Appendix A – WDT1390

[redacted]

Queue Cluster 9 Phase I Report

January 18, 2017

This study has been completed in coordination with the California Independent System Operator Corporation (ISO) per Southern California Edison Company's Wholesale Distribution Access Tariff (WDAT), Attachment I Generator Interconnection Procedures (GIP)

No.	Date	Document Title	Description of Document
1	1/18/2017	Queue Cluster 9 Phase I Appendix A Report	Final Phase I Interconnection Study Report

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ATTACHMENTS

A. INTRODUCTION

[redacted] the Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to Southern California Edison (SCE) for their proposed [redacted] (Project) interconnecting to the California ISO Controlled Grid. The Project requested a Point of Interconnection (POI) at Southern California Edison Company's (SCE) Chestnut 66 kV Bus, located in Orange, CA, and delivery to the CAISO Grid at SCE's Johanna 220 kV[1] Substation. The IC elected Full Capacity Deliverability Status (FCDS) for the Project. The IC desires an In-Service Date (ISD) of September 15, 2019 and a Commercial Operation Date (COD) of December 1, 2019. Such dates are specified in the Project's IR. Actual ISD and COD will depend on licensing, engineering, detailed design, and construction requirements to interconnect the Project after the Generator Interconnection Agreement (GIA) has been executed and filed at the Federal Energy Regulatory Commission (FERC) for acceptance.

In accordance with FERC approved SCE's WDAT Attachment I Generator Interconnection Procedures (GIP), the Project was grouped with Queue Cluster 9 (QC9) Phase I projects to determine the impacts of the group as well as impacts of the Project on the ISO Grid.

An Area Report and Subtransmission Assessment Report have been has been prepared separately identifying the combined impacts of all projects on the ISO Grid and to distribution facilities served out of the Johanna 66 kV Subtransmission System, respectively. This Appendix A report focuses only on the impacts or impact contributions of the Project at the local distribution system, and is not intended to supersede any contractual terms or conditions specified in the GIA.

The report provides the following:

1. Transmission system impacts caused by the Project.
2. Distribution system impacts caused by the Project.
3. System reinforcements necessary to mitigate the adverse impacts caused by the Project under various system conditions.
4. A list of required facilities and a good faith estimate of the Project's cost responsibility and time to construct[2] these facilities. Such information is provided in Attachment 1 and Attachment 2 as separate documents in the Appendix A Project report package.

Additionally, the Project encompasses energy storage equipment that required additional analysis be performed to evaluate the impacts of the charging facility within SCE's Distribution System. These analyses focused on the charging[3] aspects of the charging facilities in the Johanna 66 kV Subtransmission System and consider various levels of load demand with minimal generation dispatch within the local distribution system.

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[1] Identification of facility voltages (220 kV) are shown consistent with SCE System Operating Bulletin 123. However, all studies were predicated on the base voltages reflected in the Western Electricity Coordinating Council (WECC) base cases. For the SCE bulk power system, the WECC base cases reflect 230 kV and 500 kV base voltages; consequently, all per-unit calculations presented were based on 230 kV and 500 kV voltages.

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

[3] Charging is defined as when the Project draws energy from the grid to "charge" the Project-associated charging facilities.

Consequently, the report also discloses the adequacy of SCE's Distribution System to support the charging aspects of the charging facilities, identifies system limitations that may restrict the charging facility's ability to charge during certain demand conditions, and provides a high-level explanation of potential exposure to charging restrictions on the distribution system in addition to identifying distribution system improvements, which would mitigate such restrictions to charging.

All the equipment and facilities comprising the Project's Generating Facility are located in Santa Ana, California, as disclosed by the IC in its IR, as may have been amended during the Interconnection Study process, which consists of (i) [redacted] with a rated output of [redacted] each for a combined gross output of [redacted] as measured at the inverter terminals, (ii) the associated infrastructure, (iii) meters and metering equipment, (iv) appurtenant equipment, and (v) 0.182 MW of auxiliary loads.

Based on the technical data provided for the collector system equivalent, pad-mount and main transformer banks, the total internal project losses were identified to be 0.23 MW. Losses on the gen-tie were identified to be 0 MW. Subtracting losses from the gross 20.41 MW would result in a POI delivery of 19.99 MW which is within the IC's requested 20 MW POI delivery amount.

The Project shall consist of the Generating Facility and the IC's Interconnection Facilities as illustrated below in Figure A.1. Below also is Figure A.2, a map that illustrates the location of the Project. Moreover, the Project information is summarized in Table A.1 below.

Figure A.1: Project Plan of Service & IC Facilities One-Line Diagram

[redacted]

Figure A.2: Project Location Map

[redacted]

Table A.1 Project General Information per IR

Project Location	[redacted]
Distribution Provider's Planning Area	Distribution Provider's Metro Area
Interconnection Voltage	66 kV
POI	Distribution Provider's Chestnut 66 kV Switchrack
Requested Maximum Project Output as measured at POI (Note 1)	[redacted]
Number and Types of Generators	[redacted]
Power Factor Range	-1/+1
Step-up Transformer(s)	[redacted]
Generator Auxiliary Load	[redacted]
Internal Generating Facility Losses	0.23 MW
Gen-Tie	0.2 miles, 397 kcmil ACSR
Estimated total losses on Generation Tie Line	0 MW
Maximum Net Output at Generating Facility (High-Side of Main Transformer) to achieve requested POI Delivery (Note 2)	20 MW
ISD	September 15, 2019
Initial Synchronization Date/Trial Operation	October 15, 2019
COD	December 1, 2019

Note 1: The MW output at the POI varies under different operating conditions.

Note 2: The IC is reminded that this value is tied to the generation tie-line (gen-tie) losses. The estimated Maximum Net Output value at POI and gen-tie Losses illustrated above are contingent upon the accuracy of the technical data provided by the IC, and are subject to change should the IC change its gen-tie parameters during the final engineering and design phase of the Project.

Based on the technical data provided, the Project is requesting to install more megawatts (20.412 MW) as measured at the inverter terminal which will result in more than the requested 20 MW delivery at the POI. As a result, the Project will need to be limited to not exceed the values shown under Limited Maximum Net Output (metered on high-side of the main transformer bank).

B. STUDY ASSUMPTIONS

For detailed assumptions regarding the group cluster analysis, please refer to the QC9 Phase I Area Report. Below are the assumptions specific to the Project:

1. The Plan of Service (POS) is defined as the facilities needed to interconnect the Project to SCE's Distribution System. The following is the POS assumed for the Project.

   The Project was modeled with a total gross output capacity of 20 MW (combination of generation and energy storage) as measured at the high side of the main transformer bank.

2. The following facilities will be installed by SCE and **<u>are included</u>** in this Interconnection Study report:
   - Extend the 66 kV bus to equip a new 66 kV position for the new generation tie-line at Chestnut Substation.
   - The segment of a 66 kV generation tie-line inside the Chestnut 66 kV Substation property line.
   - The segments of each one of the two generators – owned telecommunications channels inside the Chestnut Substation property line.
   - Lightwave, channel banks, and associated equipment at Chestnut Substation and at the Facility.
   - Dedicated Remote Terminal Unit (RTU)
   - The required retail and wholesale load meters.

     NOTE: SCE installation does not include metering, potential transformers (PTs), current transformers (CTs), and metering cabinet. The SCE meters will be connected to the generator – owned PTs and CTs to be installed for their ISO metering.

3. The following facilities are to be installed by the Interconnection Customer and **<u>are not included</u>** in this Interconnection Study report:
   - The 66 kV generation tie-line from the Generating Facility to the Last Structure outside the Chestnut Substation property line.
   - The fiber optic cables to provide two diversely routed telecommunication paths required for the line protection relays.
   - The required ISO metering equipment (PTs, CTs, and ISO meters) and metering cabinet for SCE retail and wholesale load meters.

     NOTE: The metering, PTs, and CTs installed for the ISO metering will also be used for the SCE owned retail and wholesale load meters.

   - The 66 kV following line protection relays to be installed at the Generating Facility end of the 66 kV generation tie-line:
     - Two (2) line current differential relays via two (2) diversely routed dedicated digital communication channels to Chestnut Substation.

4. Preliminary Protection Requirements
   - Protection requirements are designed and intended to protect the Participating TO's transmission 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 1.

- The IC is responsible for the protection of its own system and equipment and must meet the requirement in the Participating TO's Interconnection Handbook provided in Attachment 4.

5. Environmental Activities, Permits, and Licensing

This study assumes that SCE's level of disturbance during construction would not require development and implementation of a Stormwater Pollution Prevention Plan.

i. Internal Substation Scope:

- SCE will perform all environmental studies and monitoring of all SCE internal substation construction activities.
- SCE's scope of work would not require a California Public Utilities Commission license.

ii. 66 kV Generation Tie Line Scope:

- SCE's scope of work will not require a California Public Utilities Commission license.
- Environmental Services (ES) will act as the environmental liaison between the SCE team and IC team, and the lead for regulatory agency communication.
  - Collaborate with the IC during the environmental study phase on proposed study methodologies and findings, as studies are being planned and performed for SCE's scope of work.
  - Review IC's California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA) documents, technical studies, surveys, and other environmental documentation addressing SCE's scope of work (IC to include SCE's scope of work in their environmental document).
  - Review of internal (SCE/ES) existing technical documents when available
  - Regulatory agency communication, consultation, and reporting
  - Permit acquisition
  - Support SCE team in developing the project description, including scope changes during permitting/pre-construction or construction.
  - Communicate scope changes to the IC's environmental team, discuss/approve subsequent actions including new surveys as necessary
  - Prepare environmental requirements for construction clearance
  - Develop communication plan
  - Construction monitoring oversight
  - General Order 131-D Consistency Determination and Environmental Evaluation
  - Environmental Awareness/Worker Environmental Awareness Program (WEAP) training
  - Pre-construction coordination field visit
  - Construction and post-construction site assessments

This study assumes the IC performs all environmental studies and prepares draft environmental permit applications related to the installation of SCE's Interconnection Facilities and Upgrades. The IC's responsibilities include, but are not limited to notifications to the Native American Heritage Commission (NAHC) and follow-up notifications to the tribes and individuals in the NAHC contact list, performing cultural and paleontological resources records searches, performing cultural resources inventories (survey and recording), performing testing and evaluation and/or data recovery of archaeological sites as applicable, and providing the appropriate documentation in the form of inventory reports, research design and/or data recovery reports as applicable, cultural and paleontological monitoring when/if required, and arranging curation agreements for artifacts and fossil specimens collected, performing a California Natural Diversity Database search, performing a habitat assessment, performing protocol or focused surveys for species with the potential of occurring in identified suitable habitat, conducting jurisdictional delineations for wetlands or other regulated waters, preparing draft environmental permit applications, performing pre-construction biological resource surveys, performing biological resource monitoring during construction, performing cultural and paleontological monitoring during construction, mitigation costs including, but not limited to, offsite/compensatory mitigation and onsite restoration, and developing mitigation plans or other environmental reports or submittals, if required, to support installation of SCE's Interconnection Facilities and Upgrades.

Prior to commencing work and during execution of work, the IC must collaborate and obtain ES concurrence on all work outlined above. Should the IC-performed environmental studies, surveys, or monitoring not meet the Federal or State industry standards in accordance with Applicable Laws and Regulations, and as determined by ES, the IC shall be obligated to remedy deficiencies under SCE/ES's direction, or ES shall undertake additional environmental studies, surveys, or monitoring at the sole expense of the IC. If these scenarios occur, the cost estimate must be updated to reflect the changes to the assumptions.

This study is based upon the scope listed in the Attachment 1. If the scope is altered, this Project's estimate is no longer valid and the estimate must be reviewed and updated.

6. Other Items Considered
    - **Other Potential Distribution Upgrades**: The Project is dependent upon the installation of the Storage Management System (SMS). The installation of the SMS was triggered by prior queued projects which currently hold the cost responsibility for the upgrade. In the event that: (i) the interconnection requests for one or more of such projects are withdrawn; (ii) any of the interconnection agreements for such projects are terminated prior to the in-service date of such distribution upgrade; or (iii) it is determined by the Distribution Provider that some or all of such distribution upgrade currently assigned to earlier-queued projects are no longer required by such projects but are required for the Project at hand, then the Interconnection Customer may be responsible for the costs of other potential distribution upgrade(s). The Interconnection Customer's cost responsibility for any distribution upgrade costs not already identified in this study report will be reflected in an addendum report or GIA amendment. Therefore, in the event that prior queued projects do not execute a GIA and the SMS is still required, the Project may be allocated up to 100% responsibility related to the initial programming (backbone) of the SMS.
    - The battery storage component of the Project will need to be metered separately. The IC should be prepared to install multiple sets of metering (i.e. separate sets of PTs & CTs

and supporting metering equipment) for the Project to separately meter their wholesale and retail loads. Additionally, the Project may also need to connect any component that will be connected as a wholesale load to a dedicated transformer separate from the transformer that will serve their retail load.

C. RELIABILITY STANDARDS, STUDY CRITERIA AND METHODOLOGY

The generator interconnection studies were conducted to ensure the CAISO-controlled grid is in compliance with the North American Electric Reliability Corporation (NERC) reliability standards, WECC regional criteria, and the CAISO planning standards. Refer to Section C of the Area Report for details of the applicable reliability standards, study criteria, and methodology.

D. POWER FLOW RELIABILITY ASSESSMENT RESULTS

Discharging Analysis of the Project

I. Steady State Power Flow Analysis Results – Bulk Electric System

The study indicated that QC9 Metro Area projects, including this Project, do not contribute to overloads following evaluation under all conditions outlined per NERC Standard TPL-004-1. The study included all existing and prior queued transmission upgrades on the Bulk Electric System. Consequently, the Project is not allocated cost for any Reliability Network Upgrades identified to address power flow issues. The details of the power analysis are provided in the Metro Bulk Area Report.

II. Steady State Power Flow Analysis Results – Subtransmission System

1. Thermal Overloads

The Johanna 66 kV Subtransmission Assessment indicated the Project does not contribute to overloads under Base Case or Single Contingency scenarios with all existing and prior queued transmission upgrades on the Johanna 66 kV Subtransmission System. Consequently, the Project is not allocated cost for any Distribution Upgrades identified to address power flow issues. The details of the power flow analysis are provided in Johanna 66 kV Subtransmission Assessment. The results identified in this section assume QC9 Phase I Projects dispatched at their requested maximum output.

2. Voltage Performance

The Project is required to provide power factor regulation capability [redacted] to alleviate power flow non-convergence and maintain the transmission transfer capability.

3. Required Mitigations

There are no required mitigations based on the discharging analysis.

Charging Analysis of the Project

I. Steady State Power Flow Analysis Results – Bulk Electric System

Under charging conditions, the study did not identify any power flow issues on the Bulk Electric System not addressed via the use of CAISO Congestion Management or via already approved transmission upgrades. Consequently, the Project is not allocated cost for any Reliability Network Upgrades identified to address power flow issues related to charging operation.

II. Steady State Power Flow Analysis Results –Subtransmission System

1. Thermal Overloads

The group study indicated that the Project did not contribute to overloads under Base Case or Single Contingency scenarios with existing and prior queued transmission upgrades with the third A-Bank installed on the Johanna 66 kV Subtransmission System.

A group sensitivity study was done without the third A-Bank installed and the subtransmission system shows overloads under Base Case and Single Contingency scenerios. Consequently, with existing and prior queued transmission upgrades, the Johanna 66 kV Subtransmission System is inadequate to accommodate the Project without mitigation. The recommended mitigation involves the use of a storage management system (SMS) which would limit or restrict charging based on the loadings on the existing Johanna 220/66 kV transformers banks.

I. Base Case (with two A-Bank transformers)

- [redacted]

II. Single Contingency (with two A-Bank transformers)

- [redacted]

The details of the analysis is provided in the Johanna Subtransmission Assessment Report. The results identified in this section assume QC9 Phase I Projects dispatched at their requested maximum output.

2. Voltage Performance

The Project is required to provide power factor regulation capability [redacted] to alleviate power flow non-convergence and maintain the transmission transfer capability.

3. Required Mitigations

The required mitigation is to install a **storage management system (SMS)** to curtail the Project's and providing [redacted] power factor regulation capability at the point of interconnection. Based on the sensitivity study at Johanna Subtransmission System with two (2) 220/66kV A-Bank transformers the SMS is necessary. With the addition of the third 220/66kV A-Bank at Johanna the mitigation for the SMS to curtail the Project will no longer be required unless there is an increase in load and/or additional projects requests interconnection in the area that studies shows the SMS is needed in the future.

E. SHORT-CIRCUIT DUTY RESULTS

Short-circuit studies were performed to determine the fault duty impact of adding the Phase I projects to the distribution 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 Phase I is determined. Each project in the cluster will be responsible for its share of the upgrade cost based on the rules set forth in Section 4 of the GIP.

1. **Short-Circuit Duty Study Input Data**
   The IC provided technical data for the identified inverter (specified in Section 2). SCE compared the technical data provided against manufacturer data, if the manufacturer Short-Circuit Duty (SCD) information for the specific inverter was available. If the technical data provided by the IC differed from the inverter manufacturer data, then SCE utilized the manufacturer data in the SCD analysis. In this case, SCE utilized the IC data.

   Inverter Based Generation Data for Each Generation Unit
   Maximum Fault Contribution: [redacted]

   Generation Tie-Line:
   This generation tie-line impedance was based on the Project tower and line conductor characteristics provided by the IC.

Length:	[redacted]
Conductor:	[redacted]
Z1(p.u.) conductor impedance information:	[redacted]
Z0(p.u.) conductor impedance information:	[redacted]

   Collector System:
   Technical data provided by the IC indicates the following parameters as representative for the collector system served out of the main transformer bank.

Z1(p.u.) conductor impedance information:	[redacted]
Z0(p.u.) conductor impedance information:	[redacted]

   Generation Step-Up and Pad-Mount Transformers
   Technical details are provided above in Table A-1.

2. **Short-Circuit Duty Study Results**
   All bus locations where the Phase I 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 Phase I 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 IRs in that Group Study pro-rata on the basis of SCD contribution of each Generating Facility.

   Please refer to the QC9 Phase I Area Report for the QC9 Phase I breaker evaluation which did not identify overstressed circuit breakers triggered with the inclusion of QC9 Phase I without ADNUs.

3. **Potential Affected Systems**
   The SCD incremental increase to neighboring utilities due to the addition of all QC9 Phase I projects are provided in the Area Report (Section J.2). The studies determined that this project does not provide any incremental duty to neighboring utilities.

4. **SCE Substations with Ground Grid Duty Concerns**
   The short-circuit studies flagged for further review a total of five (5) existing substations where the Phase I projects increased the substation ground grid duty by at least 0.25 kA. Additional review will be performed as part of Phase II to determine if any of these locations will require a detailed ground grid analysis performed as part of project execution once GIAs are in place and projects proceed forward towards interconnection.

F. TRANSIENT STABILITY EVALUATION

With the Project providing [redacted] correction as measured at the POI and including the required mitigation identified above, transient stability performance was found to be acceptable. Refer to Sections C.3 and D.2 of the Area Report, for additional details pertaining to the PI transient stability evaluation criteria and assessment results, respectively.

G. 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 [redacted]. Additionally, the generation system must be designed to accommodate a Voltage and/or VAR schedule provided by SCE. SCE will determine if the Voltage and/or VAR schedule is necessary based on future re-arrangements of SCE's Distribution System.

H. DELIVERABILITY ASSESSMENT RESULTS

1. **On Peak Deliverability Assessment**
   The Project does not contribute to any deliverability issues.

2. **Off- Peak Deliverability Assessment**
   The Project does not contribute to any off-peak deliverability issues.

3. **Required Mitigations**
   No Delivery Network Upgrades are required.

I. INTERCONNECTION FACILITIES, NETWORK UPGRADES, AND DISTRIBUTION UPGRADES

Please see Attachment 1 for the Distribution Provider's Interconnection Facilities (IFs), Reliability Network Upgrades (RNUs), Delivery Network Upgrades (DNUs), and Distribution Upgrades (DUs) allocated to the Project. Please note that SCE will not "reserve" the identified IFs for the proposed POI.

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[4] The current CAISO Tariff requires that projects be able to meet power factor requirements of 0.95 lagging and 0.95 leading at the POI, if studies identify the need based on meeting reliability and safety requirements. The requirement will change pending FERC approval of CAISO's compliance filing to FERC Order 827.

The identified scope/facilities will be allocated to the Project upon the successful execution of the GIA and SCE has completed the detailed design and engineering of the facilities according to tariff timelines.

J. COST AND CONSTRUCTION DURATION ESTIMATES

To determine the cost responsibility of each generation project in Phase I, the CAISO developed cost allocation factors (Attachment 3) for RNUs, Local Delivery Network Upgrades (LDNUs), and Area Delivery Network Upgrades (ADNUs). Attachment 2 provides the 'constant' 2016 dollars and their escalation to the estimated COD year for IFs, RNUs, DNUs, and DUs, which the Project was allocated cost.

For the QC9 Phase I Study, the estimated COD is derived by taking into account time requirements to complete the QC9 Interconnection Process and tender a draft Generator Interconnection Agreement (GIA). A GIA is not scheduled to be tendered until after the completion of the QC9 Phase II Studies, CAISOs Annual Reassessment and the CAISOs Transmission Planning Deliverability (TPD)[5] Allocation Study Process. The QC9 Phase II Study is scheduled to start on May 2017 and be completed by November 2017. Subsequently, the Annual Reassessment effort and TPD Allocation Study does not commence until late January or early February 2018. The TPD Allocation Study is scheduled to be completed by April 2018. If the CAISO and SCE can make a determination that the TPD Allocation Study Process outcomes do not change the scope requirements for the project, a letter will be provided at the end of April 2018[6] informing the IC that there will be no changes to their Network Upgrades requirements and GIA negotiations can begin. Otherwise, further re-assessment will be performed for the project. If updates to scope, cost and schedule are developed, an updated Interconnection Study report will be issued to the IC by the end of July 2018. The GIA negotiations commence after either the issuance of the letter of no change to the project's Network Upgrades requirements at the end of April 2018 or upon issuance of the updated Interconnection Study report at the end of July 2017. Provided the Project does not elect to Park for one (1) year, the letter issued by the CAISO and/or the updated Interconnection Study reports will be used as the basis to negotiate the GIA. Assuming a three (3) month timeframe for GIA negotiations after the draft GIA has been issued to the IC, an executable GIA is not expected until either early August 2018 or early November 2018 depending on TPD Allocation Study Process results, which requires a decision from the IC to Park or proceed and will determine if the Project needs to complete the Reassessment Study. QC9 Phase I assumed the duration of the work element begins in December 2018, which accounts for the negotiation and execution of a GIA and submittal of required funds by the IC.

Based on the above, the requested IC In-Service Date (ISD) of September 15, 2019 cannot be met due to the estimated 27-month timeline identified for the Plan of Service (POS) facilities and installation of the Storage Management System (SMS) required to interconnect the Project. Following the standard interconnection process, the ISD should be modified accordingly. The IC should note that a 35% Income Tax Component of Contribution (ITCC) will be assessed for IFs, DUs, and RNUs above the $60K/MW repayment cap allocated to the Project. Attachment 2 to your Interconnection Study report contains a potential ITCC estimate[7] based on the Phase I cost in this study. It does not represent the "maximum

[5] Transmission Plan Deliverability: Deliverability supported by the CAISO's Transmission Plan

[6] The TPD Allocation Process is estimated to be completed in April 2018. The actual date may vary

[7] The maximum ITCC exposure applies ITCC (35%) to assigned IF and DU facilities. For Network Upgrades, costs that are not subject to transmission credits and/or exceed the $60k/MW cap will be subject to ITCC (35%). For Option A facilities: The maximum ITCC exposure is calculated by applying the following formula: (IF*35%) + ((RNU Costs – (Project MW*($60k/MW)))*35%) + (DU*35%). For Option B facilities: The maximum ITCC exposure is calculated by applying the following formula: (IF*35%) + ((RNU Costs – (Project MW*($60k/MW)))*35%) + (DU*35%)

ITCC exposure" of the Project. Attachment 3 provides an estimated non-reimbursable RNU cost that would be subject to ITCC, taking into account the Network Upgrades maximum cost responsibility. The maximum ITCC warranted by the Project will be addressed, calculated, and included during the GIA development phase once the IC submits the TP Deliverability Allocation Study Process options form used to confirm the acceptance, waiver (parking), or denial of the awarded deliverability assigned to the Project.

K. 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's Interconnection Handbook provided in Attachment 4.

The IC is responsible for complying with IEEE Standard 519-2014 Recommended Practice and Requirements for Harmonic Control in Electric Power Systems on SCE's Transmission System.

L. SUBSYNCHRONOUS INTERACTION EVALUATIONS

Certain generators or inverter based generators when interconnected within electrical proximity of series capacitor banks on the transmission system are susceptible to Sub-Synchronous Interaction (SSI) conditions which must be evaluated. Subsynchronous Interaction evaluations include Subsynchronous Resonance (SSR) and Subsynchronous Torsional Interactions (SSTI) for conventional generation units, and Subsynchronous Control Instability (SSCI) for inverter based generators using power electronic devices (e.g. Solar PV and Wind Turbines).

For projects interconnecting at the 220 kV voltage level and above in close electrical proximity of series capacitor banks on the transmission system a study will need to be performed to evaluate the SSI between Generating Facilities and the transmission system. Given the Project location it will not be necessary to perform these evaluations.

M. ENVIRONMENTAL ACTIVITIES, PERMITS, AND LICENSING

Please see Appendix K of the Area Report.

N. AFFECTED SYSTEMS COORDINATION

Please see Section H of the Area Report.

O. 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 POS and are not sufficient for permitting of facilities. The POS is subject to change as part of detailed engineering and design.

2. The study does not include analysis related to the power output rate of change that may occur due to the following or other conditions:

   - System morning start up for solar systems. That is when each morning the generating facility commences to generate and export electrical energy to the electric system.

- Cloud Cover. Solar generating facilities have significant generation output variation (Variability) which can have an impact on electric system voltage profiles.
- The customer's Generating Facility will have equipment, software, and the appropriate controls in place to be able to control the generation output rates of change, as specified by SCE, in order to maintain appropriate voltage levels under all conditions including, but not limited to, the conditions identified above. Upon execution of the appropriate Interconnection Agreement, SCE will provide the Interconnection Customer the required ramp rate control parameters. The ramp rate controls will be a function of the generation penetration on the electric system as well as SCE's electric system configuration but other parameters may be considered. Therefore, changes to the ramp rate control scheme may be required from time to time as required by increased generation, changes in the electric system topology, or other changes in the electric system.

3. **IC's Technical Data**
   The study accuracy and results for the QC9 Phase I Study are contingent upon the accuracy of the technical data provided by the each IC for their respective IR(s). Any changes from the data provided as allowed by the tariff would need to be submitted in Attachment B within 5 business days from the Phase I results meeting. Any changes that extend beyond the modifications allowed in Appendix B submission will need to be evaluated following the Material Modification Assessment to determine if such change results in a material impact to queued-behind generation requests. These change(s) would only be allowed if it is determined that there is no material impact to queued-behind requests.

4. **Study Impacts on Neighboring Utilities**
   Results or consequences of this Phase I 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 ISO Controlled Grid, and sub-synchronous resonance (SSR). Refer to Affected Systems Coordination Section of the Area Report for additional information.

5. **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 the Distribution Provider's facilities and property. This Phase I 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 the Distribution Provider's facilities. The crossing of Distribution Provider property rights shall only be permitted upon written agreement between Distribution Provider and the IC at the 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.

6. **Distribution Provider's Interconnection Handbook**
   The IC shall be required to adhere to all applicable requirements in the Distribution Provider's Interconnection Handbook. These include, but are not limited to, all applicable protection, voltage regulation, VAR correction, harmonics, switching and tagging, and metering requirements.

7. **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.

8. **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.

9. **Standby Power and Temporary Construction Power**
   The Phase I Study does not address any requirements for standby power or temporary construction power that the Project may require prior to the ISD of the Interconnection Facilities. Should the Project require standby power or temporary construction power from the Distribution Provider prior to the ISD of the IFs, the IC is responsible to make appropriate arrangements with Distribution Provider to receive and pay for such retail service.

10. **Licensing Cost and Estimated Time to Construct Estimate (Duration)**
    The estimated licensing cost and durations applied to this Project are based on the Project scope details presented in this Phase I study. These estimates are subject to change as the Project's environmental and real estate elements are further defined. Upon execution of the GIA, 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 the RAS were assumed based on tripping of the generator's breaker in lieu of tripping the circuit breakers at the Distribution Provider's substation. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of 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 Phase I 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 detailed engineering for the Project at the SCE substations whose ground grids were flagged with duty concerns.

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 Phase I Study for the Project. Nothing in this report is

intended to supersede or establish terms/conditions specified in GIAs agreed to by the Distribution Provider, ISO, and the IC.

14. **Process for Initial Synchronization Date/Trial Operation Date and COD of the Project**
The IC is reminded that the ISO has implemented a New Resource Implementation (NRI) process that ensures that a generation resource meets all requirements before Initial Synchronization Date/Trial Operation Date and COD. The NRI uses a bucket system for deliverables from the IC that are required to be approved by the CAISO. The first step of this process is to submit an "ISO Initial Contact Information Request form" at least seven (7) months in advance of the planned Initial Synchronization Date. Subsequently an NRI project number will be assigned to the project for all future communications with the CAISO. The Distribution Providers have no involvement in this NRI process except to inform the IC of this process requirement. Further information on the NRI process can be obtained from the CAISO Website using the following links:
New Resource Implementation webpage:
http://www.caiso.com/participate/Pages/NewResourceImplementation/Default.aspx

NRI Checklist:
http://www.caiso.com/Documents/NewResourceImplementationChecklist.xls

NRI Guide:
http://www.caiso.com/Documents/NewResourceImplementationGuide.doc

15. **Potential Changes in Cost Responsibility**
The IC is advised that interconnection of its proposed Generating Facility may be dependent upon the construction of certain Network Upgrades, which are currently the obligation of projects ahead of its proposed Generating Facility in the interconnection application queue. These other potential network upgrades are referenced in Section B.5 of the Area Report and outlined in Attachment 2 to the ICs final Phase I or Phase II Study Report (Appendix A).

Whether the IC becomes responsible for all or a portion of these other potential network upgrades depends upon several factors, some of which are unknown at the time of this study. However, in an effort to alert the IC to its maximum cost responsibility for Network Upgrades, were these other potential network upgrades to become the obligation of the IC, SCE has included the IC's proportionate cost responsibility for these upgrades under the other potential network upgrades section in Attachment 2 to this report. The IC is not required to post Interconnection Financial Security for these other potential network upgrades, but the prospective obligation to finance and construct these other potential network upgrades is included in the IC's maximum cost responsibility.

The obligation to finance and construct these other potential network upgrades is governed by Sections 4.6.8 and 10.3.2 of the GIP and 14.2.2 of the GIDAP. Both the GIP and GIDAP contain similar language, which is summarized as follows:

1) If the earlier-queued generating facilities that have cost responsibility for the other potential network upgrades withdraw prior to executing a GIA (or the filing of an unexecuted GIA at FERC), the following will occur:

    a. The ISO and SCE will evaluate whether the other potential network upgrades are still needed to support the interconnection for later-queued generating facilities.

b. The ISO and SCE will reapportion the cost of the other potential network upgrades to the later-queued generating facilities that require the upgrades.

c. Steps (a and b) will occur as a result of the ISO's Annual Reassessment as set forth in Section 7.4 of GIDAP and Section 6.2.9.2 of the ISO's GIDAP business practice manual.

d. The reapportioned cost of the other potential network upgrades will be reflected in the reassessment report as outlined in the ISO's Annual Reassessment process, which will be reflected in the GIAs of the responsible parties.

2) Please refer to Section 10.3.2 of the GIP and Section 14.2.2 of the GIDAP for additional requirements regarding treatment of other potential network upgrades for ICs that select an Option (B) Generating Facility.

16. **ISO Market Dispatch**
This study did not evaluate any potential limitations that may be driven by the ISO market under real-time operating conditions.

17. Please note that the Distribution Provider has made its best efforts to convey as much information as possible based on information provided by the IC about its proposed Project. The information contained herein may indicate to ICs that a project of its magnitude may be better suited to interconnect at higher voltage levels, or downsize as to not incur significant amount of restrictions. Any determination to change POIs or downsize is purely at the IC's discretion and would be subject to a Distribution Provider's material modification review pursuant to the tariff.

18. **Future Charging Restrictions**
Charging restrictions not identified in this study may occur in the future if the underlying operating assumptions prove to be significantly different than the conditions evaluated in this study.

Attachment 1:
Interconnection Facilities, Network Upgrades and Distribution Upgrades
Please refer to separate document

Attachment 2:
Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades
Please refer to separate document

Attachment 3:
Allocation of Network Upgrades for Cost Estimates and Maximum Network Upgrade Cost Responsibility

None identified in the QC9PI Study.

Attachment 4:
Distribution Provider's Interconnection Handbook

Preliminary Protection Requirements for Interconnection Facilities are outlined in the Distribution Provider's Interconnection Handbook (separate document)

Attachment 5:
Short-Circuit Duty Calculation Study Results
Please refer to the Appendix H of the Area Report

Attachment 6:
Interconnection Customer Provided Project Dynamic Data

[redacted]

Attachment 7:
Not Used

Attachment 8:
Subtransmission Assessment Report
Please refer to separate document