Appendix A – WDT1293

[redacted]

Queue Cluster 8 Phase II Report

November 23, 2016

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)

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Attachments:

1. Interconnection Facilities, Network Upgrades, and Distribution Upgrades
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3. Not Used
4. SCE Interconnection Handbook
5. Short-Circuit Duty Calculation Study Results (see Appendix H of the Bulk Area Report)
6. Interconnection Customer Provided Dynamic Data
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8. Subtransmission Assessment Report – Barre 66 kV System

A. Introduction

[redacted]the Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to Southern California Edison Company (SCE) for their proposed [redacted] Project. The Project, located in Stanton, CA, requested a Point of Interconnection (POI) to Southern California Edison Company's (SCE) Barre 66 kV Switchrack through the proposed [redacted] Substation located in Orange County, CA (WDT1189). WDT1189 is planned to be interconnected to the Barre 66 kV switchrack AB Section. The IC elected Option A with Full Capacity Deliverability Status (FCDS) for their Project. The IC desires an In-Service Date (ISD) of March 31, 2019 and a Commercial Operation Date (COD) of June 1, 2019. Such dates are specified in the Project's Attachment B to the Generator Interconnection Study Process Agreement. Actual ISD and COD will depend on licensing, engineering, detailed design, and construction requirements to interconnect the Project to SCE's distribution system; after the Generator Interconnection Agreement (GIA) has been executed and filed at Federal Energy Regulatory Commission (FERC) for acceptance.

In accordance with FERC approved SCE's WDAT Attachment I GIP, the Project was grouped with other Queue Cluster 8 (QC8) Phase II 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 prepared separately identifying the combined impacts of all projects in the group on the ISO Grid and to distribution facilities served out of the Barre 66 kV Subtransmission System, respectively. This Appendix A report focuses only on the impacts or impact contributions specific to the Project and is not intended to supersede any contractual terms or conditions that may be specified in a 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 unit cost estimate of the Project's cost responsibility and time to construct[1] 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 energy storage facilities within SCE's distribution system. These analyses focused on the charging[2] aspects of the energy storage facilities and consider varying levels of system demand with minimal generation dispatch within the local distribution system.

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[1] 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

[2] Charging is defined as the Project drawing energy from the grid to "charge" the Project and store the energy for later release back to the grid.

Consequently, the report also discloses the adequacy of SCE's Distribution System to support the charging aspects of the energy storage facilities, identifies system limitations that may restrict the energy storage 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 equipment and facilities comprising the Project's Generating Facility are located in Stanton, California, as disclosed by the IC in its IR. The Energy Storage Facility, as may have been amended during the Interconnection Study process, is a inverter based energy storage facility which consists of (i) [redacted] with a rated output of [redacted] each for a combined gross rated output of [redacted] as measured at the inverter terminals, (ii) the associated infrastructure and step-up transformers, (iii) meters and metering equipment, and (iv) appurtenant equipment.

Based on the technical data provided for the main and pad-mount transformer banks, the total internal Project losses were identified to be 0.1 MW. The net output, as measured at the high-side of the main tranformer bank, is identified to be 19.9 MW when subtracting the total internal Project losses as identified by the IC. No losses due to the auxillary load were taken into account since no auxillary load was identified by the IC. Losses on the generation tie-line were identified to be minimal resulting in a POI delivery of 19.9 MW, which is less than the 20 MW POI delivery requested amount.

The Project shall consist of the Generating Facility and the IC's Interconnection Facilities as illustrated below in Figure A.1 and summarized in Table A.1. A map illustrating the location of the Project is provided below in Figure A.1.

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

Project Location	[redacted]
Distribution Provider's Planning Area	Distribution Provider's Metro Bulk Area
Interconnection Voltage	66 kV
POI	Distribution Provider's Barre 66 kV Switchrack (AB Section)
Requested Maximum Project Output as Measured at POI	20.0 MW (See Note 2)
Number and Types of Generators	[redacted]
Power Factor Range	[redacted]
Step-Up Transformer(s)	[redacted]
Generator Auxiliary Load	[redacted]
Internal Generation Facility Losses	0.1 MW
Maximum Net Output as Metered on High-Side of Main Transformer (Gross output less auxiliary load less internal losses)	19.9 MW
Estimated Losses on Gen-Tie Facilities	Negligible
Maximum POI Delivery (Net output less gen-tie losses)	19.9 MW (See Note 3)
Barre-WDT1293 Gen-Tie	6,000 FT of bundled 3000 CU XLP and 400 FT bundled overhead 954 AL SAC for SCE
ISD	March 31, 2019
Initial Synchronization Date/Trial Operation	March 31, 2019
COD	June 1, 2019

Notes for Table 1.1:

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 losses. The estimated Maximum Net Output at POI and Generation Tie-Line Losses values illustrated above are contingent upon the accuracy of the technical data provided by the IC in the Appendix B, and are subject to change should the IC change its generation tie line parameters during the final engineering and design phase of the Project.

Note 3: Based on the technical data provided, the Project will be outputting less than the requested amount of 20 MW at the POI.

B. Study Assumptions

For detailed assumptions regarding the group cluster analysis at the transmission and subtransmission levels, please refer to the applicable Area Report and Subtransmission Assessment 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 as interconnecting to SCE's Barre 66 kV Switchrack (AB Section) through the proposed WDT1189[redacted]Substation via the 66 kV generation tie-line (gen-tie). The ISO delivery point is at the Barre 220 kV Bus.

2. The following facilities will be installed by SCE and **<u>are included</u>** in this Interconnection Study report:

   - The new 66 kV position at Barre Substation
   - The segment of a Barre-WDT1293 66 kV generation tie-line inside the Barre 66 kV substation property line.
   - The segments of each one of the two generator-owned telecommunications channels inside the Barre Substation property line.
   - The required retail and wholesale load meters.
   - Lightwave, channel banks, and associated equipment at Barre Substation and at the Generating Facility.
     NOTE: SCE installation does not include metering potential transformers (PTs) and 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 IC and **<u>are not included</u>** in this Interconnection Study report:

   - The Barre-WDT1293 66 kV generation tie-line from the Generating Facility to the last structure outside the SCE Barre 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 (PT, and, CT and ISO meters).

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

   - The following line protection relays to be installed at the Generating Facility end of the 66 kV gen-tie line:

     - [redacted]
     - [redacted]

4. Energy Storage Facility Charging Considerations:

    - This study assumes that the IC Generating Facility will include all equipment, software, appropriate controls, and other related equipment necessary to maintain the energy storage facility demand profile per SCE requirements.
    - In order to ensure limits are communicated in a timely and reliable manner, the IC is responsible for providing reliable communications between the Project and the Point of Interconnection to transmit the required telemetry data as outlined in the Interconnection Handbook. Should the communication channel fail, the Project's operating limits will automatically revert to zero (no charging allowed).
    - Depending on the study results, the Project may need to participate in the Storage Management System (SMS).
    - An SMS, which at this stage is a technical concept, is under development to incorporate the increased amount of energy storage applications to SCE's Distribution System with minimal distribution upgrades. It is assumed that a SMS or similar system will be available prior to the In-Service Date of the energy storage facility and further details will be available during the detailed engineering and design phase of the Project. The SMS will actively communicate allowable Project limits under charging mode to maintain safe and reliable operation of the distribution system.
    - The energy storage component of the Project will need to be metered separately from the retail load components. The IC should be prepared to install multiple sets of metering (i.e. separate sets of potential and current transformers and supporting metering equipment) for the Project. Additionally, the Project may also need to connect the energy storage component to a dedicated transformer.
    - For this study, an additional reliability assessment for the charging of storage component was evaluated. Please refer to Attachment 8 for additional details.

5. Environmental Services (ES)

    a. Internal Substation Scope:

        - SCE will perform all environmental studies and monitoring of all SCE internal substation construction activities.

    b. 66 kV Generation Tie Line Scope:

        - SCE will act as the environmental liaison between the SCE team and IC team, and the lead for regulatory agency communication.
        - SCE's scope of work will not require a California Public Utilities Commission license.
        - 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

➢ 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.

C. Reliability Standards, Study Criteria and Methodology

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

D. Power Flow Reliability Assessment Results

Discharge Analysis of the Project

I. Steady State Power Flow Analysis Results – 220 kV and above

1. Thermal Overloads

   The study did not identify that the Project contributes to any overloads/non-convergence problems on the Bulk Electric System requiring Reliability Network Upgrades to mitigate. Consequently, the Project did not get allocated costs for any Network Upgrades. Refer to enclosed Area Report in the report package for the Phase II power flow analysis results.

2. Power Flow Non-Convergence

   There were no power flow overload issues identified on the Bulk Electric System with the inclusion of the Project. Refer to enclosed Area Report in the report package for the Phase II power flow analysis results.

3. 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. Refer to enclosed Area Report in the report package for the Phase II power flow analysis results

4. Required Mitigations

   No mitigation, beyond power factor regulation capability, is required by the Project on the Transmission System.

II. Steady State Power Flow Analysis Results – 66 kV

The Barre 66 kV Subtransmission Assessment indicated that the Project does not contribute to any overloads/non-convergence problems on the Barre 66 kV Subtransmission System. Consequently, the Project did not get allocated costs for any upgrades at the subtransmission level. Refer to enclosed Subtransmission Assessment Report in the report package for the power flow analysis results.

1. Thermal Overloads

   There were no power flow overload issues identified on the Subtransmission System with the inclusion of the Project. Refer to enclosed Subtransmission Assessment Report in the report package for the Phase II power flow analysis results.

2. Power Flow Non-Convergence

There were no power flow overload issues identified on the on the Subtransmission System with the inclusion of the Project. Refer to enclosed Subtransmission Assessment Report in the report package for the Phase II power flow analysis results.

3. Voltage Performance

The Project is required to provide power factor regulation capability (0.95 lead/lag at POI) to alleviate power flow non-convergence and maintain the transmission transfer capability.

4. Required Mitigations

No mitigations on the subtransmission system were identified to be required by the Project.

Charging Analysis of Project

I. Steady State Power Flow Analysis Results – 220 kV and above

Under charging conditions, the study did not identify any power flow issues on the Bulk Electric System not addressed via the use of ISO Congestion Management or via already approved transmission upgrades. Consequently, the Project is not allocated cost for any Network Upgrades identified to address power flow issues. The details of the power flow analysis are provided in Section D of the Metro Area Report.

II. Steady State Power Flow Analysis Results – 66 kV

Under charging conditions, the study indicated that the Project contributes to the following facility overloads or non-convergence problems. The details of the analysis and overload levels are provided in the Subtransmission Assessment Report.

1. Thermal Overloads

The Barre 66 kV Subtransmission Assessment indicated that the Project contributes to overloads/non-convergence problems on the Barre 66 kV Subtransmission System. Consequently, the Project has been allocated costs for upgrades at the subtransmission level

- Base Case (All facilities in service, N-0)

  The only base case overload identified involves the Project gen-tie. [redacted]

- Single Contingency (N-1)

  [redacted]

2. Power Flow Non-Convergence

There were no non-convergence issues identified with the inclusion of the Project operating at the required power factor range, refer to the Subtransmission Report for additional details.

3. Voltage Performance

The Project is required to provide power factor regulation capability [redacted] to alleviate power flow non-convergence and maintain the subtransmission transfer capability. In addition, a SMS (Distribution Upgrade) is required to mitigate the power flow impacts of the Project described above.

4. Required Mitigations

Beyond power factor regulation capability, as required by the Project on the subtransmission system, a storage management system (SMS) is required to mitigate the power flow impacts of the Project under loss of an A-bank transformer at the Barre Substation. The SMS is to provide signals that would restrict charging operation of the energy storage facility in a manner that ensures overloads will not occur under loss of an A-Bank. Refer to Attachment 1 and Attachment 2 for scope description and associated project cost responsibility of these Distribution Upgrade(s).

E. Short-Circuit Duty Results

Short-circuit studies were performed to determine the fault duty impact of adding the 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 overstressed conditions. Once overstressed circuit breakers caused by the inclusion of the QC8 projects and/or queued-ahead generation were identified, the fault current contribution from each individual project in QC8 Phase II were 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 (SCD) 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. Based on the comparison, the technical data provided by the IC is consistent with the manufacturer data.

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

Generation tie-line:
Gen-tie impedance is negligible due to s
hort distance.

Collector System:
Collector system assumed negligible for BESS Projects.

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

2. SCD Study Results

All bus locations where the Phase II projects increase the SCD 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 equipment is overstressed as a result of the inclusion of Phase II interconnections and corresponding Network Upgrades and Distribution Upgrades, if any.

The responsibility to finance short-circuit related Reliability Network Upgrades (RNU) and Distribution Upgrades (DU) identified through this SCD study shall be assigned to all Interconnection Requests in this QC8 Phase II study pro-rata on the basis of SCD contribution of each Generating Facility.

Please refer to in the Area Report for the Phase II breaker evaluation discussion, which identified overstressed circuit breakers at the SCE buses, and Attachment 2 for the pro-rata allocation with corresponding estimated costs (if any) for the Project, based on SCD contribution at each location.

However, it is important to note that QC7 Phase II identified an operational restriction that would necessitate restrictions to project operations as [redacted] This restriction is also applicable to the QC8 Project as the contribution results in incremental SCD to a location that is over maximum allowable SCD. Lastly, the QC7 Phase II studies identified a number of 66 kV circuit breakers at Barre that required upgrade. If the queued ahead Project which was studied as part of QC7 Phase II, WDAT 1189, subsequently withdrawals or if WDT1293 signs and executes an IA prior to WDAT 1189, there is no identified need to replace the triggered 66 kV breaker upgrades at Barre. [redacted] The potential need for WDT1293 to participate in such an OP would be dependent on whether the queued ahead Project subsequently signs and executes an IA for interconnection to Barre 66 kV.

3. Potential Affected Systems

   The SCD incremental increase to neighboring utilities due to the addition of all QC8 Phase II projects are provided in the Area Report (Section J.2). The studies determined this this project does not provide any incremental duty to neighboring utilities.

4. SCE Substations with Ground Grid Duty Concerns

   The short circuit studies flagged SCE-owned substations beyond the Project's POI with ground grid duty concerns that necessitate a ground grid study. However, this Project was not identified to provide meaningful single-line-to-ground fault contribution at any location where the single line to ground short circuit duty contribution increase was in excess of 0.25 kA where known ground grid ratings were less than he study results. Consequently, the project is not allocated scope or cost related to Ground Grid duty concerns.

F. Preliminary Protection Requirements

Protection requirements are designed and intended to protect the Distribution Provider's electrical 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 Generating Facility and must meet the requirements in the SCE Interconnection Handbook provided in Attachment 4.

G. Transient Stability Evaluation

With the Project providing [redacted] correction as measured at the POI, 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 transient stability evaluation criteria and assessment results, respectively

H. 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 [redacted] at POI for asynchronous generation and [redacted] at the generator terminals for synchronous generators. 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 Transmission System.

I. Deliverability Assessment Results

1. On Peak Deliverability Assessment

   The Project does not contribute to any deliverability constraint.

2. Off- Peak Deliverability Assessment

   Refer to off-peak reliability assessment.

3. Required Mitigations

   No Delivery Network Upgrades are required.

J. In-Service Date and Commercial Operation Date Assessment

The information provided by the IC in Appendix B indicates that the requested ISD and COD is March 31, 2019 and June 1, 2019, respectively. To determine if these dates could be met, an ISD and COD assessment was performed which considered both the QC8 Phase II Interconnection Study process timelines as well as the facilities needed to enable an energy only interconnection of the Project. Details pertaining to FCDS and Interim Deliverability are provided below in Section K.

1. Interconnection Process Timelines

   To enable physical interconnection, a Generation Interconnection Agreement (GIA) is required. As part of the interconnection Study cycle, a GIA is tendered following completion of the final Phase II Interconnection Study with the timing for tendering such GIA impacted by the ISO's Transmission Planning Deliverability (TPD) Allocation Study and the ISO's Annual Reassessment, if applicable.

   The TPD Allocation Study process is scheduled to be completed by April 2017 and if no changes to scope requirements are identified, a letter is provided by the ISO at the end of April 2017[3]

[3] The TPD Allocation Study Process is estimated to complete in April 2017. The actual date may vary.

outlining the TPD Allocation Study results. However, if changes to scope requirements are identified as part of the ISO's Annual Reassessment Study process, updates to scope, cost, and schedule are developed and provided in a Reassessment Study Report issued by the end of July. For Projects seeking a GIA with Partial Capacity Deliverability Status (PCDS) or FCDS pursuant to the TPD Allocation Study process, GIA negotiations may commence after the issuance of the letter at the end of April 2017, which outlines the TPD Allocation Study results, or upon issuance of the Reassessment Study Report at the end of July 2017, which updates scope, cost, and schedule. Assuming a three (3) month timeframe for GIA negotiations, after the GIA is tendered, the earliest that an executable GIA can be provided to the IC is August 2017, which is contingent on the IC's acceptance of the TPD Allocation Study results. If the Reassessment Study process affects the Project, an executable GIA is not expected until November 2017. The timeline for executing a GIA could be further delayed if the IC elects to "park" its IR until the following year's allocation of TP Deliverability.

2. Upgrade timelines needed for energy only Interconnection

   The ISD and COD assessment identified that the following facilities are required in order to interconnect the Project. The month durations shown represent the estimated amount of time needed to design and construct the facilities with the start date of the duration based on the effective date of the GIA, IC granting authorization to proceed (ATP), and IC posting financial security.

   a. Distribution Provider's Interconnection Facilities – 27 months

      These facilities involve non-network facilities located within a new SCE 66 kV substation (see Plan of Service Distribution Upgrades below) and at the IC's Project that are necessary to complete physical interconnection of the Project and ensure adequate line protection. Please refer to Section 1.b of Attachment 1 for details related to these facilities.

   b. Reliability Network Upgrades – 27 months

      SCD operational mitigation was identified taking into account new generation projects that have executed GIAs, approved Distribution Provider's Transmission Network Upgrades fully permitted and under construction, and new generation projects including the QC8 Phase II projects, which do not yet have an executed GIA. The study results for these operational studies are provided in Section II of the Generation Sequencing Implementation Short Circuit Duty evaluation (Appendix G). Based on the study results, replacement of four (4) Vincent 500 kV circuit breakers (triggered by QC3&4) are required to be in place in order to enable interconnection of the Project. Replacement of the four (4) Vincent 500 kV circuit breakers has not been initiated, because this upgrade is required only when sufficient generation projects (with executed GIAs in good standing) achieve ISD. The identification of the need for the Vincent 500 kV circuit breaker upgrades is based on the assumption that all queued generation projects actually materialize and are interconnected, but the true need occurs only when sufficient queued generation achieves ISD. This SCD mitigation will be continuously evaluated as part of ongoing GIA negotiations with queued generation projects to properly define the actual trigger of SCD mitigation based on the actual execution of GIAs and development of generation facilities.

c. Voltage Support Mitigation

No required voltage support upgrades were identified to enable this Project to interconnect.

d. Distribution Upgrades – 42 months

(i) Plan of Service – 27 months

Plan of Service Distribution Upgrades involve [redacted] Please refer to Section 3 of Attachment 1 for details.

(ii) Short-Circuit Duty Mitigation – 42 months

Short-circuit duty mitigation, triggered with the inclusion of WDT1189 (QC7 Project), involves replacing a number of 66 kV circuit breakers at the Barre 66 kV AB-Section. The timelines identified for these upgrades in the QC7 Phase II Interconnection Study report for WDT1189 was 42 months.

3. Conclusion

Based on the GIA execution timelines and milestone timelines to design and construct the facilities noted above, the IC's requested ISD of March 31, 2019 and COD of June 1, 2019 are not achievable. Such conclusion is consistent with the conclusions provided in the Project's Phase I Interconnection Study report. Assuming the earliest that an executable GIA can be provided to the IC is August 2017, which is contingent on the IC's acceptance of the 2017 TPD Allocation Study results, the ISD should be modified to reflect March 1, 2021 and the COD should be modified to reflect a date after the ISD. This date is predominately driven by the timing associated with 66 kV circuit breaker upgrades identified to be triggered by WDT1189 but aggravated by this Project. To modify such dates, the IC will need to submit a request for material evaluation following section 4.5.7.2 of the SCE's WDAT Attachment I Generator Interconnection Procedures (GIP).

K. Timing of Full Capacity Deliverability Status, Interim Deliverability, Area Constraints, and Operational Information

The IC elected Option A with FCDS for their Project. Timing of obtaining the requested FCDS is dependent on the completion of Delivery Network Upgrades. Until such time that the Delivery Network Upgrades are completed and placed into service, the Project may be granted interim deliverability based on annual system availability. The sections below provide a discussion of the timing of FCDS, interim deliverability, area constraints, and operational information.

1. System Upgrades Required for Full Capacity Deliverability Status
   No upgrades have been identified to be required (either previously triggered or triggered with the addition of QC8 Projects) for this project to obtain the requested FCDS.

2. Interim Operational Deliverability Assessment for Information Only

There are no deliverability constraints identified. The Project will have the deliverability status as granted by the Transmission Plan Deliverability allocation.

3. Conclusion
   Since no upgrades have been identified to be required to obtain FCDS, the requested Full Capacity Deliverability Status could be achieved upon interconnection.

L. Distribution Provider's Facilities, Network Upgrades, and Distribution Upgrades

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

M. Cost and Construction Duration Estimates

To determine the cost responsibility of each generation project in Phase II, the ISO 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.

The IC should note that any RNUs above the $60k/MW repayment cap allocated to the Project may be assessed 35% Income Tax Component of Contribution (ITCC), in addition to the 35% ITCC assessed to the Distribution Provider's IFs and DUs assigned to the Project. For your information, Attachment 2 contains a potential ITCC estimate based on the final Phase II cost in this study. It does not represent the "maximum ITCC exposure" to the Project. Attachment 3 provides an estimated non-reimbursable RNU cost that would be subject to ITCC, taking into account the maximum cost responsibility for Network Upgrades. The maximum ITCC assessed to the Project will be addressed, calculated, and included during the GIA development phase after the IC submits the TP Deliverability Allocation Study Process options form confirming to accept, decline, or park the allocation of deliverability awarded to the Project.

N. SCE Technical Requirements

The IC is responsible for the protection of its own system and equipment and must meet the requirements in the SCE Interconnection Handbook provided in Attachment 4. In addition, the IC is responsible for complying with IEEE Std 519-2014 Recommended Practice and Requirements for Harmonic Control in Electric Power Systems on SCE's Distribution/Subtransmission/Transmission System.

O. 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 (SI) 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 SI between generating facilities and the transmission system.

The IC is 100% responsible for any studies related to the SSR or SSTI. The only study that SCE will perform (at the IC's expense) is for SSCI; to ensure that the Project does not damage SCE's control systems.

The SSCI study will require that the IC provide a detailed PSCAD model of its Generating Facility and associated control systems, along with the manufacturer representative's contact information. The study will identify any mitigation(s) that will be required as part of project execution and need to be completed prior to initial synchronization of the Generating Facility. The study and the proposed mitigation(s) shall be at the expense of the IC.
It is the IC's responsibility to select, purchase, and install turbine/inverter based generators that are compatible with the series compensation in the area.

P. Environmental Evaluation, Permitting, and Licensing

Please see Appendix K of the QC8 Bulk Area Report.

Q. Affected Systems Coordination

Please see Section H of the QC8 Bulk Area Report.

R. 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. IC's Technical Data

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

   This 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 distribution system.
   - Cloud Cover. Solar generating facilities have significant generation output variation (Variability) which can have an impact on distribution system voltage profiles.
   - The customer's generating facility will have equipment, software, and the appropriate controls as 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 distribution system as well as SCE's distribution 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 in generation, changes in the distribution system topology, or other changes in the Distribution System.

3. Study Impacts on Neighboring Utilities

   Results or consequences of this Phase II Interconnection Study may require additional studies, facility additions, and/or operating procedures to address impacts to neighboring utilities and/or regional forums. For example, impacts may include but are not limited to Western Electricity Coordinating Council (WECC) path ratings, SCD outside of the ISO Grid, and SSR. Refer to Affected Systems Coordination Section of the QC8 Area Report for additional information.

4. Use of and/or Crossing Distribution Provider's Property

   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 property. This Phase II 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's property. The crossing of Distribution Provider property rights shall only be permitted upon written agreement between the Distribution Provider and the IC at the Distribution Provider's sole determination. Any proposed crossing of the Distribution Provider's property rights will require a separate study and/or evaluation, at the IC's expense, to determine whether such use may be accommodated.

5. SCE Interconnection Handbook

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

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. Standby Power and Temporary Construction Power

   The QC8 Phase II 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 Distribution Provider prior to the ISD of the IF, the IC is responsible to make appropriate arrangements with Distribution Provider to receive and pay for such retail service.

9. 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 study. These estimates are subject to change as Project 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.

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 generation tie line, excluding terminal equipment at both ends. In addition, the telecommunication requirements for SPS[4] 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 II Area Report. 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 Phase II may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

11. 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.

12. Applicability

    This document has been prepared to identify the impact(s) contributions of the Project on the SCE's Distribution System; as well as establish the technical requirements to interconnect the Project to the POI that was evaluated in the Phase II Study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in the GIAs agreed to by the Distribution Provider, ISO and the IC.

13. Process for synchronization/trial operations and commercial operations 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 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 ISO. 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 ISO. 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 ISO Website using the following links:

    New Resource Implementation webpage:
    http://www.ISO.com/participate/Pages/NewResourceImplementation/Default.aspx

    NRI Checklist:

[4] If applicable, Attachment 1 will refer to SPS as RAS to match the formal FERC definition change that will be occurring at the beginning of 2017.

http://www.ISO.com/Documents/NewResourceImplementationChecklist.xls

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

14. 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.

1) 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:
    a) 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:
    b) The ISO and SCE will evaluate whether the other potential network upgrades are still needed to support the interconnection for later-queued generating facilities
    c) The ISO and SCE will reapportion the cost of the other potential network upgrades to the later-queued generating facilities that require the upgrades
    d) 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
2) 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

    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.

15. Charging restrictions may occur in the future under future base case overloads.

16. Additional limitations may be driven by the ISO market and distribution system operations.

17. Please note that SCE 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 SCE material modification review pursuant to the tariff.

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
Not Used

No Network Upgrade costs were assigned to the Project.

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 Bulk Area Report

Attachment 6
Interconnection Customer Provided Dynamic Data
The following data was submitted by the IC for Dynamic simulation:

[redacted]

Attachment 7
Not Used

Attachment 8
Subtransmission Assessment Report
Please refer to separate document