
Appendix A – WDT852

[REDACTED]
[REDACTED]

Queue Cluster 4 Phase I Report

December 31, 2011

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

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Attachments:

1. Not Used
2. Dynamic Stability Plots (see Appendix F of the Group Report)
3. Not Used
4. Short Circuit Calculation Study Results (see Appendix H of the Group Report)
5. Not Used

1. Executive Summary

[REDACTED] 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 is energy only comprised of photovoltaic modules with an output of 9.5 MW to the requested Point of Interconnection (POI) on SCE's Crossley 33kV distribution line. The Interconnection Customer's (IC) requested Commercial Operation Date of 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 4 (QC4) Phase I study (Phase I) 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 Phase I projects on the CAISO Controlled Grid. This report focuses only on the impacts of the Project.

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 and;
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 Phase I 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 10 of this report.

The non-binding SCE cost estimates^{1,2} to interconnect the Project are:

| | |
|---|------------|
| Interconnection Facilities ³ | \$ 0.383 M |
| Distribution Upgrades | \$14.177 M |

¹ These upgrades are not reimbursable.

² Includes Income Tax Component of Contribution. The ITCC included in this cost estimate was computed using a 35% rate. Due to the enactment of H.R. 4853, the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010, and upon formal acceptance by the CPUC of SCE's advice letter (filed on December 27, 2010), this rate may change for electric CIAC recorded or received after September 8, 2010 through December 31, 2011.

³ The electrical facilities installed and maintained by SCE necessary to physically and electrically interconnect the Project to the SCE Distribution system from the point of change in ownership to the point of interconnection.

The cost estimate for Delivery Network Upgrades based on the CAISO alternative methodology used as part of the Queue Cluster 4 Phase 1 studies is \$0, since the Project is Energy Only. The cost estimate for Reliability Network Upgrades to interconnect the Project is \$22,000.

The estimated costs above have been provided in 2011 constant dollars. Table 10.1 provides the estimated costs escalated to the estimated Operating Date year of the upgrade, which would be the basis for the ICs financial responsibilities.

The non-binding schedule to license, engineer, and construct the Interconnection Facilities, Distribution Upgrades, and Reliability Network Upgrades is approximately 88 months from the signing of the Generator Interconnection Agreement and from SCE specified milestones associated with applicant responsibilities.

2. Project and Interconnection Information

Table 2-1 provides general information about the Project as shown in the customer's IR.

Table 2-1: [REDACTED] General Information

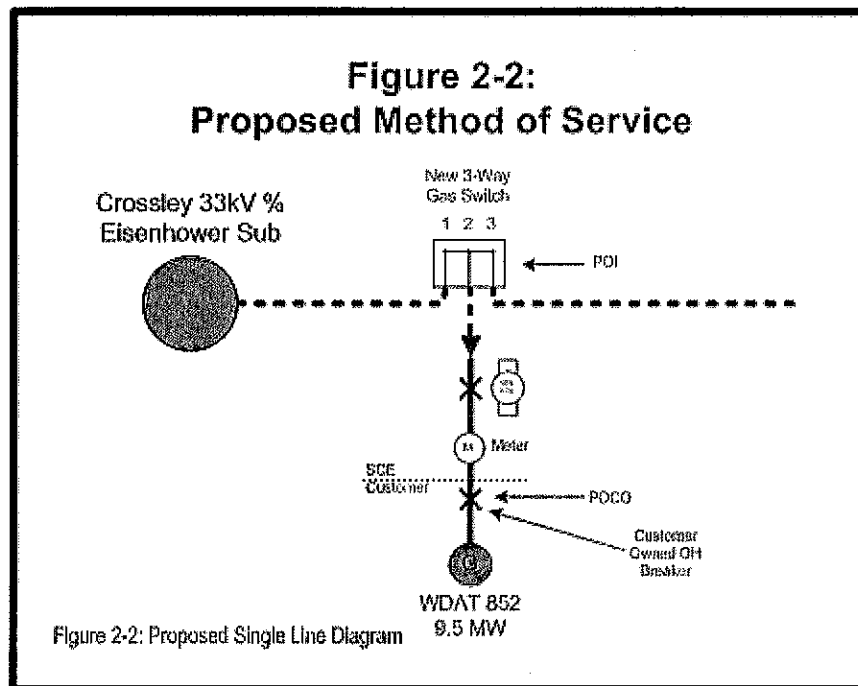
| | |
|-------------------------------|--|
| Project Location | Palm Springs, California |
| SCE Planning Area | Eastern |
| Number and Type of Generators | [REDACTED] technology |
| Interconnection Voltage | 33 kV |
| Maximum Generator Output | 9.66 MW |
| Generator Auxiliary Load | 0.16 MW |
| Maximum Net Output to Grid | 9.5 MW |
| Power Factor Range | .95 Lagging to .95 Leading |
| Step-up Transformer | [REDACTED] phase transformer rated for 33kV/48kV 1.5MVA with 5.75% impedance on a 1.0 MVA base. [REDACTED] phase transformer rated for 33kV/48kV 1.0MVA with 5.75% impedance on a 1.0 MVA base. |
| Point of Interconnection | Crossley 33kV distribution line |
| Commercial Operation Date | [REDACTED] |

⁴ The actual OD will be a function of the time to construct the required Transmission Network Upgrades, Distribution Upgrades, Interconnection Facilities, any other required facilities to interconnect the Project, and the GIA execution period.

Figure 2-1 provides the map for the Project and the transmission facilities in the vicinity. Figure 2-2 shows the conceptual single line diagram of the Project as modeled in the study

Figure 2-1 : Map of the Project

Figure 2-2: Proposed Single Line Diagram



3. Study Assumptions

For detailed assumptions, please refer to the Group Report. The following assumptions are only specific to the Project.

A. The following SCE Distribution System Planning Criteria and Conditions were included in the Phase I 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.
- Expected loading on the distribution system as projected by the SCE 2011 - 2020 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 datasheets.
- The Phase I 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 I 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.

B. The following Facilities were estimated and included in the Phase I study:

- Approximately 300 feet of primary wire (653 ACSR)
- Riser
- Overhead Pole Remote Controlled Switch
- Pole Top Metering
- Remote Terminal Unit
- Telecommunication System for RTU
- 3-Way Gas Switch
- Devers A-Bank Expansion
- Devers-Garnet No. 2 115kV Line
- Devers-Farrell-Windland 115kV Line
- Replace Circuit Breakers at various substations

C. The following facilities are to be installed by the Interconnection Customer and are not included in this Phase I study:

- Ducts
- Structures
- Point of Interconnection Breaker
- CAISO metering as required
- Protection Systems required to comply with SCE Interconnection requirements
- Transformation as required
- Metering Equipment compliant with SCE Electrical Service Requirements (<http://www.sce.com/AboutSCE/Regulatory/distributionmanuals/esr.htm>)

4. Deliverability Assessment

The deliverability assessment for this project was not performed as this project is an Energy Only project.

5. Power Flow Analysis

5.1 Transmission System – 220 kV and 500 kV

The transmission system is not sufficient to accommodate all the generation in the area. This conclusion was reached in the QC3 study. With the addition of more generation projects in QC4, system loadings will only increase thereby requiring system upgrades to address the incremental system overloads. However, the use of the Alternative Methodology limits the total output from the generators in the area to what has been studied in the QC3 Phase I study. However, since the Project elected Energy Only deliverability status, the Project is not subjected to the cost associated to the CAISO alternative methodology.

5.2 Subtransmission System – 115 kV

The Subtransmission system is not sufficient to accommodate all the new QC4 generation projects in the area. The reliability assessment has identified system issues with the addition of the QC4 Phase I Projects interconnecting in the Eastern Area 115kV Subtransmission level. Please refer to Section 7 and Section 11 of the group report for the Subtransmission power flow study results and mitigations discussion, respectively.

5.3 Distribution System – 34.5kV or Below

The Phase I distribution study indicated that the Project contributes to the following distribution facility overloads:

5.3.1 Overloaded Distribution Facilities

- None

5.3.2 Recommended Distribution Mitigations

- None

6. Short Circuit Analysis

Short circuit studies were performed to determine the fault duty impact of adding the Phase I projects to the transmission and distribution system and to ensure system coordination. The fault duties were calculated with and without the projects to identify any equipment overstress conditions. Each project in Phase I will be responsible for its share of the upgrade cost based on the rules set forth in CAISO Tariff Appendix Y.

6.1 Short Circuit Study Input Data

The customer provided technical data for the identified inverter (specified in Section 2). If the technical data obtained from the inverter manufacturer by SCE illustrates differences in the SCD parameters, then SCE utilized the manufacturer data of the inverter model specified by the IC in the application in the SCD study. Otherwise, SCE utilized the parameters provided by the IC. The IC should verify with the manufacturer the appropriate SCD contributions of the inverter prior to commencement of the Phase II study and should update the application to reflect the appropriate data. The data provided by the IC for this project did not match the technical data obtained from the inverter manufacturer.

The following input data was used in this study:

Short Circuit Data @ 9.5 MVA Base @33KV:

- Positive Sequence subtransient reactance ($X''1$) = 0.909 p.u.
- Negative Sequence subtransient reactance ($X''2$) = 0.909p.u.
- Zero Sequence subtransient reactance ($X''0$) = Infinity

Generation Step-up Transformer(s)

Main Transformer Data (total of one):

- None

Individual Padmount Transformer Data (total of 9):

One (1) transformer is three-phase 33/0.48 kV (D-Y) rated for 1.5 MVA with the following impedance information:

- H-X Impedance Value: 5.75 % @ 1.0 MVA

██████████ transformers are ██████████ 33/0.48 kV (D-Y) rated for 1.0 MVA with the following impedance information:

- H-X Impedance Value: 5.75 % @ 1.0 MVA

6.2 Results

All bus locations where the Phase I projects increase the short-circuit duty by 0.1 kA or more and where duty is 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 Phase I interconnections and corresponding distribution and network upgrades, if any.

The responsibility to finance short-circuit duty related Distribution Upgrades and 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. In addition, the SCD impact of the associated proposed Distribution and Network Upgrades was allocated to each Generating Facility using the same percentage assigned for the triggered Distribution and Network Upgrade.

As discussed in the Group Report, the Phase I breaker evaluation identified overstressed circuit breakers at the following buses. The cost allocation for this project, based on SCD contribution at each location, is also provided:

SCD Mitigation – Table of Network Breaker Upgrades

| Project | Valley 500kV | | Antelope 220kV | | Colorado River 220kV | | Kramer 220kV | | Redondo 220kV | | Vista 220kV | |
|---------|--------------|--------------|----------------|--------------|----------------------|--------------|--------------|--------------|---------------|--------------|-------------|--------------|
| | % | Cost (x1000) | % | Cost (x1000) | % | Cost (x1000) | % | Cost (x1000) | % | Cost (x1000) | % | Cost (x1000) |
| WDT852 | 0.2 | \$4 | 0.0 | \$0 | 0.1 | \$3 | 0.0 | \$1 | 0.0 | \$3 | 0.2 | \$11 |

SCD Mitigation – Table of Distribution Breaker Upgrades

| Project | Garnet 115 kV | | Inyokern 115 kV | | Lancaster 12 kV | | Piute 12 kV | | Victorville 4 kV | | Vista 66 kV | |
|---------|---------------|--------------|-----------------|--------------|-----------------|--------------|-------------|--------------|------------------|--------------|-------------|--------------|
| | % | Cost (x1000) | % | Cost (x1000) | % | Cost (x1000) | % | Cost (x1000) | % | Cost (x1000) | % | Cost (x1000) |
| WDT852 | 10.4 | \$227 | 0.01 | \$0 | 0 | \$0 | 0 | \$0 | 0 | \$0 | 1.04 | \$24 |

6.3 Preliminary Protection Requirements

Protection requirements are designed and intended to protect SCE's system only. The preliminary protection requirements were based upon the interconnection plan as shown in Figure 2-2.

The applicant is responsible for the protection of its own system and equipment and must meet the requirements in the SCE Interconnection Handbook provided as an attachment to the group report.

7. Reactive Power Deficiency Analysis

7.1 Group Study Reactive Power Deficiency Results

The reactive power deficiency conclusions were based on the analysis performed for the QC3 Phase I Projects.

The QC3 Phase I study demonstrated that the QC3 Phase I Projects collectively contribute to reactive power deficiencies in the transmission system under base case and contingency conditions, and voltage criteria violations under contingency conditions. The study concluded that construction of a combination of additional transmission facilities and reactive support devices will be required.

It is expected that the addition of the QC4 projects will further exacerbate the problematic system conditions identified in the QC3 Phase I study. These issues will be fully evaluated in a more detailed reactive power deficiency analysis to be performed as part of the Phase II study.

7.2 Individual Project Power Factor Requirements

The project is required to provide 0.95 leading/lagging power factor regulation at the POI. Applicant should be design interconnection facility to accept an SCE's VAR Schedule in accordance with the VAR requirements of the SCE's electrical distribution system configuration. The VAR schedule may change in the future as a function of distribution system reconfigurations

7.3 Distribution

The Crossley 33 kV circuit is not expected to experience a voltage rise that exceeds allowable Rule 2 requirements with the Project in service.

8. Transient Stability Evaluations

Please see Section 9 and 10 of Group Report.

9. Environmental Evaluation/Permitting

Please see Section 12 of Group Report.

10. Upgrades, Cost Estimates and Construction schedule estimates

To determine the cost responsibility of each generation project in Phase I, the CAISO developed cost allocation factors based on the individual contribution of each project. The cost allocation for the Interconnection Facilities, Network Upgrades, and Distribution Upgrades for which the Project is solely responsible is as follows:

PTO'S INTERCONNECTION FACILITIES

1. Distribution:

- Approximately 300 feet of primary wire (653 ACSR)
- Riser
- Overhead Pole Remote Controlled Switch
- Pole Top Metering
- Remote Terminal Unit
- Telecommunication System for RTU

2. Telecommunications

It is assumed that the local phone company can provide a T1 service to the project location. If local phone company cannot provide T1 line service, then cost for telecommunication may increase.

3. Metering Services Organization

Install revenue metering cabinet for the SCE revenue meters required to meter the retail load at the generating facility. The SCE meter will be installed in tandem with the ISO meter circuit.

4. Power System Control

It will be required to install one RTU at the generating facility to monitor Watts and VAR flow from the generation facility to SCEs distribution system.

5. Real Properties

It is assumed that applicant will provide all rights of way, and easements satisfactory for installation of SCE facilities without cost to SCE, based on Edison's design.

6. Corporate Environmental Health & Safety Organization

It is assumed that all SCE facilities will be included within the Generator's Environmental Licensing and Permits. There may be a need to include additional Edison Facilities within the permitting process, once Edison starts the design.

PLAN OF SERVICE RELIABILITY NETWORK UPGRADES

There were no Plan of Service Reliability Network Upgrade costs allocated to the Project.

RELIABILITY NETWORK UPGRADES

Transmission Network Circuit Breaker Upgrades (SCD)

Upgrade transmission network circuit breakers (pro-rata share of upgrade based on project contribution to SCD at each location).

- Install [REDACTED] sets of 500 kV TRV capacitors at Valley Substation
- Install [REDACTED] sets of 220 kV TRV capacitors at Antelope Substation
- Install [REDACTED] sets of 220 kV TRV capacitors at Colorado River Substation
- Replace [REDACTED] 220 kV CB's at Kramer Substation
- Replace [REDACTED] 220 kV CB's at Redondo Substation
- Install [REDACTED] sets of 220 kV TRV capacitors at Vista Substation

See the Group Report for additional details

DELIVERY NETWORK UPGRADES

As an Energy Only Delivery Status project, there were no Delivery Network Upgrade costs allocated to the Project.

DISTRIBUTION UPGRADES

1. Subtransmission

- Devers A-Bank Expansion

- Devers-Garnet No. 2 115kV Line
 - Devers-Farrell-Windland 115kV Line
- See the Group Report for additional details.

2. Distribution

Install 3-Way Gas Switch

3. Substation

None

4. Telecommunications

None

5. Real Properties

It is assumed that applicant will provide all rights of way, and easements satisfactory for installation of SCE facilities without cost to SCE, based on Edison's design.

6. Corporate Environmental Health & Safety Organization

It is assumed that all SCE facilities will be included within the Generator's Environmental Licensing and Permits. There may be a need to include additional Edison Facilities within the permitting process, once Edison starts the design.

7. Distribution Circuit Breaker Upgrades (SCD):

Upgrade distribution circuit breakers (pro-rata share of upgrade based on project contribution to SCD at each location).

- Replace [REDACTED] 115 kV CB's at Garnet Substation
- Replace [REDACTED] 115 kV CB's at Inyokern Substation
- Replace [REDACTED] 66 kV circuit breakers at Vista Substation
- Replace [REDACTED] 12 kV circuit breakers at Lancaster Substation
- Replace [REDACTED] 12 kV circuit breakers at Piute Substation
- Replace [REDACTED] 4 kV circuit breakers at Victorville Substation

See the Group Report for additional details

8. OTHER REQUIREMENTS

Harmonic Study Requirements

The harmonic impact of the subject inverter based generation was not part of this Phase I Study. Despite the relatively low THD (<3%) of the equipment, impacts on voltage distortion levels may be significant due to the high penetration level of the generation facility with respect to the local distribution grid strength. As with all equipment connected to the SCE distribution system, the generation project will be subject to the provisions of Rule 2.E, allowing SCE to require customer mitigation of interference with SCE service, including harmonic impacts, if harmonic interference is caused by the customer.

Since the THD values which were provided are for individual inverters and not for the total generation requested, it will be required to determine the total

harmonic contribution for the entire generation facility prior to approving the generation to interconnect to the SCE distribution system. Given the amount of generation and the strength of the distribution system, SCE will not require a harmonic study but strongly encourages that the applicant completes a harmonic study during the Phase II Study.

During the commissioning test of the generation system, SCE will install power quality equipment to verify that the total harmonic contribution from the generation system to the SCE meets the required standards. If during the commissioning test, it is found that the project does not meet the harmonic standards, the project will not be allowed to interconnect to the SCE system until the harmonic deviations are rectified. Therefore, it is encouraged that the applicant completes a harmonic study during the Phase II Study to insure that the harmonic requirements are met. If the applicant chooses to complete a harmonic study, SCE will then provide the required SCE distribution system data that are to be used as part of the harmonic study.

Table 10.1: Upgrades, Estimated Costs, and Estimated Time to Construct Summary
Each Upgrade category may contain multiple scope durations. The longest duration is shown under the Estimated Time to Construct.

| Type of Upgrade | Upgrade (May include the following) | Description | Estimated Cost x 1,000 Constant Dollar (2011) (Note 4) | Estimated Cost x 1,000 Constant Dollar (OD Year) (Note 4) | Estimated Time to Construct |
|---|---|--|--|---|-----------------------------|
| PTO's Interconnection Facilities (Note 1, 3, 5) | See Section 10 – PTO's Interconnection Facilities | Non-network facilities needed to enable interconnection | \$383 | \$419 | 12 Months |
| Plan of Service Reliability Network Upgrades (Note 6) | See Section 10 – Plan of Service Reliability Network Upgrades | Direct Assigned Network Upgrades needed to enable interconnection. | \$0 | \$0 | n/a |
| Reliability Network Upgrades (Note 6) | See Section 11.2 – Reliability Network Upgrades in the Group Report | Allocated Network Upgrades needed to maintain system Reliability | \$0 | \$0 | n/a |
| Reliability Network Upgrades (Note 6) | See Section 11.2 - Reliability Network Upgrades for SCD in the Group Report | SCD Mitigation Allocated to maintain system Reliability | \$22 | \$26 | 24 Months |
| Delivery Network Upgrades (Note 6) | See Section 11.3 - Delivery Network Upgrades in the Group Report | Network Upgrades needed to support Full Delivery, if requested | \$0 | \$0 | n/a |
| Distribution Upgrades (Note 2, 5, 6) | See Section 10 – Distribution Upgrades | Non-CAISO SCE Distribution Facilities | \$13,925 | \$17,641 | 88 Months |
| Distribution Upgrades (Note 2, 5, 6) | See Section 10 – Distribution Upgrade for SCD Mitigation | SCD Mitigation Allocated to maintain system Reliability | \$252 | \$284 | 24 Months |
| Total Cost | | | \$14,582 | \$18,370 | 88 Months |

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

Note 2: These upgrades are not identified in the ISO tariff, and are not reimbursable. Allocated costs may change if all projects responsible for these upgrades do not execute GIAs.

Note 3: The estimated time to construct (ETC) is for a typical project; schedules duration may change due to number of projects approved and release dates.

Note 4: SCE's Phase I cost estimating is done in 'constant' dollars 2011 and then escalated to the estimated O.D. year. For the QC4 Phase I study, the estimated O.D. is derived by assuming the duration of the work element will begin in January 2013, which is the CAISO tariff scheduled completion date of the QC4 Phase II study plus 90 days for the GIA signing period. 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 January 2015. If an IC's requested O.D. (in-service) is beyond the estimated O.D. of a work element, the IC's requested O.D. is used.

Note 5: Includes 35% ITCC.

Note 6: The estimated time to construct (ETC) is for a typical project; schedules duration may change due to number of projects approved and release dates. Stacked projects impact resources, system outage availability, and environmental windows of construction. Assumption is SCE will need to obtain CPUC licensing and regulatory approvals prior to design, procurement and construction of the proposed facilities required to serve the interconnection customer and prerequisite facilities are in service.

Cost Estimate Summary (2011 Dollars)

Scope: 9.6 kV project proposing an interconnect to the Crossley 33kV line out of Eszentower Substation

| No. | ELEMENT | INTERCONNECTION FACILITIES (Subject to ITCC) | ITCC ** (35%) | TOTAL | TOTAL CONSTANT \$ (ESTIMATED YEAR O.D.)*** |
|---------------|--|--|------------------|-------------------|--|
| 1 | Substations Element | \$ | \$ | | 2014 |
| 1 | Telecommun | \$ | \$ | | |
| 1 | Install channel and associated equipment to support SCADA RTU circuit from SGM customer location to SCE Energy Management System | \$ 64,000 | \$ 22,000 | \$ 86,000 | |
| 1 | Interconnection Facilities | | | | |
| 1 | Install 33kV pole mounted metering with Automated Airlet Rupter switch | \$ 172,000 | \$ 60,000 | \$ 232,000 | |
| 1 | Power System Control RTU at Generating Facility | \$ 48,000 | \$ 17,000 | \$ 65,000 | |
| Totals | | \$ 204,000 | \$ 69,000 | \$ 273,000 | \$ 419,000 |

* Permitt to FERC Order 2003A, ITCC is not collected on Reliability Upgrades and One Time Costs.

** ITCC cost may be waived with a letter of credit in accordance with the tax provisions of the CIA.

*** The ITCC included in this cost estimate was computed using a 35% rate. Because of recent enactment of H.R. 4853, the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010, and upon formal acceptance by the CPUC of SCE's advice letter (filed on December 27, 2010), this rate may change for electric CAC recorded or received after September 8, 2010 through December 31, 2011.

Cost estimate is only an estimate based on 2011 constant dollars and actual cost is subject to change depending on project construction date, and inflation.

**** SCE's Phase I cost estimating is done in constant dollars 2011 and then escalated to the O.D. year. For the QCI Phase I study, the estimated O.D. is derived by assuming the duration of the work elements will begin in January 2011, which is the CAISO tariff scheduled completion date of the QCI Phase I study plus 60 days for the CIA signing period. 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 January 2016. If an IC's requested O.D. is beyond the estimated O.D. of a work element, the IC's requested O.D. is used.

EPRI design is used to estimate the costs and schedule. Information of Southern California Edison is provided by the interconnecting customer in accordance with the provisions of the Facility Study Protocol. Southern California Edison has the right to monitor the construction of the facility and requires the interconnecting customer to observe the construction.

11. Items Not Covered In This Study

11.1 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 the Phase I Interconnection Study.

11.2 Customer's Technical Data

Additional technical data related to the Project may be required as part of the Phase I Study. The study accuracy and results for the Phase I 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.

11.3 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).

11.4 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.

11.5 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, harmonics, switching and tagging, and metering requirements.

11.6 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.

11.7 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 (i.e., Generation-tie or Substation modifications) may be required to allow for ample protection coordination.

11.8 Standby Power and Temporary Construction Power

The Phase I study does not address any requirements for standby power or temporary construction power that the Project may require prior to the 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.

11.9 Construction Schedule

The estimated time to construct (ETC) is for a typical project; schedules duration may change due to number of projects approved and release dates. Stacked projects impact resources, system outage availability, and environmental windows of construction.

Attachment 1
(Not Used)

Attachment 2

Dynamic Stability Plots

For Subtransmission level and above, please refer to Appendix F of the Group Report.

Attachment 3

(Not Used)

Attachment 4

Short Circuit Calculation Study Results

Please refer to Appendix H of the Group Report.

Attachment 5

Not Used