Revision to Appendix A – WDT1490

Queue Cluster 10 Phase I Report

February 23, 2018

This study has been completed in coordination with Southern California Edison per ISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP)
the Interconnection Customer (IC), received a Queue Cluster 10 (QC10) Phase I Interconnection Study report dated January 16, 2018 for its Interconnection Request (IR) to Southern California Edison (SCE) for their proposed Project (Project) interconnecting to the SCE electrical grid, queue position WDT1490.

Subsequent to the release of the QC10 Phase I Interconnection Study report, it was identified that the estimated duration provided for the Pardee-Pastoria-Warne 220 kV line reconductor upgrade, classified as a Local Delivery Network Upgrade, inadvertently stated a 27 month duration in Attachment 2, instead of the 76 months required for such upgrade.

This revision to the Appendix A report rectifies the following:

- The resource type in Table 2 and the Project Location in Table A.1 of the Appendix A report.
- Attachment 2 of the Appendix A report to reflect the 76 month duration estimate associated with the Pardee-Pastoria-Warne 220 kV line reconductor upgrade.

The Attachment 2 document provided as part of this Appendix A Revised report dated February 23, 2018 replaces and supersedes the Attachment 2 document provided as part of the Queue Cluster 10 Phase I Report – Appendix A – WDT1490 report package dated and issued on January 16, 2018.

The Attachment 1 document dated January 16, 2018 remains unaffected by this report Revision
### Interconnection Study Document History

<table>
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<th>No.</th>
<th>Date</th>
<th>Document Title</th>
<th>Description of Document</th>
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<td>2</td>
<td>2/23/18</td>
<td>Revision to Queue Cluster 10 Phase I Appendix A Report</td>
<td>Revision of Final Phase I Interconnection Study report to correct escalation for Pardee-Pastoria-Warne 220 kV reconductor upgrade to 76 months (LDNU) in Attachment 2, and correct the resource type in Table 2 and the Project Location in Table A.1 of the Appendix A report.</td>
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<td>1/16/18</td>
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<td>Final Phase I interconnection study report</td>
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A. INTRODUCTION

[Redacted] the Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to Southern California Edison (SCE) for its proposed [Redacted] (Project). The project requested a Point of Interconnection (POI) at the Vestal-Growers-Kern River 3 66 kV Line, with delivery to the California Independent System Operator (ISO) at the Vestal 220 kV Substation. The Project 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 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 to distribution facilities served out of the Vestal 66 kV Subtransmission System, respectively. 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. Transmission and 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.

All equipment and facilities comprising the Interconnection Customer’s 56 net MW 58/58 MVA gross capacity [Redacted] Generating Facility in Tulare, 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) [Redacted] each rated at 1060 MVA with a proposed output of 1.0 MW for a combined total of 58 MW (ii) the associated infrastructure and (iii), and meters and metering equipment. The Project shall consist of the Generating Facility and the Interconnection Customer’s Interconnection Facilities.

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

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2 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.
Based on the information provided in the interconnection request and the inverter manufacturer datasheet, the Generating Facility does not have the capability of producing and delivering the requested 56.0 MW at the Point of Interconnection (POI) as shown in the table above when taking into account internal Project and interconnection facilities losses. The Project shall consist of the Large Generating Facility and the Interconnection Customer’s Interconnection Facilities, and is shown in the diagram below.

Figure A.1: Project One-Line Diagram
Table A.1 Project General Information per IR

<table>
<thead>
<tr>
<th>Project Location</th>
<th>Distribution Provider's Planning Area</th>
</tr>
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<tbody>
<tr>
<td>Interconnection Voltage</td>
<td>66 kV</td>
</tr>
<tr>
<td>Point of Interconnection</td>
<td>Growers 66 kV Substation</td>
</tr>
<tr>
<td>Number and Types of Generators</td>
<td>Each rated at 1060 kVA with a proposed output of 1.0 MW for a combined output of 58 MW at inverter terminal</td>
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<tr>
<td>Requested Maximum Project Delivery at Point of Interconnection</td>
<td>56 MW</td>
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<tr>
<td>Generation Tie Line</td>
<td>0.00825 miles, 954 ACSR Line Rating: 359A / 478A Z1(p.u.): 0.000019+j0.000135, B = 0.000002 Z0(p.u.): 0.000075+j0.005005, B = 0.000002</td>
</tr>
<tr>
<td>Main Step-Up Transformer(s)</td>
<td></td>
</tr>
<tr>
<td>Collector Equivalent</td>
<td>Equivalent Rating: 100 MVA Nominal Voltage: 34.5 kV Z1(p.u.): 0.000578+j0.004100, B = 0.000006 Z0(p.u.): 0.001734+j0.012300, B = 0.000006</td>
</tr>
<tr>
<td>Pad-Mount Transformer(s)</td>
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<tr>
<td>Generator Data</td>
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</tbody>
</table>

4 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 56 MW at the Point of Interconnection.
<table>
<thead>
<tr>
<th>Feature</th>
<th>Specification Details</th>
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</thead>
<tbody>
<tr>
<td>Generator Auxiliary Load and/or Station Light and Power</td>
<td>1.365 MW</td>
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<tr>
<td>Voltage Regulation Devices Downstream of Main Transformer Bank T1</td>
<td>Six (6) sets of 2.0 MVAR capacitor bank</td>
</tr>
<tr>
<td>Dynamic Models Used Downstream of Main Transformer Bank T1</td>
<td>regc_a, reec_b, repc_a, lhvr_t, and lhfr_t</td>
</tr>
<tr>
<td>Deliverability Requested</td>
<td>Full Capacity</td>
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<tr>
<td>Proposed Dates</td>
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<td>In-Service Date (ISD)</td>
<td>5/1/2019</td>
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<tr>
<td>Initial Synchronization Date/Trial Operation</td>
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</tr>
<tr>
<td>Commercial Operation Date (COD)</td>
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</tr>
</tbody>
</table>

**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:
   - 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.

**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.

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5 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.
6 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.
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.

![Project Power Factor Control Diagram](image)

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 2.8, 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**

*Analysis of the Project*

**Steady State Power Flow Analysis Results - Bulk Electric System**
1. **Thermal Overloads**
   The group study indicated that the Project contributes to overloads on the following facilities listed below under normal, single contingency, and/or 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 Report.

   I. **Normal Conditions**
      - No overloads identified

   II. **Single Contingency**
      - Magunden-Vestal 220 kV No.1 Transmission Line under the loss of the Magunden-Vestal No. 2 220 kV Transmission Line.
      - Magunden-Vestal 220 kV No.2 Transmission Line under the loss of the Magunden-Vestal No. 1 220 kV Transmission Line.

   III. **Multiple Contingency**
      - Magunden-Vestal 220 kV No.1 Transmission Line under the loss of the Magunden-Springville No. 1 and No.2 220 kV Transmission Lines.
      - Magunden-Vestal 220 kV No.2 Transmission Line under the loss of the Magunden-Springville No. 1 and No.2 220 kV Transmission Lines.
      - Springville-Rector 220 kV No.2 Transmission Line under the loss of the Magunden-Vestal No. 1 and No.2 220 kV Transmission Lines.
      - Magunden-Springville 220 kV No.2 Transmission Line under the loss of the Magunden-Vestal No. 1 and No.2 220 kV Transmission Lines.
      - Magunden-Pastoria No. 1 220 kV Transmission Line under the loss of the Magunden-Pastoria No.2 and No.3 220 kV Transmission Lines
      - Magunden-Pastoria No. 2 220 kV Transmission Line under the loss of the Magunden-Pastoria No.1 and No.3 220 kV Transmission Lines

2. **Required Mitigations**
   The study indicated the Project contributes to overloads in the Big Creek Corridor under contingency scenarios with all existing and prior queued transmission upgrades. A combination of congestion management and modifications to add the QC10PL Bulk projects to the Big Creek/San Joaquin Valley RAS are required to mitigate the power flow impacts of the QC10 Phase I Projects in the Big Creek Corridor. Specific to this Project, the use of congestion management is the only required reliability mitigation assigned to the Project. The details of the power flow analysis are provided in the Northern Area Report.

**Steady State Power Flow Analysis Results - Subtransmission System**

1. **Thermal Overloads**
   The subtransmission study indicated that the Project contributes to overloads on the following facilities listed below under normal, 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 Vestal Subtransmission Assessment Report.
I. Normal Conditions
   • Under Normal Conditions the Vestal leg of the Vestal-Growers-Kern River 3 66 kV Line is overloaded due to the addition of this project

II. Single Contingency
   • Under Single Contingency the Vestal-Glennville-Greenhorn-Kern River 3 66 kV Line is overloaded with the loss of the Vestal leg of the Vestal-Growers-Kern River 3 66 kV Line
   • Under Single Contingency the Kern River 3 leg of the Vestal-Growers-Kern River 3 66 kV Line is overloaded with the loss of the Vestal leg of the Vestal-Growers-Kern River 3 66 kV Line
   • Under Single Contingency the Vestal-Browning-Quinn-Ultragen 66 kV Line is overloaded with the Vestal Pos. 5 bus side breaker out for maintenance followed by a bus outage
   • Under Single Contingency the Browning leg of the Vestal-Browning-Delano 66 kV Line is overloaded with the Vestal Pos. 5 bus side breaker out for maintenance followed by a bus outage

III. Multiple Contingency
   • No overloads were identified under Multiple Contingencies.

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. 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 having the Project operate at unity power factor at the PV inverter terminal to achieve a gross output to meet the desired MW at the POI, the Project does not meet the 0.95 power factor requirement as measured at the high-side of the main transformer bank. The Project will need to install additional reactive support (i.e. capacitor banks and/or additional inverters with a control system) or demonstrate proper reactive power control in order to meet the 0.95 power factor at the high side of the transformer.

5. Required Mitigations

Power flow mitigations on the Subtransmission system were identified to be required. The mitigation requirement is as follows:

a. Base Case Mitigations

i. The Project will need to reconductor the Vestal leg of the Vestal-Growers-Kern River 3 66 kV Line to 954 SAC.

b. Single Contingency

i. A Transfer Trip was placed into service as part of WDT433 project execution. The Transfer Trip trips the customer breaker for the following outages: Vestal Pos.5 bus side breaker out for maintenance followed by bus outages, and the Vestal leg of the Vestal-Growers-Kern River 3 66 kV Line. To mitigate these overloads the Project may utilize the existing Transfer Trip.

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 the Point of Interconnection are provided below.
Voltage and Frequency plots for Generating Facility at high side of main transformer bank
P Plot for Generating Facility at both inverter terminals

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). 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.
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 WDT1490 is provided in the table below.

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 G1As are in place and projects proceed forward towards interconnection. Refer to the Area Report and/or Subtransmission Assessment Report (if applicable) for further information.

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**H. DELIVERABILITY ASSESSMENT RESULTS**

1. **On Peak Deliverability Assessment**
   
The Project contributes to the following overloads in this Cluster Study:

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 following upgrades are identified for the Project:

   - Reconductor Pardee – Pastoria – Warne 220kV transmission line.
Upgrade the Antelope – Vincent 500kV No. 1 and No. 2 transmission lines to increase the area deliverability.

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 facilities located within SCE’s Growers 66 kV Substation and at the IC’s Project that are necessary to complete physical interconnection of the Project and ensure adequate line protection. Please refer to Attachment 1 for details related to these facilities.
   b. Voltage Support Mitigation
      No required voltage support mitigations were identified in this Phase I Interconnection Study.
   c. Distribution Upgrades – 18 months
      Reconductor the Vestal leg of the Vestal-Growers-Kern River 3 66 kV Line to 954 SAC.

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.

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7 At the IC’s discretion, the IC or parties other than the applicable Distribution Provider pursuant to Section 10.2 of the GIP Attachment I may construct an Option (8) Generating Facility Area Delivery Network Upgrades (ADNU’s) not allocated IF 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 GIP Attachment I.
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**

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<th>Reference starting point</th>
<th>Days/months for calculation</th>
<th>Issuance of Phase II Interconnection Study Report</th>
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<td>Phase II Results Meetings</td>
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<td><strong>11/25/18</strong></td>
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<td>Add:</td>
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<td>Starting Point: TPD Results issued and IC response provided</td>
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<td><strong>4/2/19</strong></td>
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<td>Add:</td>
<td>90 CD</td>
<td>Earliest reasonable Tender draft GIA</td>
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<td>Add:</td>
<td>Construction Duration (Months) 27</td>
<td>GIA negotiation time, execution, and related activities</td>
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<td>Construction duration outlined in the Phase I Study Report. Construction completion no earlier than date which reflects earliest ISD</td>
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<td>IC-requested ISD via IR</td>
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<td>Duration difference between ISD and COD</td>
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<td>Equals:</td>
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<td>Earliest achievable In-Service Date (ISD) per estimated construction duration</td>
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<tr>
<td></td>
<td></td>
<td><strong>10/31/21</strong></td>
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<tr>
<td></td>
<td></td>
<td>Earliest achievable Commercial Operation Date (COD) (Using difference between ISD and COD requested by IC)</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>12/1/21</strong></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 DNU's 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 5/1/2019 and COD of 6/1/2019 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\(^8\) (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).

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.

\(^8\)The TPD Allocation Process is estimated to be completed in April 2019. The actual date may vary.
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 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 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 GI, 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 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:

NRI Guide:

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.
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></th>
<th>NU Total Cost (2017 $k)</th>
<th>Project Allocation (%)</th>
<th>Allocated Cost (2017 $k)</th>
<th>Allocated Cost (Escalated $k)</th>
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<tbody>
<tr>
<td><strong>LDNU</strong></td>
<td>$171,550</td>
<td>31.82%</td>
<td>$54,584</td>
<td>$65,675</td>
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<tr>
<td>Pardee-Pastoria-Warne 220 kV line reconductor</td>
<td>$171,550</td>
<td></td>
<td>$54,584</td>
<td>$65,675</td>
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<tr>
<td><strong>Total</strong></td>
<td>$171,550</td>
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<td>$54,584</td>
<td>$65,675</td>
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### Phase I ADNU Cost Assignment

<table>
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<tr>
<th></th>
<th>NU Total Cost (2017 $k)</th>
<th>Incremental Deliverability MW</th>
<th>Cost Rate (2017 $/MW)</th>
<th>Project MW</th>
<th>Allocated Cost (2017 $k)</th>
<th>Allocated Cost (Escalated $k)</th>
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</thead>
<tbody>
<tr>
<td>Antelope - Vincent 500kV Transmission Line Upgrade</td>
<td>$9,618</td>
<td>1946</td>
<td>$5</td>
<td>56.00</td>
<td>$277</td>
<td>$303</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$9,618</td>
<td></td>
<td></td>
<td></td>
<td>$277</td>
<td>$303</td>
</tr>
</tbody>
</table>
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