# Appendix A – WDAT659

[redacted]

## QUEUE CLUSTER 3 & 4 PHASE II REPORT

**December 17, 2012**

This study has been completed in coordination with Southern California Edison per CAISO Tariff Appendix Y Generator Interconnection Procedures (GIP) for Interconnection Requests in a Queue Cluster Window.

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**Attachments:**

## A. Executive Summary

[redacted] the Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to the Southern California Edison Company (SCE) for their proposed [redacted] (Project) under the terms of SCE's Wholesale Distribution Access Tariff (WDAT). The Project has requested Energy Only Deliverability status and is comprised of photovoltaic modules with an output of 8.5 MW to the requested Point of Interconnection (POI) on SCE's Duntley 12 kV out of Neenach Substation. The generated power would be delivered to the California Independent System Operator ("CAISO") grid at the 66 kV bus of SCE's Neenach Substation. The IC requested Commercial Operation Date for the Project is [redacted]

Pursuant to the Generator Interconnection Procedures (GIP) for Interconnection Requests in a Queue Cluster Window (CAISO Appendix Y), including Appendix 8 of the GIP (Transition of Existing SGIP Interconnection Requests to the GIP) under the terms of SCE's WDAT, the Project was grouped with the Queue Cluster 3&4 (QC 3&4) Phase II Study (Phase II) projects to determine the impacts of the group as well as impacts of the Project on the CAISO Controlled Grid and SCE's distribution system.

The group report has been prepared separately identifying the combined impacts of all QC3&4 Phase II projects on the CAISO Controlled Grid. This report focuses only on the impacts of the Project. This report focuses only on the impacts or impact contributions of this Project, and it is not intended to supersede any contractual terms or conditions specified in an interconnection agreement.

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 non-binding, good faith estimate of the Project's cost responsibility and time to construct these facilities.

The QC3&4 Phase II Study was performed to determine problems for which mitigation plans may be proposed for the Project. Mitigation plans for the Project are detailed in Section C of this report.

The QC3&4 Phase II Study has determined that the Project contributes to various reliability and/or deliverability problems for which mitigation plans have been proposed. These mitigation plans are detailed in Section C of this report.

The non-binding SCE cost estimates to interconnect the Project are:

| | |
|---|---|
| Interconnection Facilities | $ 534,000 |
| ITCC for Interconnection Facilities | $ 187,000 |
| Distribution Upgrades | $ 1,052,000 |
| ITCC for Distribution Upgrades | $ 368,000 |

The non-binding cost estimate of Interconnection Facilities[1] and Distribution Upgrades[2] to interconnect the Project is approximately $721,000 and $1,420,000 respectively, including ITCC[3].

If the project were not dependent on upgrades triggered by queued ahead projects, the non-binding schedule to license, engineer, and construct the Interconnection Facilities, Distribution Upgrades is approximately 24 months from the signing of the Generator Interconnection Agreement and the receipt of all required information & funding, and from SCE specified milestones associated with applicant responsibilities. However, the Project is dependent on a Reliability Network Upgrade to the Bailey-Neenach-Westpac 66 kV line being in place prior to interconnection. This upgrade was identified in the Phase I study, and was triggered by QC1&2 and continues to be triggered by QC1&2. It is estimated to require 72 months to construct after the execution of an interconnection agreement that would trigger the commencement of the upgrade. To date, the triggering project(s) for this upgrade have not executed an Interconnection Agreement for their project(s). Should the queued ahead projects withdraw, the need for this upgrade will be shifted to this project, WDAT659, since all available capacity will be utilized by Q297 which will be fully in-service and operational in 2013. The estimated cost for this upgrade was identified in QC1&2 Phase II as approximately $30,336,000 (2011 constant dollars), and when escalated as approximately $31,385,000 (2012 constant dollars).

## B. Project Information and Interconnection Details

All equipment and facilities comprising the [redacted] generating facility located in Rosamond, 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] solar on 500 1 kV inverters, (ii) [redacted] 2000 kVA 12/0.42 kV transformers (iii) [redacted] kVA 12/0.42 kV transformer, photovoltaic panels.

Table B.1 provides a summary of the project information and Figure B.1 provides a map of the project location and transmission facilities in the vicinity.

**Table B-1: Project General Information**

| | |
|---|---|
| Project Location | |
| Distribution Provider's Plann | |
| Number and Type of Genera | |
| Interconnection Voltage | |
| Maximum Generator Output | |
| Generator Auxiliary Load | |
| Maximum Net Output to Gri | |
| Power Factor Range | |
| Step-up Transformer(s) | |

[1] The electrical facilities installed and from the point of change in ownershi
[2] These upgrades are not part of the
[3] Income Tax Component of Contribu

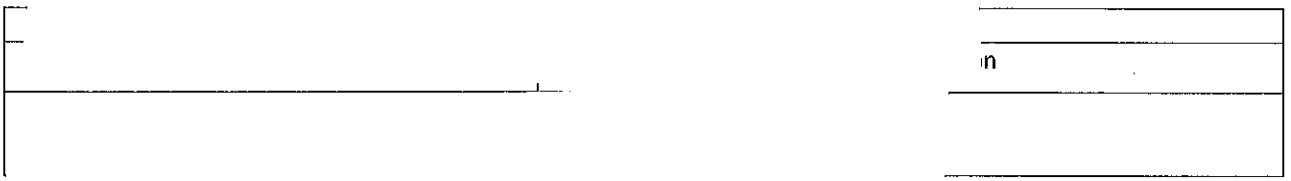

**Figure B.1 : Map of the Project**

## C. Interconnection Facilities, Network Upgrades, and Distribution Upgrades

The Distribution Provider's Interconnection Facilities, Network Upgrades and Distribution Upgrades described in this section are based on the Distribution Provider's preliminary engineering and design. Such descriptions are subject to modification to reflect the actual facilities constructed and installed following the Distribution Provider's final engineering and design, identification of field conditions, and compliance with applicable environmental and permitting requirements.

**1. Interconnection Facilities.**

(a) **Interconnection Customer's Interconnection Facilities**. The study assumes that the Interconnection Customer will:

(i) Install a 12 kV switchgear ("Last Structure") within the Interconnection Customer's property line, designed and engineered in accordance with the Distribution Provider's specification, to terminate the Distribution Provider's conductors.

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

(iii) Install a breaker within the Interconnection Customer's property line in accordance with the Electrical Service Requirements to comply with the Distribution Provider's protection requirements. Additional protection requirements may be required.

(iv) Install, in coordination with, and as specified by the Distribution Provider, a dedicated T1 circuit from the local telephone company to support the RTU communication to the Distribution Provider's energy management system in accordance with the Interconnection Handbook, if an RTU is installed locally at the Generating Facility.

(v) Allow the Distribution Provider to review the Interconnection Customer's telecommunication equipment design and perform inspections to ensure compatibility with the Distribution Provider's terminal equipment and protection engineering requirements; allow the Distribution Provider to perform acceptance testing of the telecommunication equipment and the right to request and/or to perform correction of installation deficiencies, if telecommunication is installed locally at the Generating Facility.

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

(vii) Make available adequate space, facilities, and associated dedicated electrical circuits within a secure building having suitable environmental controls for the installation of the Distribution Provider's RTU, and provide required data signals in accordance with the Interconnection Handbook, if an RTU is installed locally at the Generating Facility.

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

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

(x) Allow the Distribution Provider to install revenue meters and appurtenant equipment required to meter the retail load at the Generating Facility.

(xi) Provide all engineering and design drawings and bills of material associated with the Interconnection Customer-Constructed Interconnection Facilities.

(xii) Provide switchgear drawings which shall comply with Distribution Provider's Electrical Service Requirements of which can be obtained at http:www.sce.com/AboutSCE/Regulatory/distributionmanuals/esr.htm

(b) **Distribution Provider Interconnection Facilities**. The Distribution Provider's Interconnection Facilities are comprised of the Interconnection Customer-Constructed Interconnection Facilities and the Distribution Provider-Constructed Interconnection Facilities.

(i) **Interconnection Customer-Constructed:** The Interconnection Customer shall:

1. Perform underground civil work per Distribution Provider's design, specifications, requirements and acceptance (including but not limited to all necessary trenching, backfilling, and other digging as required, and furnishing and installing of all necessary substructures, conduits and protective structures), for new 12 kV underground line (refer to Section C.1 (b) (ii) 2 below) from 1789920E toward the customer's 12 kV panel's pull section.
2. Obtain all necessary permits and easements associated with installation of Interconnection Customer-Constructed Interconnection Facilities.
3. Permit Distribution Provider to inspect the construction being done pursuant to this Section C.1-1 (b) (i) 1. In the event the work is not being completed pursuant to Distribution Provider's requirements, Distribution Provider will be permitted to assume work, with costs to be charged to Interconnection Customer. Prior to any such assumption of work, Interconnection Customer shall be provided with thirty (30) days written notice of Distribution Provider's intention to assume work and to cure any defects in, or concerns relating to, that construction to Distribution Provider's satisfaction.
4. Immediately transfer ownership of, and transfer title to each and every component part thereof, to Distribution Provider free and clear of all liens and encumbrances, upon Interconnection Customer's completed construction, and subject to Distribution Provider's approval of those facilities.
5. If applicable, provide the following:
    a. Completed Interconnection Customer information sheet.
    b. Street improvement plans
    c. Unique address for point of interconnect.
    d. Public right-of-way (street) base maps as required by the interconnection.
    e. Site plot plan on a 30:1 scale digital file as follows:
        1. Easements/lease agreement
        2. Grading plans
        3. Sewer and storm plot plans
        4. Landscape, sprinkler, pedestal locations
        5. Underground civil construction is released by the Distribution Provider's inspectors.

(ii) **Distribution Provider-Constructed:** The Distribution Provider shall:

1. Install a 3-Way pad-mounted gas switch with automation, and riser.
2. Install approximately 250 feet of 1000 JCN 12 kV primary underground line extension to Interconnection Customer's 12 kV.
3. Install approximately 1300ft of 653 ACSR line extension to the project site.

4. Telecommunications.

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

5. Real Properties, Transmission Project Licensing, and Corporate Environmental Services.

   Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities, as necessary, for the installation of the Distribution Provider's Interconnection Facilities.

6. Metering.

   Install revenue meters, potential and current transformers, and appurtenant equipment required to meter the retail load at the Generating Facility. Notwithstanding that the meters and appurtenant equipment will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider will own, operate and maintain such facilities as part of the Distribution Provider's Interconnection Facilities.

7. Power System Controls.

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

**2. Network Upgrades.**

(a) **Stand Alone Network Upgrades** - None.

(b) **Other Network Upgrades** - None.

**3. Distribution Upgrades** - The Distribution Provider shall:

(a) Reconductor approximately 2750 feet of 1/0 ACSR to 653 ACSR 12 kV primary overhead line.

(b) Insta [redacted] 3-phase bi-directional Watt transducer on Driver 12 kV line position at Neenach Substation.

(c) Replace the existing relays with [redacted] and [redacted] new line PTs.

(d) Install [redacted] new Automatic Recloser

(e) Install a new voltage regulator

(f) Real Properties, Transmission Project Licensing, and Corporate Environmental Services.

Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of Distribution Upgrades.

**4. Point of Change of Ownership.**

The Point of Change of Ownership shall be the point where the conductors of the Distribution Provider's Duntley 12 kV line are attached to the Interconnection Customer's 12 kV pull section terminal at the last structures. The Interconnection Customer shall own and maintain the Last Structure, the conductors, insulators and jumper loops from such Last Structure to the Interconnection Customer's Generating Facility.

**5. Point of Interconnection.**

The Distribution Provider's Duntley 12 kV line.

PAGES OMITTED FOR CEII REGULATIONS

## Table D.1: Summary of Estimated Costs and Estimated Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades

| Element | Interconnection Facilities Cost x 1,000 Constant Dollar (2012) | Reliability Network Upgrades Cost x 1,000 Constant Dollar (2012) | Delivery Network Upgrades Cost x 1,000 Constant Dollar (2012) | Distribution Upgrades Cost x 1,000 Constant Dollar (2012) | ITCC* x 1,000 Constant Dollar (2012) | One Time Cost x 1,000 Constant Dollar (2012) | Total Estimated Cost w/o ITCC x 1,000 Constant Dollar (2012) | Total Estimated Cost x 1,000 Constant Dollar (2012) | Total Estimated Cost x 1,000 Escalated Constant Dollar (OD Year) | Estimated Time to Construct (Note 3) |
|---|---|---|---|---|---|---|---|---|---|---|
| **DP's Interconnection Facilities** (Note 1) | | | | | | | | | | |
| Install a 3-Way pad-mounted gas switch with automation, and riser.<br>Install approximately 250 feet of 1000 JCN 12 kV primary underground line extension to Interconnection Customer's 12 kV.<br>Install approximately 1300ft of 653 ACSR of overhead line extension to the project site. | $302 | | | | $106 | | | | | |
| Telemetry | $15 | | | | $ 5 | | | | | |
| Corporate Environmental Services | $217 | | | | $76 | | | | | |
| Subtotal | $534 | | | | $187 | | $534 | $721 | $781 | 24 |
| **Distribution Upgrades** (Note 2) | | | | | | | | | | |
| Reconductor approximately 2750 feet of 1/0 ACSR to 653 ACSR 12 kV primary overhead line (Note 5).<br>Install one (1) 3-phase bi-directional Watt transducer on Driver 12 kV line position at Neenach Substation (Note 5).<br>Install one new Automatic Recloser | | | | $296 | $104 | | | | | |
| Replace the existing relays with 2-SEL 351 relays and 3-12 kV new line PTs (Note 5). | | | | $189 | $66 | | | | | |
| One new Voltage regulator | | | | $246 | $86 | | | | | |
| Corporate Environmental Services | | | | $ 321 | $112 | | | | | |
| Subtotal | | | | $1,052 | $368 | | $1,052 | $1,420 | $1,540 | 24 |
| **Other** | | | | | | | | | | |
| Ground Grid Analysis | | | | | | $21 | | | | |
| Subtotal | | | | | | $21 | $21 | $21 | $22 | 24 |
| Total | $534 | | | $1,052 | $555 | $21 | $1,607 | $2,162 | $2,343 | 24 |

Note 1: The Interconnection Customer is obligated to fund these upgrades and will not be reimbursed.

Note 2: The Interconnection Customer is obligated to fund these upgrades and will not be reimbursed. Allocated costs may change if all projects responsible for these upgrades do not execute GIAs.

Note 3: The estimated licensing cost and durations applied to this project are based on the project scope details presented in this study. These estimates are subject to change as project environmental and real-estate elements are further defined. Upon execution of the Interconnection Agreement, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property-right checks may enable licensing cost and/or duration updates to be provided.

Note 4: SCE's QC3&QC4 Phase II cost estimating is done in 'constant' dollars 2012 and then escalated to the estimated O.D. year. For the QC3&QC4 Phase II Study, the estimated O.D. is derived by assuming the duration of the work element will begin in March 2013, which is the CAISO tariff scheduled completion date of the QC3&4 Phase II Study plus 90 days for the Interconnection Agreement negotiations/execution. For instance, if a work element is estimated to take a total of 24 months (permitting, design, procurement, and construction), then the estimated O.D. would be March 2015. If an IC's requested O.D. (In-Service Date) is beyond the estimated O.D. of a work element, the IC's requested O.D. is used. However, should the Generator Interconnection Agreement not be executed, or the necessary information, funding, and written authorization to proceed is not be provided by the IC, in time for the Distribution Provider to perform the work within these time frames, the information provided in Table D.1 may be subject to change.

Note 5: These facilities are not expected to be subject to O&M charges.

## E. Study Assumptions

For detailed assumptions, please refer to the QC3&4 Phase II area group report. The following assumptions are only specific to the Project:

1. **The following SCE Distribution System Planning Criteria and Conditions were included in the Phase II Study:**
   - The thermal rating of any conductor, connector, or apparatus should not exceed 100% of its normal rated capacity with all facilities in service (base case).
   - The thermal rating of any conductor, connector, or apparatus should not exceed 100% of its emergency rating under N-1 conditions.
   - Operational flexibility and reliability of the distribution system shall be maintained at all times.
   - Circuit voltage profiles should be maintained to comply within CPUC's Rule 2 requirements.
   - The power factor for the new generation facility was assumed to be within WDAT requirements of 0.95 lagging or leading.
   - The generation system must be designed to accommodate a VAR Schedule provided by SCE if necessary by a re-arrangement of SCE's distribution system.
   - Expected loading on the distribution system as projected by the SCE 2012 - 2021 distribution system plan was used.
   - Distributed Generation resources connected to the distribution system are analyzed offline and online during peak load conditions as well as during minimum daytime load conditions as to determine worst case scenario.
   - The Short circuit contribution from the inverter systems was determined using inverter manufacturer documents.
   - The Phase II Study assumes the upgrades triggered by previously queued projects, including Rule 21 projects under CPUC jurisdiction as in-service, are included in the base case for the Phase II projects. If any previously queued projects were to withdraw, then the Phase II projects may be subjected to the cost identified for those previously queued projects.
   - Current distribution standards are being updated to address generation interconnection systems. The proposed method of service in this report may change according on final design to comply with the updated distribution design standards.

2. **The following Facilities were estimated and included in the Phase II Study:**
   - Approximately 250 feet of primary conductor (1000JCN)
   - 12 kV meter, CTs, PTs, and associated wiring
   - 12 kV pad-mounted 3-way gas switch with automation
   - Telemetry
   - [redacted]3-phase bi-directional WATT transducers on the Duntley 12 kV line
   - 1300' of 653 ACSR line extension to project location
   - Installing a new automatic recloser
   - Reconductor approximately 2750ft of 1/0A to 653ACSR
   - Replace existing relays with[redacted]

- Install a new voltage regulator

3. **The following facilities are to be installed by the Interconnection Customer and are not included in this Phase II Study:**
   - Ducts as required
   - Structures as required
   - Point of interconnection breaker
   - CAISO metering as required
   - Protection Systems required to comply SCE Interconnection requirements
   - Transformation as required
   - Metering Equipment compliant with SCE Electrical Service Requirements (http://www.sce.com/AboutSCE/Regulatory/distributionmanuals/esr.htm)

## F. Power Flow Analysis

1. **Transmission Level Assessment – 66 kV or above**

   Please see Section G of the QC3&4 Phase II Northern area group report for the transmission level power flow analysis discussion and results.

2. **Distribution System – 34.5 kV or below**

   The QC3&4 Phase II distribution study indicated that the Project contributes to the following distribution facility overloads:

   (a) **Overloaded Distribution Facilities**

   (i) Under normal base case conditions, daytime minimum load and maximum generation, the addition of this project triggered an overload on the distribution facilities. The existing 1/0 ACSR conductor on the Duntley 12 kV will become overloaded by 129% of the conductor's normal rating.

   (b) **Recommended Distribution Mitigations**

   Reconductor approximately 2750 ft. of 1/0 ACSR overhead conductor to 653 ACSR.

   (i) Under emergency (N-1) conditions, daytime minimum load and maximum generation, the addition of this project did not trigger an overload on any distribution facilities. However, due to the dynamic distribution system configurations, SCE may deem it necessary to isolate this project until the distribution system returns to normal conditions.

## G. Short Circuit Analysis

Short circuit studies were performed to determine the fault duty impact of adding the QC3&4 Phase II projects to the transmission system and to ensure system coordination. The fault duties were calculated with and without the projects to identify any equipment overstress conditions. Once overstressed circuit breakers are identified, the fault current contribution from each individual project in QC3&4 Phase II is determined. Each project in the cluster will be responsible for its share of the upgrade cost based on the rules set forth in CAISO Tariff Appendix Y.

1. **Short Circuit Study Input Data**

The following input data provided by the Interconnection Customer and was used in this study:

PV Inverter Data for each generation unit (on 8.5 MVA Base):

- X"1 - positive sequence subtransient reactance: 1.0 PU
- X"2 - negative sequence subtransient reactance: 1.0 PU
- X"0 - zero sequence subtransient reactance: 1.0 PU

Generation Step-up Transformer[redacted]

Four of the transformers are three-phase,[redacted] winding 12/0.42 kV (D- Y), for 2000 kVA with an H-X Impedance Value of 5.75 % @ 2000 kVA base.[redacted] three-phase transformer[redacted] winding 12/0.42 kV (D- Y), for 500 kVA with an H-X Impedance Value of 4.07 % @ 500 kVA base.

2. **Short Circuit Duty Study Results**

All bus locations where the QC3&4 Phase II projects increase the short-circuit duty by 0.1 kA or more and where duty was found to be in excess of 60% of the minimum breaker nameplate rating are listed in the group report Appendix H. These values have been used to determine if any equipment is overstressed as a result of the inclusion of QC3&4 Phase II interconnections and corresponding network upgrades, if any.

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

As discussed in the group report, the QC3&4 Phase II breaker evaluation identified overstressed circuit breakers. Per the short circuit methodology for QC3&4 Phase II, the Short Circuit Duty (SCD) mitigation(s) for those overstressed circuit breakers and their associated costs were not allocated to the Project.

(a) SCE Substations with Ground Grids Duty Concerns

The short circuit studies identified substations where the QC3&4 Phase II projects increased the substation ground grid duty by 0.5 kA or more. The SCE substations flagged to have ground grid duty concerns are disclosed in Section H of the QC3&4 Phase II area group report.

3. **Preliminary Protection Requirements**

Protection requirements are designed and intended to protect the Distribution Provider's system only. The preliminary protection requirements were based upon the interconnection plan as shown in the one-line diagram depicted in line item #6 of Section C of this report.

The applicant is responsible for the protection of its own system and equipment and must meet the requirements in the Distribution Provider's Interconnection Handbook provided in Attachment 3.

## H. Transient Stability Evaluation

Please see Sections I and J of the QC3&4 Phase II Northern area group report for the transient stability evaluation discussion and results.

## I. Reactive Power Deficiency Analysis

### 1. Transmission Level Assessment – 66 kV or above

Please see Section G of the QC3&4 Phase II Northern area group report for the transmission level power flow analysis discussion and results.

### 2. Individual Project Power Factor Requirements

Based on the results of the Study, the Project will need to be designed to maintain a composite power delivery at continuous rated power at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging. Additionally, the generation system must be designed to accommodate a VAR schedule provided by SCE. SCE will determine if the VAR schedule is necessary based on future re-arrangements of SCE's distribution system.

### 3. Distribution System Power Factor Requirements – 34.5 kV or below

A portion of the Duntley 12 kV circuit is expected to experience a voltage rise of 6.802%, which exceeds allowable Rule 2 requirements by 5.16% with the addition of the project under the generating facility's condition of maximum generation during minimum load. The proposed mitigation is to install a new voltage regulator to limit the voltage rise.

## J. Deliverability Assessment

No Deliverability Assessment required due to Energy Only status of the Project.

## K. Operational Studies

### 1. IC Proposed Project Timelines

The latest information provided by the IC has indicated that the requested generator In-Service Date is August 1, 2013.

### 2. System Upgrade Timelines for Energy Only Interconnection

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

(a) **DP's Interconnection Facilities**

See Section C.1.b

(b) **Distribution Upgrades**

The Distribution Upgrades allocated to this project are mentioned in Sections C.1.b.i, C.1.b.ii, and C.3. Timing of such upgrades is tied to the available construction resources to perform the work.

(c) **Other Energy Only Operational Issues**

**EKWRA Dependency**

The study included the modeling of the East Kern Wind Resource Area ("EKWRA") 66 kV reconfiguration project. This project was proposed by SCE in the CAISO 2010 Transmission Plan as a reliability project to address numerous reliability criteria violations in the existing Antelope-Bailey 66 kV network. This project was presented and

recommended for approval by CAISO at the February 16, 2010 CAISO transmission plan stakeholder meeting. The EKWRA project was approved by CAISO on April 8, 2010.

In today's operational system, existing generation projects are being curtailed due to insufficient 66 kV system capabilities. Because of this reality, all higher queued projects seeking interconnection in the Antelope-Bailey 66 kV system area that aggravate the constraints have been informed that they must wait for EKWRA prior to interconnection. Based on this Project's physical location, connecting this Project ahead of EKWRA would aggravate the existing constraints.

The QC3&QC4 Phase II Operational Study has reaffirmed the conclusion that the addition of this Project is not possible prior to the completion of the EKWRA Project. See Section H of the QC3&4 Phase II area group report.

**Bailey-Neenach-Westpac 66 kV Line Upgrade Dependency**

3. **The Project is dependent on a Reliability Network Upgrade to the Bailey-Neenach-Westpac 66 kV line being in place prior to interconnection. This upgrade was identified in the Phase I study, and was triggered by QC1&2 and continues to be triggered by QC1&2. It is estimated to require 72 months to construct after the execution of an interconnection agreement that would trigger the commencement of the upgrade. To date, the triggering project(s) for this upgrade have not executed an Interconnection Agreement for their project(s). Should the queued ahead projects withdraw, the need for this upgrade will be shifted to this project since all available capacity will be utilized by Q297 which will be fully in-service and operational in 2013. The estimated cost for this upgrade was identified in QC1&2 Phase II as approximately $30,336,000 (2011 constant dollars), and when escalated as approximately $31,385,000 (2012 constant dollars).System Upgrades Required for Full Capacity Deliverability Status**

   No Deliverability Assessment required due to the Energy Only status of the Project.

4. **South of Vincent-Lugo Area Nomogram**

5. **This project and all projects in the Northern Area will be competing for transmission capacity available following Tehachapi Renewable Transmission Project (TRTP) with projects located in the East of Lugo Area, see Attachment 7 for additional details.Conclusion**

   The requested generator In-Service Date of September 1, 2013 cannot be met due to the anticipated duration of 24 months for the facilities needed to enable Interconnection, and the 72 month duration required for the Bailey-Neenach-Westpac 66 kV line upgrade that is currently triggered by QC1&2.

## L. Environmental Evaluation/Permitting

Please see Section L of the QC3&4 Phase II area group report.

## M. Items not covered in this study

1. **Conceptual Method of Service**

The results provided in this study are based on conceptual engineering and a preliminary plan of service and are not sufficient for permitting of facilities. The Plan of Service is subject to change as part of Final Engineering and Design.

2. **Customer's Technical Data**

   The study accuracy and results for the QC3&4 Phase II Study are contingent upon the accuracy of the technical data provided by the Interconnection Customer. Any changes from the data provided could void the study results.

3. **Study Impacts on Neighboring Utilities**

   This generation project interconnection may require additional studies, facility additions, and/or operating procedures to address impacts to neighboring utilities. For example, impacts may include but are not limited to WECC Path Ratings, short circuit duties outside of the CAISO Controlled Grid, and sub-synchronous resonance (SSR).

4. **Relocations and Other Use of SCE Facilities**

   The Interconnection Customer is responsible for all costs associated with necessary relocation of any SCE facilities as a result of this project and acquiring all property rights necessary for the Interconnection Customer's Interconnection Facilities, including those required to cross SCE facilities and property. The relocation of SCE facilities or use of SCE property rights shall only be permitted upon written agreement between SCE and the Interconnection Customer. Any proposed relocation of SCE facilities or use of SCE property rights may require a separate study and/or evaluation to determine whether such use may be accommodated, and any associated cost would be non-refundable.

5. **SCE Interconnection Handbook**

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

6. **Western Electricity Coordinating Council (WECC) Policies**

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

7. **System Protection Coordination**

   Adequate Protection coordination will be required between SCE-owned protection and Interconnection Customer-owned protection. If adequate protection coordination cannot be achieved, then modifications to the Interconnection Customer-owned facilities may be required to allow for ample protection coordination.

8. **Standby Power and Temporary Construction Power**

   The QC3&QC4 Phase II Study does not address any requirements for standby power or temporary construction power that the Project may require prior to the In-Service Date of the interconnection facilities. Should the Project require standby power or temporary construction power from SCE prior to the In-Service Date of the interconnection facilities, the IC is responsible to make appropriate arrangements with SCE to receive and pay for such retail service.

9. **Licensing Cost and Duration Estimate (Estimated Construction Schedule)**

The estimated licensing cost and durations applied to this project are based on the project scope details presented in this study. These estimates are subject to change as project environmental and real estate elements are further defined. Upon execution of the Interconnection Agreement, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

## 10. Ground Grid Analysis

The results provided for the ground grid review are preliminary and may be subject to change. A more detailed ground grid analysis will need to be part of the final engineering for the project.

## 11. Applicability

This document has been prepared to identify the impact(s) contributions of the Project on the SCE electrical system; as well as establish the technical requirements to interconnect the Project in accordance to the Point of Interconnection that was evaluated in the QC3&4 Phase II Study for the Project. Nothing in this report is intended to supersede or establish terms/ conditions specified in Interconnection Agreements agreed to by SCE and the Interconnection Customer.

## Attachment 1

**Not Used.**

## Attachment 2

## Not Used

## Attachment 3

## Distribution Provider Interconnection Handbook

Preliminary Protection Requirements for Interconnection Facilities are outlined in the Distribution Provider Interconnection Handbook.

## Attachment 4

## Short Circuit Calculation Study Results

Please refer to the Appendix H of the group report.

## Attachment 5

## Not Used

## Attachment 6

## Not Used

## Attachment 7

## SCE Northern Hemisphere Import Nomogram

Please refer to the separate document.