Appendix A – WDAT931

[redacted]

QUEUE CLUSTER 5 PHASE II REPORT

December 6, 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)

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A. Introduction

[redacted] the Interconnection Customer (IC), submitted a completed Interconnection Request (IR) to Southern California Edison Company (SCE) for their proposed [redacted] (Project) under the Generator Interconnection Procedures (GIP) of Attachment I of SCE's Wholesale Distribution Access Tariff (WDAT). The Project will utilize [redacted] The proposed Point of Interconnection (POI) is at Southern California Edison Company's (Distribution Provider) Remote 33 kV Circuit out of Barstow Substation out of Tortilla 115/33 kV Substation. The IC has requested Full Capacity Deliverability Status, with a proposed In-Service Date of August 1, 2015, and a proposed Commercial Operation Date (COD) of October 31, 2015[1]. The Project elected Option (A)[2] for the Full Capacity Deliverability Status.

In accordance with Section 4.5 of the GIP, the Project was grouped with Queue Cluster 5 (QC5) Phase II projects to determine the impacts of the group as well as impacts of the Project on the CAISO Controlled Grid.

The Transmission assessment information and corresponding results identifying the combined impacts of all projects in the group for the Area Bulk System (CAISO-controlled) are provided in the Area report. The Area report has been prepared separately and provided as part of the QC5 Phase II report package.

This report focuses only on the impacts or impact contributions of the Project on the SCE Distribution system, and it is not intended to supersede any contractual terms or conditions specified in an Interconnection Agreement.

The report provides the following:

1. 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 to construct[3] these facilities. Such information is provided in Attachment 2 and Attachment 3 as separate documents in the Appendix A Project report package.

All equipment and facilities comprising the Project located in [redacted] as disclosed by the IC in its IR, as may have been amended during the Interconnection Study process, will consist of (i) [redacted] (ii) the associated infrastructure, (iii) meters and metering equipment, (iv) appurtenant equipment, and (v) auxiliary loads.

Table A.1 provides a summary of the Project information and Figure A.2 provides a map of the Project location and transmission facilities in the vicinity.

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[1] Date as requested in the Attachment B. Actual COD depends on design and construction requirements.

[2] Option (A) – Under this option the Generating Facility requires TP Deliverability to be able to continue to Commercial Operation. Amount of TP Deliverability allocated to the Project will be determined after the completion of the Phase II Study. The Interconnection Customer will be required take on the cost responsibility assigned to it for IF, Distribution Upgrades, RNUs and LDNUs.

[3] It should be noted that construction is only part of the duration of months specified in the study, includes final engineering, licensing, etc, and other activities required to bring such facilities into service. These durations are from the execution of the Interconnection Agreement, receipt of: all required information, funding, and written authorization to proceed from the IC as will be specified in the Interconnection Agreement to commence the work.

Table A.1: Project General Information

Project Location	[redacted] Barstow, CA San Bernardino County
Distribution Provider's Planning Area	SCE North of Lugo Area
Number and Type of Generators	[redacted]
Interconnection Voltage	33 kV
Maximum Generator Output	20 MW
Generator Auxiliary Load	0 MW
Maximum Net Output to Grid	20 MW
Power Factor Range	Lead 0.90 / Lag 0.90
Step-up Transformer(s)	[redacted]
POI	Distribution Provider's Remote 33 kV Circuit out of Barstow 33/33 kV Substation out of Tortilla 115/33 kV Substation
IC Requested COD	October 31, 2015

Figure A.2: Map of the Project

[redacted]

B. Study Assumptions

B.1 SCE Distribution System Assumptions

Below are the assumptions specific to the Project in respect to the SCE Distribution System.

1. **The following SCE Distribution System Planning Criteria and Conditions were included in the Phase II Study:**
   - The thermal rating of any conductor, connector, or apparatus shall not exceed 100% of its normal rated capacity with all facilities in service (base case).
   - The thermal rating of any conductor, connector, or apparatus shall not exceed 100% of its emergency rating under loss of one element (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 2013 - 2022 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 II 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 II projects. If any previously queued projects were to withdraw, then the Phase II 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.
   - This study assumes that the IC's generating facility will include all equipment, software, and appropriate controls necessary to maintain the generator output profile per SCE requirements. The IC will be responsible for maintaining designated voltage levels under all conditions, including but not limited to the conditions identified above. Upon execution of the Interconnection Agreement, SCE will provide the IC with the required ramp rate control parameters. The ramp rate controls will be a function of the generation penetration on the distribution system, as well as SCE's distribution system configuration (additional parameters maybe considered, as need). Changes to the ramp rate control scheme may be required as determined by increased generation, changes in the distribution system topology, or other changes in the distribution system.

2. **The following Facilities were estimated and included in the Phase II Study:**
   - Approximately 250 feet line extension of primary conductor (336 ACSR)

- Reconductor approximately 1,975 feet of 2/0 ACSR to 336 ACSR and approximately 836 feet of 4/0 CLP 750 CLP
- Replace existing distribution poles with 5-60 foot distribution poles
- 33 kV Pole top metering cabinet, current transformers (CTs), potential transformers (PTs),
- 33 kV Remote Automatic Recloser (RAR)
- Add three (3) Bi-Directional Watt Transducers and two (2) MW data points

3. **The following facilities are to be installed by the IC and are not included in this Phase II Study:**
   - Ducts as required
   - Structures as required
   - POI breaker
   - CAISO metering as required
   - Protection Systems required to comply SCE Interconnection requirements
   - Transformation as required
   - One (1) gang-operated, overhead switch

C. Reliability Standards, Study Criteria and Methodology

Refer to Section B.1 SCE Distribution study assumptions above for the Reliability Standards, Study Criteria and Methodology applied in this study.

D. Reliability Assessment Results

1. System Steady State Power Flow Analysis Results

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

(a) Distribution System Impacts of the Project

(i) Thermal Overloads

- Under normal base case conditions, daytime minimum load and maximum generation, the addition of the Project resulted in a reverse power flow back into the 33 kV bus at Barstow Substation and Tortilla Substation, which triggered a thermal overload on existing distribution facilities. Furthermore, SCE's system operator will need to determine when power flow is being generated back into the identified substations and operate the system accordingly.
- Under emergency (N-1) conditions, daytime minimum load and maximum generation, the addition of the 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 the Project until the distribution system returns to normal conditions

(ii) Recommended Distribution Mitigations

- Upgrades have been identified to mitigate thermal overloads. These upgrades include reconductoring approximately 1,975 feet of 2/0 ACSR to 336 ACSR and reconductoring 835 feet of 4/0 CLP to 750 CLP.

(b) Transmission System Impacts of the Project

The Project was found to contribute to the congestion of the North of Kramer (NOK) Subarea, the CAISO deemed these transmission overloads to be remediated by Congestion Management, therefore:

(i) Thermal Overloads

- Lugo No.1 500/220 kV Transformer AA-Bank
- Lugo No.2 500/220 kV Transformer AA-Bank

(ii) Required Mitigations

- None, it is assumed that congestion management will mitigate system overloads in the North of Lugo area.

The Project is seeking interconnection in a known **Transmission Constrained Area** for which the Serially-triggered Cool Water-Lugo Transmission Project (CWLTP) intends to alleviate the existing two Kramer-Lugo 220 kV Transmission Lines which been identified as the capacity delivery bottle-neck with limited transfer capability due to overloading problems.

CWLTP was proposed to create another transmission path from Kramer to Lugo Substation to mitigate identified overloads. The Project COD is anticipated to be in service in 2018[4].

ANY generation project, regardless of deliverability status requested, seeking interconnection into the NOK Subarea cannot be accommodated until the CWLTP is in service. Please see more information in Section 6. Transmission Export Limitations for more information.

2. Short Circuit Analysis

Short circuit studies were performed to determine the fault duty impact of adding the QC5 Phase II projects to the transmission 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 Phase II is determined. Each project in the cluster will be responsible for its share of the upgrade cost based on the rules set forth in CAISO Tariff Appendix Y.

(a) Short Circuit Study Input Data

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

4 (www.sce.com/coolwaterlugo)

[redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

(b) Short Circuit Duty Study Results

All bus locations where the QC5 Phase II projects increase the short-circuit duty by 0.1 kA or more and where duty was found to be in excess of 60% of the minimum breaker nameplate rating are listed in the area report (Appendix H). These values have been used to determine if any equipment is overstressed as a result of the inclusion of QC5 Phase II interconnections and corresponding network upgrades, if any.

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 short circuit duty contribution of each Generating Facility.

As discussed in the area report, the QC5 Phase II breaker evaluation identified overstressed circuit breakers at the following buses. The pro-rata cost allocation for the Project, based on SCD contribution at each location, is also provided:

SCD Mitigation – Table of Network Upgrades

N/A

SCD Mitigation – Table of Distribution Upgrades

N/A

(c) SCE Substations with Ground Grids Duty Concerns

The short circuit studies did not flag any SCE substations beyond the POI with ground grid duty concerns that may necessitate a ground grid study.

(d) Preliminary Protection Requirements

Protection requirements are designed and intended to protect the Distribution Provider's system only. The preliminary protection requirements were based upon the interconnection plan as shown in the one-line diagram depicted in line item #7 in Attachment 2.

The IC is responsible for the protection of its own system and equipment and must meet the requirements in the Distribution Provider Interconnection Handbook provided in Attachment 4.

3. Voltage Performance

(a) Individual Project Power Factor Requirements

Based on the results of the Study, the Project will need to be designed to maintain a composite power delivery at continuous rated power at the POI 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.

(b) Distribution System Power Factor Requirements – 34.5 kV or below

The Remote 33 kV Circuit is not expected to experience a voltage rise that exceeds allowable Rule 2 requirements with the Project in service. Information regarding VAR schedule is described above in Section I, number 2.

E. Deliverability Assessment Results

1. On Peak Deliverability Assessment

The Project contributes to the Lugo #1 AA, Lugo #2 AA, and Barre-Ellis #1 230 kV area constraints as shown in the area report Section E.1 Table E.1.2.

2. Off- Peak Deliverability Assessment

For off-peak condition studies, see Section D.1.1 Table D.1.1.2 and Section D.1.2 Table D.1.2.2 in the area report.

3. Required Mitigations

For area constraints, the project is subjected to TPD allocation.

F. In-Service Date and Commercial Operation Date Assessment

1. IC Proposed Project Timelines

The latest information provided by the IC has indicated that the requested generator In-Service Date is August 1, 2015, and the COD is October 31, 2015[5].

From a Transmission perspective, the Project COD may be impacted as it will have to wait until Coolwater-Lugo Transmission Project Upgrades are in place in order to interconnect safely and reliably into SCE's Service Territory.

[5] Date as requested in the Attachment B. Actual COD depends on design and construction requirements.

2. **System Upgrade Timelines for Reliable Interconnection**

The Operational Studies identified that the following facilities are required in order to provide for reliable interconnection:

(a) Distribution Provider's Interconnection Facilities
See Section 1.b in Attachment 2.

(b) Reliability Network Upgrades

(i) Plan of Service Reliability Network Upgrades - None.

(ii) Special Protection System (SPS) - None.

(iii) Short-Circuit Duty (SCD) Mitigation

1. Pre-QC5 Phase II Projects
The circuit breaker upgrades that were triggered by queued-ahead projects are identified in Section C.7.1 of the QC5 Phase II area report.

2. Including the QC5 Phase II Projects
The Operational Study undertaken with the inclusion of the QC5 Phase II projects identified the required timing for circuit breaker upgrades and/or SCD mitigation(s) under six different scenarios. These scenarios were selected as the most appropriate operational study conditions and are discussed in Appendix G of the QC5 Phase II area report.

   Additionally, the Operational study results, which discuss the timing for breaker upgrades and/or required SCD mitigation(s) at each of the substations identified, are addressed in Appendix G of the QC5 Phase II area report.

   It should be noted that the timing of the need for the breaker upgrades and SCD mitigation(s) is dependent on actual timing of generation projects and corresponding upgrades materializing. The identified breaker upgrades and/or SCE mitigation(s) will not adversely impact the COD of the Project. Additional review for the identified breaker upgrades and/or SCE mitigation(s) discussed in Appendix G of the QC5 Phase II area report will be performed to evaluate timing of these breaker replacements and SCD mitigation(s) as projects execute Interconnection Agreements.

(iv) Reactive Support Upgrades – None. Although no reactive support network upgrades are required for the Project, the Project will still be required to maintain 0.95 lead/lag power factor while in operation.

(v) Subtransmission Upgrades – None.

(c) Distribution Upgrades –
See Section 3 in Attachment 2.

3. **System Upgrades Required for Full Capacity Deliverability Status**

In order to provide for Full Capacity Deliverability Status, the following facilities are required in addition to the Reliability Network Upgrades in Section 2.(b):

(a) Triggered Delivery Network Upgrades

None

(b) Delivery Network Upgrades Triggered by Earlier Queued Projects

In order for the Project to interconnect for a Full Capacity Deliverability Status, the Coolwater- Jasper-Lugo transmission project has to be in operation. The Coolwater-Jasper-Lugo transmission project currently has an expected completion date of 2018.

(c) Approved Transmission Upgrades

None.

(d) Transmission Upgrades outside the CAISO Controlled Grid

None

4. Interim Operational Deliverability Assessment for Information Only

The operational deliverability assessment was performed for study years 2014 and 2017 by modeling the transmission and generation in service in the corresponding study year. The study has identified the following deliverability constraints before Coolwater-Jasper-Lugo upgrade is in service:

- Base case overloads of Lugo-Kramer 220kV No. 1 or No. 2 line.

ISO has approved transmission upgrades and identified Network Upgrades for earlier queued cluster to mitigate the above constraints as shown in section 3 above. These upgrades are expected to be in-service in 2018. The Project may get Interim Deliverability Status prior to the completion of these upgrades. For details of the transmission and generation assumption, refer to Section F of the area report. If some or all the transmission upgrades are delayed or more generation is actually in commercial operation than assumed, the interim deliverability of the Project will be impacted.

5. SCE Northern Hemisphere Import Nomogram

As part of the QC5 Phase II studies there were no Delivery Network Upgrades allocated to the Project for its requested Full Capacity Deliverability Status. It is important to note that while no Delivery Network Upgrades were allocated to the Project, this outcome does not mean that the Project will be able to generate at its maximum Generating Facility output. Congestion could happen whenever the amount of generating resources exceeds the available transmission capability. The generating resources' output may be curtailed, regardless of their deliverability status, as the result of congestion under the CAISO market operation.

As stated in Attachment 7, studies indicate that as high amounts of resources in the East of Lugo area develop and are dispatched, the amount of available transmission capacity for the Northern Area resources is diminished. Such conclusions point to a potential need for congestion management, and generation resource curtailments. For additional information on potential congestion under expected amounts of renewable generation development in 2021, please see Chapter 5 of the ISO 2012-2013 Transmission Plan report http://www.caiso.com/Documents/Board-approvedISO2012-2013-TransmissionPlan.pdf.

6. North of Kramer Area Constraints

Any Project seeking interconnection into the North of Kramer (NOK) Subarea regardless of size shall wait for the Coolwater-Lugo Transmission Project (CWLTP) Upgrades [6] to be In-Service prior to their interconnection. With the inclusion of the QC5 projects there are a total of 1,254.4 MW of generation interconnection requests within the North of Lugo Bulk System as shown in the table below. The 2,513 MWs of existing North of Lugo area generation currently exceeds the export capability of the Kramer transmission and subtransmission lines south to Lugo and Victor Substations, respectively. SCE's CWLTP will only provide approximately 1,000 MW of additional export capacity to Lugo Substation.

SCE is pursuing licensing on the Coolwater-Lugo Transmission Project to create more transmission capacity to export generation from Kramer south bound to Lugo Substation. Projects connecting into the North of Kramer area cannot be interconnected until the Coolwater-Lugo Transmission Project is anticipated to go into service in 2018.

Study Type	NOL Queued Project MWs	Cumulative Total MWs
Rule 21	93.7	93.7
Serial	532.0	625.7
Transition Cluster	40.7	666.4
SGIPs	161.0	827.4
Queue Cluster 1	0.0	827.4
Queue Cluster 2	0.0	827.4
Queue Cluster 3	0.0	827.4
Queue Cluster 4	30.0	857.4
Queue Cluster 5	277.0	1134.4
Cumulative Total		**1254.4**

In areas where transmission capacity is limited, e.g. North of Lugo's NOK Subarea, generation resources will be in competition for available transmission capacity with other resources in that are either in queue or already interconnected; and generation market bid prices will dictate which generators actually get to generate. Since the market bid prices for renewable resources is typically zero, the outcome will likely be that both Full Capacity Deliverability projects and Energy Only Deliverability projects could be subjected to curtailment if the total amount of generation that ultimately materializes is in excess of system capacity.

In other words, the "Full Capacity Deliverability" label provides resource adequacy status, but does not guarantee firm transmission rights as there is no correlation between the "Full Capacity Deliverability" label and the dispatch of these resources.

As more resources seeking interconnection in the North of Lugo Area develop and are dispatched, the amount of available transmission capacity for the Greater East of Lugo Area is further diminished, thus increasing the curtailment exposure.

[6] http://www.sce.com/PowerandEnvironment/Transmission/ProjectsByCounty/SanBernardinoCounty/southofkramer.htm

7. Conclusion

The requested IC In-Service Date is August 1, 2015 cannot be met due to the anticipated duration of 18 months for the facilities needed to enable Energy Only Interconnection. The requested Full Capacity Deliverability Status will not be available until the appropriate Deliverability system upgrades are placed into service.

G. Interconnection Facilities, Network Upgrades, and Distribution Upgrades

Please see Attachment 2 for the Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades and Distribution Upgrades allocated to the Project.

H. 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, Local Delivery Network Upgrades and Area Delivery Network Upgrades. Attachment 3 provides the 'constant' 2013 dollars and their escalation to the estimated COD 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 COD is derived by assuming the duration of the work element will begin in June 2014, which is the CAISO Tariff scheduled completion date of the QC5 Phase II Study plus 120 days for the Interconnection Agreement signing period and submittal of required funds by the IC.

I. SCE Technical Requirements

The IC is responsible for the protection of its own system and equipment and must meet the requirements in the Distribution Provider Interconnection Handbook provided in Attachment 4

J. Environmental Evaluation, Permitting, and Licensing

Please see Appendix K of the QC5 Phase II Area report.

K. 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 final engineering and design.

2. IC's Technical Data

The study accuracy and results for the QC5 Phase II Study are contingent upon the accuracy of the technical data provided by the IC. Any changes from the data provided could void the study results.

3. Study Impacts on Neighboring Utilities

Results or consequences of this QC5 Phase II 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 Distribution Provider Facilities**

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

5. **Distribution Provider Interconnection Handbook**

The IC shall be required to adhere to all applicable requirements in the Distribution Provider 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 IC 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 Distribution Provider-owned protection and IC-owned protection. If adequate protection coordination cannot be achieved, then modifications to the IC-owned facilities (i.e., Generation-tie or Substation modifications) may be required to allow for ample protection coordination.

8. **Affected Systems Coordination**

The CAISO Generator Interconnection and Deliverability Allocation Procedures (GIDAP) tariff Appendix DD section 3.7 requires that as part of the generator interconnection process, the ISO must regularly coordinate with adjacent electric systems in order to facilitate studies of potential reliability concerns caused by the interconnection of generation in the ISO generation interconnection queue to the ISO controlled grid. Similarly, generators interconnecting to the facilities of transmission owners in adjacent electric systems may cause potential reliability concerns on the ISO controlled grid.

The ISO tariff defines an "Affected System" as an electric system other than the ISO controlled grid that may be affected by the proposed interconnection, and an "Affected System Operator" as the entity operating an Affected System. The ISO tariff provides a general framework for addressing the impact on Affected Systems of generation projects in the ISO interconnection queue. The tariff states that, in the initial project study stages, the ISO will:

- Notify potential Affected System Operators that could be impacted by a generator interconnection;
- Coordinate the conduct of studies to determine possible impacts; and
- Include potential Affected System Operators in all customer meetings.

However, the ISO does not comprehensively study the impacts of generator interconnections on Affected Systems, for several reasons. First, the ISO does not have detailed information about Affected Systems on a transmission-element level, nor does the ISO know the details of the various reliability and operating criteria applicable to the Affected Systems. Second, because the operation of transmission systems changes over time along with NERC reliability standards, the ISO cannot presume to know all of the impacts of these changes on Affected Systems. Consequently, the interconnection customer is responsible for:

- Cooperating with the ISO in all matters related to the Affected System studies;
- Signing a separate study agreement with the Affected System Operator so that potential impacts on the Affected System can be evaluated; and
- Paying for necessary studies and any upgrades necessary to mitigate the impacts of their interconnection on the Affected System.

Further, the Affected System Operator is required to cooperate with the ISO on all matters related to the conduct of studies and modifications to the Affected System.

The interconnection customer is obligated by the terms of the ISO's relevant generator interconnection agreement (large or small) to enter into an agreement with the Affected System Operator, which must specify the terms governing payments for studies and mitigation, if required, to be made by the customer to the Affected System owner, and repayment by the Affected System Operator.

The ISO has advised the Interconnection Customer as to which systems their interconnection is potentially affecting. Prior to its generating unit in-service date, an Interconnection Customer must provide documentation to the ISO confirming that the Affected System Operators have been contacted, that any system reliability impacts have been addressed (or that there are no system impacts), or that the interconnection customer has taken all reasonable steps to address potential reliability system impacts with the Affected System Operator but has been unsuccessful.

9. Standby Power and Temporary Construction Power

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

10. Licensing Cost and Estimated Time to Construct Estimate (Duration)

The estimated licensing cost and durations applied to the 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.

11. 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 generation tie line, 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 Distribution Provider substation. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of QC5 Phase II, 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 II may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

12. Ground Grid Analysis

A detailed ground grid analysis will be required as part of the final engineering for the Project at the SCE substations whose ground grids were flagged with duty concerns in Section D.5 of the area report.

13. 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 POI that was evaluated in the QC5 Phase II 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 IC.

14. Potential Changes in Cost Responsibility

The IC is hereby placed on notice that interconnection of its proposed generating facility may be dependent upon certain Network Upgrades which are currently the cost responsibility of projects ahead of the proposed generating facility in the interconnection application queue. In accordance with Section 4.5.4 of the GIP, the estimated costs of Network Upgrades are to be assigned in accordance with CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP). Section 14.2.2 of the GIDAP provides that should Network Upgrades required for queued-ahead projects be included in an executed Interconnection Agreement (or unexecuted Interconnection Agreement filed at FERC) at the time of withdrawal of the earlier queued generating facility, and the upgrades are determined to still be needed by later queued generating facilities, the financial responsibility for such upgrades falls to the Participating Transmission Owner. However, if the Network Upgrades required by earlier queued generating facilities are not subject to an executed Interconnection Agreement (or unexecuted Interconnection Agreement filed at FERC) the financial responsibility for such upgrades may fall to the IC. Section 14.2.2 also discusses how Network Upgrades required by interconnection customers selecting Option (B) might be required to be reapportioned among interconnection customers selecting Option (B) in the case of withdrawals of earlier queued generating facilities. Changes in costs allocated to the IC could also arise as the result of the CAISO's reassessment process described in Section 7.4 of the GIDAP. SCE encourages the IC to review Sections 7.4 and 14.2.2 of the GIDAP for the rules and processes under which the financial responsibility might be reapportioned to the IC. Potential changes in the IC's cost responsibility resulting from application of the provisions of these Sections of GIDAP are not included in this Phase II study, nor are the potential impacts to the IC's maximum cost responsibility outlined in this Phase II study.

15. System Variability

This study does not include analysis related to the following system variability conditions:

- Generator ramp rate: Solar photovoltaic generator's increasing output profile during sunrise, i.e. system start-up
- Generator output variability: Solar photovoltaic generator's output variation correlated with weather conditions, i.e. cloud cover

Attachment 1

Not Used

Attachment 2

Interconnection Facilities, Network Upgrades, and Distribution Upgrades

Please refer to separate document.

Attachment 3

Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades

Please refer to separate document.

Attachment 4

Distribution Provider Interconnection Handbook

Preliminary Protection Requirements for Interconnection Facilities are outlined in the Distribution Provider Interconnection Handbook.

Attachment 5

Short Circuit Calculation Study Results

Please refer to the Appendix H of the area report.

Attachment 6

Not Used

Attachment 7

SCE Northern Hemisphere Import Nomogram

Please refer to separate document.