Appendix A – WDAT930

[redacted]

Queue Cluster 5 Phase I Report

January 30, 2013

This study has been completed in coordination with the California Independent System Operator (CAISO) per CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

Table of Contents

Attachments:

1. Allocation of Network Upgrades for Cost Estimates
2. Not Used
3. Interconnection Handbook
4. Short Circuit Calculation Study Results (see Appendix H of the group report)
5. Not Used
6. Not Used
7. SCE Northern Hemisphere Import Nomogram

A. Executive Summary

[redacted] an Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to the Southern California Edison Company (SCE) for their proposed [redacted] (Project), under the terms of SCE's Wholesale Distribution Access Tariff (WDAT). The Project is a Full Capacity Deliverability Status, Solar Photovoltaic (PV) Plant with a total rated output of 20.0 MW to the proposed Point of Interconnection (POI) on SCE's Baroid 33 kV Circuit out of Gale 115/33 kV Substation. The generated power would be delivered to the California Independent System Operator (CAISO) grid at the 115 kV bus of SCE's Cool Water Substation, in San Bernardino County, California. The customer has requested an In-Service Date of December 1, 2013 and a Commercial Operation Date of [redacted]

In accordance with Federal Energy Regulatory Commission (FERC) approved Generation Interconnection and Deliverability Allocation Procedures (GIDAP) (CAISO Tariff Appendix DD), the Project was grouped with Queue Cluster 5 Phase I (QC5) study projects 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 report focuses only on the impacts of this Project.

The report provides the following:

1. Transmission and Distribution system impacts caused by the Project;
2. System reinforcements necessary to mitigate the adverse impacts caused by the Project under various system conditions;
3. A list of required facilities and a good faith estimate of the Project's cost responsibility and time required to bring these facilities into service.

The QC5 study has determined that the Project contributes to various reliability and/or deliverability problems for which mitigation plans have been proposed. These mitigation plans are detailed in Section C of this report. The cost responsibility and estimated time to construct the facilities required for the Project are summarized below.

The good faith cost estimates of Interconnection Facilities[1] (IF) and Distribution Upgrades[2] to interconnect the Project are:

Interconnection Facilities	$2,254,000
ITCC for Interconnection Facilities	$789,000
Distribution Upgrades to support interconnection	$877,000
ITCC for Distribution Upgrades to support interconnection	$307,000

The non-binding cost estimate of Interconnection Facilities (IF) and Distribution Upgrades to interconnect the Project is approximately $3,043,000 and $1,184,000 respectively, including ITCC[3].

[1] The electrical facilities installed and maintained by SCE necessary to physically and electrically interconnect the Project to the SCE Distribution system from the point of change in ownership to the point of interconnection, and are not reimbursable.
[2] These upgrades are not part of the CAISO Controlled Grid, and are not reimbursable.
[3] Income Tax Component of Contribution. The ITCC included in this cost estimate was computed using a 35% rate.

The good faith cost estimate for the allocated Reliability Network Upgrades[4] (RNUs) necessary to interconnect the project is $391,000.

There were no Local Delivery Network Upgrades[5] (LDNUs) identified or allocated in this Phase I study in order to provide the Full Capacity Deliverability Status requested in the interconnection request.

The good faith estimated cost for Area Delivery Network Upgrades[6,7] (ADNUs) is $15,386,000. The good faith estimated cost for Distribution Upgrades needed to support the ADNUs is $151,000.

The non-binding estimated time to interconnect the project and construct[8] the facilities corresponding with the mitigation plans associated to the Project is as follows:

Facility Type	Duration (Months)
Interconnection Facilities	12
Distribution Upgrades to support interconnection	24
Reliability Network Upgrades	24
Local Delivery Network Upgrades	NA
Area Delivery Network Upgrades	115
Distribution Upgrades to support ADNU	109

These durations are from the execution of the Generator Interconnection Agreement, receipt of: all required information, funding, and written authorization to proceed from the IC as will be specified in the Generator Interconnection Agreement to commence the work. Note, interconnection of this project in advance of the upgrades identified will necessitate telecommunication whose scope is currently being defined for licensing. As such, this project will have to wait until the telecommunications is placed into service.

B. Project and Interconnection Information

The Project's general information, as stated in the IR provided by the IC, and Interconnection Facilities are illustrated below in Table B.1, Figure B.1 provides the map for the Project and the transmission facilities in the vicinity, and Figure B.2 shows the conceptual single line diagram of the Project as modeled in the study.

[4] The SCE transmission facilities, other than Interconnection Facilities, at or beyond the point of interconnection necessary to physically and electrically interconnect the Project, needed to maintain system integrity and reliability.

[5] The SCE transmission facilities, other than Interconnection Facilities, at or beyond the point of interconnection necessary to physically and electrically interconnect the Project, and are network upgrades built to address local deliverability constraints for projects that request Full or Partial Capacity Deliverability Status.

[6] The SCE transmission facilities, other than Interconnection Facilities, at or beyond the point of interconnection necessary to physically and electrically interconnect the Project, and are network upgrades built to address area deliverability constraints for projects that request Full or Partial Capacity Deliverability Status.

[7] The CAISO developed the $/MW cost rate for Incremental Area Delivery Network Upgrades. The cost rate multiplied by the requested deliverable MW capacity provides the cost estimate for the Area Delivery Network Upgrades

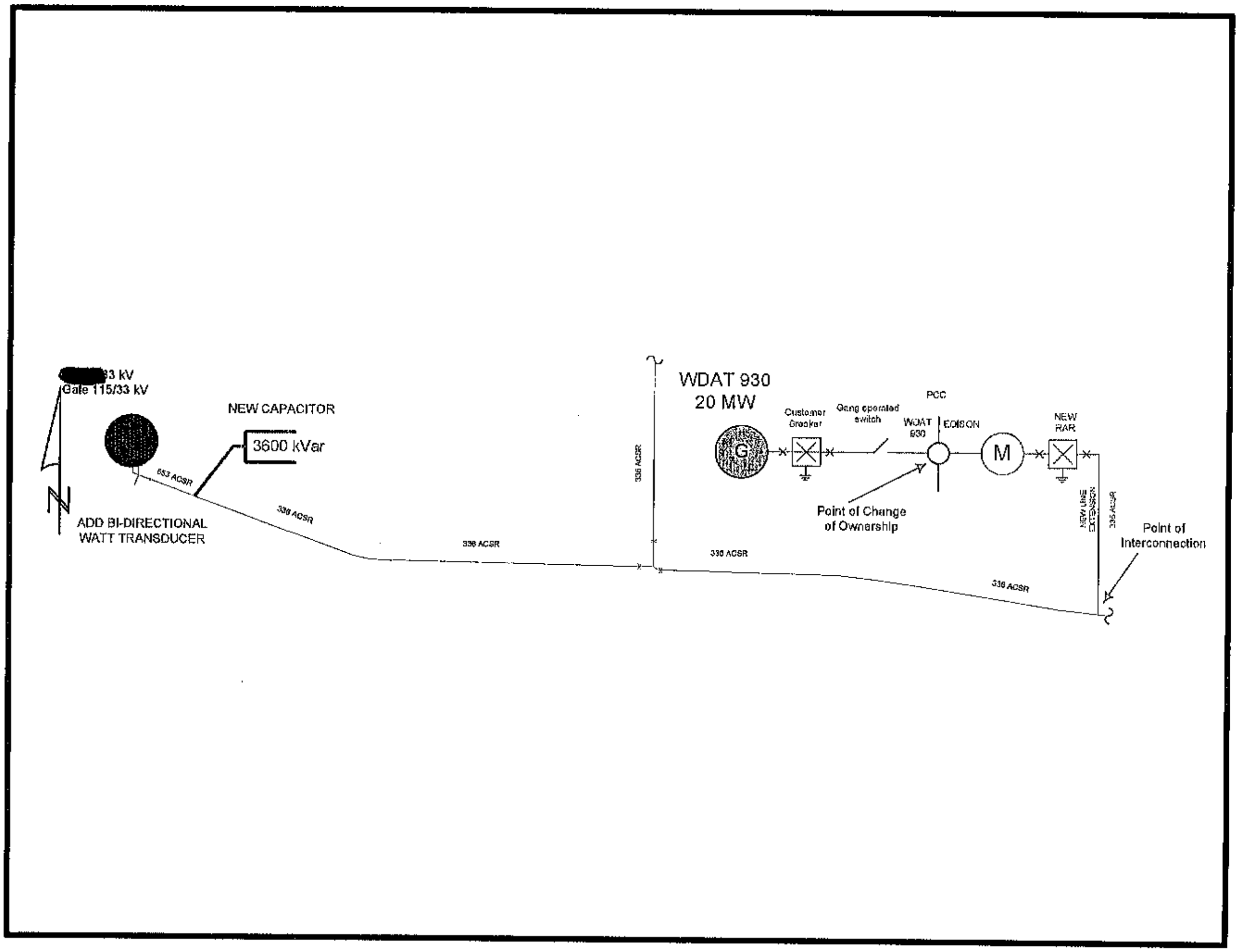
[8] Construction is only part of the duration of months scheduled in the study, includes final engineering, licensing, etc. and other activities required to bring such facilities into service

Table B.1: Project General Information

Project Location	[redacted] **San Bernardino County**
Participating TO's Planning Area	SCE East of Lugo System
Number and Type of Generators	[redacted]
Interconnection Voltage	33 kV
Maximum Generator Output	20.0 MW
Generator Auxiliary Load	0 MW
Maximum Net Output to Grid	20.0 MW
Power Factor Range	Lead 0.90 / Lag 0.90
Step-up Transformer(s)	**Padmount Transformers (20):** 33/0.270 (Y-Y), 1 MVA H-X Impedance Value: 6 % @ 1 MVA
Point of Interconnection	Baroid 33 kV out of Gale 115/33 kV Substation
Interconnection Customer Requested Commercial Operation Date	[redacted]

Figure B.1: Map of the Project

Figure B.2: Proposed Single Line Diagram



C. *Interconnection Facilities, Network Upgrades, and Distribution Upgrades*

To determine the cost responsibility of each generation project in QC5, the CAISO developed cost allocation factors (Attachment 1) for Reliability Network Upgrades and Local Delivery Network Upgrades. The CAISO developed the $/MW cost rate for incremental Area Delivery Network Upgrades. The cost rate multiplied by the requested deliverable MW capacity provides the cost estimate for the Area Delivery Network Upgrades. The Interconnection Facilities are the sole cost responsibility of the Project. The Interconnection Facilities and Network Upgrades are listed below:

DISTRIBUTION PROVIDERS INTERCONNECTION FACILITIES

1. **Distribution**
   - Install 7,700 ft. line extension from [redacted]33 kV to customer breaker.
   - Install 33 kV pole top metering and overhead breaker.
   - Install telecommunications circuit and associated RTU with PSC support for telemetry.

2. **Telecommunications**

   Install all required equipment (including terminal equipment) supporting the RTU including the communications interface with the Distribution Provider's energy management system. In accordance with the Interconnection Handbook, the Distribution Provider shall provide the required interface equipment at the Generating Facility necessary to connect the RTU to the Interconnecting Customer's T1 circuit if an RTU is installed locally at the Generating Facility. Notwithstanding that certain telecommunication equipment, including the telecommunications terminal equipment, will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain such telecommunication equipment as part of the Distribution Provider's Interconnection Facilities if an RTU is installed locally at the Generating Facility.

   Also install all required lightwave, channel and related terminal equipment at each end of both FO paths to interface with the required Line Protection Relays and RTU.

3. **Metering Services Organization**

   Install revenue meters, potential and current transformers, and appurtenant equipment required to meter the retail load at the Generating Facility. Notwithstanding that the meters and appurtenant equipment will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider will own, operate and maintain such facilities as part of the Distribution Provider's Interconnection Facilities.

4. **Power System Controls**

   Install one (1) RTU at the Generating Facility to monitor typical generation elements such as MW, MVAR, terminal voltage and circuit breaker status for the Generating Facility and plant auxiliary load, and transmit the information received thereby to the Distribution Provider's Grid Control Center if an RTU is installed locally at the Generating Facility. Notwithstanding that the RTU will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider will own, operate and maintain the RTU as part of the Distribution Provider's Interconnection Facilities if an RTU is installed locally at the Generating Facility.

5. **Real Properties, Transmission Project Licensing, and Corporate Environmental Services**

   Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities, as necessary, for the installation of the Distribution Provider's Interconnection Facilities.

PLAN OF SERVICE DISTRIBUTION UPGRADES

No Plan of Service Distribution Upgrades were allocated to the Project as part of this QC5 Phase I study for Project.

RELIABILITY NETWORK UPGRADES (RNU)

1. **Modify Mojave Desert (Water Valley) SPS**
2. **Modify proposed Jasper SPS**
3. **Modify High Desert Power Plant SPS**

See group report Section K for details.

LOCAL DELIVERY NETWORK UPGRADES (LDNU)

No Local Delivery Network Upgrades were identified as part of this QC5 Phase I study for Project.

AREA DELIVERY NETWORK UPGRADES (ADNU) AND ASSOCIATED DISTRIBUTION UPGRADES USED TO DERIVE DOLLAR-PER-MW VALUE

1. **Kramer 500 kV expansion, Llano 500 kV Switching Station, Kramer-Llano 500 kV T/L, Looping Lugo-Vincent No.2 500 kV T/L into Llano.**
2. **Distribution Upgrades to support the Kramer 500 kV Substation expansion**
3. **East of Pisgah Area Delivery Network Upgrade(s) allocated to Project**
   - **Expand SCE Pisgah 220 kV Substation to 500 kV and Loop Eldorado-Lugo 500 kV T/L into Pisgah 500 kV Substation.**
   - **New Eldorado – Pisgah (Presently Eldorado – Lugo) 500 kV T/L series capacitor**

See group report Section K for details.

DISTRIBUTION UPGRADES

1. **Distribution:**
   - Install one (1) new 33 kV capacitor bank
2. **Substation:**
   - Add 3-phase bi-directional Watt transducer on the Baroid 33 kV line position at Gale Substation.

<u>NOTE:</u> The Distribution Upgrades to support the Kramer 500 kV Substation expansion are addressed in the ADNU scope and cost tables.

D. Cost and Construction Duration Estimates

To determine the cost responsibility of each generation project in QC5, the CAISO developed cost allocation factors (Attachment 1) for Reliability Network Upgrades and Local Delivery Network Upgrades. The CAISO developed the $/MW cost rate for incremental Area Delivery Network Upgrades. The cost rate multiplied by the requested deliverable MW capacity provides the cost estimate for the Area Delivery Network Upgrades. Table D.1 below provides the 'constant' 2012 dollars and their escalation to the estimated operating date year for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades which the Project was allocated cost. For the QC5 study, the estimated O.D. is derived by assuming the duration of the work element will begin in March 2014, which is the CAISO tariff scheduled completion date of the QC5 Phase II study plus 90 days for the interconnection agreement signing period.

Table D.1: Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades

Element	Interconnection Facilities Costs x 1,000 Constant Dollar (2012)	Reliability Network Upgrades Costs x 1,000 Constant Dollar (2012)	Delivery Network Upgrades Costs x 1,000 Constant Dollar (2012)	Distribution Upgrades Costs x 1,000 Constant Dollar (2012)	One Time Costs x 1,000 Constant Dollar (2012)	Total Estimated Costs w/o ITCC x 1,000 Constant Dollar (2012)	Total Estimated Costs w/o ITCC x 1,000 Escalated Constant Dollar (OD Year)	ITCC x 1,000 Constant Dollar (2012)	Total Estimated Costs w ITCC x 1,000 Constant Dollar (2012)	Total Estimated Costs w ITCC x 1,000 Escalated Constant Dollar (OD Year)	Estimated Time to Construct (Note 3 & 4)
DP's Interconnection Facilities (Note 1)											
7,700 Line extension to customer breaker, pole top metering and new overhead breaker	$1,379							$483			
Telecommunications	$64							$22			
Power System Controls – Generating Facility	$93							$33			
Corporate Environmental Services	$718							$251			
Subtotal	**$2,254**					**$2,254**	**$2,372**	**$789**	**$3,043**	**$3,203**	**12**
Distribution Upgrades (Note 2)											
Add 33 kV cap bank				$563				$197			
Install PTs at sub to set relay directional				$202				$71			
Install a 3-phaseBi – Directional Watt transducer on the Baroid 33 kV line				$54				$19			
Corporate Environmental Services				$58				$20			
Subtotal				**$877**		**$877**	**$951**	**$307**	**$1,184**	**$1,284**	**24**
DP's Reliability Network Upgrades											
Expand Mojave Desert SPS		$127			$25						24
Modify the Jasper SPS		$85			$20						24
Modify High Desert Power Plant SPS		$116			$17						24
Subtotal		**$328**			**$62**	**$ 390**	**$423**		**$390**	**$423**	**24**
Total	**$2,254**	**$328**	**NA**	**$ 877**	**$ 62**	**$3,521**	**$3,818**	**$1,096**	**$4,617**	**$5,006**	**24**

Table D.2: Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades for Allocated Area Delivery Upgrades

Element	Interconnection Facilities Costs x 1,000 Constant Dollar (2012)	Reliability Network Upgrades Costs x 1,000 Constant Dollar (2012)	Delivery Network Upgrades Costs x 1,000 Constant Dollar (2012)	Distribution Upgrades Costs x 1,000 Constant Dollar (2012)	One Time Costs x 1,000 Constant Dollar (2012)	Total Estimated Costs w/o ITCC x 1,000 Constant Dollar (2012)	Total Estimated Costs w/o ITCC x 1,000 Escalated Constant Dollar (OD Year)	ITCC x 1,000 Constant Dollar (2012)	Total Estimated Costs w ITCC x 1,000 Constant Dollar (2012)	Total Estimated Costs w ITCC x 1,000 Escalated Constant Dollar (OD Year)	Estimated Time to Construct (Note 3 & 4)
Area Delivery Network Upgrades											
Kramer 500 kV expansion with one 500/230 kV transformer, Llano 500 kV Switching Station, Kramer-Llano 500 kV T/L, Looping Lugo-Vincent No.2 500 kV T/L into Llano			$10,254		$1						109
Distribution Upgrades to support the Kramer 500 kV substation expansion				$112				$39			109
Area Delivery Network Upgrades - EOP Upgrades allocated to NOL Projects											
Upgrade the Pisgah Substation to 500 kV with one 500/230 kV transformer Loop the Eldorado – Lugo 500 kV Line into the Pisgah 500 kV Substation			$4,112		$3						115
New Eldorado–Pisgah 500 kV T/L Series Capacitor			$1,016								40
Subtotal	NA	NA	$15,382	$112	$4	$15,498	$20,029	$39	$15,537	$20,079	115
Project Total	**$2,254**	**$328**	**$15,382**	**$989**	**$66**	**$19,019**	**$23,847**	**$1,135**	**$20,154**	**$25,085**	**115**

Note 1: The Interconnection Customer (IC) is obligated to fund these upgrades, and the IC will not be reimbursed for these upgrade costs.
Note 2: The Interconnection Customer is obligated to fund these upgrades, and the IC will not be reimbursed for these upgrade costs. Allocated costs may change if all projects responsible for these upgrades do not execute Interconnection Agreements.
Note 3: The estimated licensing cost and construction durations applied to this project are based on the project scope details presented in this study. These estimates are subject to change after project environmental and real estate elements are further defined. After execution of the Interconnection Agreement, additional evaluation, including but not limited to, preliminary engineering, environmental surveys, and property right checks may result in licensing cost and/or construction duration updates which will be provided to the IC.
Note 4: SCE's Phase I cost estimating is done in 'constant' dollars 2012 and then escalated to the estimated O.D. year. For the Phase I Study, the estimated O.D. is derived by assuming the duration of the work element will begin in March 2014, which is the CAISO tariff scheduled completion date of the QC5 Phase II Study plus 90 calendar days for the Interconnection Agreement negotiations/execution. For instance, if a work element is estimated to take a total of 24 months for permitting, design, procurement, and construction, then the estimated O.D. would be March 2016. If an IC's requested O.D. (In-Service Date) is beyond the estimated O.D. of a work element, the IC's requested O.D. is used. However, should the Generator Interconnection Agreement not be executed, or if the necessary information, funding, and written authorization to proceed is not provided by the IC in time for the Participating TO to perform the work within these time frames, then the information provided in Table D.1 may be subject to change.

E. Study Assumptions

For detailed assumptions, please refer to the group report. The following assumptions are only specific to the Project:

1. **The following SCE Distribution System Planning Criteria and Conditions were included in the Phase I Study:**
   - The thermal rating of any conductor, connector, or apparatus should not exceed 100% of its normal rated capacity with all facilities in service (base case).
   - The thermal rating of any conductor, connector, or apparatus should not exceed 100% of its emergency rating under N-1 conditions.
   - Operational flexibility and reliability of the distribution system shall be maintained at all times.
   - Circuit voltage profiles should be maintained to comply within CPUC's Rule 2 requirements.
   - The power factor for the new generation facility was assumed to be within WDAT requirements of 0.95 lagging or leading.
   - Expected loading on the distribution system as projected by the SCE 2012 - 2021 distribution system plan was used.
   - Distributed Generation resources connected to the distribution system are analyzed offline and online during peak load conditions as well as during minimum daytime load conditions as to determine worst case scenario.
   - The Short circuit contribution from the inverter systems was determined using inverter manufacturer documents.
   - The Phase I Study assumes the upgrades triggered by previously queued projects, including Rule 21 projects under CPUC jurisdiction as in-service, are included in the base case for the Phase I projects. If any previously queued projects were to withdraw, then the Phase I projects may be subjected to the cost identified for those previously queued projects.
   - Current distribution standards are being updated to address generation interconnection systems. The proposed method of service in this report may change according on final design to comply with the updated distribution design standards.
2. **The following Facilities were estimated and included in the Phase I Study:**
   - 7,700 ft 33 kV Line Extension
   - 33 kV metering, current transformers (CTs), and potential transformers (PTs)
   - 33 kV Overheard breaker
   - Remote Terminal Unit (RTU)
   - Telecommunication circuit for RTU
   - 33 kV Capacitor bank
   - Installation of PTs at sub to set relay directional
   - Install a three phase Bi-Directional Watt transducer on the Baroid 33 kV line
   - Replace Circuit Breakers at SCE's substation(s)
3. **The following facilities are to be installed by the Interconnection Customer and are not included in this Phase I Study:**
   - Ducts as required
   - Structures as required
   - Point of interconnection Breaker
   - CAISO metering as required

- Protection Systems required to comply SCE Interconnection requirements
- Transformation as required
- Metering Equipment compliant with SCE Electrical Service Requirements (http://www.sce.com/AboutSCE/Regulatory/distributionmanuals/esr.htm)

F. Deliverability Assessment

The deliverability assessment indicated that the Project contributes to the following deliverability constraints:

Category "A" Overloads

- Lugo No.1 500/230 kV Transformer
- Lugo No.2 500/230 kV Transformer
- Kramer-Lugo No.1 230 kV Line
- Kramer-Lugo No.2 230 kV Line

Category "B" Overloads

- Jasper-Pisgah 230 kV Line
- Kramer-Lugo No.1 230 kV Line
- Kramer-Lugo No.2 230 kV Line
- Lugo No.1 500/230 kV Transformer
- Lugo No.2 500/230 kV Transformer

Category "C" Overloads

- Roadway-Victor 115 kV Line
- Kramer-Roadway 115 kV Line
- Kramer-Victor 115 kV Line

To mitigate the overloads identified, network upgrades are required. For details of the study methodology, refer to the Group Report Section F.

Reliability Network Upgrade

- The Project is responsible for the Mojave Desert (Water Valley) SPS, Jasper SPS and High Desert Power Plant SPS.

Local Delivery Network Upgrade

- There were no Local Delivery Network Upgrades (LDNUs) identified or allocated in this Phase I study in order to provide the Full Capacity Deliverability Status requested in the Interconnection Request.

Area Delivery Network Upgrade

- Kramer 500 kV expansion, Llano 500 kV Switching Station, Kramer-Llano 500 kV T/L, Looping Lugo-Vincent No.2 500 kV T/L into Llano.
- Expand SCE Pisgah 220 kV Substation to 500 kV and Loop Eldorado-Lugo 500 kV T/L into Pisgah 500 kV Substation. New Eldorado – Pisgah (Presently Eldorado – Lugo) 500 kV T/L series capacitor.

See group report Section K for details.

G. Power Flow Analysis

1. Transmission Level Assessment – 220 kV or above

Please see Section G of the group report for the transmission level power flow analysis discussion and results.

2. Subtransmission System – 115 kV

The QC5 distribution study indicated that the Project does not contribute to any subtransmission facility overloads. Further analysis will be completed during the Phase II Study.

3. Distribution System – 34.5 kV or below

The QC5 distribution study indicated that the Project contributes to the following distribution facility overloads:

(a) *Overloaded Distribution Facilities*

(i) Under normal base case conditions, daytime minimum load and maximum generation, the addition of this project resulted in a reverse power flow back into the 33 kV bus at Gale Substation, which did not trigger an overload on any distribution facilities. However, SCE's system operator will need to determine when power flow is being generated back into the substation and operate the system accordingly.

(ii) Under emergency (N-1) conditions, daytime minimum load and maximum generation, the addition of this project did not trigger an overload on any distribution facilities. However, due to the dynamic distribution system configurations, SCE may deem it necessary to isolate this project until the distribution system returns to normal conditions.

(b) *Recommended Distribution Mitigations*

Install a 3-phase Bi-directional transducer on the Baroid 33 kV line position at Gale Substation to monitor reverse power flow into the 33 kV bus.

H. Short Circuit Analysis

Short circuit studies were performed to determine the fault duty impact of adding the QC5 projects to the Distribution Provider's system and to ensure system coordination. The fault duties were calculated with and without the projects to identify any equipment overstress conditions. Once overstressed circuit breakers are identified, the fault current contribution from each individual project in QC5 is determined. Each project in QC5 will be responsible for its share of the upgrade cost based on the rules set forth in CAISO Tariff Appendix DD.

1. Short Circuit Study Input Data

The customer provided technical data for the identified inverter (specified in Section B). If the technical data obtained from the inverter manufacturer by SCE illustrates differences in the Short Circuit Duty

(SCD) parameters, then SCE utilized the manufacturer data of the inverter model specified by the IC in the application in the SCD study. Otherwise, SCE utilized the parameters provided by the IC. The IC should verify the appropriate SCD contributions of the inverter with the manufacturer prior to commencement of the Phase II study and should update the application to reflect the appropriate data.

The following additional input data was used in this study:

PV Inverter Data for each generation unit (on 0.5 MVA Base):

- X"1 - positive sequence subtransient reactance: 1.5 PU
- X"2 - negative sequence subtransient reactance: 1.5 PU
- X"0 - zero sequence subtransient reactance: 1.5 PU

Padmount Transformers (total of 20)

Each transformer is a three-phase, 33/0.270 kV (Y-Y), 1.0 MVA with the following impedance information:

- H-X: 6.0% @ 1.0 MVA

2. Short Circuit Duty Study Results

All bus locations where the QC5 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 the group report Appendix H. These values have been used to determine if any equipment is overstressed as a result of the QC5 interconnections and corresponding network upgrades, if any.

The responsibility to finance short circuit related upgrades identified through a group study shall be assigned to all Interconnection Requests in that group study pro-rata on the basis of short circuit duty contribution of each Generating Facility. In addition, the SCD impact of the associated proposed Network Upgrades was allocated to each Generating Facility using the same percentage assigned for the triggered Network Upgrade.

(a) Application Queue with RNUs and LDNUs Analysis Results

Fault duties were calculated with the inclusion of the QC5 projects and the identified RNUs and LDNUs to identify the incremental impacts associated with these Facilities. As discussed in Section H of the group report, under this scenario the QC5 study breaker evaluation identified overstressed circuit breakers. The following is the pro-rata cost allocation for this project, based on SCD contribution at each location.

SCD Mitigation - Table of Network Breaker Replacements (RNU)

NA

(b) Application Queue with RNUs, LDNUs, & ADNUs Analysis Results

Fault duties were re-calculated to include the QC5 projects and the identified RNUs, LDNUs, and ADNUs from the power flow and stability analysis to identify the incremental impacts associated with these Facilities. As discussed in Section H of the group report, under this scenario the QC5 study breaker evaluation identified overstressed circuit breakers at Mira Loma and Valley. As part of this Phase I cost estimates for mitigation of short circuit duty impacts under this scenario are not included. As part of Phase II if this mitigation is identified to still be required, cost estimates and corresponding pro-rata cost allocation will be determined.

(c) Application Queue Distribution Analysis Results

Fault duties were calculated for the QC5 projects on the distribution system. Under this scenario the QC5 study breaker evaluation identified overstressed circuit breakers at the following distribution substations. The following is the pro-rata cost allocation for this project, based on SCD contribution at each location.

SCD Mitigation -Table of Distribution Breaker Replacements

NA

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 B.2.

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

I. Reactive Power Deficiency Analysis

1. Transmission Level Assessment – 115 kV or above

Please see Section G of the group report for the transmission and subtransmission level reactive power deficiency analysis discussion and results.

2. Individual Project Power Factor Requirements

Based on the findings obtained from QC5 study analysis, it is expected that the Project will need to be designed to maintain a composite power delivery at continuous rated power at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging. Additionally, the generation system must be designed to accommodate a VAR schedule provided by SCE. SCE will determine if the VAR schedule is necessary based on future re-arrangements of SCE's distribution system. This will be fully evaluated as part of the Phase II Study.

3. Distribution System Power Factor Requirements– 34.5 kV or below

The Baroid 33 kV circuit is not expected to experience a voltage rise that exceeds allowable Rule 2 requirements with the Project in service.

J. Transient Stability Evaluation

Please see Sections I and J of the group report for the transient stability evaluation discussion and results.

K. Environmental Evaluation/Permitting

Please see Section L of the QC5 group report.

L. Items not covered in this study

1. Conceptual Plan of Service

The results provided in this study are based on conceptual engineering and a preliminary plan of service and are not sufficient for permitting of facilities. The Plan of Service is subject to change as part of the Phase II Interconnection Study.

2. Customer's Technical Data

Additional technical data related to the Interconnection Customer's project may be required as part of the Phase II study. The study accuracy and results for the QC5 Phase I 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.

3. **Study Impacts on Neighboring Utilities**

Results or consequences of this QC5 Phase I Study and/or to-be-performed 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).

4. **Use of Participating TO Facilities**

The Interconnection Customer is responsible for acquiring all property rights necessary for the Interconnection Customer's Interconnection Facilities, including those required to cross Participating TO facilities and property. This Interconnection Study does not include the method or estimated cost to the Interconnection Customer of Participating TO mitigation measures that may be required to accommodate any proposed crossing of Participating TO facilities. The crossing of Participating TO property rights shall only be permitted upon written agreement between Participating TO and the Interconnection Customer at Participating TO's sole determination. Any proposed crossing of Participating TO property rights will require a separate study and/or evaluation, at the Interconnection Customer's expense, to determine whether such use may be accommodated.

5. **Participating TO Interconnection Handbook**

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

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.

7. **System Protection Coordination**

Adequate Protection coordination will be required between Participating TO-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.

8. **Standby Power and Temporary Construction Power**

The QC5 Phase I 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 Participating TO prior to the In-Service Date of the Interconnection Facilities, the IC is responsible to make appropriate arrangements with Participating TO to receive and pay for such retail.

9. **Licensing Cost and Duration Estimate (Estimated Construction Schedule)**

The estimated licensing cost and durations applied to this project are based on the project scope details presented in this study. These estimates are subject to change as project environmental and real estate elements are further defined. Upon execution of the Interconnection Agreement, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

10. **Network/Non-Network Classification of Telecommunication Facilities**

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 the IC. The IC will own, operate, maintain, and construct diverse telecommunication paths associated with the IC's gen tie, excluding terminal equipment at both ends. 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 Participating TO substation. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of QC5 Phase I, telecommunication upgrades for higher queued projects were not considered in this study. Depending on the outcome of interconnection studies for higher queued projects, the telecommunication upgrades identified for QC5 Phase I may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

11. Applicability

This document has been prepared to identify the impact(s) contributions of the Project on the SCE electrical system; as well as establish the technical requirements to interconnect the Project to the Point of Interconnection that was evaluated in the QC5 Phase I study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in interconnection agreements agreed to by SCE, CAISO and the Interconnection Customer.

Attachment 1

Allocation of Network Upgrades for Cost Estimates

Table 1: Allocation of RNU cost

Upgrade	Type	Needed For	Total Cost ($1000) (2012)	Cost Share	Allocated Cost ($1000) (2012)
Expand Mojave Desert SPS	RNU	Contingency overloads on Kramer-Victor 115 kV Line, Kramer-Roadway 115 kV Line and Roadway-Victor 115 kV Line under loss of Kramer-Lugo No.1 & No.2 230 kV Lines	153	100%	153
Modify the Jasper SPS	RNU	Contingency overloads on Lugo-Pisgah 230 kV Line, Jasper-Pisgah 230 kV Line, Kramer-Lugo No.1 230 kV Line and Kramer-Lugo No.2 230 kV Line under loss of (1) Cool Water-Jasper 230 kV Line or (2) Jasper-Lugo 230 kV Line	105	100%	105
Modify High Desert Power Plant SPS	RNU	Contingency overload on the remaining Lugo 500/230 kV Transformer under loss of the other Lugo 500/230 kV Transformer.	133	100%	133

Attachment 1 continued

Allocation of Network Upgrades for Cost Estimates

Table 2: Allocation of ADNU cost

Upgrades	Type	Needed For	MW	Cost Rate ($1000/MW) (2012)	Allocated Cost ($1000) (2012)
Kramer 500 kV expansion, Llano 500 kV Switching Station, Kramer-Llano 500 kV T/L, Looping Lugo-Vincent No.1 500 kV T/L into Llano	ADNU	Lugo No.1 and No.2 500/230 kV Transformers Capacity, Kramer-Lugo No.1 and No.2 230 kV Lines, and Pisgah-Lugo 230 kV Line Constrains	20	513	10,256
Upgrade the Pisgah Substation to 500 kV with one 500/230 kV transformer Loop the Eldorado – Lugo 500 kV Line into the Pisgah 500 kV Substation	ADNU		20	206	4,114
New Eldorado–Pisgah 500 kV T/L Series Capacitor	ADNU		20	51	1,016

Attachment 2

Not Used

Attachment 3

Participating TO Interconnection Handbook

Preliminary Protection Requirements for Interconnection Facilities are outlined in the Participating TO Interconnection Handbook.

Attachment 4

Short Circuit Calculation Study Results

Please refer to the Appendix H of the group report.

Attachment 5

Not Used

Attachment 6

Not Used

Attachment 7

SCE Northern Hemisphere Import Nomogram

Please refer to separate document.