Appendix A – WDT1200 A

[redacted]

[redacted]

Queue Cluster 7 Phase II Report
Addendum #2

September 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

Interconnection Study Document History

No.	Date	Document Title	Description of Document
6	9/23/2016	Queue Cluster 7 Phase II Report Addendum #2	The purpose of this report is to update the scope and cost as a result of the SCE-proposed change in the Point of Interconnection.
5	8/29/2016	EDP&C Letter Agreement	The purpose of this Letter agreement is to initiate the design, engineering, procurement, and construction of the interconnection facilities.
4	12/29/2015	Queue Cluster 7 Phase II Report Addendum #1	The purpose of this report is to memorialize cost updates known at this point required by the Project; and to publish the written comments provided by the IC to SCE in accordance with the timelines stated per Section 4.6.10 in GIP.
3	11/24/2015	Queue Cluster 7 Phase II Report	To disclose results of final Phase II interconnection study report.
2	1/20/2015	Queue Cluster 7 Phase I Report Addendum #1	Addendum to reflect appropriate cost Associated with the Moorpark SPS allocated to the Project.
1	12/17/2014	Queue Cluster 7 Phase I Report	To disclose results of final Phase I interconnection study report.

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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
4. Distribution Provider's Interconnection Handbook
5. Short-Circuit Duty Calculation Study Results (see Appendix H of the Area Report)
6. Not Used
7. SCE Northern Hemisphere Import Nomogram
8. Santa Clara 66 kV 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] The Project plans to have a total output of 9.99 MW at the Generating Facility. SCE proposed a new Point of Interconnection (POI) at [redacted] queue position WDT1200A. This report focuses on the 9.99 MW 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 23, 2016 and a Commercial Operation Date of December 31, 2016.

The Phase I Study Report was later amended on January 20, 2015. The Interconnection Customer has requested an In-Service Date of November 1, 2016. The Phase I Study Report identified a timeline of twenty seven (27) months to complete the Distribution Provider's Interconnection Facilities, Distribution Upgrades, the Distribution Provider's Reliability Network Upgrades and ADNUs and LDNUs for the interconnection and operation of the Project.

A Phase II Interconnection Study was completed and the results were provided to the Interconnection Customer on November 25, 2015 in a study report titled, "Interconnection Customer Project Queue Cluster 7 Phase II Report" (Phase II Study Report) containing the scope of work, estimated cost and estimated completion schedule for the Distribution Provider's Interconnection Facilities, Distribution Upgrades, the Distribution Provider's Reliability Network Upgrades and ADNUs and LDNUs.

An addendum to the Phase II Interconnection Study report, which includes a revised estimated cost, was issued to the Interconnection Customer on December 29, 2015.

This Project was shortlisted in the [redacted] and is required to achieve an In-Service Date by December 23, 2016. The Interconnection Customer requested the Distribution Provider to proceed with the interconnection process of this Project on July 22, 2016. It was determined that in order for the Distribution Provider to meet [redacted] In-Service Date of December 23, 2016, the design, engineering, licensing, permitting, procurement and construction of the Distribution Provider's Interconnection Facilities and Distribution Upgrades may commence prior to the subsequent execution of the GIA.

The Project's Plan of Service (POS) was re-evaluated by the Distribution Provider and results were presented to the Interconnection Customer on August 5, 2016. The Interconnection Customer accepted the proposed alternate POS on August 5, 2016 which includes a change in the Point of Interconnection from the [redacted]

In the interest of timely completion of the Distribution Provider's Interconnection Facilities and Distribution Upgrades, the Distribution Provider and Interconnection Customer entered into a Letter Agreement with the desire to commence work prior to the execution of the GIA.

The report provides the following:

1. Transmission 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 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.

All the equipment and facilities comprising the Project are located in Santa Paula, CA, as disclosed by the IC in its Interconnection Request (IR), as may have been amended during the Interconnection Study process, which consists of (i) [redacted] (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 and summarized below in Table A.1. Figure A.2 provides a map that illustrates the location of the Project.

[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

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 Northern Area
Number and Types of Generators	[redacted]
Interconnection Voltage	16 kV
Maximum Generator Output	[redacted]
Generator Auxiliary Load	[redacted]
Maximum Net Output at Generating Facility	[redacted]
Power Factor Range	Lead 0.95 / Lag 0.95 at POI per interconnection application
Step-up Transformer(s)	[redacted]
POI	[redacted]
IC Requested ISD	December 19, 2016
IC Requested COD	December 31, 2016

B. Study Assumptions

For detailed assumptions regarding the group cluster analysis at the transmission and subtransmission levels, please refer to the applicable QC7 Phase II Area Report and Subtransmission Assessment Report. 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 9.99 MW at the Generating Facility with its POI to SCE's Distribution System at the [redacted] via a line extension to the applicant-owned 16 kV switchgear at the Point of Change of Ownership (POCO).

2. The following facilities will be installed by SCE and are included in this Phase II Study:

   - [redacted]

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

- 16 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 **are not included** in this Phase II Study:
   - Ducts as required
   - Structures as required
   - Isolating circuit breaker
   - Protection System requirements to comply with the Distribution Provider's Interconnection Handbook
   - Transformation as required
   - Metering equipment compliant with SCE Electrical Service Requirements
   - CAISO metering as required
   - Retail and wholesale load meters

   NOTE: All civil work inside [redacted] will be designed and constructed by the Distribution Provider.

   SCE will install metering PTs and CTs to be used for the SCE-owned revenue meters. The PTs and CTs 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 California Public Utilities Commission's (CPUC) Rule 2 requirements.
   - The power factor for the new Generating Facility was assumed to be within WDAT requirements of 0.95 lagging or leading.
   - Expected loading on the distribution system as projected by the SCE 2016-2026 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 in order 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 POS in this report may change according to detailed design required to comply with the updated distribution design standards.
- This study assumes that the IC's Generating Facility will include all equipment, software, and appropriate controls necessary to maintain the generator output profile per SCE requirements. The IC will be responsible for maintaining designated voltage levels under all conditions, including but not limited to the conditions identified above. Upon execution of the 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 may be considered, as needed). 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 energy storage (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 sources such that they would not increase demand on the local distribution system.

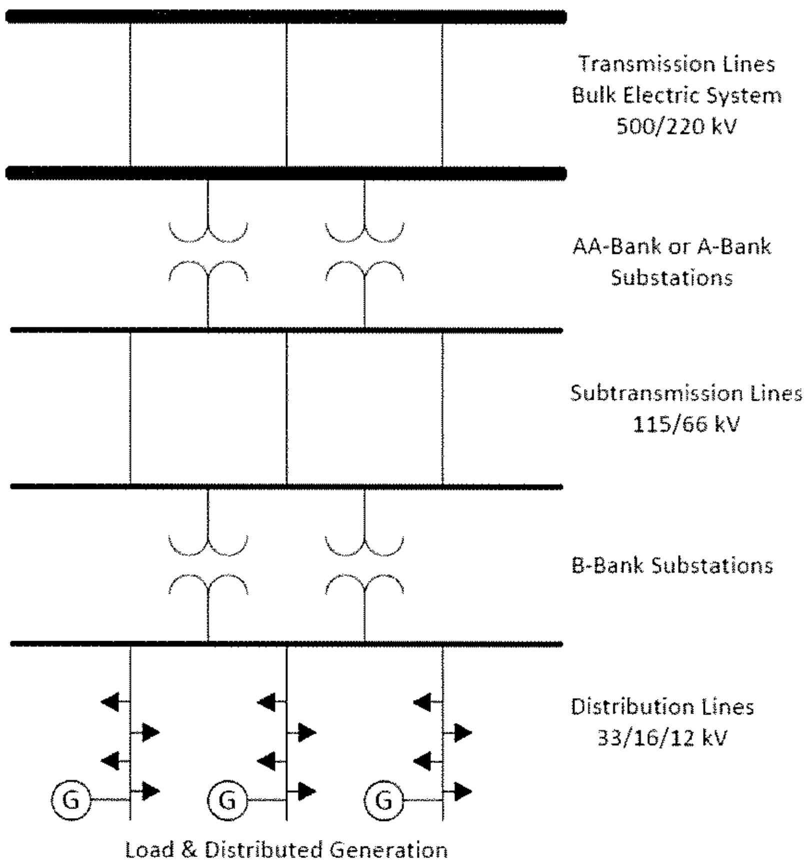
6. Energy Storage Facility Charging Considerations

   - SCE's distribution standards and practices are in the process of being updated to address energy storage facilities. The proposed POS in this report may require changes to comply with the updated distribution design standards and practices.
   - This study assumes that the IC's facility will include all equipment, software, appropriate controls, and other related equipment necessary to maintain the energy storage facility demand profile per SCE requirements.
   - Upon execution of the Generator Interconnection Agreement, SCE will provide the IC with the required ramp rate[2] control parameters. 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 SCE System to transmit the required telemetry data as outlined in the Distribution Provider's 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 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

[4] It is assumed that ramp rates for each energy storage facility 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.

minimal distribution upgrades. 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 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 energy storage component to a dedicated transformer.

Figure 2-1[3]
Topology of SCE's Electric System



[3] For illustrative purposes only.

7. Charging Analysis Load Assumptions

   The load assumptions used for SCE's Distribution System considers SCE's 2016– 2026 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 2016-2016 B-Bank and circuit data were 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 Wakefield 66/16 kV Substation B-Bank and Castro 16 kV Circuit hourly demand performance.

Figure 2-2

[redacted]

B-Bank Hourly Demand Performance

[redacted]

Figure 2-3
[redacted]
Hourly Demand Performance

[redacted]

C. Reliability Standards, Study Criteria and Methodology

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

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[4] with all facilities in service (N-0 or base case).
- 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 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 energy storage system facility is assumed to be within WDAT requirements of 0.95 leading or lagging.
- Expected loading on the distribution system as projected by SCE's internal 2016 - 2026 distribution system forecast is utilized for the purposes of this charging analysis.
- Energy storage facilities 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, in order 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 energy storage facilities, 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 subject to the cost identified for those previously queued projects.

[4] 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.

D. Power Flow Reliability Assessment Results

Discharge Analysis of the Project

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

The proposed material modification for 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 proposed material modification for 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

I. Thermal Overloads

The group 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 QC7 Phase II Northern Area Report.

- Base Case (All facilities in service, N-0)
  - [redacted]
    - No thermal overloads have been identified.
  - [redacted]
    - The addition of the Project did not cause a thermal overload.
- Single Contingency (Loss of a single element, N-1)
  - [redacted]
    - No thermal overloads have been identified.
  - [redacted]
    - The addition of the Project did not cause a thermal overload.

II. 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.

III. Protection

Protection requirements are designed and intended to protect the Distribution Provider's electrical system only. The charging study determined that additional protection requirements are required to protect and coordinate the SCE'S Distribution System. It will be required to reset the existing trip settings for [redacted] to accommodate the addition of the [redacted]

IV. Required Mitigations

The Project is required to provide 0.95 leading/0.95 lagging power factor regulation capability at the POI.

Charging Analysis of Project

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

The proposed material modification for 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 proposed material modification for 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.

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

1. Thermal Overloads

The group 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 Area Report

- Base Case (all facilities in service, N-0)
  - [redacted]
    - None identified in the Phase II Interconnection Study.
  - [redacted]
    - None identified in the Phase II Interconnection Study.

- Single Contingency (loss of a single element, N-1)
  - [redacted]
    - None identified in the Phase II Interconnection Study.
  - [redacted]
    - None identified in the Phase II Interconnection Study.

Due to the dynamic distribution system conditions and configurations, under emergency N-1 conditions (loss of a B-Bank, or loss of the [redacted] the Distribution Provider may deem it necessary to open the source to remove the Project from Distribution Provider's Distribution System. Once the Distribution Provider's system is restored to normal, the Distribution Provider would then close in the source and the generation system can resume normal operation.

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 0.95 leading and 0.95 lagging. Additionally, the generation system must be designed to accommodate the 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 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

There were no additional protection requirements.

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 2015-2016 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 estimate 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 SMS 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 SMS as means of increasing the loading limit that can be accommodated. The SMS would need to result in the automatic shutdown of energy storage charging operation upon loss of one B-Bank and with possibility of utilizing the SMS 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 energy storage facility 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]

# of Charging Hours Restricted for Energy Storage System

[redacted]

Table 2-2

[redacted]

Charging Hour Restrictions of Day for Energy Storage System

[redacted]

Table 2-3

[redacted]

#Number of Charging Hour for Energy Storage System

[redacted]

Table 2-4

[redacted]

Charging Hour Restrictions of Day for Energy Storage System

[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 SMS 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.

7. Required Mitigations

The Project is required to provide 0.95 leading/0.95 lagging 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. Storage Management System.

The Storage Management System is needed at [redacted] for normal operations and loss of a B-bank transformer. The Storage Management System provides continuous monitoring of specified/identified contingencies in which the charging/negative generation component of energy storage facilities contributes 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 QC8 Phase I 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 QC8 Phase I is determined. Each project in the cluster will be responsible for its share of the upgrade cost based on the rules set forth in 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 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.

2. Short-Circuit Duty Study Results

   All bus locations where the QC7 Phase II projects increase the short-circuit duty by 0.1 kA or more and where duty was found to be in excess of 60% of the minimum breaker nameplate rating are listed in the Area Report (Appendix H). These values have been used to determine if any equipment is overstressed as a result of the inclusion of 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 Grid 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 Distribution Provider's Interconnection Handbook provided in Attachment 4.

F. Transient Stability Evaluation

With the Project providing power factor correction as measured at the POI and including the required mitigation identified above, transient stability performance was found to be acceptable. Refer to Sections C.3 and D.2 of the Area Report, for additional details pertaining to the QC8 PI transient stability evaluation criteria and assessment results, respectively.

G. Deliverability Assessment Results

1. On Peak Deliverability Assessment

The Project does not contribute to any deliverability constraint.

2. Off- Peak Deliverability Assessment

Under off-peak conditions, [redacted] is overloaded under various contingency conditions. For details, see Section E.2 of the Area Report.

3. Required Mitigations

No Delivery Network Upgrades are required.

H. In-Service Date and Commercial Operation Date Assessment

The latest information indicates that the generator ISD is December 23, 2016 and a COD of December 31, 2016. 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 and is anticipated to be executed by October 2016. In order to meet the proposed ISD, SCE and the IC entered into a Letter Agreement to initiate the engineering, design, preparation of specifications, procurement of material and equipment, and construction.

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

      No RNUs were identified to be required to enable this project to interconnect.

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
   - Storage Management System at [redacted]

3. **Conclusion**

   The proposed In-Service Date of 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.

4. 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 - installation of two additional 500/220 kV transformers at Whirlwind Substation.

   c. Approved Transmission Upgrades
      The entire Tehachapi Renewable Transmission Project (TRTP) is required to support the FCDS of the Project. The expected in-service date of TRTP is late 2016.

   d. Transmission Upgrades outside the CAISO Controlled Grid - None

5. Interim Operational Deliverability Assessment for Information Only

   The operational deliverability assessment was performed for study years 2015, 2016 and 2019 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.3 of the Area Report. [redacted]s overloaded in 2016. The Project is not deliverable in 2016. Once [redacted] are in service, the Project will have the deliverability status as granted by the Transmission Plan Deliverability allocation.

   December 23, 2016 can be met to meet the requirements for the [redacted]

F. 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.

As part of the QC7 Phase II studies there were no Delivery Network Upgrades allocated to the Project for its requested Full Capacity Deliverability Status. It is important to note that while no Delivery Network Upgrades were allocated to the Project, this outcome does not mean that the Project will be able to generate at its maximum Generating Facility output. Congestion could happen whenever the amount of generating resources exceeds the available Transmission capability. The generating resources' output may be curtailed, regardless of their deliverability status, as the result of congestion under the CAISO market operation.

As stated in Attachment 7, studies indicate that as high amounts of resources in the East of Lugo area develop and are dispatched, the amount of available Transmission capacity for the Northern Area resources is diminished. Such conclusions point to a potential need for congestion management, and generation resource curtailments. For additional information on potential congestion under expected amounts of renewable generation development in 2021, please see Chapter 5 of the ISO 2013-2014 Transmission Plan report. http://www.caiso.com/Documents/Board-Approved2013-2014TransmissionPlan_July162014.pdf

G. Interconnection Facilities, Network Upgrades, and Distribution Upgrades

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

H. 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[5] provides the 'constant' 2016 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 end of October 2016, which includes the 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 22% Income Tax Component of Contribution (ITCC) pending the results of the TPD allocation Process several months after the Phase II Study Reports are released, in addition to the 22% ITCC assessed for the IFs, DUs, and RNUs above the $60K/MW repayment cap allocated to the Project. For your information, Attachment 2 contains a potential ITCC estimate[6] 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 development phase once the IC submits the TP Deliverability allocation options form

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

[6] The maximum ITCC exposure applies ITCC (22%) 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: (IF*22%)+ ((RNU Costs – (Project MW * ($60k/MW)))*22%)+(LDNU*22%)+(ADNU*22%)+(DU*22%)

confirming the acceptance, waiver (parking), or denial of awarded deliverability assigned to the Project.

I. 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.

J. 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.

K. Environmental Evaluation, Permitting, and Licensing

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

L. Affected Systems Coordination

Please see Section H of the QC7 Phase II Area Report.

M. 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 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's Facilities

   The IC is responsible for acquiring all property rights necessary for the IC's Interconnection Facilities, including those required to cross Distribution Provider's 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's Interconnection Handbook

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

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 I Study does not address any requirements for standby power or temporary construction power that the Project may require prior to the In-Service Date of the Interconnection Facilities. Should the Project require standby power or temporary construction power from Distribution Provider prior to the ISD of the Interconnection

Facilities, 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 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 QC8 Phase I, telecommunication upgrades for higher queued projects were not considered in this study. Depending on the outcome of interconnection studies for higher queued projects, the telecommunication upgrades identified for QC8 Phase I 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 QC8 Phase I Study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in GIAs 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 seven (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 PTOs 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 advised that interconnection of its proposed Generating Facility may be dependent upon the construction of certain Network Upgrades, which are currently the obligation of projects ahead of its proposed Generating Facility in the interconnection application queue. These other potential network upgrades are referenced in Section B.5 of the Area Report and outlined in Attachment 2 to the ICs final Phase I or Phase II Study Report (Appendix A).

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

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

1. If the earlier-queued generating facilities that have cost responsibility for the other potential network upgrades withdraw prior to executing a GIA (or the filing of an unexecuted GIA at FERC), the following will occur:
    a. The ISO and SCE will evaluate whether the other potential network upgrades are still needed to support the interconnection for later-queued generating facilities
    b. The ISO and SCE will reapportion the cost of the other potential network upgrades to the later-queued generating facilities that require the upgrades
    c. Steps (a and b) will occur as a result of the ISO's Annual Reassessment as set forth in Section 7.4 of GIDAP and Section 6.2.9.2 of the ISO's GIDAP business practice manual
    d. The reapportioned cost of the other potential network upgrades will be reflected in the reassessment report as outlined in the ISO's Annual Reassessment process, which will be reflected in the GIAs of the responsible parties
2. Please refer to Section 10.3.2 of the GIP and Section 14.2.2 of the GIDAP for additional requirements regarding treatment of other potential network upgrades for ICs that select an Option (B) Generating Facility.

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

Not Used.

Attachment 4

Distribution Provider's Interconnection Handbook

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

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

Attachment 6
Interconnection Customer Provided Project Dynamic Data
Not Used.

Attachment 7
SCE Northern Hemisphere Import Nomogram
Please refer to separate document

Attachment 8
Subtransmission Assessment Report
Please refer to separate document