Appendix A – WDT1477

Queue Cluster 10 Phase I Report

January 16, 2018

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

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<th>No.</th>
<th>Date</th>
<th>Document Title</th>
<th>Description of Document</th>
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<td>1</td>
<td>1/16/18</td>
<td>Queue Cluster 10 Phase I Appendix A Report</td>
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A. INTRODUCTION

The Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to Southern California Edison (SCE) for their proposed [Project]. The Project shall consist of the Generating Facility and the IC’s Interconnection Facilities as illustrated in Figure A.1. Below also is Figure A.2, a map that illustrates the location of the Project. Moreover, the Project information is summarized in Table A.1 below.

In accordance with FERC approved SCE’s WDAT Attachment I Generator Interconnection Procedures (GIP), the Project was grouped with Queue Cluster 10 (QC10) Phase I projects to determine the impacts of the group as well as impacts of the Project on the ISO Grid.

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

The report provides the following:

1. 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* these facilities. Such information is provided in Attachment 1 and Attachment 2 as separate documents in the Appendix A Project report package.

The Project encompasses energy storage equipment that triggered the need to analyze its charging impacts the Distribution Provider’s (SCE) electric system. The analyses focused on the charging demand** aspects of the Project and considered varying levels of system demand with minimal generation dispatch within the local distribution system.

Consequently, the report also discloses the adequacy of SCE’s Electric System to support the Project when operating in charging mode, identifies system limitations that may restrict the Project when operating in charging mode during certain demand conditions, and provides a high-level explanation of potential exposure of the Project of charging restrictions on the electric system. The Generating Facility will follow ISO market dispatch instructions when in charging mode and in discharging mode.

All equipment and facilities comprising the Interconnection Customer’s 5 net MW 6.6 MVA gross capacity Generating Facility in Irvine, California, as disclosed by the Interconnection Customer in its Interconnection Request, as may have been amended during the Interconnection Study process, which consists of (i) the associated infrastructure and step-up transformers, (ii) meters and metering equipment, and (iv) appurtenant equipment. The [Project] shall consist of the Generating Facility and the Interconnection Customer’s Interconnection Facilities.

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*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.

**Charging is defined as the Act when the Project draws energy from the grid to “charge” the Project-associated charging facilities.
Table A.1 Project General Information per IR

<table>
<thead>
<tr>
<th>Project Location</th>
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<tbody>
<tr>
<td>Distribution Provider’s Planning Area</td>
<td>Distribution Provider’s Metro Area</td>
</tr>
<tr>
<td>Interconnection Voltage</td>
<td>12 kV</td>
</tr>
<tr>
<td>Point of Interconnection</td>
<td>Billings 12 kV Circuit out of the Fairview 66/12 kV Substation in the Johanna 66 kV System</td>
</tr>
<tr>
<td>Number and Types of Generators</td>
<td>with an individual rated output of 2.09 MW for a combined installed capacity of 6.27 MW at inverter terminal</td>
</tr>
<tr>
<td>Requested Maximum Project Delivery at Point of Interconnection</td>
<td>5 MW</td>
</tr>
<tr>
<td>Pad-Mount Transformer(s)</td>
<td></td>
</tr>
<tr>
<td>Generator Data</td>
<td></td>
</tr>
<tr>
<td>Generator Auxiliary Load and/or Station Light and Power</td>
<td>0 MW</td>
</tr>
<tr>
<td>Deliverability Requested</td>
<td>Full Capacity</td>
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<tr>
<td>Proposed Dates</td>
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<tr>
<td>In-Service Date (ISD)</td>
<td>5/4/2021</td>
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<td>Initial Synchronization Date/Trial Operation</td>
<td>5/18/2021</td>
</tr>
<tr>
<td>Commercial Operation Date (COD)</td>
<td>6/1/2021</td>
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Note 1: The MW output at the POI varies under different operating conditions. Please note that the Project shall not exceed the total net output of 5 MW at the Point of Interconnection.

Based on the technical data provided, the Project is requesting to install more megawatts (6.27 MW) as measured at the inverter/converter terminal which will result in more than the requested 5 MW delivery at the POI. As a result, the Project will be limited to not exceed the values shown under Limited Maximum Net Output (metered at the Point of Change of Ownership). Additionally, this may trigger the installation of a directional power relay to prevent the Generating Facility from exceeding the contractual net output of the Project.

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2The MW output at the Point of Interconnection varies under different operating conditions. The IC is reminded that this value is tied to the generation tie-line (gen-tie) losses.
3The estimated Maximum Net Output value at Point of Interconnection and gen-tie losses illustrated above are contingent upon the accuracy of the technical data provided by the IC, and are subject to change should the IC change its gen-tie parameters during the detailed engineering and design phase of the Project. Please note that the Project shall not exceed the total net output of 5 MW at the Point of Interconnection.
4Such dates are specified in the Project’s IR. Actual ISD and COD will depend on licensing, engineering, detailed design, and construction requirements to interconnect the Project.

Appendix A – QC10 Phase I
B. STUDY ASSUMPTIONS

For detailed assumptions regarding the group cluster analysis, please refer to the QC10 Phase I Area Report. Below are the assumptions specific to the Project:

1. The Project was modeled as described in Table A.1.

2. The facilities that will be installed by SCE and the IC are detailed in Attachment 1.

3. Roles and Responsibilities for Environmental Activities, Permits, and Licensing

   The assumptions for the Environmental Activities, Permits, and Licensing are as follows:
   
   - **Internal Substation Scope:**
     - **SCE Responsibility:** The study assumes Environmental Services (ES) will perform all environmental studies and perform monitoring of all SCE internal substation construction activities. This study assumes no nesting bird issues during construction.
     - **IC Responsibility:** ES recommends that the IC includes SCE’s scope of work in their environmental document

   - **Generation Tie Line Scope:**
     - **CPUC License:** This study assumes that SCE’s scope of work would not require a California Public Utilities Commission license.
     - **SCE Responsibility:** This study assumes ES will act as the environmental liaison between SCE’s team and IC’s team, and the lead for regulatory agency communication. This estimate includes, but is not limited to, the following ES activities, as applicable:
       - Collaborate with the IC during the environmental study phase on proposed study methodologies and findings, as studies are being planned and performed for SCE’s scope of work
       - Review IC’s California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA) documents, technical studies, surveys and other environmental documentation addressing SCE’s scope of work (IC to include SCE’s scope of work in their environmental document)
       - Review of internal (SCE/ES) existing technical documents when available
       - Regulatory agency communication, consultation, and reporting
       - Permit or license acquisition
       - Support SCE team in developing the project description, including scope changes during permitting/pre-construction or construction.
       - Communicate scope changes to IC’s environmental team, discuss/approved subsequent actions including new surveys as necessary
       - Prepare Environmental Requirements for Construction Clearance
       - Develop communication plan
       - Construction monitoring oversight
- General Order 131-D Consistency Determination and Environmental Evaluation
- Environmental Awareness/Worker Environmental Awareness Program (WEAP) training
- Preconstruction coordination field visit
- Construction and post-construction site assessments

**IC Responsibility:** This estimate assumes the IC performs all environmental studies and prepares draft environmental permit applications related to the installation of SCE’s Interconnection Facilities and Upgrades. Prior to commencing work and during execution of work, the IC must collaborate and obtain CES concurrence on all work outlined below. Should the IC-performed environmental studies, surveys, or monitoring not meet the Federal or State industry standards in accordance with Applicable Laws and Regulations, and as determined by CES, the IC shall be obligated to remedy deficiencies under SCE/SES’s direction, or CES shall undertake additional environmental studies, surveys, or monitoring at the sole expense of the IC. If these scenarios occur, the cost estimate must be updated to reflect the changes to the assumptions. The IC’s responsibilities include, but are not limited to:
  - Notifications to the Native American Heritage Commission (NAHC) and follow-up notifications to the tribes and individuals in the NAHC contact list
  - Performing cultural and paleontological resources records searches, performing cultural resources inventories (survey and recording), performing testing and evaluation and/or data recovery of archaeological sites as applicable, and providing the appropriate documentation in the form of inventory reports, research design and/or data recovery reports as applicable
  - Cultural and paleontological monitoring during construction, when/if required
  - Arranging curation agreements for artifacts and fossil specimens collected
  - Performing a California Natural Diversity Database search
  - Performing a habitat assessment
  - Performing protocol or focused surveys for species with the potential of occurring in identified suitable habitat
  - Conducting jurisdictional delineations for wetlands and other regulated waters
  - Preparing draft environmental permit applications
  - Performing pre-construction biological resource surveys
  - Performing biological resource monitoring during construction
  - Mitigation costs including, but not limited to, offsite/compensatory mitigation, onsite restoration, and habitat mitigation plans
  - Developing other mitigation plans
  - Developing environmental reports or submittals, if required

- This study is based upon the scope listed in the Attachment 1. If the scope is altered, this study is no longer valid and the study must be reviewed and updated.
4. Other Items to Consider:
   - The Project is dependent upon the installation of Distributed Energy Resource Management System (DERMS). Should DERMS not be operational prior to this Project initializing commercial operation, this Project may elect to: (i) follow a static charging restriction schedule provided by SCE until DERMS is operational, or (ii) wait for DERMS to be completed.

5. Charging Facility Considerations:
   - The Project encompasses energy storage facilities. The details pertaining to the Reliability Study for the Generating Facility, when operating in charging mode, are included in this Appendix A report.
   - The load assumptions used for the Distribution Provider’s Distribution System consider SCE’s 2016-2025 Distribution Load Forecast.
   - To model the hourly forecast demand performance of the Distribution Provider’s Distribution System, historical year 2016-2017 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.
   - The IC should note that, due to the dynamic nature of the Distribution Provider’s distribution system, the operational limitations yielded by the charging analysis results disclosed in this report are for informational purposes only. Furthermore, the charging analysis used historical system performance information, which can only speak to past system performance. Hence, the charging analysis results cannot establish firm conditions for future real-time operational conditions for which the Project’s charging is restricted to operate.
   - Distribution Provider’s Distribution Standards and Practices are in the process of being updated to address charging 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 Generating Facility will include all equipment, software, appropriate controls, and other related equipment necessary to maintain the charging facility demand restriction per the Distribution Provider requirements.
   - Upon execution of the GIA, the Distribution Provider will provide the IC with the required ramp rate control parameters and other necessary information to allow the customer to develop its storage control limit.
   - Ongoing changes to the ramp rate control scheme may be required as determined by changes in the distribution system topology or other changes in the distribution system. However, typical ramp rates for facilities connected to the Distribution Provider’s Distribution System are 10% of nameplate rating, per minute.
   - A Distributed Energy Resource Management System (DERMS), which at this stage is conceptual, is under development. It is assumed that DERMS will not be available prior to the In Service Date (ISD) of the Generating/Storage Facility. Further details will be available during the detailed engineering and design phase of the Project. In concept, DERMS provides monitoring of system loading conditions from both monitored data of

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1 It is assumed that ramp rates for each Generating 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.
C. TECHNICAL REQUIREMENTS*

1. Protection Requirements
   Protection requirements are designed and intended to protect the Distribution Provider’s electric system only. The preliminary protection requirements were based upon the interconnection plan as shown in the one-line diagram depicted in line item #4 in Attachment 1.

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*The IC is advised that there may be technical requirements in addition to those that outlined above in Section C of this report that are included in the Interconnection Handbook or that will be addressed in the Project’s GIA.
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.

2. **Power Factor Requirements**
The Generating Facility will be required to maintain a composite power delivery at continuous
rated power output at the high-side of the generator substation at a power factor within the
range of 0.95 leading to 0.95 lagging.

3. **Operating Voltage Requirements**
Under real-time operations, the project will be required to operate under the control of
automatic voltage regulator with settings as shown in the figure below. The actual values of the
Vmin and Vmax will be provided once the project executes a Generation Interconnection
Agreement and detailed engineering and design is complete. The Vmin and Vmax values are to
be used as the basis for setting up the automatic voltage control mode (with its automatic
voltage regulator in service and controlling voltage) of the Generating Facility in order to
maintain scheduled voltage at a reference point.

4. **Harmonic Requirements**
The harmonic impact of the subject inverter-based generation was not part of this study.
Impacts on voltage distortion levels may be significant due to the penetration level of the
Generating Facility with respect to the local distribution grid strength. As with all equipment
connected to SCE's Distribution System, the generation project will be subject to the provisions
of CPUC Rule 2.E, allowing SCE to require the IC to mitigate interference with service other SCE
customers, including harmonic impacts, if the harmonic interference is caused by the IC.
Given the amount of generation and the strength of the distribution system, SCE may require a harmonic study during the execution and construction phase to insure that the generation facility complies with the harmonic current limits outlined in IEEE 519-2014. During that time, SCE will then provide the required SCE distribution system data that are to be used as part of the harmonic study.

5. **Low Voltage Ride-Through (LVRT) Capability**
Actual fault events have demonstrated that certain asynchronous generators (i.e., inverters) from specific manufacturers may be susceptible to false tripping or temporary shutdown during fault conditions. The most severe disturbance to date resulted in the temporary loss of 1,178 MW at photovoltaic plants when inverter control systems throughout Southern California responded to a 500 kV fault by temporarily stopping the production of electric power. Based on the results of an investigation performed into this issue, several causes and contributing factors have been identified which include:

a. Apparent miscalculated frequency at many inverters when fault-induced phase shifts occurred in the reference voltage
b. Inverter protection settings set to meet IEEE 1547 standards
c. Momentary overvoltage
d. Momentary under-voltage

The NERC PRC-024-2 standard currently allows generators to trip if the system conditions are outside of a defined set of bounds. Because different inverter manufacturers use different methods to calculate frequency (zero crossing, DFT, PLL, etc.), the methods used by some manufacturers have resulted in calculations of the instantaneous frequency during power system disturbances that do not accurately reflect actual frequency. Inaccurate frequency calculations may result in the reduction of electric power from inverter-based resources which is an unacceptable response. In addition, voltage transients caused by capacitive switching (among other potential causes) can cause inverters to trip due to a momentary overvoltage condition which too is an unacceptable response unless the Project has reached the power factor lead (buck) limits and the voltage is still in excess of the maximum allowable voltage limit for a duration longer than the no trip timer defined in PRC-0240-2.

When under-voltage occurs during the fault, some inverters may cease operation temporarily. Such performance impacts system reliability and may not be allowed in the future reliability standards/interconnection standards.

The IC should work with the inverter manufacturer to ensure these three issues are properly addressed. Dynamic simulation study results illustrating the frequency and voltage performance of the Project based on the technical parameters supplied for the Project are provided as part of the study results. The results will evaluate performance to ensure that the Project remains online during voltage disturbances up to the time periods and corresponding maximum allowable voltage levels set forth in NERC PRC-024-2 and producing power immediately following fault disturbance clearing at the levels prior to the disturbance.

6. **Frequency Disturbance Ride-Through Capability**
An Asynchronous Generating Facility shall comply with the off nominal frequency requirements set forth in the WECC Under Frequency Load Shedding Relay Application Guide or successor requirements as they may be amended from time to time.
7. **Environmental Activities, Permits, and Licensing**
   Please see Appendix K of the Area Report.

**D. RELIABILITY STANDARDS, STUDY CRITERIA AND METHODOLOGY**

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

1. **Discharging Analysis Planning Criteria**
   Refer to above Section B: Study Assumptions 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 I Study are as follows:
   - The thermal rating of any conductor, connector, or apparatus shall not exceed 100% of its normal rated capacity 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 lagging or leading.
   - Expected loading on the distribution system, as projected by SCE’s internal 2017-2026 distribution system forecast, is utilized for the purposes of this charging analysis.
   - Charging 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, as to determine the worst case scenario between these two “book-ends” of demand.
   - The short-circuit duty contribution from the inverter system was determined using inverter manufacturer specification sheets (as needed).

**E. POWER FLOW RELIABILITY ASSESSMENT RESULTS**

*Discharging Analysis of the Project*
I. Steady State Power Flow Analysis Results – 55 kV and above

1. Thermal Overloads
   The Metro Bulk Area studies indicate that the Project contributes to overloads under contingency conditions when operated in discharge mode. However, mitigation and corresponding cost allocation were not assigned to this project due to the relatively small project contribution.

   At the subtransmission level, the Johanna Subtransmission Assessment did not identify any thermal overloads allocated to this Project when operated in discharge mode.

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

1. Thermal Overloads
   The study found that the Project does not contribute to the following facility overloads with all existing facilities and prior queued upgrades. The details of the analysis as well as the recommended mitigations are provided as follows:

   I. Normal Conditions (Base Case)
      • No thermal overloads have been identified

   II. Single Contingency (N-1)
      • No thermal overloads have been identified

2. Voltage Performance
   The Billings 12 kV Circuit is not expected to experience a voltage rise that exceeds allowable Rule 2 requirements with the Project in service. The Generating Facility should to maintain a composite power delivery at continuous rated power output at the point of interconnection within the range of .95 leading to .95 lagging to improve power flow non-convergence and maintain the transmission transfer capability. Additionally, the generation system must be designed to accommodate a VAR schedule provided by the Distribution Provider. The Distribution Provider will determine if the VAR schedule is necessary based on future re-arrangements of the Distribution Provider’s distribution system.

3. Protection
   No additional protection requirements are triggered by the Project.

4. Relevant Project Notes
   Under emergency N-1 conditions (loss of a B-Bank, or loss of the Billings 12 kV Circuit), no thermal overloads were triggered by the Project.

5. Required Mitigations
   Per the WDAT, the Project is required to provide 0.95 leading/0.95 lagging power factor regulation capability at the POI.
The study indicated that the Project does not contribute to any overloads on the electric system of the area, however the Project will need to install necessary distribution upgrade facilities to support the interconnection of the Project to the Billings 12 kV Circuit.

Refer to Attachment 1 and Attachment 2 for scope description and associated project cost responsibility of these Distribution Upgrade(s).

Charging Analysis of the Project

I. Steady State Power Flow Analysis Results – 55 kV and above

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

At the subtransmission level, the Subtransmission Assessment identified thermal overloads at the Johanna Substation A Banks. As a result, DERMS will be require3d to monitor the A Banks at Johanna while this Project is in charge mode. Refer to Attachment 1 and Attachment 2 for additional details.

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

1. Thermal Overloads
The study found that the Project does not contribute to overloads on the following facilities listed below. The details of the analysis as well as the recommended mitigations are provided as follows:

   • Normal Conditions (Base Case)
     • No thermal overloads have been identified

   • Single Contingency (N-1)
     • No thermal overloads have been identified

2. Voltage Performance
The Billings 12 kV Circuit is not expected to experience a voltage rise that exceeds allowable Rule 2 requirements with the Project in service. The should maintain a composite power delivery at continuous power factor near unity at the rated output of a Distribution specified power factor in accordance with the following requirements:

   I. Default Power Factor setting: 1.0 +/- 0.01 (0.99 lagging To 0.99 leading)

   II. Aggregate Generating Facility is greater than 15 Kw: 1.0 +/- 0.15 (0.85 Lagging to 0.85 leading) down to 20% rated power based on available reactive power

   III. Aggregate Generating Facility is less than or equal TO 15 KW: 1.0 +/- 0.10 (0.90 Lagging to 0.90 Leading) down to 20% rated power based on available reactive power.
Additionally, the generation system must be designed to accommodate a VAR schedule provided by the Distribution Provider. The Distribution Provider will determine if the VAR schedule is necessary based on future re-arrangements of the Distribution Provider’s distribution system.

In addition, the Generating Facility including smart inverter technology should be designed to parallel with the Distribution Provider’s electric system without causing a voltage fluctuation at the PCC greater than plus/minus 5% of the prevailing voltage level of Distribution Provider’s electric system at the PCC.

The Generating Facility, including smart inverter technology, should also be designed to meet the Distribution Provider’s flicker requirement (IEEE 1547-4.1.3). Furthermore, the Generating Facility shall not create objectionable flicker for other customers on the Distribution Provider’s distribution or transmission system. To minimize the adverse voltage effects experienced by other customers (IEEE 1547-4.3.2), flicker at the PCC caused by the Generating Facility should not exceed the limits defined by the “Maximum Borderline of Irritation Curve” identified in IEEE 519-1992 (IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems, IEEE STD 519-1992). This requirement is necessary to minimize the adverse voltage effects experienced by other Customers on the Distribution Provider’s electric system.

3. Distribution System

   a. Individual Project Power Factor Requirements
      Please refer to the Technical Requirements section above.

   b. Distribution System Power Factor Requirements – 34.5 kV or below
      The Billings 12 kV Circuit out of Fairview 66/12 kV Substation is not expected to experience a voltage rise that exceeds Rule 2 requirements with the Project in service.

4. Protection

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

5. Charging Restrictions

   a. System Condition
      
        • Base Case

      Based on the assessment of the system loading projections, there were charging restrictions identified for the Project. The charging restrictions are a function of system loading conditions and load forecast. Modifications or adjustments to the charging restrictions will be evaluated as required by SCE to maintain its distribution system within operating criteria. These modifications or adjustments reviews may be completed on a yearly basis, at any time when significant load is added to the distribution system, or as determined necessary by SCE. These reviews may trigger the storage charging capabilities. Assuming adjusted 2016-2017 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.

- Single Contingency (N-1 condition)
  - Fairview 66/12 kV Substation:
    
    At this time, the available capacity at the substation does not allow the Project to charge.

II. Additional Factor(s) to Restrictions

SCE provides, in Table 2-1, an estimated number of hours that the charging facility may be restricted to charge at a given demand value in a given month. This is subject to change as loading on the system changes. 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). The Project’s charging restrictions will be based on the most restrictive loading conditions and real time information from the distribution and transmission systems.

Table 2-1: Fairview 66/12 kV Substation

# of Charging Hours Restricted for Energy Storage System
Table 2-2: Fairview 66/12 kV Substation
Charging Hour Restrictions of Day for Energy Storage System

Table 3-1: Billings 12 kV Circuit
# of Charging Hours Restricted for Energy Storage System
6. Required Mitigations

The Project is required to provide 0.95 leading/0.95 lagging power factor regulation capability at the Point of Interconnection, in addition to the following Distribution Upgrade(s) to mitigate the power flow impacts of the Project described above under Voltage Performance.

a. Distributed Energy Resources Management System (DERMS)
   1. The Billings 12 KV Circuit out of Fairview 66/12 kV Substation

Refer to Attachment 1 and Attachment 2 for scope description and associated project cost responsibility of these Distribution Upgrade(s).

F. SHORT-CIRCUIT DUTY RESULTS

Short-circuit studies were performed to determine the fault duty impact of adding the Phase I projects to the distribution system and to ensure system coordination. The fault duties were calculated with and without the projects to identify any equipment overstress conditions. Once overstressed circuit breakers are identified, the fault current contribution from each individual project in Phase I is
determined. Each project in the cluster will be responsible for its share of the upgrade cost based on the rules set forth in Section 4 of the GIP.

**Short-Circuit Duty Study Results**
All bus locations where the Phase I projects increase the short-circuit duty by 0.1 kA or more and where duty was found to be in excess of 60% of the minimum breaker nameplate rating are listed in the Area Report (Appendix H). These values have been used to determine if any equipment is overstressed as a result of the inclusion of Phase I interconnections and corresponding Network Upgrades, if any.

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

The QC10 Phase I breaker evaluation did not identify any additional overstressed circuit breakers triggered with the inclusion of the projects in QC10 Phase I. Please refer to the QC10 Phase I Area Report for additional details.

**G. DELIVERABILITY ASSESSMENT RESULTS**

1. **On Peak Deliverability Assessment**
The Project does not contribute to any on peak deliverability constraint.

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

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

**H. INTERCONNECTION FACILITIES, NETWORK UPGRADES, AND DISTRIBUTION UPGRADES**
Please see Attachment 1 for the Distribution Provider’s Interconnection Facilities (IF’s), Reliability Network Upgrades (RNU’s), Delivery Network Upgrades (DNU’s), and Distribution Upgrades (DU’s) allocated to the Project. Please note that SCE will not “reserve” the identified IFs for the proposed Point of Interconnection. 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.

**I. COST AND CONSTRUCTION DURATION ESTIMATE**

1. Cost Estimate
The Project’s estimated interconnection costs, adjusted for inflation and provided in 'constant' 2017 dollars, are provided in Attachment 2 and the Project’s allocated cost for shared network upgrades are provided in Attachment 3. The costs will be utilized in developing the GIA. However, should there be a delay in executing the GIA beyond 2019, a new adjustment for inflation will be required and inserted into the GIA.

2. Construction Duration Estimate
The construction duration for the identified facilities is as follows:
a. Distribution Provider’s Interconnection Facilities
These facilities involve non-network facilities located within SCE’s Fairview 66/12 kV Substation, Billings 12 kV Circuit, and at the IC’s Project that are necessary to complete physical interconnection of the Project. Please refer to Attachment 1 for details related to these facilities.

b. Reliability Network Upgrades
No required Reliability Network Upgrade mitigations were identified in this Phase I Interconnection Study.

c. Voltage Support Mitigation
No required voltage support mitigations were identified in this Phase I Interconnection Study.

d. Distribution Upgrades – 27 months
These facilities involve:

- The facilities located at Billings 12 kV Circuit which is necessary to support the physical interconnection of the Project.
- Point addition at Fairview 66/12 kV Substation.
- The Project was identified to participate in DERMS to monitor the Johanna 66 kV Substation A Banks and Joaquin 12 kV Circuit.

Please refer to Attachment 1 for details.

J. IN-SERVICE DATE AND COMMERCIAL OPERATION DATE ASSESSMENT
An ISD and COD assessment was performed for this project to establish the Distribution Provider’s estimate of the earliest achievable ISD based on the QC10 Phase I Interconnection Study process timelines and the time required for the Distribution Provider to complete the facilities needed to enable physical interconnection as an Interim Deliverability or Energy Only Deliverability interconnection (as applicable) for the Project. This date may be different from the Interconnection Customer’s requested ISD and will be the basis for establishing the associated milestones in the draft GIA.

Details pertaining to Full Capacity Deliverability Status and Partial Deliverability Status are provided below.

1. ISD Estimation Details
For the QC10 Phase I Interconnection Study, the estimated earliest achievable ISD is derived by the time requirements to complete the QC10 Interconnection Study Process, tender a draft GIA, negotiate and execute the GIA, and construct the necessary facilities as described below in Table A.2.

<table>
<thead>
<tr>
<th>Reference starting point</th>
<th>Days/months for calculation</th>
<th>Issuance of Phase II Interconnection Study Report</th>
<th>11/25/18</th>
</tr>
</thead>
<tbody>
<tr>
<td>Add: 30 CD</td>
<td></td>
<td>Phase II Results Meetings</td>
<td>12/25/18</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Starting Point: TPD Results issued and IC response provided</td>
<td>4/2/19</td>
</tr>
</tbody>
</table>

Table A.2 ISD and COD Assessment
<table>
<thead>
<tr>
<th>Add:</th>
<th>30 CB</th>
<th>Earliest reasonable Tender draft GIA</th>
<th>5/2/19</th>
</tr>
</thead>
<tbody>
<tr>
<td>Add:</td>
<td>90 CD</td>
<td>GIA negotiation time, execution, and related activities</td>
<td>7/31/19</td>
</tr>
<tr>
<td>Add: Construction Duration (Months)</td>
<td>27</td>
<td>Construction duration outlined in the Phase I Study Report. Construction completion no earlier than date which reflects earliest ISD</td>
<td>10/31/21</td>
</tr>
<tr>
<td>Reference</td>
<td>IC-requested ISD via IR</td>
<td></td>
<td>5/4/21</td>
</tr>
<tr>
<td>Reference</td>
<td>IC-requested COD via IR</td>
<td></td>
<td>6/1/21</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Duration difference between ISD and COD</td>
<td>1 month</td>
</tr>
<tr>
<td>Equals:</td>
<td></td>
<td>Earliest achievable In-Service Date (ISD) per estimated construction duration</td>
<td>10/31/21</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Earliest achievable Commercial Operation Date (COD) (Using difference between ISD and COD requested by IC)</td>
<td>11/28/21</td>
</tr>
</tbody>
</table>

Notes on the Achievable ISD and COD calculation:

1. Assumes duration required to construct those facilities required for an Interim Deliverability Interconnection or Energy Only interconnection (as applicable) for the Project until the applicable DNUs are completed.

2. The construction durations shown represent the estimated amount of time needed to design, procure, and construct the facilities with the start date of the duration based on the effective date of the GIA; and necessarily include timely receipt of all required information and written authorizations to proceed (ATP), and timely receipt of construction payments and financial security postings and other milestones.

2. ISD Conclusion

Based on these timelines, the IC’s requested ISD of 5/4/2021 and COD of 6/1/2021 does not appear to be achievable.

The Distribution Provider can reasonably tender a draft GIA by May 2019. The draft GIA will include the earliest ISD and COD as identified in Table A.2.

The ISO will perform its Annual Reassessment (January - July 2019) and Transmission Plan Deliverability (TPD) Allocation7 (due April 2019). Any changes to the deliverability allocation resulting in changes in scope, cost, or schedule requirements that come out of ISO’s Annual Reassessment and TPD Allocation will be reflected in a 2019 Reassessment Report which will be used to revise the draft GIA (if under negotiation) or amend the GIA (if already executed).

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7 The TPD Allocation Process is estimated to be completed in April 2019. The actual date may vary.
If ISO and SCE determine that the TPD Allocation Study Process outcomes do not change the scope requirements for the Project, a letter will be provided at the end of April 2019 informing the IC that there will be no changes to the allocated Network Upgrades requirements.

K. AFFECTED SYSTEMS COORDINATION
   Please see Section H of the Area Report.

L. ADDITIONAL STUDY ANNOTATIONS
   1. Conceptual Plan of Service
      The results provided in this study are based on conceptual engineering and a preliminary Plan of Service (POS) and are not sufficient for permitting of facilities. The POS is subject to change as part of detailed engineering and design.

   2. The study does not include analysis related to the power output rate of change that may occur due to the following or other conditions:
      - System morning start up for solar systems of generating facilities. That is when each morning the Generating Facility commences to generate and export electrical energy to the electric system.
      - Cloud Cover: Solar generating facilities have significant generation output variation (Variability) which can have an impact on electric system voltage profiles.
      - The customer’s Generating Facility will have equipment, software, and the appropriate controls as in place to be able to control the generation output rates of change, as specified by SCE, in order to maintain appropriate voltage levels under all conditions including, but not limited to, the conditions identified above. Upon execution of the appropriate Interconnection Agreement, SCE will provide the Interconnection Customer the required ramp rate control parameters. The ramp rate controls will be a function of the generation penetration on the electric system as well as SCE’s electric system configuration but other parameters may be considered. Therefore, changes to the ramp rate control scheme may be required from time to time as required by increased generation, changes in the electric system topology, or other changes in the electric system.

   3. IC’s Technical Data
      The study accuracy and results for the QC10 Phase I Study are contingent upon the accuracy of the technical data provided by the IC. Any changes from the data provided as allowed by the tariff would need to be submitted in Attachment B prior to commencement of the Phase II study. Any changes that extend beyond the modifications allowed prior to commencement of the Phase II Study will need to be evaluated following the Material Modification Assessment to determine if such a change results in a material impact to queued-behind generation requests. These change(s) would only be allowed if it is determined that there is no material impact to queued-behind requests.

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

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

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

7. **Western Electricity Coordinating Council (WECC) Policies**
The IC shall be required to adhere to all applicable WECC policies including, but not limited to, the WECC Generating Unit Model Validation Policy.

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

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

10. **Licensing Cost and Estimated Time to Construct Estimate (Duration)**
The estimated licensing cost and durations applied to this Project are based on the Project scope details presented in this Phase I study. These estimates are subject to change as the Project’s environmental and real estate elements are further defined. Upon execution of the GIA, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

11. **Network/Non-Network Classification of Telecommunication Facilities**
   a. **Non-Network (Interconnection Facilities) Telecommunications 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 main and diverse telecommunication paths associated with the IC’s generation tie line, excluding terminal equipment at both ends. In addition, the telecommunication requirements for the RAS were assumed based on tripping of the generator’s breaker in lieu of tripping the circuit breakers and opening the IC’s gen-tie at the Distribution Provider’s substation.

b. Network (Network Upgrades) Telecommunications Upgrades: Due to uncertainties related to telecommunication upgrades for the numerous projects in queues ahead of this Project Phase I, telecommunication upgrades for earlier higher queued projects without a signed GIA and these upgrades have not been constructed were not considered in this study. Depending on the scope of these earlier higher queued projects, the cost of telecommunication upgrades identified for Phase I may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication upgrades.

12. Ground Grid Analysis
A detailed ground grid analysis will be required as part of the detailed engineering for the Project at the SCE substations whose ground grids were flagged with duty concerns.

13. SCE Technical Requirements
The IC is advised that there may be technical requirements in addition to those that outlined above in Section C of this report that are included in the Interconnection Handbook or that will be addressed in the Project’s GIA.

14. 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 Point of Interconnection that was evaluated in the Phase I Study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in GIAs agreed to by the Distribution Provider, ISO, and the IC.

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

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

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

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

19. Future Charging Restrictions
   Charging restrictions not identified in this study may occur in the future if the underlying operating assumptions prove to be different from the conditions evaluated in this study.
Attachment 1:
Interconnection Facilities, Network Upgrades and Distribution Upgrades
Please refer to separate document
Attachment 2:
Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades
Please refer to separate document
Attachment 3:
Allocation of Network Upgrades for Cost Estimates and Maximum Network Upgrade Cost Responsibility

No network upgrade cost is assigned to the Project as part of the QC10 Phase I study.
Attachment 4:

Distribution Provider’s Interconnection Handbook

Preliminary Protection Requirements for Interconnection Facilities are outlined in the Distribution Provider’s Interconnection Handbook at the following link:

Attachment 5:
Short-Circuit Duty Calculation Study Results
Please refer to the Appendix H of the Area Report
Attachment 6:
Not Used