Appendix A – WDT1185A

[redacted]

Queue Cluster 7 Phase II Report

November 24, 2015

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

Table of Contents

Attachments:

1. Interconnection Facilities, Network Upgrades, and Distribution Upgrades
2. Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades
3. Allocation of Network Upgrades for Cost Estimates and Maximum Network Upgrade Cost Responsibility
4. Distribution Provider Interconnection Handbook
5. Short Circuit Calculation Study Results (see Appendix H of the Area Report)
6. Not Used
7. Not Used
8. Subtransmission Assessment Report (if applicable)

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 plans to have a total output of [redacted] at the generating facility. The project requested a Point of Interconnection (POI) at [redacted] out of the [redacted] queue position WDT1185 (WDT1185A & WDT1185B). This report focuses on the [redacted] of the project interconnecting to the [redacted] The IC elected that the Project be Option A with Full Capacity Deliverability Status, and desires an In-Service Date (ISD) of December 1, 2018 and a Commercial Operation Date (COD) of December 1, 2019. Such dates are specified in the Project Attachment B. Actual ISD and COD will depend on design and construction requirements to interconnect for the Project.

In accordance with Federal Energy Regulatory Commission (FERC) approved CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP), the Project was grouped with Queue Cluster 7 (QC7) Phase II projects to determine the impacts of the group as well as impacts of the Project on the CAISO Controlled Grid.

Please note that the discussion related to the combined impacts at the transmission and subtransmission levels of the group resides in the Area Report and Subtransmission Assessment Reports; both reports are included in the QC7 PII report package. This report focuses only on the impacts or impact contributions of the Project at the local Distribution system, and it is not intended to supersede any contractual terms or conditions specified in a Generator Interconnection Agreement (GIA).

The report provides the following:

1. Distribution System impacts caused by the Project;
2. System reinforcements necessary to mitigate the adverse impacts caused by the Project under various system conditions;
3. A list of required facilities and a good faith estimate of the Project's cost responsibility and time to construct[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 [redacted] that required additional analysis be performed to evaluate the impacts of [redacted] These analyses focused on the charging[2] aspects of the [redacted] and consider varying levels of system demand with minimal generation dispatch within the local distribution system.

Consequently, the report also discloses the adequacy of SCE's Distribution System to support the charging aspects of the [redacted] identify system limitations that may restrict the [redacted]

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

[2] Charging is defined as when the Project draws energy from the grid to "charge" the Project-associated [redacted]

[redacted] ability to charge during certain demand conditions, and provide a high-level explanation of potential exposure to charging restrictions on the distribution system.

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

The Project shall consist of the Generating Facility and the IC's Interconnection Facilities as illustrated below in Figure A.1, as well as, Figure A.2 is a map that illustrates the location of the Project. Similarly, the Project information is summarized in Table A.1 below. The Project shall not exceed the total net output at the high voltage terminal of the main step-up transformer.

Figure A.1: Project 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	SCE Metro Area System
Number and Types of Generators	[redacted]
Interconnection Voltage	[redacted]
Maximum Generator Output	[redacted]
Generator Auxiliary Load	[redacted]
Maximum Net Output at Generation Facility	[redacted]
Power Factor Range	[redacted] at POI per interconnection application
Step-up Transformer(s)	[redacted]
POI	[redacted]
IC Requested COD	December 1, 2018

B. Study Assumptions

For detailed assumptions regarding the group cluster analysis at the transmission and subtransmission level, please refer to the applicable QC7 Phase II Area Report and Subtransmission Assessment Reports. Below are the assumptions specific to the Project.

1. The following is the Plan of Service (POS) assumed for the Project in the Phase II Study:

   The project was modeled as with a net output of [redacted] at the generation facility with its POI to the SCE Distribution System at the [redacted] at the Point of Change of Ownership (POCO).

2. The following Facilities will be installed by SCE and **<u>are included</u>** in this Phase II Study:
   - The required revenue metering cabinet and revenue load meters.

   NOTE: SCE installation does not include metering, voltage, and current transformers. The SCE Meters will be connected to the generator – owned voltage and current transformers to be installed for their CAISO metering.

   - Approximately 8,000 feet of 1000 JCN
   - Operational Control Switch (OCS) for isolation
   - One (1) underground clearing switch
   - 12 kV Primary Metering, CTs, PTs, and Associated Wiring
   - Telemetry – Remote Terminal Unit (RTU)
   - Substation Automation System Point addition

3. The following Facilities will be installed by the IC and **<u>are not included</u>** in this Phase II Study:
   - Ducts as required
   - Structures as required
   - Isolating circuit breaker
   - Protection System requirements to comply with the SCE Interconnection Handbook
   - Transformation as required
   - Metering Equipment compliant with SCE Electrical Service Requirements
   - CAISO metering as required

NOTE: SCE will install metering voltage, and current transformers to be used for the SCE owned revenue meters. The voltage and current transformers can be used for the customer CAISO metering.

4. The following SCE Distribution system Planning Criteria and Conditions were included in the Phase II Study:

   - The thermal rating of any conductor, connector, or apparatus shall not exceed 100% of its normal rated capacity with all facilities in service (base case).

   - The thermal rating of any conductor, connector, or apparatus shall not exceed 100% of its emergency rating under loss of one element (N-1) conditions.

   - Operational flexibility and reliability of the Distribution system shall be maintained at all times.

   - Circuit voltage profiles shall be maintained to comply within CPUC's Rule 2 requirements.

   - The power factor for the new generation facility was assumed to be within WDAT Tariff requirements of 0.95 lagging or leading.

   - Expected loading on the Distribution system as projected by the SCE 2014 - 2023 Distribution system plan was used.

   - Distributed Generation resources connected to the Distribution system are analyzed offline and online during peak load conditions as well as during minimum daytime load conditions as to determine worst case scenario.

   - The short circuit contribution from the inverter systems was determined using inverter manufacturer documents.

   - The Phase II Study assumes the upgrades triggered by previously queued projects, including Rule 21 projects under CPUC jurisdiction as In-Service, are included in the base case for the Phase II projects. If any previously queued projects were to withdraw, then the Phase II projects may be subjected to the cost identified for those previously queued projects.

   - Current Distribution standards are being updated to address generation interconnection systems. The proposed method of service in this report may change according on detailed design to comply with the updated Distribution design standards.

   - This study assumes that the IC generating facility will include all equipment, software, and appropriate controls necessary to maintain the generator output profile per SCE requirements. The IC will be responsible for maintaining designated voltage levels under all conditions, including but not limited to the conditions identified above. Upon execution of the Generator Interconnection Agreement, SCE will provide the IC with the required ramp rate control parameters. The ramp rate controls will be a function of the generation penetration on the Distribution system, as well as SCE's Distribution system configuration (additional parameters maybe considered, as need). Changes to the ramp rate control scheme may be required as determined by increased generation, changes in the Distribution system topology, or other changes in the Distribution system

5. Charging Termination Assumptions

   Dispatch of SCE's Distribution System with connected [redacted] (existing and queued) was done in a manner that would provide for relief on the system if needed. (Emergencies, N-1, Base case overloads, etc.) This effectively results in termination of charging sources such that they would not increase demand on the local distribution system.

6. Energy Storage Facility Charging Considerations

   - SCE's distribution standards and practices are in the process of being updated to address [redacted] The proposed method of service in this report may require changes to comply with the updated distribution design standards and practices.
   - This study assumes that the IC facility will include all equipment, software, appropriate controls, and other related equipment necessary to maintain the [redacted] demand profile per SCE requirements.
   - Upon execution of the Generator Interconnection Agreement, SCE will provide the IC with the required ramp rate[3] control parameters to operate the Generating Facility. The ramp rate controls will be a function of the demand on the distribution system, as well as SCE's Distribution System configuration (additional parameters maybe considered, as necessary).
   - 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 SCE system 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).
   - If the Project does not follow the given charging limitations, the Project will be disconnected
   - Depending on the study results, the Project may need to participate in the storage control system.
   - A [redacted] which at this stage is a technical concept, is under development to incorporate the increased amount of [redacted] applications to SCE's Distribution System with minimal distribution upgrades. It is assumed that a [redacted] or similar system will be available prior to the In-Service Date of the [redacted] and further details will be available during the detailed engineering and design phase of the Project. The [redacted] will actively

[3] It is assumed that ramp rates for each [redacted] will be dependent upon their inherent technology types. While very quick response ramp rates (i.e. going from full charge to full discharge instantaneously, or vice-versa) may be beneficial for other grid services, the Distribution Provider, may, at its discretion, require establishing limits to maintain safety and reliability of its distribution system.

communicate allowable Project limits under charging mode to maintain safe and reliable operation of the distribution system.

- The [redacted] of the Project will need to be metered separately from the revenue load components. 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. Additionally, the Project may also need to connect the [redacted] to a dedicated transformer.

Figure 2-1 [4]
Topology of SCE's Electric System

[redacted]

7. Charging Analysis Load Assumptions

The load assumptions used for SCE's Distribution System considers SCE's 2014 – 2023 Distribution Load Forecast and the previous two (2) years of historical data.

To model the hourly forecast demand performance of SCE's Distribution System, historical year 2013-2014 B-Bank and circuit data was obtained and adjusted to reflect the worst case year within SCE's Distribution Load forecast. The use of historical data established a baseline upon which to build a comparable hourly demand performance for the worst case year in SCE's Distribution Load Forecast. Shown below is the adjusted SCE [redacted] hourly demand performance.

[4] For illustrative purposes only.

Figure 2-2

[redacted]

Figure 2-3

[redacted]

C. Reliability Standards, Study Criteria and Methodology

1. Discharge Analysis Planning Criteria

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

2. Charging Analysis Planning Criteria

   This study was conducted by applying SCE's Distribution Planning Criteria. More specifically, the key criteria applicable to this Phase II Study are as follows:

   - The thermal rating of any conductor, connector, or apparatus shall not exceed 100% of its normal rated capacity[5] with all facilities in service (N-0 or base case).

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[5] Normal rated capacity or Planned Loading Limit (PLL) capacity is determined by the lesser of the limiting component on the distribution system or 75% of minimum trip of the upstream protection device.

- The thermal rating of any conductor, connector, or apparatus shall not exceed 100% of its emergency rated capacity under loss of one element (N-1) conditions.
- The thermal rating of any B-Bank shall not exceed 100% of its nameplate rated capacity with all facilities in service (N-0 or base case).
- The thermal rating of any B-Bank shall not exceed 100% of its nameplate rating capacity under loss of one element (N-1) or emergency conditions.
- Operational flexibility, safety, and reliability of the distribution system shall be maintained at all times.
- Circuit voltage profiles shall be maintained to comply with SCE's CPUC Jurisdictional Rule 2 tariff requirements. The Interconnection Customer (IC) will be responsible for maintaining designated voltage levels under all conditions, including but not limited to the conditions identified above.
- The power factor for the [redacted]s assumed to be within WDAT Tariff requirements of [redacted]
- Expected loading on the distribution system as projected by SCE's internal 2014 - 2023 distribution system forecast is utilized for the purposes of this charging analysis.
- [redacted] connected to the distribution system are analyzed offline (pre project) and online (post project) during peak demand conditions, as well as during absolute minimum demand conditions, as to determine the worst case scenario between these two "book-ends" of demand.
- The short circuit contribution analysis is not required for the charging study of [redacted] as it was performed in the generation study described in Appendix A.
- The charging study associated with the Phase II Report assumes the upgrades triggered by previously queued projects, including Rule 21 projects under CPUC jurisdiction as In-Service, are included in the base case for the Phase II projects. If any previously queued projects were to withdraw, then the Phase II projects may be subjected to the cost identified for those previously queued projects.

D. Power Flow Reliability Assessment Results

❖ Discharge Analysis of the Project

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

The group study indicated that the Project does not contribute to any overloads/non-convergence problems on the Transmission system of the area. Consequently, the Project did not get allocated costs for any Network Upgrades.

II. Steady State Power Flow Analysis Results – 66 kV and 115 kV
The group study indicated that the Project does not contribute to any overloads/non-convergence problems on the Subtransmission System of the area. Consequently, the Project did not get allocated costs for any upgrades at the subtransmission level.

III. Steady State Power Flow Analysis Results – 33 kV and below

1. Thermal Overloads

   The details of the analysis and overload levels are provided in the area study.

   - Category "A" (All facilities in service, N-0)
     - [redacted]
       - None
     - [redacted]
       - None
   - Category "B" (loss of a single element, N-1)
     - [redacted]
       - None
     - [redacted]
       - None

2. Power Flow Non-Convergence

   There were no non-convergence issues identified with the inclusion of the Project due to the limited system capacity.

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.

4. Required Mitigations

   The Project is required to provide [redacted] in accordance with tariff requirements.

❖ Charging Analysis of Project

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

An analysis was performed focusing on the charging aspect of the [redacted] in the [redacted] to determine any system limitations that may impinge the [redacted]

[redacted]ability to charge. It was determined that there are adverse impacts to the grid for the [redacted] in the [redacted] when charging.

The study identified that certain bulk system conditions will necessitate market dispatch to address potential overloaded condition on the bulk system under various contingencies. Such re-dispatch could involve restrictions to the charging operations of this project. Restrictions to charging operations are directly linked to the amount of resources that are dispatched via market signals. As more generation resources are made available, the ability for charging operations increases proportionally. Since all QC7-Phase II [redacted] projects are assumed to follow ISO's dispatch instructions, which include curtailment in both charging and discharging states, the mitigation to the overloads identified for charging operations is to rely on market dispatch signals to increase the generation supply or simply rely in the curtailment of charging operations if insufficient generation is made available

II. Steady State Power Flow Analysis Results – 66 kV and 115 kV

The group study indicated that the Project contributes to overloads/non-convergence problems on the (66 kV and 115 kV) Subtransmission System of the area. Consequently, the Project has been allocated a [redacted] to help mitigate the power flow impacts on the Subtransmission System. Further details are provided in section III below.

III. Steady State Power Flow Analysis Results – 33 kV and below

1. Thermal Overloads

The details of the analysis and overload levels are provided in the area study.

- Category "A" (All facilities in service, N-0)
    - [redacted]
        - None
    - [redacted]
        - None
- Category "B" (loss of a single element, N-1)
    - [redacted]
        - None
    - [redacted]
        - None

- Note: Under emergency N-1 conditions, No thermal overloads were triggered by the Project. However, due to the dynamic distribution system conditions and configurations, SCE may deem it necessary to disconnect this project under N-1 conditions until the distribution system returns to normal conditions.

2. Power Flow Non-Convergence

   There were no non-convergence issues identified with the inclusion of the Project due to the limited system capacity.

3. Voltage Performance

   a. Individual Project Power Factor Requirements

   Based on the results of the Study, the Project will need to be designed to maintain a composite power delivery at continuous rated power at the POI at a power factor within the range of [redacted] Additionally, the generation system must be designed to accommodate a VAR schedule provided by SCE. SCE will determine if the VAR schedule is necessary based on future re-arrangements of SCE's system.

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

   [redacted] is not expected to experience a voltage rise that exceeds Rule 2 requirements with the Project in service.

4. Protection

   - [redacted]

   Relays settings at the substation are required to be reset.

   - [redacted]

   No additional protection requirements are triggered by the charging aspect of the Project.

5. Charging Restrictions

   a. System Condition

      i. Base Case

      Based on the assessment results, charging restrictions associated with the Project will occur during different time periods. Assuming adjusted 2013-2014 historical demand patterns adequately represent worst case year within SCE's Distribution Load forecast performance, the evaluation identified the need to restrict charging during portions of the day, month, and year. The need to restrict charging will increase over time as normal system demand continues to grow. See tables below for projected charging forecast

      ii. Emergency

         1. B-Bank

During a loss of either B-Bank, the results of the study estimates that the remaining B-Bank capacity is insufficient to allow the Project to charge at any level due to overload. To mitigate the overload, it is assumed that the [redacted] will be able to trip the Project upon loss of either B-Bank.

2. Distribution

There were no emergency overloads identified on the [redacted] because under emergency conditions, these distribution circuits will be de-energized resulting in disconnection of the Project(s). Additionally, due to the dynamic distribution system conditions and configurations, SCE may deem it necessary to disconnect the Project under N-1 conditions on other distribution circuits until the distribution system returns to normal conditions.

b. Additional Factor(s) to Restrictions

It is important to note that the increased risk of restrictions is not only based on load forecast, load growth, and demand performance assumptions but are also based on the feasibility of implementing real-time automatic control and ability to use the [redacted] as means of increasing the loading limit that can be accommodated. The storage control system would need to result in the automatic shutdown of [redacted] operation upon loss of one B-Bank and with possibility of utilizing the [redacted] to limit amount of charging to stay within the limits of SCE's equipment ratings.

The assessment includes an hourly evaluation. Utilizing the adjusted hourly demand performance shown above in Figure 2-2, the number of hours the [redacted] is restricted to charge at a given demand value in a given month are shown below. Note that charging restrictions illustrated in the tables below are for the respective areas within the distribution system (i.e. distribution substation or distribution circuit). However, it should not be misinterpreted that the Project is not restricted for a specific time or for a certain number of hours only based on these tables alone. The Project's charging restrictions will be based on the most restrictive conditions from the distribution circuit to the transmission system.

Table 2-1

[redacted]

[redacted]

Table 2-2

[redacted]

[redacted]

6. Relevant Project Notes

In the event of an N-1 condition (loss of a B-Bank), SCE would send a signal through the storage control system that will require the charging facility to be de-energized to stop charging. Once the distribution system is restored to normal, SCE would then send a signal to the IC so that they can resume normal operation.

7. Required Mitigations

The Project is required to provide [redacted] power factor regulation capability at the POI, in addition to the following Distribution Upgrades to mitigate the power flow impacts of the Project described above.

a. [redacted]

The [redacted] is needed at [redacted] for loss of a B-bank transformer. The [redacted] provides continuous monitoring of specified/identified contingencies in which the charging/negative generation component of [redacted] contribute to. From the monitored data of both SCE facilities & IC facilities calculated charging capacity limits are generated and transmitted to the IC to stay within. If the IC does not comply with the provided limits SCE will mitigate for the identified contingencies at its discretion.

Refer to Attachment 1 for scope description of these Distribution Upgrade(s).

Please note that operational flexibility to charge at any time may not be attainable even with substation and distribution system upgrades due to limitations that may exist further upstream on SCE's Transmission systems. Furthermore, the results included utilize historical data to make a projection of possible charging profiles. As is typically the case with utilizing historical data to make projections, past performance is not guaranteed to be an indicator of future performance. For example, this can be the case due to changes in system topology on the distribution system, which can occur more frequently than on the transmission system

E. Short Circuit Duty Results

Short circuit studies were performed to determine the fault duty impact of adding the QC7 Phase II projects to the Transmission system and to ensure system coordination. The fault duties were calculated with and without the projects to identify any equipment overstress conditions. Once overstressed circuit breakers are identified, the fault current contribution from each individual project in QC7 Phase II is determined. Each project in the cluster will be responsible for its share of the upgrade cost based on the rules set forth in CAISO Tariff Appendix DD.

1. Short Circuit Duty Study Input Data

   The customer provided technical data for the identified inverter (specified in Section 2). If the technical data obtained from the inverter manufacturer by SCE illustrates differences in the Short Circuit Duty (SCD) parameters, then SCE utilized the manufacturer data of the inverter model specified by the IC in the application in the SCD study. SCE did not utilize the parameters provided by the IC.

   "Inverter Based Generation" Data for Each generation unit:

   Maximum Fault contribution: [redacted]

   Generation Step up and Pad-Mount Transformers technical details are provided in table A-1.

   This generation tie-line impedance was based on Distribution Provider calculation of generation tie-line electrical parameters utilizing tower and line conductor characteristics provided by the IC.

2. Short Circuit Duty Study Results

   All bus locations where the QC7 Phase II projects increase the short-circuit duty by [redacted] 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 QC7 Phase II interconnections and corresponding network upgrades, if any.

The responsibility to finance short circuit related Reliability Network Upgrades identified through a Group Study shall be assigned to all Interconnection Requests in that Group Study pro rata on the basis of short circuit duty contribution of each Generating Facility.

Please refer to the QC7 Phase II Area Report for the QC7 Phase II breaker evaluation 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.

3. SCE Substations with Ground Grids Duty Concerns

   The short circuit studies flagged SCE-owned substations beyond the Project POI with ground grid duty concerns that necessitate a ground grid study. However, the Project does not contribute to the duty concerns at hand, and did not get allocated costs for ground grid studies at the flagged SCE-owned substations.

4. Preliminary Protection Requirements

   Protection requirements are designed and intended to protect the Distribution Provider's system only. The preliminary protection requirements were based upon the interconnection plan as shown in the one-line diagram depicted in line item #7 in Attachment 1.

   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.

F. Transient Stability Evaluation

1. Area Study Transient Stability Results – 220 kV and above

Refer to enclosed Area Report in the QC7 PII report package, for the QC7 PII transient stability evaluation criteria, and assessment results, respectively, at the 220 kV and above voltage level.

2. Area Transient Stability Results – 66 kV or 115 kV

Refer to enclosed Subtransmission Assessment Report in the QC7 PII report package for the QC7 PII transient stability evaluation, criteria, and assessment results at the applicable subtransmission voltage level (66 kV or 115 kV).

3. Area Transient Stability Results – 33 kV or below

At the 33 kV and below voltage level this study is not performed.

G. Deliverability Assessment Results

1. On Peak Deliverability Assessment

   The Project does not contribute to any deliverability constraint.

2. Off- Peak Deliverability Assessment

There is no wind generators in the study area. The off-peak deliverability assessment is not performed.

3. Required Mitigations

   No Delivery Network Upgrades are required.

H. In-Service Date and Commercial Operation Date Assessment

The latest information provided by the IC has indicated that the requested generator ISD is December 1, 2018 and a COD of December 1, 2019. To determine if these dates could be met, an In-Service Date and Commercial Operation Date Assessment was performed which considered both the QC7 Phase II process timelines as well as the following facilities needed to provide for reliable energy only interconnection of the Project. Timing of the upgrades required to provide for the requested Full Capacity Deliverability Status are discussed in the section below.

The In-Service Date and Commercial Operation Date Assessment identified that the following facilities are required in order to provide for reliable interconnection for the Project:

1. QC7 Interconnection Process Timelines

   To enable physical interconnection, a Generator Interconnection Agreement (GIA) is required. As part of the QC7 interconnection process, a GIA is not scheduled to be tendered until after completion of the CAISO's Reassessment and Transmission Planning Deliverability (TPD) Allocation Study Process which does not commence until late January or early February 2016. The TPD Allocation is scheduled to be completed by April and if no changes to scope requirements are identified, a letter is provided at the end of April outlining the TPD Allocation results. However, if changes are identified, updates to scope, costs and schedules are developed and updated reports are issued by the end of July. The GIA negotiations commences after either the issuance of the letter outlining the TPD allocation results at the end of April or upon issuance of the updated reports at the end of July. Provided the Project does not elect to Park, the letter or updated reports are used as the basis to proceed with the GIA negotiations. Assuming a three month timeframe for GIA negotiations, a GIA is not expected until either early August 2016 or early November 2016 depending on TPD study results and decision to Park or proceed.

2. System Upgrade Timelines for Reliable Interconnection

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

   a. Distribution Provider's Interconnection Facilities

      Refer to Section 1.b of Attachment 1 for details.

   b. Reliability Network Upgrades

i. Short-Circuit Duty (SCD) Mitigation

Short circuit duty operation mitigation was identified taking into account new generation projects which have executed GIAs, approved transmission system upgrades fully permitted and under construction, and new generation projects including QC7 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 (GSI) Short Circuit Duty evaluation (Appendix G). Based on the study results, upgrades/mitigation are not required to be in place in order to enable energy only interconnection of this Project.

In addition to the above mitigation requirements which already have established in-service dates, the following additional SCD mitigation, which have not been initiated since timing need is dependent on development of queued generation projects that have not yet executed a GIA, may be needed in order to enable energy only interconnection:

- [redacted]

It should be noted that the timing for the installation and completion of the additional SCD mitigation identified is contingent on future development of generation projects requesting interconnection. The identification of need was based on the assumption that all queued generation projects actually materialize and are interconnected (as energy only). Timing to implement this incremental SCD mitigation is currently estimated at 27 months from the date the need is identified. This additional 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 GIA negotiations with corresponding requested in-service dates and commence project development.

c. Voltage Support Mitigation

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

d. Distribution Upgrades

- The plan of service as illustrated in Figure A.1 and described in Section 1 & 3 of Attachment 1, is required to interconnect the project.
- duct bank expansion
- substation Relay reset
- substation point addition

- [redacted]

3. Conclusion

   The requested IC In-Service Dates of December 1, 2018 cannot be met due to the following reasons:

   - The QC7 Interconnection Process Timelines will not yield a Generator Interconnection Agreement until either early August 2016 or early November 2016 depending on TPD study results. Timelines associated with constructing the Interconnection Facilities needed for physical interconnection are estimated at 27 months from the date the GIA is executed, payments are made, and notice to proceed with interconnection is provided. Following the standard process, this would result in a best case in-service date of December 2018 or March 2019 depending on TPD study results. Such dates are beyond the requested in-service timelines for the generator. It should be noted that the ability to meet a best case in-service date is tied directly to the IC's timely execution of the Generator Interconnection Agreement, submittal of payments, and notice to proceed.
   - Potential need to replace [redacted] which requires an estimated 27 months to complete from the day a project is initiated to replace the breakers.

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

The IC elected that the Project be Option A with Full Capacity Deliverability Status (FCDS). 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 Status based on annual system availability. The sections below provide a discussion of the timing of Full Capacity Deliverability Status, Interim Deliverability, Area Constraints, and Operational Information.

1. System Upgrades Required for Full Capacity Deliverability Status

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

   a. Triggered Delivery Network Upgrades - None

   b. Delivery Network Upgrades Triggered by Earlier Queued Projects - None

   c. Approved Transmission Upgrades - None

   d. Transmission Upgrades outside the CAISO Controlled Grid - None

2. Interim Operational Deliverability Assessment for Information Only

   The operational deliverability assessment was performed for study years 2018 and 2020 by modeling the Transmission and generation in service in the corresponding study year. For details of the Transmission and generation assumption, refer to Section E.2 of the Area Report. There are no deliverability constraints identified. The Project will have the deliverability status as granted by the Transmission Plan Deliverability allocation.

J. Interconnection Facilities, Network Upgrades, and Distribution Upgrades

Please see **Attachment 1** for the Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades and Distribution Upgrades allocated to the Project. Please note that SCE will not "reserve" the identified Interconnection Facilities (IF's) for the proposed POI. The identified scope/facilities will be allocated to the project upon the successful execution of the Generator Interconnection Agreement (GIA) and SCE has completed the detailed design and engineering of the facilities according to tariff timelines.

K. Cost and Construction Duration Estimates

To determine the cost responsibility of each generation project in QC7 Phase II, the CAISO developed cost allocation factors (Attachment 3) for Reliability Network Upgrades, Local Delivery Network Upgrades and Area Delivery Network Upgrades. Attachment 2[6] provides the 'constant' 2015 dollars and their escalation to the estimated COD year for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades which the Project was allocated cost.

For the QC7 Phase II Study, the estimated COD is derived by assuming the duration of the work element will begin in December 2016, which accounts for the CAISO tariff scheduled completion date of the QC7 Phase II study plus: the TP Deliverability (TPD)[7] allocation, Annual Reassessment effort, and the Generator Interconnection Agreement signing period and submittal of required funds by the IC.

The IC should note that any Local Delivery Network Upgrades and Area Delivery Network Upgrades allocated to the Project may be assessed 35% Income Tax Component of Contribution (ITCC) pending the results of the TPD allocation Process several months after the Phase II Study Reports are released, [redacted] For your information, Attachment 2 contains a potential ITCC estimate[8] based on the Phase II cost in this study. It does not represent the "maximum 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 Upgrade maximum cost responsibility. The maximum ITCC warranted by the Project will be addressed, calculated, and included during the Generator Interconnection Agreement

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[6] For Energy Storage Projects the Attachment 2 includes upgrade(s) identified from the "Charging" analysis.

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

[8] The maximum ITCC exposure applies ITCC (35%) to assigned IF and DU facilities. Network upgrades that are not subject to transmission credits incremental to a repayment $/MW cap or an award of 0 MW TPD Allocation, and that SCE will own the facilities in question. The maximum ITCC exposure is calculated by applying the following formula: [redacted]

development phase once the IC submits the TP Deliverability allocation options form confirming the acceptance, waiver (parking), or denial of awarded deliverability assigned to the Project.

L. SCE Technical Requirements

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

M. Environmental Evaluation, Permitting, and Licensing

Please see Appendix K of the QC7 Phase II Area Report.

N. Affected Systems Coordination

Please see Section H of the QC7 Phase II 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 Plan of Service and are not sufficient for permitting of facilities. The Plan of Service is subject to change as part of detailed engineering and design.

2. IC's Technical Data

   The study accuracy and results for the QC7 Phase II Study are contingent upon the accuracy of the technical data provided by the IC. Any changes from the data provided could void the study results.

3. Study Impacts on Neighboring Utilities

   Results or consequences of this QC7 Phase II Study may require additional studies, facility additions, and/or operating procedures to address impacts to neighboring utilities and/or regional forums. For example, impacts may include but are not limited to WECC Path Ratings, short circuit duties outside of the CAISO Controlled Grid, and sub-synchronous resonance (SSR). Refer to Affected Systems Coordination Section of the Area Report for additional information.

4. Use of Distribution Provider Facilities

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

5. Distribution Provider Interconnection Handbook

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

6. Western Electricity Coordinating Council (WECC) Policies

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

7. System Protection Coordination

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

8. Standby Power and Temporary Construction Power

   The QC7 Phase II Study does not address any requirements for standby power or temporary construction power that the Project may require prior to the In-Service Date of the Interconnection Facilities. Should the Project require standby power or temporary construction power from Distribution Provider prior to the In-Service Date of the Interconnection Facilities, the IC is responsible to make appropriate arrangements with Distribution Provider to receive and pay for such revenue 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 Generator Interconnection Agreement, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

10. Network/Non-Network Classification of Telecommunication Facilities

    The cost for telecommunication facilities that were identified as part of the IC's Interconnection Facilities was based on an assumption that these facilities would be sited, licensed, and constructed by the IC. The IC will own, operate, maintain, and construct diverse telecommunication paths associated with the IC's generation tie line, excluding terminal equipment at both ends. In addition, the telecommunication requirements for SPS were assumed based on tripping of the generator breaker as opposed to tripping the circuit breakers at the Distribution Provider substation. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of QC7 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 QC7 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 electrical system; as well as establish the technical requirements to interconnect the Project to the POI that was evaluated in the QC7 Phase II Study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in Generator Interconnection Agreements agreed to by SCE, CAISO and the IC.

13. Process for synchronization/trial operations and commercial operations of the Project

    The IC is reminded that the CAISO has implemented a New Resource Implementation (NRI) process that ensures that a generation resource meets all requirements before synchronization/trial operations and commercial operations. 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 7 months in advance of the planned initial synchronization. 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

14. Potential Changes in Cost Responsibility

    The IC is hereby placed on notice that interconnection of its proposed generating facility may be dependent upon certain Network Upgrades which are currently the cost responsibility of projects ahead of the proposed generating facility in the interconnection application queue. Section 14.2.2 of the GIDAP provides that should Network Upgrades required for queued-ahead projects be included in an executed GIA (or unexecuted GIA filed at FERC) at the time of withdrawal of the earlier queued generating facility, and the upgrades are determined to still be needed by later queued generating facilities, the financial responsibility for such upgrades falls to the Distribution Provider. However, if the Network Upgrades required by earlier queued generating facilities are not subject to an executed GIA (or unexecuted GIA filed at FERC) at the time of withdrawal of the earlier queued generating facilities, the financial responsibility for such upgrades may fall to the IC[9]. Section 14.2.2 also discusses how Network Upgrades required

[9] Such circumstance was not identified for the Project in the Study.

by interconnection customers selecting Option (B) might be required to be reapportioned among interconnection customers selecting Option (B) in the case of withdrawals of earlier queued generating facilities. Changes in costs allocated to the IC could also arise as the result of the CAISO's reassessment process described in Section 7.4 of the GIDAP. SCE encourages the IC to review Sections 7.4 and 14.2.2 of the GIDAP for the rules and processes under which the financial responsibility might be reapportioned to the IC. Potential changes in the IC's cost responsibility resulting from application of the provisions of these Sections of GIDAP are not included in this Phase II study, nor are the potential impacts to the IC's maximum cost responsibility outlined.

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 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
Allocation of Network Upgrades for Cost Estimates and Maximum Network Upgrade Cost Responsibility

None

Attachment 4
Distribution Provider Interconnection Handbook

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

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

Attachment 6

Not Used.

Attachment 7

Not Used.

Attachment 8
Subtransmission Assessment Report
Please refer to separate document

Queue Cluster 7 Phase II - Attachment 1
WDT1185A – [redacted]
Interconnection Facilities, Network Upgrades, and Distribution Upgrades

Interconnection Facilities, Network Upgrades and Distribution Upgrades

Distribution Provider's Interconnection Facilities, Network Upgrades and Distribution Upgrades described below are based on the Distribution Provider's preliminary engineering and design. Such descriptions are subject to modification to reflect the actual facilities that are constructed and installed following the Distribution Provider's detailed engineering and design, identification of field conditions, and compliance with applicable environmental and permitting requirements.[1]

1. Distribution Provider's Interconnection Facilities.

(a) **Interconnection Customer's Interconnection Facilities.** The Interconnection Customer shall:

(i) [redacted]

(ii) [redacted] which complies with Distribution Provider's Electrical Service Requirements as described in the Interconnection Handbook.

(iii) Procure and construct underground duct banks and related structures required for Distribution Provider's Interconnection Facilities and Distribution Upgrades ("Civil Construction[2]") in accordance with specifications and designs provided by the Distribution Provider.

(iv) Obtain all necessary permits and easements associated with the installation of Civil Construction.

(v) If applicable, provide the following:

1. Completed Interconnection Customer information sheet
2. Street improvement plan(s)
3. Unique address for Point of Interconnection
4. Public right-of-way (street) base map(s) as required by the interconnection
5. Site plot plan on a 30:1 scale digital file as follows:
    a. Easements/lease agreement(s)
    b. Grading plan(s)
    c. Sewer and storm plot plan(s)
    d. Landscape, sprinkler, pedestal location(s)

[1] Such descriptions are subject to modification to reflect the actual facilities that are constructed and installed following the Distribution Provider's detailed engineering and design, identification of field conditions, and compliance with applicable environmental and permitting requirements.

[2] The Interconnection Customer understands and acknowledges that the Civil Construction in support of the interconnection for the Project may be classified as the Interconnection Customer-constructed Distribution Provider interconnection facilities and/or Distribution Upgrades and may require transfer of ownership pursuant to Section 3 (1) under Appendix C of the GIA. The Interconnection Customer understands and acknowledges that it shall be responsible for the ITCC and ongoing monthly Interconnection Facilities Charge and/or Distribution Upgrades charge of the portion of Civil Construction and prior to the in-service date of the Civil Construction, Interconnection Customer shall provide to Distribution Provider the final invoiced costs of the portion of Civil Construction transferred to Distribution Provider and shall be an acceptable form to Distribution Provider.

e. Complete construction of underground systems for the Distribution Provider's Interconnection Facilities and Distribution Provider's Distribution Upgrades

(vi) Acquire an agreement from the property owner at [redacted] for the Distribution Provider to have the following:

1. The right to enter property owner's premises for any purpose connected with the Distribution Provider's Interconnection Facilities or interconnection service.
2. The right for the use of a Distribution Provider approved locking device if Interconnection Customer wants to prevent unauthorized access to Distribution Provider's Interconnection Facilities.
3. The right for safe and ready access for Distribution Provider's personnel free from unrestrained animals.
4. The right for unobstructed ready access for Distribution Provider's vehicles and equipment to install, remove, repair, and maintain its Interconnection Facilities.
5. The right to remove Distribution Provider's Interconnection Facilities after termination of interconnection service.

(vii) Telemetry.

In accordance with specifications provided by the Distribution Provider, provide the following in compliance with the telemetry requirements of the Interconnection Handbook:

a. Allow the Distribution Provider to review and approve the Interconnection Customer's telemetry equipment design and perform inspections to ensure compatibility with the Distribution Provider's telemetry equipment; allow the Distribution Provider to perform acceptance testing of the telemetry equipment and the right to require the correction of installation deficiencies.
b. Provide broadband internet service to support communication of the telemetering data to the Distribution Provider's grid control center.
c. Provide and install a Distribution Provider approved serial device server ("SDS") in an approved enclosure located in an area with a suitable environment.
d. Provide a convenience power source to the SDS enclosure for SDS power.
e. Provide and install data communication cabling for the required telemetering data from the Interconnection Customer's data acquisition system to the SDS enclosure.
f. Allow the Distribution Provider to terminate the data communication cables inside the Interconnection Customer's SDS enclosure and program the SDS.

(viii) Install, in coordination with, and as specified by, the Distribution Provider, a dedicated T1 circuit from the local telephone company to support the Remote Terminal Unit ("RTU") communication to the Distribution Provider's energy management system in accordance with the

Interconnection Handbook if a RTU is installed locally at the Generating Facility[3].

(ix) Designate, to the T1 circuit provider, the Distribution Provider as a representative authorized to report trouble to, and to initiate repairs with, the communication circuit provider on the Interconnection Customer's behalf in the event of an interruption of service on the communication circuit if a T1 circuit is required for the support of a RTU installed locally at the Generating Facility.

(x) Allow the Distribution Provider to review the Interconnection Customer's telecommunication equipment design and perform inspections to ensure compatibility with the Distribution Provider's RTU, or equipment related to an alternative approved by the Distribution Provider, and related terminal equipment; allow the Distribution Provider to perform acceptance testing of the telecommunication equipment and the right to request and/or to perform correction of installation deficiencies.

(xi) Provide required data signals, make available adequate space, facilities. and associated dedicated electrical circuits within a secure building having suitable environmental controls for the installation of the Distribution Provider's RTU, or equipment related to an alternative approved by the Distribution Provider, in accordance with the Interconnection Handbook.

(xii) Make available adequate space, facilities, and associated electrical circuits within a secure building having suitable environmental controls for the installation of the Distribution Provider's telecommunications terminal equipment in accordance with the Interconnection Handbook if a RTU is installed locally at the Generating Facility.

(xiii) Install all required ISO-approved compliant metering equipment at the Generating Facility, in accordance with Section 10 of the ISO Tariff.

(xiv) Allow the Distribution Provider to install, in the switchgear provided by the Interconnection Customer, revenue meters, potential transformers ("PTs"), and current transformers ("CTs"), to meter retail load at the Generating Facility in accordance with the Distribution Provider's Electrical Service Requirements ("ESR") as described in the Interconnection Handbook.

(xv) Allow the Distribution Provider to install, in the switchgear provided by the Interconnection Customer, revenue meters, potential transformers ("PTs"), and current transformers ("CTs"), to meter wholesale load at the Generating Facility in accordance with the Distribution Provider's Electrical Service Requirements ("ESR") as described in the Interconnection Handbook.

(xvi) Install all equipment necessary to comply with the power factor requirements of Article 9.6 of the GIA, including the ability to regulate power factor to a schedule (VAR schedule) in accordance with the Interconnection Handbook.

[3] The cost and scope of telemetry may significantly increase to include a dedicated RTU, as required by SCE's Interconnection Handbook, in the event that the centralized RTU method is not feasible for this project.

(xvii) Provide switchboard drawings which shall comply with Distribution Provider's ESR which can be obtained at: http://www.sce.com/AboutSCE/Regulatory/distributionmanuals/esr.htm

(xviii) Install disconnect facilities in accordance with the Distribution Provider's Interconnection Handbook to comply with the Distribution Provider's switching and tagging procedures.

(xix) Install a breaker within the Interconnection Customer's property line in accordance with the ESR to comply with the Distribution Provider's protection requirements.

(xx) Install all equipment and controls necessary to maintain the Generating Facility's output ramp rate within the parameters set forth, and provided to the Interconnection Customer, by the Distribution Provider.

(xxi) Stay within charging capacity limits transmitted by the Distribution Provider. Charging capacity limits are continuously changing depending on system conditions, it is the responsibility of the Interconnection Customer to integrate the provided signals into their control systems to effectively ramp down charging within transmitted limits in a timely manner. In the event that the Interconnection Customer cannot ramp down charging in a timely manner, the distribution provider will disconnect the Interconnection Customer's facility through the Distribution Providers owned and maintained facilities.

(b) **Distribution Providers's Interconnection Facilities.**The Distribution Provider shall:

(i) [redacted]

(ii) **Telecommunications.**

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

Distribution Provider's Interconnection Facilities if an RTU is installed locally at the Generating Facility.

(iii) **Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety.**
Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of the Distribution Provider's Interconnection Facilities, including any associated telecommunication equipment.

(iv) **Metering.**

a. Install [redacted] meters and appurtenant equipment required to meter the retail load at the Generating Facility. Notwithstanding that the meters and appurtenant equipment will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain such facilities as part of the Distribution Provider's Interconnection Facilities.
b. Install [redacted] meters and appurtenant equipment required to meter the wholesale load at the Generating Facility. Notwithstanding that the meters and appurtenant equipment will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain such facilities as part of the Distribution Provider's Interconnection Facilities.

(v) **Power System Control.**
Telemetry.

a. Terminate the Interconnection Customer provided communication cables inside the Interconnection Customer's SDS enclosure.
b. Program and test the SDS.
c. Perform setup and programming on the Distribution Provider's telemetry equipment as required to support communication of the telemetered data to the Distribution Provider's grid control center.
d. Perform a functional test of the telemetry equipment to verify compliance with the requirements of the Interconnection Handbook.

Or if required, Install [redacted] at the Generating Facility to monitor typical generation elements such as MW, MVAR, terminal voltage and circuit breaker status for the Generating Facility and plant auxiliary load, and transmit the information received thereby to the Distribution Provider's grid control center. Notwithstanding that the [redacted] will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain the [redacted] as part of the Distribution Provider's Interconnection Facilities.

2. Network Upgrades.

(a) **Stand Alone Network Upgrades.**
None identified as part of the Phase II study.

(b) **Other Network Upgrades.**

(i) **Distribution Provider's Reliability Network Upgrades.**

None identified as part of the Phase II study.

(ii) **Distribution Provider's Delivery Network Upgrades.**

1. **Area Delivery Network Upgrades.**

None identified as part of the Phase II study.

2. **Local Delivery Network Upgrades.**

None identified as part of the Phase II study.

3. Distribution Upgrades.

The Distribution Provider shall:

(a) **Telemetry Points for the [redacted]**

(i) [redacted] Install additional telemetry points for the [redacted] at [redacted] to monitor the reverse power flow caused by the Project.

(ii) Reprogram substation relays as needed.

(iii) Power Systems Control: Perform associated programming work for the installation for telemetry points addition at [redacted]

(iv) Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety: Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of theDistribution Upgrades, including any associated telecommunication equipment.

(b) **Storage Control System at Chestnut Substation**

(i) Power System Control

1. Create [redacted] program in [redacted] to support charging aspect of energy storage project.
2. [redacted]
3. SAS point addition

(ii) Substation

1. Service and test [redacted]

(iii) Telecommunication

1. Install [redacted]

(c) [redacted]

(i) Power System Control

1. Create [redacted] program in [redacted] to support charging aspect of energy storage project.
2. Intall [redacted]
3. SAS point addition

(ii) Substation

1. Service and test [redacted]

2. Affected System Upgrades.
Not Used.

3. Point of Change of Ownership.

The Point of Change of Ownership shall be at the pull section of the new [redacted] provided, installed and owned by the Interconnection customer.

4. Point of Interconnection.
A Tap on the Distribution Provider's [redacted]

5. One-Line Diagram of Interconnection to [redacted]

[redacted]

Addendum to Appendix A – WDT1185

[redacted]

Addendum #1

Cluster 7 Phase II Final Report

December 28, 2015

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

Interconnection Study Document History

Project No.		No	Date	Document Title	Description of Document
WDT1185	[redacted]	2	12/28/2015	Addendum #1 to Queue Cluster 7 Phase II Appendix A Final Report	The purpose of this report is to memorialize appropriate project costs known at this point and publish the written comments provided by the IC to SCE in accordance with the timelines stated per Section 4.6.10 in GIP
WDT1185	[redacted]	1	11/24/2015	Queue Cluster 7 Phase II Appendix A Final Report	Report to disclose results of QC7 Phase II cluster.

Executive Summary

[redacted] an Interconnection Customer (IC), received a Queue Cluster 7 Phase II (QC7 Phase II) study report dated November 24, 2015 for its Interconnection Request (IR) to Southern California Edison (SCE) for their proposed [redacted] (Project), queue position WDT1185.

Subsequent to the release of the QC7 Phase II report package for the Project dated November 24, 2015 it was determined that the following item(s) in the QC7 Phase II report package for the Project required an update to reflect the appropriate costs allocated to the Project.

1. Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades (Attachment 2 to Project Appendix A report dated November 24, 2015)

These item(s) have been updated accordingly, and are attached as part of this QC7 Phase II Addendum report package. The corresponding changes replace and supersede those same sections in the Project's QC7 Phase II Appendix A report dated November 24, 2015

In addition, to comply with GIP obligation to IC's written comments on interconnection studies as modified by FERC Order 792, SCE is publishing any written comments submitted by the IC per Section 4.6.10:

- Within ten (10) Business Days of receipt of the QC7 PII report, but in no event less than three (3) Business Days before the Results Meeting conducted to discuss the report; and/or
- Additional comments on the final QC7 Phase II Interconnection Study report up to (3) Business Days following the Results Meeting

This addendum report discloses below the written comments provided by the IC to SCE in accordance with the timelines stated in GIP for QC7 Phase II study report dated November 24, 2015. The Phase II study report is unaffected by this addendum report.

QC7 Phase II – WDT1185 - [redacted]

1. Written comments provided by IC within ten (10) Business Days of receipt of the QC7 PII report
   a. The Appendix A report mentions "Attachment 3 - Allocation of Network Upgrades for Cost Estimates and Maximum Network Upgrade Cost Responsibility". I do not find this in the documents that you have sent. Do we have any cost exposure for the [redacted] or any other Network upgrades remote from the project?
2. Written comments provided by IC three (3) Business Days following the Results Meeting
   a. None