 16

Attachments:

1. **Generator Machine Dynamic Data**
2. **Dynamic Stability Plots (see Appendix F)**
3. **SCE Interconnection Handbook**

4. **Short Circuit Calculation Study Results (see Appendix H)**
5. **Deliverability Assessment Results**
6. **Allocation of Network Upgrades for Cost Estimates**
7. **Results of Operational Studies (Removed)**

1. Executive Summary

Solar Millennium, LLC, an Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to the California Independent System Operator Corporation (CAISO) for their proposed Palen Solar Power Project (Project), interconnecting to the CAISO Controlled Grid. The Project is a solar plant using parabolic trough technology with an output of 500 MW to the primary Point of Interconnection (POI) which is at Southern California Edison Company's (SCE) proposed Red Bluff Substation in Desert Center, California. The IC has proposed a Commercial Operation Date of the Project of July 1, 2013.

In accordance with Federal Energy Regulatory Commission (FERC) approved Large Generator Interconnection Procedures (LGIP) for Interconnection Requests in a Queue Cluster Window (CAISO Appendix Y), the Project was grouped with Transition Cluster projects in a Phase II Interconnection Study to determine the impacts of the group as well as impacts of the Project on the CAISO Controlled Grid.

The group report has been prepared separately identifying the combined impacts of all projects in the group on the CAISO Controlled Grid. This individual report focuses only on the impacts associated with the Project.

The report provides the following:

1. Transmission system impacts caused by the Project;

2. System reinforcements necessary to mitigate the adverse impacts caused by the Project under various system conditions; and

3. A list of required facilities and a non-binding, good faith estimate of (a) the Project's cost responsibility, and (b) the time required to permit, engineer, design, procure and construct these facilities.

The Phase II Study results have determined that the Project contributes to overloading of transmission facilities for which mitigation plans have been proposed. A combination of congestion management for base case and contingency overloads, West-of-Devers Upgrades Project, looping the 2nd 500 kV T/L into the Red Bluff Substation, and the use of SPS under identified contingency outage conditions is required to mitigate the power flow impacts of the project described above. See the group report for additional details.

The non-binding costs to interconnect the Project are:

Interconnection Facilities[1] **$**[redacted] including ITCC[2];

Network Upgrades[3] **$**[redacted]

---

[1] The transmission facilities necessary to physically and electrically interconnect the Project to the CAISO Controlled Grid at the point of interconnection. These costs are not reimbursable.

[2] Income Tax Component of Contribution.

Distribution Upgrades[4] $[redacted]

The anticipated time to construct the facilities associated with the Project is approximately 84 months from the signing of the Large Generator Interconnection Agreement (LGIA). In addition there may be operational constraints related to the construction of upgrades to accommodate projects ahead in queue. See Section 9 "Operational Studies" for additional details.

2. Project and Interconnection Information

During the period between the Transition Cluster Phase I and Phase II technical analysis, the IC submitted a revised Appendix B to the CAISO LGIP which requested modifications to the Project's original plan. As a result of this request, SCE applied the following changes to the Project's depiction in the Transition Cluster Phase II Study.

Project Changes in Phase II Study:

1. Reduction in generation from 750 MW to 500 MW

Table 2-1 provides general information about the Project as modeled in the Phase II Study.

Table 2-1: Palen Solar Power Project General Information

Project Location	Desert Center, California
SCE Planning Area	Eastern Bulk System
Number and Type of Generators	2 [redacted] synchronous steam generator using parabolic trough field technology
Interconnection Voltage	220 kV
Maximum Generator Output	536.6 MW
Generator Auxiliary Load	36.6 MW (min.)
Maximum Net Output to Grid	500 MW
Power Factor Range	0.9 Lagging to 0.9 Leading
Step-up Transformer	Two three phase transformer rated for 220/18 kV 210/280/350 MVA with 8% impedance on a 210 MVA base
Point of Interconnection	Connect to the proposed Red Bluff 500/220 kV Substation
Commercial Operation Date	July 1, 2013 (customer requested date)

[3] 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.

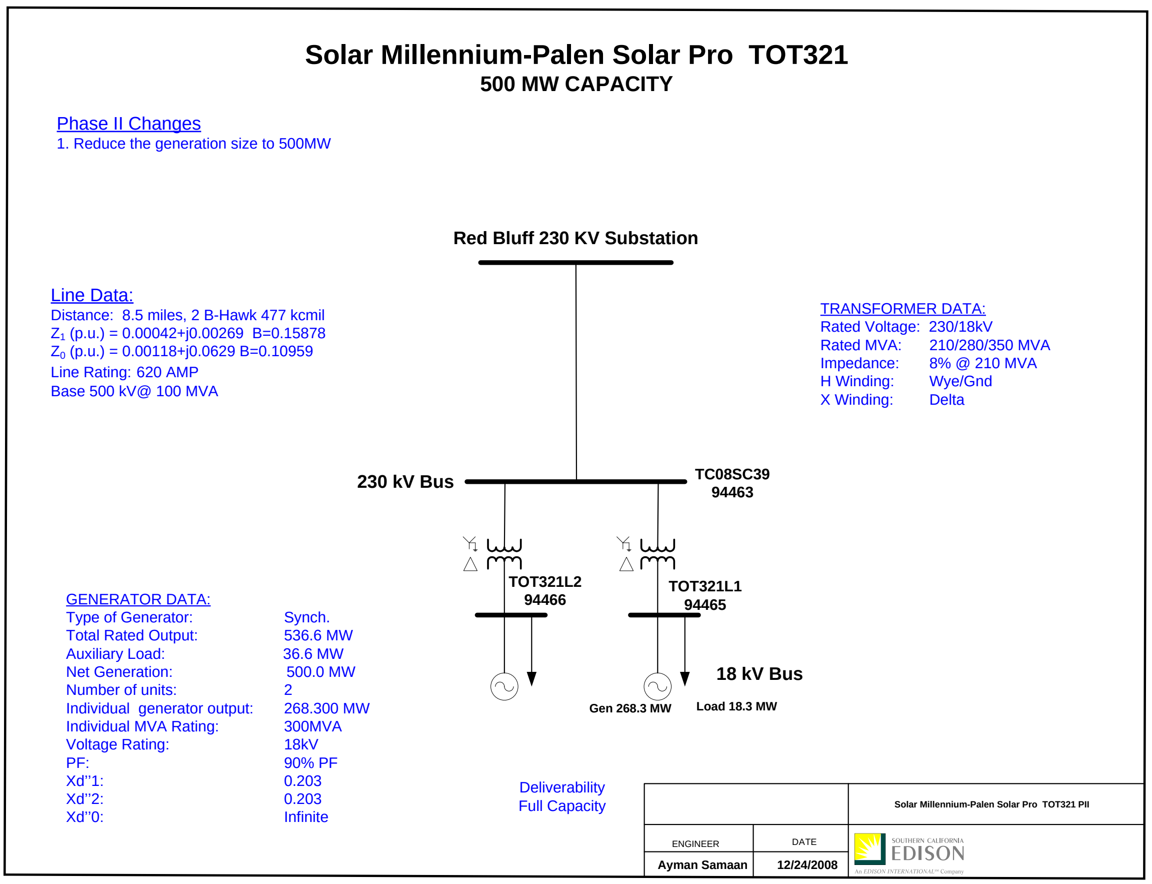
[4] These upgrades are not part of the CAISO tariff and are not reimbursable

Figure 2-1 provides the map for the Project and the transmission facilities in the vicinity. Figure 2-2 shows the conceptual single line diagram of the Project as modeled in the Phase II Study.

Figure 2-1 : Map of the Project

Photo Redacted for CEIII Purposes

Figure 2-2: Proposed Single Line Diagram as modeled in the Phase II Study



3. Study Assumptions

For details about the Transition Cluster interconnection information and the group study assumptions, including relevant changes between the Phase I and Phase II studies, see the group report Sections 2 and 4.

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.

The following design assumptions are applicable to the Project:

A. The following Facilities were estimated and included in the Phase II Study:

- o The second telecommunications path from the generating facility to the Red Bluff Substation will be installed by SCE.
- o All telecommunication terminal equipment at the end of the gen tie line (on the IC's side), which will interface with the generator-owned line protection relays and the special protection system (SPS) relays, will be installed by SCE.
- o It is assumed SCE would be required to install one additional dead-end Structure and a total of two spans of line to reach the station 220 kV switchyard.
- o The required revenue metering cabinet and retail load meters to be installed at the generating facility will be installed by SCE.
- o The required remote terminal unit (RTU) to be installed at the generating facility will be installed by SCE.

B**.** The following Facilities were not included in the Phase II Study:

- o The Project 220 kV gen tie line from the generating facility to the last structure outside the Red Bluff Substation property line will be installed by the generator.
- o The 220 kV gen tie line right of way should extend up to the edge of the Red Bluff Substation property line
- o The Project 220 kV gen tie line must be equipped with optical ground wire (OPGW) to provide the telecommunication path required for the line protection scheme and <u>one of the two</u> telecommunication paths required for the SPS.
- o The cost of the OPGW will be included in the cost of the gen tie line to be installed by the Generator.
- o All required CAISO metering equipment at the generating facility will be provided by the Generator.
- o All required revenue metering equipment to meter the generating facility retail load will be specified by SCE and installed by the Generator.
- o The following 220 kV gen tie line protection and SPS Relays to be installed at the generating facility will be specified by SCE and provided by the Generator:
    - One G.E. L90 current differential relay with telecommunication channel to Red Bluff Substation via the 220 kV gen tie line OPGW.
    - One SEL 311C current differential relay. No telecommunication channels required.
    - Two N60 relays (One each for SPS A and B) to trip the generator breakers.
    - One SEL – 2407 satellite synchronized clock.

4. Power Flow Analysis

The group study indicated that this project is contributing into overloading of the following transmission facilities. The details of the analysis and overload levels are provided in the group study.

4.1 Overloaded Transmission Facilities

Category "A"

- Devers-San Bernardino 220 kV No.1 and No.2 lines
- Devers-Vista 220 kV line No.1

Category "B"

- Devers-Vista 220 kV No.2 line
- Devers-San Bernardino 220 kV No.1 and No.2 lines
- Devers-Vista 220 kV line No.1

Category "C"

- Devers-Vista 220 kV No.2 line
- Devers-San Bernardino 220 kV No.1 and No.2 lines
- Devers-Vista 220 kV line No.1
- Mira Loma – Vista 220 kV No.2 line

4.2 Power Flow Non-Convergence

None

4.3 Recommended Mitigations

The Phase II Study results have determined that the Project contributes to overloading of transmission facilities for which mitigation plans have been proposed. A combination of congestion management for base case and contingency overloads, West-of-Devers Upgrades Project, looping the 2nd 500 kV T/L into the Red Bluff Substation, and the use of SPS under identified contingency outage conditions is required to mitigate the power flow impacts of the project described above. See the group report for additional details.

5. Short Circuit Analysis

Short circuit studies were performed to determine the fault duty impact of adding the Phase II Projects to the transmission system. The fault duties were calculated with and without the Projects to identify any equipment overstress conditions.

The cost responsibility of each individual project was determined based on the methodology applied in the Phase I Study once overstressed circuit breakers were identified. Costs of replacing and/or upgrading circuit breakers located within a Transition Cluster Group were allocated among all generation projects located within that Group. Costs of replacing and/or upgrading circuit breakers not located within a particular Transition Cluster Group were allocated over the entire Transition Cluster. Costs were allocated 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.

5.1 Short Circuit Study Input Data

The following input data provided by the IC was used in this study:

<u>Toshiba Synchronous Generator Short Circuit Data @ 500 MVA Base:</u>

Positive Sequence subtransient reactance (X''1)	= 0.203 p.u.
Negative Sequence subtransient reactance (X''2)	= 0.203 p.u.
Zero Sequence subtransient reactance (X''0)	= Infinite

<u>Station Step-up Transformer</u>

The transformer is a three-phase 230/18 kV rated for 210/280/350 MVA OA/FA/FA @ 55 degree C temperature rise with an impedance of 8% at 220 MVA base.

<u>Generation Tie Line</u>

The generation tie line assumed 8.5 miles of 2B-Hawk 477 kcmil conductor.

5.2 Results

All bus locations where the Phase II Projects increase 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 of the Group Report . These values have been used to determine if any equipment is overstressed as a result of the Phase II interconnections and corresponding network upgrades, if any. The Phase II breaker evaluation identified the following overstressed circuit breakers:

- Vincent 500 kV Substation: 500 kV CB962, CB862, CB852, CB812, CB912, CB 952, CB 722, CB 712, CB 752, CB762, and CB822
- Kramer 220 kV Substation: 220 kV CB4022, CB6022, CB6012, CB4082, and CB4102
- Windhub 220 kV Substation: 220 kV CB4102, CB4122, CB6102, CB6122, CB4122, CB4132, CB2132, CB6112, and CB6132
- Antelope 66 kV Substation: 66 kV CB21E and CB 21W

Based on the cost assignment methodology applied in the Phase II Study, the Project will have the assigned cost responsibility for mitigation of the short-circuit duty results described above. The total cost responsibility allocated to the Project is provided in Attachment 6.

5.3 Preliminary Protection Requirements

Protection requirements are designed and intended to protect SCE's system only. The preliminary protection requirements were based upon the interconnection plan as shown in Figure 2-2.

The applicant is responsible for the protection of its own system and equipment and must meet the requirements in the SCE Interconnection Handbook provided in Attachment 3.

6. Reactive Power Deficiency Analysis

Reactive power deficiency analysis was performed in the group study. The reactive power deficiency analysis included power flow sensitivity analysis in the eastern bulk system. The study found no reactive deficiency from this project to the SCE bulk system. For additional details, please see the group report.

7. Transient Stability Evaluation

Transient stability studies were conducted using the full loop base cases to ensure that the transmission system remains in operating equilibrium, as well as operating in a coordinated fashion, through abnormal operating conditions after the Phase II projects begin operation. The generator dynamic data used in the study for the Project is shown in Attachment 1.

7.1 Transient Stability Study Scenarios

Disturbance simulations were performed for a study period of 10 seconds to determine whether the Phase II projects will create any system instability during a variety of line and generator outages. 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.

For the list of specific line and generator outages evaluated, see the group report.

7.2 Results

Stability analysis was performed for the Eastern Bulk systems to identify the stability impacts of this Phase II queued generation project.

In the stability analysis performed in the 500 kV, 220 kV and 115 kV systems with the upgrades in place to mitigate base case and outage related overload problems, system instability was identified from the worse Category "C" outage. A proposed SPS to trip up to 1400 MW Phase II project capacity including tripping this project mitigated the system impact. Stability plots are shown in Appendix F of the group report.

8. Deliverability Assessment

8.1 On Peak Deliverability Assessment

CAISO performed a 2013 On-Peak Deliverability Assessment. The detail on-peak deliverability assessment results can be found in the group report.

8.2 Off- Peak Deliverability Assessment

There is no off-peak deliverability assessment 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.

9. Operational Studies

9.1 IC Proposed Project Timelines

The latest information provided by the IC has indicated that the proposed date for the generator step-up transformer to receive back feed power is April 1, 2013 and the proposed Commercial Operation Date for the entire 500 MW project is July 1, 2013. Due to the modular nature of the solar facilities, the IC has indicated that construction of this project will commence on November 1, 2010 with the initial block to be ready for testing on May 1, 2013.

9.2 System Upgrade Timelines

The Project involves the installation of the following interconnection facilities:

1. A dead end structure and a shared breaker and half position at the planned Red Bluff 220 kV substation to bring in the Project generation tie line;
2. An RTU at the Project Facility; and

3. The installation of telecommunications equipment to provide diverse protection and data transfer capability to the RTU, and SCADA data recording equipment.

The anticipated time to construct these interconnection facilities is 24 months upon execution of LGIA. However, start of construction of such Interconnection Facilities cannot commence until SCE receives all appropriate regulatory approvals and necessary licenses for the expansion of the new proposed Red Bluff Substation, and required telecommunication facilities to support an initial “Energy Only” Interconnection.

This 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.

The circuit breaker upgrades that were triggered by queued-ahead projects are identified in Section 4.6 of the group report. The Operational Study undertaken as part of this Phase II Study identified the required timing for circuit breaker upgrades triggered by queued-ahead generation projects. The Table below identifies the first year that circuit breaker upgrades triggered by queued-ahead projects were found to be required in this Operational Study at each substation location.

Table 9-1: Circuit Breaker Upgrades Triggered by Queued-ahead Projects

Year	Location
2010	Devers 115 kV Ellis 66 kV Etiwanda 220 kV Inyokern 115 kV Vincent 220 kV Antelope 66 kV Neenach 66 kV
2011	Terawind 115 kV
2012	Mira Loma 220 kV Villa Park 220 kV
2013	Antelope 220 kV Chino 220 kV Devers 220 kV Lugo 500 kV Mesa 220 kV Vincent 500 kV

2014	Mira Loma 500 kV Vincent 220 kV
2015	None
2016	None

This Phase II Study assumed that the timelines for construction of the upgrades listed in Table 9-1 to accommodate queued-ahead projects will also be sufficient to accommodate the operational requirements for the Transition Cluster projects. In the event that the Transition Cluster projects will need to accelerate these upgrades, the projects will need to do so via a separate agreement. Operational studies will be conducted on an annual basis or more frequently as needed to identify such requirements.

The circuit breaker upgrades that were triggered by Transition Cluster projects are identified in Section 8.2 of the group report. The Operational Study undertaken as part of this Phase II Study identified the required timing for circuit breaker upgrades triggered by Transition Cluster projects. The Table below identifies the first year that circuit breaker upgrades triggered by Transition Cluster projects were found to be required in this Operational Study at each substation location.

Table 9-2: Circuit Breaker Upgrades Triggered by Transition Cluster Projects

Year	Location
2013	Antelope 66 kV
2014	None
2015	Vincent 500 kV Windhub 220 kV
2016	Kramer 220 kV

9.2.1 Reliability Network Upgrade Timelines

To balance power flow on the Colorado River – RedBluff – Devers 500 kV line and the Colorado River – Devers 500 kV line, the Phase II Study identified that the inclusion of all the Eastern area projects located within the Blythe area and the Desert Center area Project will require looping of the second Colorado River – Devers 500kV No.2 T/L into the Red Bluff Substation. The anticipated time to construct this reliability network upgrade is 36 months upon execution of LGIA. The new proposed Red Bluff Substation is triggered by queued ahead serial interconnection project. The anticipated time to construct the Red Bluff Substation is 36 months from the execution of the LGIA by the queued ahead Serial project.

The Phase II Study identified that the inclusion of all Eastern area Projects located within the Desert Center area triggered the need to equip a position at SCE-owned Red Bluff 220 kV switchyard. The anticipated time to construct this reliability network upgrade is 24 months upon execution of LGIA. It is important to note that the start of construction of such reliability network upgrades cannot commence until SCE receives all appropriate permitting approvals and licenses for the new proposed Red Bluff substation and the looping-in of Devers-Colorado River (DCR) to Red Bluff Substation.

The Phase II Study identified that the inclusion of all Eastern area Projects triggered the need for upgrading the Mira Loma – Vista No.2 220kV T/L drops at Vista Substation to mitigate the overload under certain 220kV outages. The anticipated time to construct this reliability network upgrade is 12 months upon execution of LGIA.

Lastly, to maintain system reliability the Phase II Study identified that the inclusion of all Eastern area projects located within the Blythe area and the Desert Center area triggered the need for a new SPS to address impacts on the SCE system under certain 500 kV outages. The anticipated time to construct this reliability network upgrade is 24 months upon execution of LGIA. This Project will be added to this new SPS once the Project is placed into service.

9.2.2 Delivery Network Upgrade Timelines

To provide the requested Full Delivery, the Phase II identified the need for significant Delivery Network Upgrades. Specifically, the project has been identified to contribute to the need for upgrades four 220kV T/L in the West of Devers area to mitigate the base case overload. The anticipated time to construct all of these Delivery Network Upgrades associated with "Full Delivery" Interconnection is 84 months upon execution of LGIA.

9.2.3 Distribution Upgrade Timelines

The Phase II Study concluded that the Project was not allocated any Distribution Upgrades.

9.3 Conclusion

Based on information available at this time, assuming an anticipated LGIA execution date of September 2010, there are potential operational constraints to the Project associated with base case congestion exposure under an interim "Energy Only" Interconnection.

The current schedule for the Network Reliability Upgrades indicate a 36-month time duration to construct the SCE-owned Red Bluff 220 kV switchyard with one new SCE-owned 500/220 kV transformer bank and the Red Bluff 500 kV switchyard after execution of the LGIA with the triggering queued ahead generation project. This schedule appears to suggest that the facilities needed to interconnect the Project, under an initial "Energy Only" arrangement, can be constructed by the requested transformer back feed date of April 1, 2013, provided that Red Bluff Substation is constructed to interconnect Serial queued ahead projects.

The project interim Energy only status would remain until all the Delivery Network Upgrades are constructed. Based on the current schedules, this condition could exist for up to 84 months, and possibly longer depending on actual permitting and construction timelines of the Delivery Network Upgrades.

These conclusions are based on the estimated time for engineering, licensing, procurement, and construction of a typical project. Schedule durations may change due to the number of projects approved and release dates to construct the project. The ability to meet the IC proposed operating date is subject to constraints such as resource availability, system outage availability, and environmental windows of construction.

10. Environmental Evaluation/Permitting

Please see Section 12 of group report.

11. Upgrades, Cost Estimates and Construction schedule estimates

To determine the cost responsibility of each generation project in Phase II Study, the CAISO developed cost allocation factors based on the individual contribution of each project (Attachment 6). The cost allocation for the Interconnection Facilities and Network Upgrades for which the Project is solely responsible is as follows:

PTO'S INTERCONNECTION FACILITIES

1. Transmission:

The Project 220 kV Gen Tie Line
Install one 220 kV dead-end structure, two spans of conductors and OPGW and twelve dead end insulator / hardware assemblies between the last Generator owned structure and the Substation dead – end rack at the 220 kV switchyard.

2. Substations:

Red Bluff 500/220 kV Substation
Install the following Interconnection facilities components to terminate the new 220 kV gen tie line at a shared breaker and a half position.

- Two dead-end structures (60 ft. high x 50 ft. wide)
- Three 220 kV coupling capacitor voltage transformers
- One 220 kV gen tie line isolating motorized disconnect switch
- One G.E. L90 current differential relay with telecommunications channel to the generating facility via the 220 kV gen tie line OPGW.
- One SEL 311C current differential relay. No telecommunication

channels required.

3. **Metering Services Organization**
   Install a Revenue Metering Cabinet and Revenue Meters required to meter the Retail load at the Generating Facility.
   The Generator will provide the required Metering Equipment (Voltage and Current Transformers).

4. **Power System Control**
   Install one RTU at the generating facility to monitor the typical generation elements such as MW, MVAR, terminal Voltage and Circuit Breaker Status at each Generating Unit and the Plant Auxiliary Load and transmit this information to the SCE Grid Control Center.

5. **Telecommunications**
   Install approximately 8.2 Miles of new All Dielectric Self Supported (ADSS) Fiber Optic Cable from the Red Bluff Substation to the generating facility to meet the diverse routing requirements for the SPS relays.

   Also install all required light-wave, channel and related terminal equipment at each end of the gen tie line.

6. **Real Properties, Transmission Project Licensing, and Environmental Health and Safety**
   Obtain easements and / or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of the 8.2 miles of telecommunication and the SCE portion of the Project gen tie line and telecommunication route.

PLAN OF SERVICE RELIABILITY NETWORK UPGRADES

Red Bluff 500/220 kV Substation
Install the following additional equipment for a shared 220 kV Line / Bank Position on a Breaker-and-a-Half Configuration to terminate the Project No.1 220 kV Gen Tie Line at an existing Bank Position:

- One 220 kV 3000 A – 50 kA Circuit Breakers
- Two 220 kV 3000 A – 80 kA Horizontal-Mounted Group-Operated Disconnect Switches
- One Grounding Switch Attachment
- 2-1590 KCMIL ACSR Conductors
- One GE C60 Breaker Management Relays inside existing Control Room
- Also remove 220 kV Bus Supports with associated steel pedestals

Power System Control

Expand the existing RTU to install additional points required for the Queue #365 No.1 and No.2 220 kV gen tie line positions.

RELIABILITY NETWORK UPGRADES

Below is a list of Reliability Network Upgrades with costs that have been allocated to the Project. See group report section 11 for scope details.

- Loop the 2nd 500 kV line between Red Bluff Sub and Colorado River Sub into the Red Bluff 500/220 kV Substation
- Replace Line Drops on Mira Loma – Vista 220 kV No.2 T/L at Vista Substation
- Develop a SPS for N-2 of Devers-Red Bluff 500 kV lines

DELIVERY NETWORK UPGRADES

Below is a list of Delivery Network Upgrades with costs that have been allocated to the Project. See group report section 11 for scope details:

- West of Devers 220 kV Line Upgrade Project
- Colorado River Substation Expansion - No.2 AA Bank

DISTRIBUTION UPGRADES

None

Table 11.1: Upgrades, Estimated Costs, and Estimated Time to Construct Summary

Type of Upgrade	Upgrade (May include the following)	Description	Estimated Cost x 1000	Estimated Time to Construct *(Note 3)*
PTO's Interconnection Facilities *(Note 1)*	Transmission, Substations, Metering Services Organization, Power System Control, Telecommunications, Real Properties, Transmission Projects Licensing, and Environmental Health and Safety	Non-network facilities needed to enable interconnection	[redacted]	24 Months
Plan of Service Reliability Network Upgrades	Substation, Power System Control	Direct Assigned Network upgrades needed to enable interconnection.	[redacted]	24 Months
Reliability Network Upgrades	Transmission, Substations, Metering Services Organization, Power System Control, Telecommunications, Real Properties, Transmission Projects Licensing, and Environmental Health and Safety	Allocated Network upgrades needed to maintain system Reliability	[redacted]	36 Months
Delivery Network Upgrades	Transmission, Substations, Metering Services Organization, Power System Control, Telecommunications, Real Properties, Transmission Projects Licensing, and Environmental Health and Safety	Network upgrades needed to support Full Delivery, if requested	[redacted]	84 Months
Distribution Upgrades *(Note 2)*	None	Non-CAISO SCE Distribution Facilities	[redacted]	N/A
Total			[redacted]	**84 Months**

Note 1: The Interconnection Customer is obligated to fund these upgrades and will not be reimbursed.

Note 2: These upgrades are not identified in ISO tariff, and are not reimbursable.

Note 3: The estimated time to construct (ETC) is for a typical project; schedules duration may change due to number of projects approved and release dates. Stacked projects impact resources, system outage availability, and environmental windows of construction. Assumption is SCE will need to obtain CPUC licensing and regulatory approvals prior to design, procurement and construction of the proposed facilities required to serve the interconnection customer and prerequisite facilities are in service.

12. Items not covered in this study

12.1 Plan of Service

The Plan of Service developed for the Project is based on the data submittals provided for each specific project in the cluster group and will serve as the basis for developing the LGIA and for permitting purposes. However, the final Plan of Service is subject to change based upon completion of preliminary and final engineering, identification of field conditions, and compliance with applicable environmental and permitting requirements.

12.2 Customer's Technical Data

The study accuracy and results for the Phase II Study are contingent upon the accuracy of the technical data provided by the Interconnection Customer. Any changes from the data provided could void the study results.

12.3 Study Impacts on Neighboring Utilities

Results or consequences of this Phase II Interconnection Study may require additional studies, facility additions, and/or operating procedures to address impacts to neighboring utilities and/or regional forums. For example, impacts may include but are not limited to WECC Path Ratings, short circuit duties outside of the CAISO Controlled Grid, and sub-synchronous resonance (SSR).

12.4 Relocations and Other Use of SCE Facilities

The Interconnection Customer is responsible for all costs associated with necessary relocation of any SCE facilities as a result of this project and acquiring all property rights necessary for the Interconnection Customer's Interconnection Facilities, including those required to cross SCE facilities and property. The relocation of SCE facilities or use of SCE property rights shall only be permitted upon written agreement between SCE and the Interconnection Customer. Any proposed relocation of SCE facilities or use of SCE property rights may require a separate study and/or evaluation to determine whether such use may be accommodated, and any associated cost would be non-refundable.

12.5 SCE Interconnection Handbook

The Interconnection Customer shall be required to adhere to all applicable requirements in the SCE Interconnection Handbook. These include, but are not limited to, all applicable protection, voltage regulation, VAR correction, harmonics, switching and tagging, and metering requirements.

12.6 Western Electricity Coordinating Council (WECC) Policies

The Interconnection Customer shall be required to adhere to all applicable WECC policies including, but not limited to, the WECC Generating Unit Model Validation Policy.

12.7 System Protection Coordination

Adequate Protection coordination will be required between SCE-owned protection and Interconnection Customer-owned protection. If adequate protection coordination cannot be achieved, then modifications to the Interconnection Customer-owned facilities (i.e., Generation-tie or Substation modifications) may be required to allow for ample protection coordination

12.8 Standby Power and Temporary Construction Power

The Phase II Study does not address any requirements for standby power or temporary construction power that the Project may require prior to the in-service date of the interconnection facilities. Should the Project require standby power or temporary construction power from SCE prior to the in-service date of the interconnection facilities, the IC is responsible to make appropriate arrangements with SCE to receive and pay for such retail service.

12.9 Construction Schedule

The estimated time to construct (ETC) is for a typical project; schedules duration may change due to number of projects approved and release dates. Stacked projects impact resources, system outage availability, and environmental windows of construction. Assumption is SCE will need to obtain CPUC licensing and regulatory approvals prior to design, procurement and construction of the proposed facilities required to serve the interconnection customer and prerequisite facilities are in service.

12.10 Telecommunication Assumptions

The cost for telecommunication facilities that were identified as part of the IC's Interconnection Facilities was based on an assumption that these facilities would be sited, licensed, and constructed by SCE as opposed to the IC doing this work. In addition, the telecommunication requirements for SPS were assumed based on tripping of the generator breaker as opposed to tripping the circuit breakers at the SCE substation. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

Attachment 1

Generator Machine Dynamic Data

#TOT321 500 MW connected to Red Bluff 220kV bus
genrou 94465 "TOT321L1" 18.00 " 1" : #9 mva=300.0000 "tpdo" 6.8000 "tppdo" 0.0240 "tpqo" 1.4000 "tppqo" 0.0400 "h" 3.5230 "d" 0.0000 "ld" 1.8600 "lq" 1.8200 "lpd" 0.2600 "lpq" 0.4060 "lppd" 0.2030 "ll" 0.1750 "s1" 0.1650 "s12" 0.6070 "ra" 0.00089 "rcomp" 0.0000 "xcomp" 0.0000 "accel" 0.0000
ieeeg1 94465 "TOT321L1" 18.00 " 1" : #9 mwcap=300.0000 "k" 20.0000 "t1" 0.0000 "t2" 0.0000 "t3" 0.1500 "uo" 0.500000 "uc" -1.000000 "pmax" 1.1000 "pmin" 0.050000 "t4" 0.4270 "k1" 0.30 "k2" 0.0 "t5" 10.000 "k3" 0.23 "k4" 0.0 "t6" 0.9970 "k5" 0.47 "k6" 0.0 "t7" 0.0 "k7" 0.0 "k8" 0.0 "db1" 0.06 "eps" 0.0 "db2" 1.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0
genrou 94466 "TOT321L2" 18.00 " 1" : #9 mva=300.0000 "tpdo" 6.8000 "tppdo" 0.0240 "tpqo" 1.4000 "tppqo" 0.0400 "h" 3.5230 "d" 0.0000 "ld" 1.8600 "lq" 1.8200 "lpd" 0.2600 "lpq" 0.4060 "lppd" 0.2030 "ll" 0.1750 "s1" 0.1650 "s12" 0.6070 "ra" 0.00089 "rcomp" 0.0000 "xcomp" 0.0000 "accel" 0.0000
ieeeg1 94466 "TOT321L2" 18.00 " 1" : #9 mwcap=300.0000 "k" 20.0000 "t1" 0.0000 "t2" 0.0000 "t3" 0.1500 "uo" 0.500000 "uc" -1.000000 "pmax" 1.1000 "pmin" 0.050000 "t4" 0.4270 "k1" 0.30 "k2" 0.0 "t5" 10.000 "k3" 0.23 "k4" 0.0 "t6" 0.9970 "k5" 0.47 "k6" 0.0 "t7" 0.0 "k7" 0.0 "k8" 0.0 "db1" 0.06 "eps" 0.0 "db2" 1.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0

Attachment 2

Dynamic Stability Plots

Attachment 3

SCE Interconnection Handbook

Attachment 4

Short Circuit Calculation Study Results

Attachment 5

Deliverability Assessment Results

The deliverability assessment results can be found in the Transition Cluster Phase II group report for the Eastern Bulk system.

Attachment 6

Allocation of Network Upgrades for Cost Estimates

Type	Upgrades	Needed For	Cost factor	Cost Share ($1000)
Delivery	West of Devers 220kV upgrades: Reconductoring four 230kV lines of West of Devers.	Normal and contingency overload.	27.40%	[redacted]
Reliability	Loop-in the Red Bluff (RB) 500/220 kV Substation into the Colorado - Devers 500 kV #2 line	To balance power flow on DPV 1 and DPV 2 lines	23.26%	[redacted]
Reliability	Replace the line raiser on Mira Loma – Vista 220 kV #2 line to 3500amps or higher	Emergency overload in off-peak reliability study	22.73%	[redacted]
Reliability	Develop a SPS to trip 1400MW TC2 generation to mitigate dynamic voltage violations under the N-2 of Devers – RedBluff No.1 and No.2 500 kV lines.	Dynamic voltage violation under N-2 contingency	23.26%	[redacted]
Plan of Service Reliability Network Upgrade	Substation, Power System Control	Direct Assigned Network upgrades needed to enable interconnection.	100.00%	[redacted]
			Total:	[redacted]

Attachment 7

Results of Operational Studies