Appendix A – WDT1457

Queue Cluster 10 Phase I Report

January 16, 2018

This study has been completed in coordination with Southern California Edison per ISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP)
### 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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<tbody>
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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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Appendix A – QC10 Phase I
A. INTRODUCTION

The Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to Southern California Edison (SCE) for its proposed Project. The Project requested a Point of Interconnection (POI) at the Antelope-Cal Cement-Rosamond 66 kV Line via the new Bruin 66 kV Substation triggered by WDT1267 and WDT1268, with delivery to the California Independent System Operator (ISO) at the Antelope 66 kV Substation. The Project, as proposed, is to share a generation tie-line with a previously queued project (WDT1268) and consists of the Generating Facility and the IC's Interconnection Facilities as illustrated below in Figure A.1. A map that illustrates the location of the Project is provided below in Figure A.2. Moreover, the Project information is summarized in Table A.1.

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 SCE Distribution System and 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 and distribution facilities served out of the Antelope 66 kV Subtransmission System, respectively. This Appendix A report focuses only on the impacts or impact contributions of the Project, and is not intended to supersede any contractual terms or conditions that may be specified in a forthcoming Generator Interconnection Agreement (GIA).

The report provides the following:

1. Transmission and distribution system impacts caused or contributed to by the Project.
2. System reinforcements necessary to mitigate the adverse impacts caused or contributed to 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 construct1 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 to the Distribution Provider’s (SCE) electric system. The analyses focused on the charging demand2 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 to the Project of charging restrictions on the electric system.

All equipment and facilities comprising the Interconnection Customer’s 20 net MW (41.29 MW/45.88 MVA gross capacity) Photovoltaic and Energy Storage Generating Facility to be located

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1 It should be noted that construction is only part of the duration of months specified in the study, which includes detailed engineering, licensing, and other activities required to bring such facilities into service. These durations are from the execution of the GIA, receipt of all required information, funding, and written authorization to proceed with design and engineering, procurement, and construction from the IC as will be specified in the GIA to commence the work.
2 Charging is defined as when the Project draws energy from the grid to "charge" the Project-associated charging facilities.
in Rosamond, California, as disclosed by the Interconnection Customer in its Interconnection Request, as may have been amended during the interconnection Study process. The project consists of (i) [redacted] [redacted], (ii) a generating capacity of 1100 kVA and 900 kVA at 50°C and 25°C respectively, (iii) the associated infrastructure and step-up transformers, (iv) meters and metering equipment, (v) appurtenant equipment, and (vi) pad-mount and main transformer bank(s). The Project shall consist of the Generating Facility and the Interconnection Customer’s Interconnection Facilities and both the solar photovoltaic and energy storage will be operated in such a manner as to not exceed a collective 20 MW at the POI.

Based on the technical data provided for individual generator unit(s), the collector system equivalent, pad-mount and main transformer bank(s), the internal project losses are shown in Table 1. In addition, losses incurred on the generation tie line are shown in Table 2 below.

Table 1

Table 2

Since the Generating Facility has the capability of producing and delivering more MW at the POI than the requested amount of 20 MW, the Interconnection Customer will need to install or demonstrate that a control system will be put in place which will manage the Generating Facility for both the energy storage (under discharge operation) and solar photovoltaic output to not exceed a combined 20.10 MW as measured at the low side (20.01 MW if measured on the high-side) of the main transformer banks. Under charging mode operation only (no PV output), the project will be limited to not exceed 19.90 MW as measured at the low side (19.99 MW if measured on the high side) of the main transformer banks. The [redacted] shall consist of the Large Generating Facility and the Interconnection Customer’s Interconnection Facilities, and is shown in the diagram below.
Figure A.2: Project Location Map
Table A.1 Project General Information per IR

<table>
<thead>
<tr>
<th>Project Location</th>
<th>Distribution Provider’s Planning Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interconnection Voltage</td>
<td>66 kV</td>
</tr>
<tr>
<td>Point of Interconnection</td>
<td>Antelope - Cal Cement - Rosamond 66 kV Line</td>
</tr>
<tr>
<td>Number and Types of Generators</td>
<td>Each rated at 2200 kVA and 2000 kVA at 50°C and 25°C respectively</td>
</tr>
<tr>
<td>Requested Maximum Project Delivery at Point of Interconnection(^3)</td>
<td>20 MW</td>
</tr>
<tr>
<td>Generation Tie Line</td>
<td>0.25 miles, 226.8 km/lin ACSR</td>
</tr>
<tr>
<td>Line Rating: 337/449 A (Normal/Emergency) Z(_1) (p.u.): 0.002190+j0.004140, B = 0.00140 Z(_0) (p.u.): 0.005570+j0.013220, B = 0.00140</td>
<td></td>
</tr>
<tr>
<td>Main Step-Up Transformer(s)</td>
<td></td>
</tr>
<tr>
<td>Collector Equivalent</td>
<td>For ES and PV: Equivalent Rating: N/A Nominal Voltage: 34.5 kV Z(_1) (p.u.): 0.000139+j0.000332, B = 0.00225 Z(_0) (p.u.): 0.000269+j0.001104, B = 0.00225</td>
</tr>
<tr>
<td>Pad-Mount Transformer(s)</td>
<td></td>
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</tbody>
</table>

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\(^3\) The 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. The 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 20 MW at the Point of Interconnection.
Generator Data

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4. This inverter kVA rating is temperature dependent.
5. Actual power factor based on temperature adjusted kVA and corresponding Pgen output.
6. This inverter kVA rating is temperature dependent.
7. Actual power factor based on temperature adjusted kVA and corresponding Pgen output.
<table>
<thead>
<tr>
<th><strong>Generator Auxiliary Load and/or Station Light and Power</strong></th>
<th>0.6 MW</th>
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<tbody>
<tr>
<td><strong>Voltage Regulation Devices</strong></td>
<td>VAR compensation (if and as needed) – noted on single line diagram</td>
</tr>
<tr>
<td><strong>Downstream of Main Transformer Bank T1</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Dynamic Models Used</strong></td>
<td>PV - regc_a, reec_b, repc_a, lhvt, and lhfrt</td>
</tr>
<tr>
<td><strong>Downstream of Main Transformer Bank T1</strong></td>
<td>ES - regc_a, reec_b, repc_a, lhvt, and lhfrt</td>
</tr>
<tr>
<td><strong>Deliverability Requested</strong></td>
<td>Full Capacity</td>
</tr>
<tr>
<td><strong>Proposed Dates</strong></td>
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<tr>
<td><strong>In-Service Date (ISD)</strong></td>
<td>2/15/2020</td>
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<tr>
<td><strong>Initial Synchronization Date/Trial Operation</strong></td>
<td>3/1/2020</td>
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<tr>
<td><strong>Commercial Operation Date (COD)</strong></td>
<td>4/14/2020</td>
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**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.
   No Environmental activities were included in the analysis of this Project, as no environmental impacts were identified.
4. Other Items to Consider:
   - Final metering requirements will be identified as part of project execution and could result in modifications to the Project.
   - 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. Energy Storage Generating 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.
   - SCE’s distribution standards and practices are in the process of being updated to address energy storage facilities. The proposed Plan of Service in this report may require changes to comply with the updated distribution design standards and practices.

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*Such dates are specified in the Project’s IR. Actual ISD and COD will depend on licensing, engineering, detailed design, and construction requirements to interconnect the Project.*
• 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 GIA, SCE will provide the IC with the required ramp rate\(^9\) control parameters. The ramp rate controls will be a function of the demand on the distribution system, as well as SCE’s Electric System configuration (additional parameters may be 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 Distribution Energy Resource Management System (DERMS).
• DERMS, which at this stage is a technical concept, is under development to incorporate the increased amount of energy storage applications to SCE’s Electric System with minimal distribution upgrades. DERMS 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 potential transformers & current transformers and supporting metering equipment) for the Project. Additionally, the Project may also need to connect the energy storage component to a dedicated transformer.

6. Other Items to Consider:
• Note that the Project proposed to share a generation tie-line with a previously queued project (WDT1268). Since the generation tie-line is required to interconnect the Project regardless of the other project, the Project is assumed as a stand-alone project, as such was allocated 100% of the Interconnection Facilities to establish the maximum cost cap.
• Relay coordination study will be required for this Project. Results of the relay coordination study may add protection related scope which will be the cost responsibility of this Project.
• Dedicated Transformer Bank Requirement: The IC is advised that it might not be possible for the projects to share a main transformer bank due to metering issues. Final metering requirements will be identified as part of project execution and could result in modifications to the Project.
• The following facilities will be installed by SCE and paid for by WDT1267 and WDT1268. Should WDT1267 and WDT1268 withdraw or not proceed with the upgrade prior to WDT1457’s GIA execution, WDT1457 will be financially responsible for the following Distribution Upgrades:

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\(^9\) 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 modifying limits to maintain safety and reliability of its distribution system.
Engineer and construct the Bruin 66 kV Substation to loop the existing Antelope-Cal Cement-Rosamond 66 kV Line into Bruin Substation and form two new lines: Antelope-Bruin-Cal Cement and Bruin-Rosamond 66 kV Lines and other associated work related to this upgrade.

- For the purposes of this study SCE assumed that all facilities associated with the pending SCE Bruin Substation are already in service. Should the future Bruin Substation not materialize, the Project’s facilities to interconnect will need to be reassessed which may potentially change the Plan of Service and associated Project costs.

C. TECHNICAL REQUIREMENTS

1. Preliminary Protection Requirements
   Protection requirements are designed and intended to protect SCE’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.

   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.

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. This power factor range standard shall include dynamic capability.

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.

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10 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.
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 Electric 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 to other SCE customers, including harmonic impacts, if the harmonic interference is caused by the IC.

5. Low/High Voltage Ride-Through (LHVRT) and Low/High Frequency Ride-Through (LHFRT) 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. 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.

E. POWER FLOW RELIABILITY ASSESSMENT RESULTS
   Discharging Analysis of the Project

Steady State Power Flow Analysis Results

1. Thermal Overloads
   The group and/or subtransmission study indicated that the Project contributes to overloads on the following facilities listed below under single contingency, and multiple contingency conditions. The details of the analysis and overload levels as well as the details of the recommended mitigation to address these overloads are provided in the corresponding Northern Area and Antelope Subtransmission Assessment Reports.

   I. Normal Conditions
      • No thermal overloads have been identified
II. Single Contingency

- Antelope No. 1A and 4A 220/66 kV Transformer Bank under the loss of the Antelope No. 2A 220/66 kV Transformer Bank
- Antelope No. 1A and 2A 220/66 kV Transformer Bank under the loss of the Antelope No. 4A 220/66 kV Transformer Bank
- Remaining Antelope 500/220 kV Transformer Bank under the loss of the Antelope No.1 or No.2 500/220 kV Transformer Bank
- Remaining Antelope-Vincent 500 kV Transmission Line under loss of the Antelope-Vincent No.1 or No.2 500 kV Transmission Line

III. Multiple Contingency

- Antelope-Vincent No. 1 500 kV Transmission Line under the loss of the Antelope-Vincent No. 2 500 kV and the Vincent-Whirlwind 500 kV Transmission Lines
- Antelope-Vincent No. 2 500 kV Transmission Line under the loss of the Antelope-Vincent No. 1 500 kV and the Vincent-Whirlwind 500 kV Transmission Lines

2. Power Flow Non-Convergence

There were no non-convergence issues identified with the inclusion of the Project operating at the required power factor range, refer to Northern Area and Antelope Subtransmission Assessment Reports for additional details.

3. Voltage Performance

There were no voltage performance issues identified with the inclusion of the Project, refer to Northern Area and Antelope Subtransmission Assessment Reports for additional details.
4. **Power Factor Evaluation**

FERC Order 827 provides the reactive power requirements for newly interconnecting non-synchronous generators which requires these resources to design the facility to be capable of providing reactive power to meet power factor 0.95 as measured on the high-side of the main transformer bank.

Base case power flow was evaluated to determine reactive power losses internal to the Project in order to ascertain if the reactive capability of the Project are adequate to supply these losses and meet the power factor requirements. A summary of the power factor evaluation is provided in the table below.

Based on the technical details provided and studying the Project operating at 0.8873 power factor at the PV terminal or 0.8896 power factor at the ES terminal, when taking into account temperature restrictions, the PV portion of the project is ES does meet the 0.95 power factor requirement as measured at the high-side of the main transformer. Adequate power factor is achieved when operating both the PV and BESS but limiting output to not exceed 20 MW at the POI. Consequently, if only the PV portion of the Project were developed, the Project will need to add more reactive compensation to satisfy the 0.95 power factor requirement as measured at the high-side of the main transformer.

5. **Required Mitigations**

The study indicated the Project contributes to overloads under contingency scenarios with all existing and prior queued transmission upgrades. A combination of congestion management and modifications to add the QC10 Bulk projects to the Antelope AA Bank RAS and Antelope A Bank transfer trip are required to mitigate the power flow impacts of QC10 Phase I Projects in the Antelope System. Costs are allocated for these upgrades due to the Project contributing to the system issues that triggered the need for these upgrades. However, the Project will not be a participant to the RAS or transfer-trip scheme.

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11 PV Inverter limited to 2000 kVA at 50°C based on temperature restrictions per Inverter Technical Datasheet. Maximum temperature in the local area is identified to be 37.2°C per [https://www.usclimate-data.com/climate/united-states/us](https://www.usclimate-data.com/climate/united-states/us) resulting in an individual inverter capability of 2102.4 kVA.
In addition, as mentioned in Section B(4) above, the upgrade to the Antelope Leg of the Antelope-Del Sur-Rosamond 66 kV line reconductor, which was triggered with the inclusion of QC9 Phase II, is also required to support interconnection of this Project. The details of the power flow analysis are provided in Northern Area and Antelope 66 kV Subtransmission Assessment Reports.

**Charging Analysis of the Project**

**Steady State Power Flow Analysis Results**

1. **Thermal Overloads**
   The group study indicated that the Project contributes to overloads on the following facilities listed below single contingency conditions. The details of the analysis and overload levels as well as the details of the recommended mitigation to address these overloads are provided in the corresponding Northern Area and Antelope Subtransmission Assessment Reports.

   - Antelope No. 1A and 4A 220/66 kV Transformer Bank under the loss of the Antelope No. 2A 220/66 kV Transformer Bank
   - Antelope No. 1A and 2A 220/66 kV Transformer Bank under the loss of the Antelope No. 4A 220/66 kV Transformer Bank

2. **Power Flow Non-Convergence**
   There were no non-convergence issues identified with the inclusion of the Project operating at the required power factor range, refer to Area Report for additional details.

3. **Voltage Performance**
   There were no voltage performance issues identified with the inclusion of the Project, refer to Area Report for additional details.

4. **Required Mitigations**
   A Distributed Energy Resource Management System (DERMS) to restrict Project charging is required which would restrict charging of the Project to ensure loadings on the remaining two Antelope 220/66 kV transformer banks remain within allowable emergency limits following loss an A-Bank at Antelope as described above. The Project will be added as a participant to the proposed Antelope Area 66 kV DERMS.

**F. TRANSIENT STABILITY EVALUATION**

1. **Project Performance**
   Dynamic simulation study results illustrating the frequency and voltage performance of the Project based on the technical parameters supplied for the Project with fault applied at Point of Interconnection are provided below.
The results indicate acceptable project performance and reflect the expected performance when Project ultimately interconnects.

2. System Performance
System transient stability performance was found to be acceptable. Refer to the Area Report, for additional details pertaining to the Phase I transient stability evaluation criteria and assessment results, respectively.

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

1. **Distribution Provider**
   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) and Antelope Subtransmission Assessment Report (Attachment 7). 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 identified a total of forty-one (41) Antelope 66 kV overstressed circuit breakers triggered with the inclusion of the projects in QC10 Phase I. Replacement of these circuit breakers with 50 kA will be required to address this issue. Please refer to the QC10 Phase I Northern Area and Antelope Subtransmission Assessment Reports for additional details.

2. **Affected Systems**
   The SCD incremental increase to neighboring utilities due to the addition of all QC10 Phase I projects are provided in the Area Report (Section H.2). The specific SCD contribution from WDT1457 is provided in the table below.

   ![Short-Circuit Duty Evaluation of Adjacent Facilities Impacted by WDT1457](image)

3. **Distribution Provider's Ground Grid Duty Concerns**
   The short-circuit studies flagged certain existing substations for further review where the Phase I projects increased the substation ground grid duty by at least 0.25 kA. Additional review will be performed as part of Phase II to determine if any of these locations will require a detailed ground grid analysis. The ground grid study will be performed as part of project execution once GIAs are in place and projects proceed forward towards interconnection. Refer to the Area Report and/or Subtransmission Assessment Report (if applicable) for further information.
H. DELIVERABILITY ASSESSMENT RESULTS

1. On Peak Deliverability Assessment
   The Project was assigned Distributed Generator Deliverability prior to QC10 study. It does not contribute to the peak deliverability overloads caused by the QC10 projects.

2. Off-Peak Deliverability Assessment
   Under off-peak conditions, Antelope – Vincent 500kV No. 1 and No. 2 transmission lines are overloaded under various contingency conditions. For details, see Section E.2 of the Area Report.

3. Required Mitigations
   The Project was assigned Distributed Generator Deliverability prior to QC10 study. It does not contribute to the peak deliverability overloads caused by the QC10 projects.

I. 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.

J. 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 – 27 months
      
      These facilities involve non-network and non-distribution facilities located within SCE’s proposed Brin 66 kV Substation identified as required to support WDT1267 and WDT1268 and at the Project. These facilities are necessary to complete physical interconnection of the Project and ensure adequate line protection. While the Brin 66 kV Substation is identified for WDT1267 and WDT1268, which both have an executed GIA, cost responsibility for this substation may transfer to this Project if both WDT1267 and WDT1268 withdraw. Please refer to Attachment 1 for details related to these facilities.

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11 At the IC’s discretion, the IC or parties other than the applicable Distribution Provider pursuant to Section 10.2 of the GIF Attachment I may construct an Option (B) Generating Facility Area Delivery Network Upgrades (ADNU’s) not allocated TP Deliverability. If the applicable Distribution Provider does not construct the ADNU’s, the IC is not required to make the third Interconnection Financial Security posting to the Applicable Distribution Provider pursuant to Section 4.8.4.2.1 of the GIF Attachment I.
b. Reliability Network Upgrades - 45 months
   i. Short-Circuit Duty (SCD) Mitigation
      The required SCD mitigation is to upgrade all 66 kV 40 kA breakers connected to the
      Antelope 66 kV bus to 50 kA.

c. Voltage Support Mitigation
   No required voltage support mitigations were identified and allocated to this Project as part
   of the Phase I Interconnection Study.

d. Distribution Upgrades - 27 months
   i. Plan of Service Distribution Upgrades
      These facilities involve a new looping substation (referred to as Bruin 66 kV
      Substation) and all equipment not classified as Interconnection Facilities at this
      looping substation that are identified as required to support WDT1267 and WDT1268
      and which are also necessary to connect the Project to SCE’s Antelope 66 kV
      Subtransmission System. Please refer to Attachment 1 for details.
   
   ii. DERMS
      The Project will need to be added as a participant to the proposed Antelope Area 66
      kV DERMS.

K. 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 A.2 ISD and COD Assessment

<table>
<thead>
<tr>
<th>Reference starting point</th>
<th>Days/months for calculation</th>
<th>Issuance of Phase II Interconnection Study Report</th>
<th>ISD Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Add:</td>
<td>30 CD</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>

11/25/18
<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: 90 CD</td>
<td></td>
<td>GIA negotiation time, execution, and related activities</td>
<td>7/31/19</td>
</tr>
<tr>
<td>Add: Construction Duration (Months)</td>
<td>45</td>
<td>Construction duration outlined in the Phase I Study Report. Construction completion no earlier than date which reflects earliest ISD</td>
<td>4/30/23</td>
</tr>
<tr>
<td>Reference</td>
<td></td>
<td>IC-requested ISD via IR</td>
<td>2/15/20</td>
</tr>
<tr>
<td>Reference</td>
<td></td>
<td>IC-requested COD via IR</td>
<td>4/14/20</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Duration difference between ISD and COD</td>
<td>1 months</td>
</tr>
<tr>
<td>Equals:</td>
<td></td>
<td>Earliest achievable In-Service Date (ISD) per estimated construction duration</td>
<td>4/30/23</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>6/28/23</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 2/15/2020 and COD of 4/14/2020 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) Allocation (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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12 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.

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

M. 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 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.

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 II Interconnection Study may require additional studies, facility additions, and/or operating procedures to address impacts to neighboring utilities and/or regional forums. For example, impacts may include but are not limited to 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 Interconnection Study does not include the method or estimated cost to the IC of Distribution Provider’s mitigation measures that may be required to accommodate any proposed crossing of the Distribution Provider’s facilities. The crossing of Distribution Provider’s
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’s 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 Interconnection 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 (IF’s). Should the Project require standby power or temporary construction power from the Distribution Provider prior to the ISD of the IF’s, 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 Interconnection 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, telecommunication upgrades for earlier queued projects without a signed GIA which upgrades have not been constructed were not considered in this study. Depending on the scope of these earlier 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) of the Project on the SCE’s electric system; as well as establish the technical requirements to interconnect the Project to the Point of Interconnection that was evaluated in the final Phase I Interconnection Study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in GIA as 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:

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

17. 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

**Phase I RNU, LDNU and Potential NU Cost Allocation**

<table>
<thead>
<tr>
<th>Description</th>
<th>NU Total Cost (2017 $k)</th>
<th>Project Allocation (%)</th>
<th>Allocated Cost (2017 $k)</th>
<th>Allocated Cost (Escalated $k)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RNU</td>
<td>$46,188</td>
<td></td>
<td>$4,237</td>
<td>$4,867</td>
</tr>
<tr>
<td>Antelope 66kV SCD</td>
<td>$44,976</td>
<td>9.14%</td>
<td>$4,110</td>
<td>$4,721</td>
</tr>
<tr>
<td>Antelope 66kV SCD ground grid study</td>
<td>$46</td>
<td>100.00%</td>
<td>$46</td>
<td>$53</td>
</tr>
<tr>
<td>Antelope A bank transfer trip Monitoring Infrastructure</td>
<td>$328</td>
<td>8.95%</td>
<td>$29</td>
<td>$34</td>
</tr>
<tr>
<td>New Antelope AA Bank RAS Monitoring Infrastructure</td>
<td>$838</td>
<td>6.18%</td>
<td>$52</td>
<td>$59</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$46,188</strong></td>
<td></td>
<td><strong>$4,237</strong></td>
<td><strong>$4,867</strong></td>
</tr>
</tbody>
</table>

### Additional Notes:

**A. RNU Cost ($k)**

$4,867

**B. LDNU Cost ($k)**

$-

**C. Project RNU and LDNU Cost Responsibility ($k) (=A+B)**

$4,867

**D. Potential NU Cost ($k)**

$-

**E. Maximum RNU and LDNU Cost Responsibility ($k) (=C+D)**

$4,867

**F. Project ADNU Cost Estimate ($k)**

$-

### Notes:

"Project RNU and LDNU Cost Responsibility" is the RNU and LDNU cost currently assigned to the Project. It doesn’t include the cost share of the Potential Network Upgrades. This is the RNU and LDNU cost that the Interconnection Customer is required to post the Interconnection Financial Security for.

"Maximum RNU and LDNU Cost Responsibility" is the maximum RNU and LDNU cost that could be assigned to the Project before the completion of the Phase II interconnection study.

"Project ADNU Cost Estimate" is the ADNU cost assigned to the Project before the completion of the Phase II interconnection study if the Project chooses to be Option B Generating Facility.
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:
Interconnection Customer Provided Project Dynamic Data
Attachment 7:
Subtransmission Assessment Report
Please refer to separate document