Appendix A – WDT315

[redacted]

Final Report

July 28, 2010

This study has been completed in coordination with Southern California Edison Cluster Large Generator Interconnection Procedures (CLGIP) for Interconnection Requests in a Queue Cluster Window

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Attachments:

1. **Generator Machine Dynamic Data**
2. **Dynamic Stability Plots (see Appendix F)**
3. **SCE Interconnection Handbook**
4. **Short Circuit Calculation Study Results (see Appendix H)**
5. **Deliverability Assessment Results**
6. **Allocation of Network Upgrades for Cost Estimates**

1. Executive Summary

On December 19, 2008, the Southern C[redacted] received an interconnection [redacted] for the interconnection of its [redacted] Project), pursuant to the Cluster Large Generator Interconnection Procedures ("CLGIP") under the SCE Wholesale Distribution Access Tariff ("WDAT"). The Project is a geothermal plant with an output of 40.7 MW to the requested Point of Interconnection (POI) on Southern California Edison Company's (SCE) Casa Diablo – 33 kV new line. The Interconnection Customer's requested Commercial Operation Date of the Project is [redacted]

In accordance with Federal Energy Regulatory Commission (FERC) approved Large Generator Interconnection Procedures (LGIP) for Interconnection Requests in a Queue Cluster Window (CAISO Appendix Y), the Project was grouped with Transition Cluster projects in a Phase II Interconnection Study 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 projects in the group on the CAISO Controlled Grid. This individual report focuses only on the impacts associated with 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 (a) the Project's cost responsibility, and (b) the time required to permit, engineer, design, procure and construct these facilities.

The Phase II Study results have determined that the Project contributes to overloading of distribution facilities for which mitigation plans have been proposed.

In addition, the Project is partly responsible for overstressing circuit breakers at the Kramer 220 kV[1] bus.

The Project will materially affec[redacted] Substation bus voltage, and all local distribution voltage. The Project will be required to operate in accordance with the requirements in SCE's Interconnection Handbook (see Attachment 3) to maintain voltage and power factor requirements. Also, the Project will be subjected to all other

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[1] Identification of facility voltages (220 kV) in this Phase II Study are shown consistent with SCE System Operating Bulletin 123. However, all studies were predicated on the base voltages reflected in the Western Electricity Coordinating Council (WECC) base cases. For the SCE bulk power system, the WECC base cases reflect 230 kV and 500 kV base voltages; consequently, all per-unit calculations presented were based on 230 kV and 500 kV voltages.

applicable SCE rules, and Federal Energy Regulatory Commission (FERC) approved rules, tariffs, and regulations.

The non-binding costs to interconnect the Project are:

Interconnection Facilities[2]	**$4,678,000** including ITCC[3];
Network Upgrades[4]	**$43,703,000**
Non-CAISO Transmission Upgrades[5]	**$349,000**
Distribution Upgrades[6]	**$3,088,000**

The anticipated time to construct the facilities associated with the Project is approximately 84 months from the signing of the Large Generator Interconnection Agreement (LGIA), assuming no delays associated with the initial construction of Whirlwind substation. In addition there may be operational constraints related to the construction of upgrades to accommodate projects ahead in queue. See Section 9 "Operational Studies" for additional details.

2. Project and Interconnection Information

During the period between the Transition Cluster Phase I and Phase II technical analysis, The IC submitted a revised Appendix B to the CAISO LGIP which requested modifications to the Project's original plan. As a result of this request, SCE applied the following changes to the Project's depiction in the Transition Cluster Phase II Study.

Project Changes in Phase II Study:

Project Generator gross output increased from 48 MW to 49.9 MW

Project Generator net output decreased from 43.9 MW to 40.7 MW

33 kV line from [redacted] to Project site changed from customer-built in Phase I to SCE-built in Phase II

Table 2-1 provides general information about the Project as modeled in the Phase II Study.

Table 2-1: Project General Information

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[2] The transmission facilities necessary to physically and electrically interconnect the Project to the CAISO Controlled Grid at the point of interconnection. These costs are not reimbursable.

[3] Income Tax Component of Contribution.

[4] The additions, modifications, and upgrades to the CAISO Controlled Grid required at or beyond the Point of Interconnection to accommodate the interconnection of the Generating Facility to the CAISO Controlled Grid. Network Upgrades shall consist of Delivery Network Upgrades and Reliability Network Upgrades.

[5] Non-CAISO Transmission Upgrades are not reimbursable.

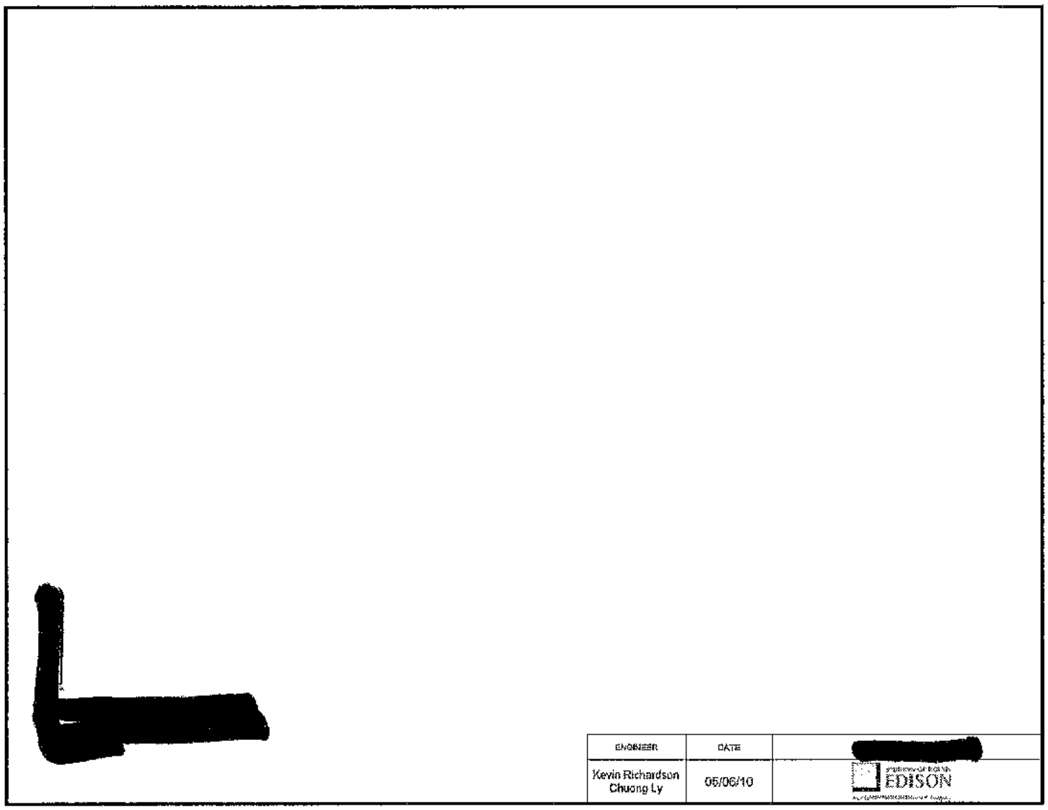
[6] These upgrades are not part of the CAISO tariff and are not reimbursable

Project Location
SCE Planning Area
Number and Type of Generators
Interconnection Voltage
Maximum Generator Output
Generator Auxiliary Load
Maximum Net Output to Grid
Power Factor Range
Step-up Transformer
Point of Interconnection
Commercial Operation Date
Individual Project Appendix B Changes between Phase I and Phase II

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

Figure 2-1 : Map of the Project

Figure 2-2: Single Line Diagram as modeled in the Phase II Study



3. Study Assumptions

For details about the Transition Cluster interconnection information and the group study assumptions, including relevant changes between the Phase I and Phase II studies, see the group report Sections 2 and 4.

The following design assumptions are applicable to the Project:

A. The following Facilities were estimated and included in the Phase II Study:

- It is clarified that the project shall interconnect 49.9 (gross) MW of generation to a new dedicated SCE owned and operated 33 kV distribution line out o[redacted]Substation and shall not share interconnection facilities with any other SCE customers.
- Point of receipt to be at the SCE's[redacted]Substation.
- Point of Interconnection to be at the Project 33 kV switchgear.
- Total Generation net output of 40.7 MW.
- Mainline electrical system to run a 33 kV line fro[redacted]ubstation to the generator substation to be installed by SCE.

- The required revenue metering cabinet, retail load meters, and required equipment to be installed at the generating facility will be installed by SCE.

- The required remote terminal unit (RTU) to be installed at the generating facility will be installed by SCE.

- The upgrade of two existing RTUs [redacted] Substation.

- Technical data for the interconnection study was provided by [redacted]

B. The following facilities are to be installed by the Interconnection Customer and <u>are not</u> included in this TCII Study:

- All required CAISO metering equipment at the generating facility will be provided by the customer.
- Mainline vault and duct system will be provided by the customer.
- The circuit breaker required at the point of interconnection (customer's site) will be provided by the customer.

4. Power Flow Analysis

4.1 Distribution Analysis

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

Distribution:
New 33 kV Circuit
[redacted] of 49.9 MW is too large to be fed from the existing Vulcan 33 kV circuit; given the presence of 32 MW of existing generation. The Project will result in a thermal overload on the Vulcan 33 kV line of approximately 208% of its normal rating (336 ACSR).

Therefore, a new 33 kV circuit is required to accommodate the Project. This would consist of approximately 4,000f ft. of new underground 33 kV circuitry with two runs of 1500 CLP cable. The new 33 kV circuit would originate from [redacted] Substation going underground along the existing dirt road, joining the existing paved road toward the new proposed facility. The new line would serve the new generation only and should be considered as part of the Interconnection Facilities. A portion of new 33 kV circuit will be on Inyo National Forest property and the rest o[redacted] property. There may be substantial environmental review required. SCE will own, operated, and maintain the new 33 kV circuit.

Substation:
[redacted] Substation

1. The study was performed assuming the following conditions: (Load flow plots are included in Figure 6.1)

    - Light Loading Base Case with WDAT in service

- Light Loading Base Case with WDAT not in service
- Light Loading N-[redacted] XFMR with WDAT not in service
- Light Loading N-[redacted] XFMR with WDAT in service
- No Load, N-1[redacted] with WDAT in service
- Heavy loading conditions were determined not to be relevant during the analysis

2. No Base Case (N-0) overloads were identified for the [redacted] kV distribution transformer banks (No. 1 & No. 2).

3. The worst case N-1 contingency is for loss of the 28 MVA #2 East Bank. The remaining capacity of the #1 Bank and the #2 West Bank at the N-1 ratings of those banks was demonstrated by load flow to be slightly less than the maximum generation case. However, with expected 7.5 MW minimum distribution load, discounted by 50% (as is typical to allow for variation in this value), it was concluded that during an N-1 contingency for 1-28 MVA bank loading would not exceed N-1 ratings.

4. An operating contingency (N-2) analysis was performed for temporary loss of both transformers included in either [redacted] Substation distribution (No. 1 or No. 2) transformer bank with all local generation at maximum contract output. This N-2 condition will occur temporarily when a bank circuit breaker relays, until such time as manual switching can restore one or both transformers to service. This operational analysis revealed that for this N-2 condition, an overload of the remaining banks may occur during light load, maximum generation conditions. Loading could reach 125% of N-1 rating (181% of nameplate) for the 28 MVA transformer, within the remaining bank, and the 14 MVA transformer would also exceed its rating. Should this scenario occur, [redacted] would need to reduce output by up to 13.5 MW depending on actual generation output and actual distribution load at the time of contingency. SCE may limit the operation, disconnect, or require the disconnection of the generation from SCE's distribution system at any time, with or with out notice, to correct unsafe operating conditions at SCE's [redacted] Substation.

4.2 Transmission System Analysis

4.2.1 Overloaded Transmission Facilities

The group study indicated that the Project contributes to the following transmission facility overloads or non-convergence problems. The details of the analysis and overload levels are provided in the group study.

Category "A"

- [redacted] Transformer Bank [redacted] existing and [redacted] pre-TC triggered)
- [redacted]
- [redacted]
- [redacted]

s

[redacted]

s

4.2.3 Recommended Transmission Mitigations

The mitigation plans for the group include the use of congestion management for base case and contingency overloads, upgrades at Kramer and Inyokern Substations, new transmission lines, new substations, and Special Protection Systems (SPS) to trip the Project under identified contingency outage conditions.

5. Voltage Control

5.1 Distribution

The total generation (MW) output and total VAR production of generation facility [redacted] will materially affec[redacted] Substation bus voltage, and all local distribution voltage. The Project will be required to operate in accordance with the requirements in SCE's Interconnection Handbook (see Attachment 3) to maintain voltage and power factor requirements. Also, the Project will be subjected to all other applicable SCE rules, and Federal Energy Regulatory Commission (FERC) approved rules, tariffs, and regulations.

6. Short Circuit Analysis

Short circuit studies were performed to determine the fault duty impact of adding the Transition Cluster projects to the transmission system. The fault duties were calculated with and without the projects to identify any equipment overstress conditions.

Once overstressed circuit breakers were identified, the cost responsibility of each individual project was determined based on the methodology applied in the Phase I study. Costs of replacing and/or upgrading circuit breakers located within a Transition Cluster Group were allocated among all generation projects located within that Group. Costs of replacing and/or upgrading circuit breakers not located within a particular Transition Cluster Group were allocated over the entire Transition Cluster. Costs were allocated pro rata on the basis of the maximum megawatt electrical output of each proposed new Large Generating Facility or the amount of megawatt increase in the generating capacity of each existing Generating Facility.

6.1 Short Circuit Study Input Data

The following input data provided by the IC was used in this study:

<u>Brush Synchronous Generator Short Circuit Data @ 300 MVA Base:</u>

Positive Sequence subtransient reactance (X"1)	= N/A p.u.
Negative Sequence subtransient reactance (X"2)	= 0.15 p.u.
Zero Sequence subtransient reactance (X"0)	= 0.09 p.u.

<u>Station Step-up Transformer</u>

The transformer is a three-phase 12.47/34.5 kV rated for 42/42 MVA OA @ 65 degree C temperature rise with an impedance of 13.2% at 42 MVA base.

New SCE 33 kV Line

The new SCE 33 kV line assumed 0.8 miles of double circuit 1500 CLP conductor.

6.2 Results

All bus locations where the Transition Cluster 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 Appendix H of the Group Report. These values have been used to determine if any equipment is overstressed as a result of the Transition Cluster interconnections and corresponding network upgrades, if any. The Transition Cluster Phase II breaker evaluation identified the following overstressed circuit breakers:

-
-
-
- [redacted]

Based on the cost assignment methodology applied in the Phase II Study, the Project will have the assigned cost responsibility for mitigation of the short-circuit duty results described above. The total cost responsibility allocated to the Project is provided in Attachment 6.

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 in Attachment 3.

6.4 Additional SCD Discussion

The Phase II study has shown significant increases in SLG short circuit duty with the addition of numerous grounded interconnection transformers. For details, see Appendix H.

7. Reactive Power Deficiency Analysis

Reactive power deficiency analysis was performed. With the Reliability and Delivery Network Upgrades identified to be required in place, the power flow studies for Category "B" and Category "C" contingencies indicated that this Phase II project did not cause the SCE system to fail to meet applicable voltage criteria.

8. Transient Stability Evaluation

Transient stability studies were conducted using the full loop base cases to ensure that the transmission system remains in operating equilibrium, as well as operating in a coordinated fashion, through abnormal operating conditions after the Transition Cluster projects begin operation. The generator dynamic data used in the study for the Project is shown in Attachment 1.

8.1 Transient Stability Study Scenarios

Disturbance simulations were performed for a study period of 10 seconds to determine whether the Transition Cluster Phase II projects will create any system instability during a variety of line and generator outages. The most critical single contingency and double contingency outage conditions in the North of Kramer area within the greater overall East of Lugo System were evaluated. For the list of specific line and generator outages evaluated, see the group report.

8.2 Results

Stability analysis was performed for the Lugo Hub and North of Kramer sub areas of the East of Lugo Bulk System to identify the stability impacts of the Phase II queued generation project.

In the stability analysis performed with the upgrades to mitigate base case and outage related overload problems in place, which included the implementation of Special Protection Systems, significant transmission system stability problems relative to existing stability criteria were identified. The problems were identified to not be attributed to the addition of this project but rather mainly attributed to the addition generation resources seeking interconnection to a non-SCE non-CAISO Controlled 220 kV transmission line located north of SCE's Control Substation. The studies determined that mitigation internal to the non-SCE non-CAISO Controlled transmission line would address the remaining stability problems.

With these additional mitigations in place and the use of Special Protection Systems to trip generation, the Phase II Study concluded that the transmission system would not become unstable under Category "B" and Category "C" outages. For a more detailed discussion on the stability analysis see the group report. The stability plots are provided in Appendix F of the group report.

9. Deliverability Assessment

9.1 On Peak Deliverability Assessment

CAISO performed an On-Peak Deliverability Assessment. The power flow study results for Category "A", "B", and "C" are detailed in Attachment 5.

10. Operational Studies

10.1 IC Proposed Project Timelines

The latest information provided by the IC has indicated that the proposed date for the generator step-up transformer to receive back feed power is December 2011 with generator testing on December 2011 and proposed Commercial Operation Date of December 2011.

10.2 System Upgrade Timelines

10.2.1 Reliability Network Upgrade Timelines

This Phase II Study assumed that all previously triggered short-circuit duty impacts would be mitigated by the corresponding triggering project. Consequently, this study evaluated the incremental impacts associated with the addition of the Transition Cluster projects, including appropriate transmission upgrades as identified in this study, in an effort to cost allocate the incremental upgrades associated with the addition of the Transition Cluster projects. However, it should be clear that for reliability reasons it may be necessary to implement mitigation upgrades previously triggered by queued ahead generation projects prior to allowing interconnection of Transition Cluster generation projects.

The circuit breaker upgrades that were triggered by queued-ahead projects are identified in Section 4.6 of the group report. The Operational Study undertaken as part of this Phase II Study identified the required timing for circuit breaker upgrades triggered by queued-ahead generation projects. The Table below identifies the first year that circuit breaker upgrades triggered by queued-ahead projects were found to be required in this Operational Study at each substation location.

Table 9-1: Circuit Breaker Upgrades Triggered by Queued-ahead Projects

Year	Location

This Phase II Study assumed that the timelines for construction of the upgrades listed in Table 9-1 to accommodate queued-ahead projects will also be sufficient to accommodate the operational requirements for the Transition Cluster projects. In the event that the Transition Cluster projects will need to accelerate these upgrades, the projects will need to do so via a separate agreement. Operational studies will be conducted on an annual basis or more frequently as needed to identify such requirements.

The circuit breaker upgrades that were triggered by Transition Cluster projects are identified in Section 8.2 of the group report. The Operational Study undertaken as part of this Phase II Study identified the required timing for circuit breaker upgrades triggered by Transition Cluster projects. The Table below identifies the first year that circuit breaker upgrades triggered by Transition Cluster projects were found to be required in this Operational Study at each substation location.

Table 9-2: Circuit Breaker Upgrades Triggered by Transition Cluster Projects

10.2.2 Delivery Network Upgrade Timelines

To provide for the requested "Full Delivery", the TC Phase II Study identified the need for significant Delivery Network Upgrades. The anticipated time to construct all of these Delivery Network Upgrades associated with "Full Delivery" Interconnection is 84 months upon execution of LGIA.

10.2.3 Distribution Upgrade Timelines

To provide for the requested "Full Delivery", the TC Phase II Study identified the need for minor Distribution Upgrades in the form of 115 kV line relocations. Because theses upgrades are linked to the permitting process of the Delivery Network Upgrades, the anticipated time to construct these Distribution Upgrades is also estimated to require 84 months upon execution of LGIA.

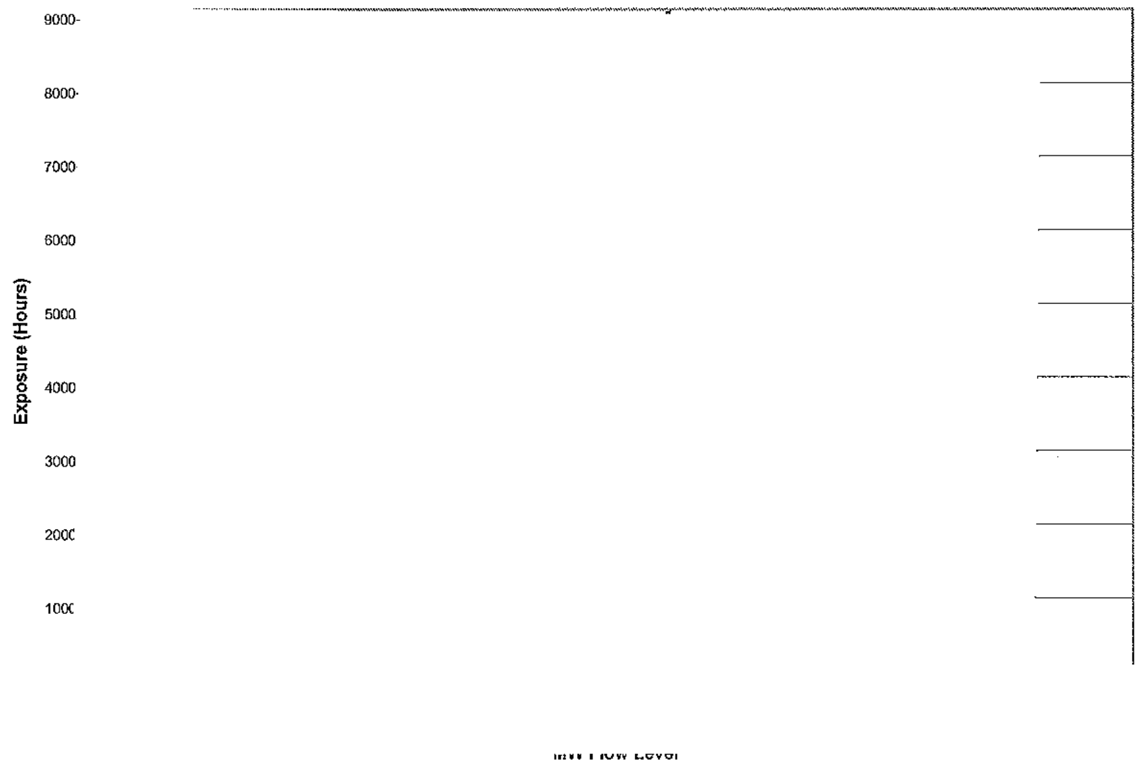
10.3 Congestion Assessment under Initial Energy Only Interconnection

10.3.1 Control Area Congestion Assessment

Previous Congestion Assessments have been performed to evaluate the possibility of interconnecting new generation resources in the Control Substation area under interim "Energy Only" arrangements. Results of these studies which include the interconnection of a serial interconnection request of approximately 60 MW in size are provided in the paragraphs below.

Five minute historical Inyo phase-shift flow data covering the period between August 17, 2005 and August 17, 2007 was provided by the CAISO and use in the congestion assessment. This data was used to establish the expected base flows prior to the addition of future generation. The histogram provided below in Figure 10-3-1 illustrates the number of hours of expected MW flow on the Inyo phase-shift transformer in increments of 5 MW. Note that the existing generation connected in the Control Area did not result in a base case overload condition on the Inyo phase-shift transformer which is rated at 56 MVA.

Figure 10-3-1
Inyo Phase-Shift Transformer MW Flow Histogram



There is an LGIA currently pending at FERC for an approximately 60 MW project in this area with an IC proposed in-service date of February 1, 2012. With the inclusion of such project, the base flows were adjusted according to the derived generation shift factors. Such adjustment resulted in identifying that the Inyo phase-shift transformer will load in excess of the thermal limits approximately 48 percent of the year. Utilizing congestion management to mitigate such thermal overloads would require reducing generator capacity factor from 100% down to 84%. This reduction in capacity factor assumes that each generation unit is equipped with ramp down capability to zero. The capacity factor will be significantly lower when the minimum generation level is considered. In other words, the units will need to be completely shut down if the minimum generation output is below the minimum generation design threshold. Figure 10-3-2 provides the Inyo phase-shift histogram comparing the base against the value obtained after the addition of approximately 60 MW. Figure 10-3-3 provides the curtailment histogram after the inclusion of approximately 60 MW.

Given the magnitude and extent of congestion created with the addition of approximately 60 MW, SCE has previously recommended that the Inyo phase-shift transformer be upgraded to provide for additional phase-shift capability in order to limit the amount loop flow from SCE's system to the Los Angeles Department of Water and Power's (LADWP) electrical system. Such upgrade is already included into the LGIA currently pending at FERC.

Figure 10-3-2
Inyo Phase-Shift Transformer MW Flow Histogram

SCE hourly historical metered data was previously also used to establish the expected base flows on the existing Control-Inyokern 115 kV transmission lines prior to the addition of approximately 60 MW of new generation resources in SCE's Control Substation Area. The histogram below in Figure 10-3-4 illustrates the number of hours of expected MW flow on the highest loaded Control-Inyokern 115 kV line in increments of 5 MW. Note that the existing generation connected in the Control Area did not result in a base case overload condition on the Control-Inyokern 115 kV lines. With the addition of approximately 60 MW of new generation resources at Control, the study identified approximately 22 hours of congestion exposure that would be anticipated on these 115 kV lines. Given the relatively small congestion exposure, available emergency conductor capability, and limited amount of generation curtailment required to mitigate these overloads, the use of congestion management was identified to be adequate to manage loadings on these transmission lines for the first 60 MW of new generation resources. However, an SPS would be required to mitigate the contribution to flows south of Control. This requirement was based on the fact that the existing system already includes special protection systems to mitigate both thermal and transient stability problems under outage conditions.

Figure 10-3-4

Control-Inyokern 115 kV line flow (MW)

Separate studies undertaken for the next serial interconnection project determined that continued use of congestion management to accommodate additional generation beyond the 60 MW evaluated is unmanageable. Such determination was based on impacts associated with changes internal to LADWP's electric system which would make implementation of congestion protocols extremely difficult. As a result, additional upgrades were recommended to interconnect the next serial generation project. Because this project adds to the problem, additional facility upgrades will be required prior to allowing interconnection of additional resources beyond the first 60 MW who already have an LGIA pending at FERC.

10.3.2 South of Kramer Congestion Assessment

Previous Congestion Assessments have been performed in this area which has evaluated the extent of potential congestion that the existing North of Kramer Sub-area could experience with additional "Energy Only" Interconnection Projects. Results of these studies which include the interconnection of several queued ahead serial projects as well as the addition of three Transition Cluster Projects, including this Project, are provided in the paragraphs below.

The curtailment analysis was based on adjusted historical power flow as well as the use of typical solar and geothermal production profiles. Five years of historical metered data was used as the basis for developing the "expected" flow patterns on the existing network over the entire calendar year. Power flow studies were performed to determine the incremental flow contribution on the two Kramer-Lugo 220 kV transmission lines with the addition several projects in the North of Kramer Sub-area. The main purpose of the power flow studies was to identify the expected distribution factor for the projects identified in Table 10-3-1. These projects reflect the total projects seeking interconnection in the North of Kramer sub-area that could be included into an expanded Kramer SPS under initial "Energy Only" service until the Delivery Network Upgrades are constructed.

Table 10-3-1
Queued Ahead Generation Projects Modeled in Congestion Assessment

Based on the results of the power flow studies that were performed, the addition of the generation projects that could be included into an expanc Kramer SPS were found to increase flows on the two Kramer-Lugo 220 kV transmission lines whose total capability is limited to 988 MVA. Each of the individual generators were evaluated to determine how much of the generation output is anticipated to flow down the two Kramer-Lugo 220 kV transmission line. A summary of each project's expected contribution on the two Kramer-Lugo 220 kV transmission lines is provided below in Table 10-3-2.

Table 10-3-2
Generation Project Contributior
Flows on the Kramer-Lugo No.1 and No.2

	C	
Total Flow Increase:		

To develop the appropriate Kramer-Lugo No.1 and No.2 220 kV transmission line "expected" power flow data over an entire calendar year, the historical data profiles for years 2005 through 2009 were adjusted to reflect the identified project contributions as shown above in Table 10-3-2. The adjustment involved "increasing" the historical data by applying the identified distribution factor to the corresponding typical project production profiles and adding the resulting contribution to the historical data. This methodology resulted in appropriately increasing flows only when additional generation is anticipated to increase flows. In other words, the incremental contribution of each generation hourly data point was not added to the corresponding historical hourly data point at times when solar production was not expected to occur but only during expected daytime periods.

The historical peak flow on the two Kramer-Lugo 220 kV transmission lines and the "adjusted" peak flow after the inclusion of each new generation project that would increase flows on the two Kramer-Lugo 220 kV transmission lines are provided below in Table 10-3-3.

Table 10-3-3
Kramer-Lugo 220 kV Transmission Line Peak Flow (MW)

	2005	2006	2007	2008	2009

As can be seen in Table 10-3-3, the addition of the projects shown in Table 10-3-1 will result in an expected base case congestion condition. Such base case congestion is associated with the thermal limits of the [redacted] 1033 kcmil ACSR conductor used on th[redacted] existing Kramer-Lugo 220 kV transmission lines (988 MVA). Figure 10-4-1 through Figure 10-4-5 illustrate the expected impact as identified in the previous Congestion Assessment.

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Figure 10-4-5
Kramer-Lugo 220 kV Transmission Line Historical and Adjusted Peak Flow
Year 2009

— 2009 Adjusted — 2009 Historical

Note that the existing system currently does not experience any base case congestion. Thermal overloads on the Kramer-Lugo 220 kV transmission line and system instability under outage conditions in this area is currently mitigated by the Kramer RAS. These problems could occur during high generation conditions under loss of one or both Kramer-Lugo 220 kV transmission lines. The existing RAS monitors the line flows on the two Kramer-Lugo 220 kV transmission lines and alarms for an Operator to arm existing generation units if the total flow level metered on these two transmission lines exceeds the SPS arming threshold. Generation tripping only occurs if an outage monitored as part of this SPS is detected and generation units were armed to trip for such outage condition.

Please note that the congestion analysis was based on adjusted historical power flow and should be used for informational purposes only. CAISO and SCE cannot, and do not, warrant that the analysis will correctly predict future system performance and the associated potential congestion.

10.3.3 **Operational Stability Assessment**

A Stability Assessment was performed which considered the addition of new generation resources to determine point where the system begins to experience severe stability problems which are not mitigated with existing SPS. Base on such Operational Stability Assessment, the determination was made that the existing system can only accommodate a total of approximately 100 MW prior to experiencing significant system stability problems. Specifically, the study identified that under a three phase fault at the Control 115 kV bus the system would experience instability if the Bishop Hydro Units are not in-service (or trip due to 115 kV line fault), or under loss of the Control-Inyokern 115 kV T/L. The resulting transient stability plots are provided in Figures 9-3-5 and 9-3-6.

Figure 9-3-5

Stability Plot of Three Phase Fault at Control 115 kV (Loss of the Bishop Hydro Units 3 and 4)

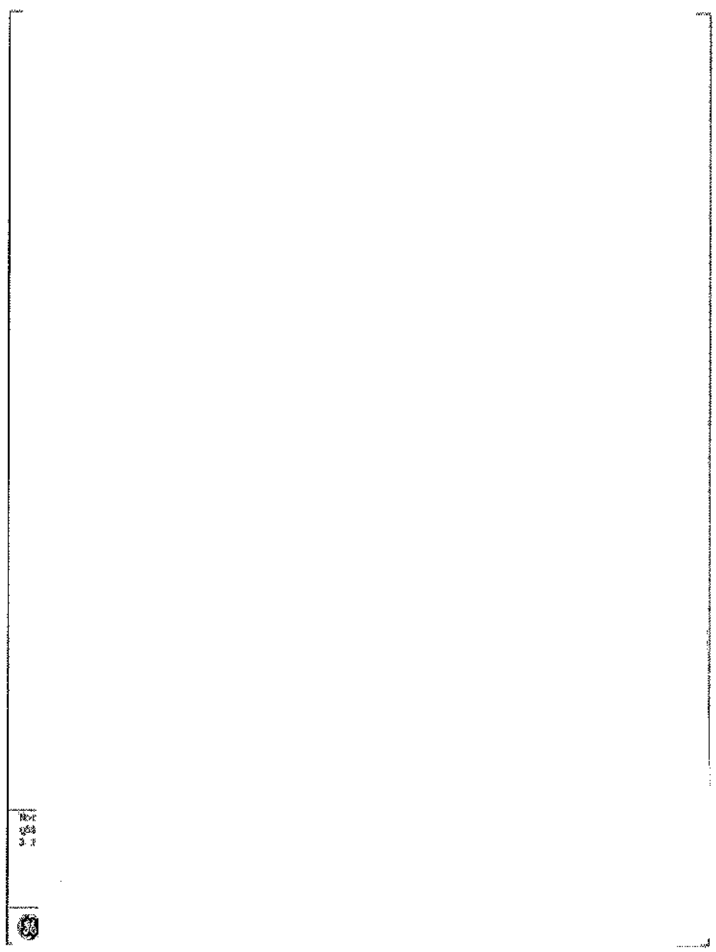
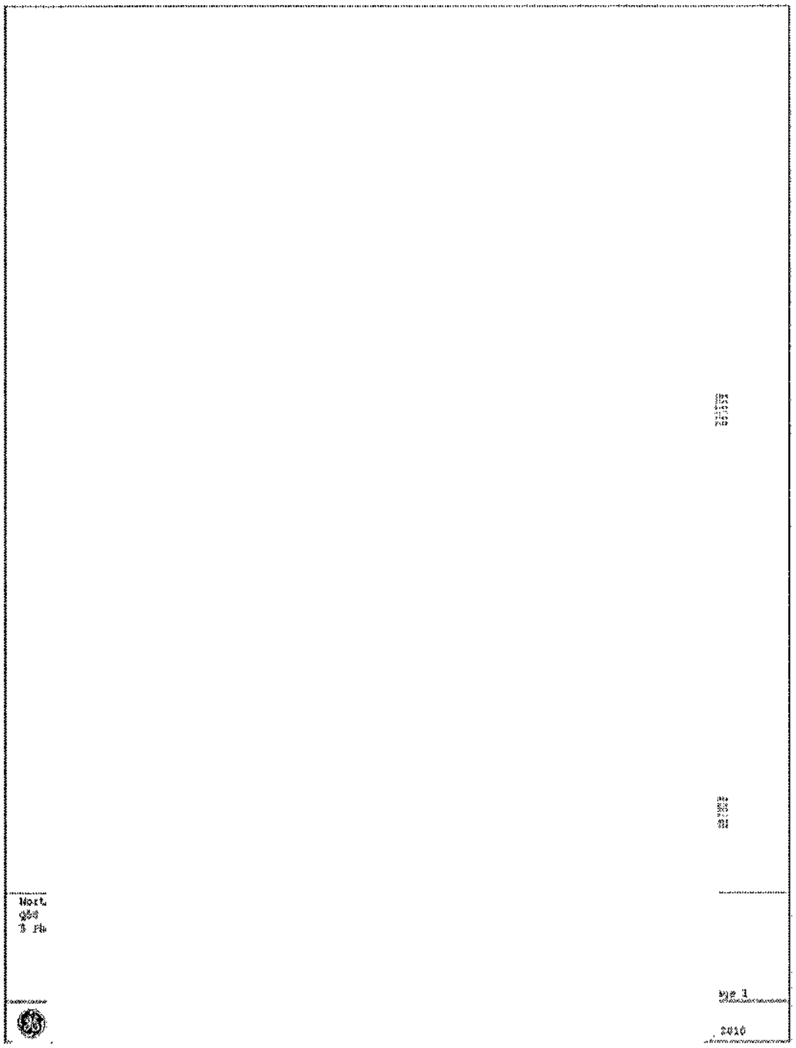


Figure 9-3-6
Stability Plot of Three Phase Fault at Control 115 kV (Loss of the Control-Inyokern 115 kV T/L)



Note the un-damped oscillations occurring under this outage condition. More severe system stability is likely to be experienced under different stressed conditions.

10.3.4 Use of an Automated Curtailment Procedure

It may be possible to allow additional projects to make temporary deliveries with the installation of an automatic trip feature. Such feature would open the appropriate circuit breaker to disconnect generation resources.

Because such determination requires further evaluation and is outside the scope of the Phase II Study, the determination of such possible means of allowing interim deliveries will need to be undertaken as part of a separate analysis done under Letter Agreement.

10.4 Conclusion

Based on the previous congestion assessment performed and the system stability limitations, additional generation beyond the first ~60 MW cannot be accommodated until additional system upgrades are in place beyond those upgrades currently identified in the LGIA pending before FERC. Because queued ahead serial interconnection requests exist in this area with an IC proposed in-service date that is prior to this project, the conclusion is that the existing system cannot accommodate new Transition Cluster generation projects.

Consequently, the Transition Cluster will need to wait for additional upgrades to be implemented to allow for the interconnection of the projects. Based on the current schedules, such interconnection could be delayed for up to 84 months, and possibly longer depending on actual permitting and construction timelines of the required "shared" generation Interconnection Facilities.

11. Environmental Evaluation/Permitting

See Section 12 of the Group Report.

12. Upgrades, Cost Estimates and Construction schedule estimates

To determine the cost responsibility of each generation project in Transition Cluster, the CAISO developed cost allocation factors based on the individual contribution of each project (Attachment 6). The cost allocation for the Interconnection Facilities and Network Upgrades for which the Project is solely responsible is as follows:

PTO's INTERCONNECTION FACILITIES

1. **Distribution:**
   WDT315 33 kV Generation Line
   Install parallel runs of 1500JCN and pole mounted 33 kV primary metering (PTs, CTs, and metering cabinet).

2. **Substation:**
   [redacted] Substation
   Equip a new 33 kV position to terminate the WDT315 33 kV line.

   The Interconnection Facilities will be installed as follows:
   - 33 kV U.G. cables inside 100' duct bank between Position 9 to the substation perimeter fence.
   - Protection relays:
     - [redacted]
     - [redacted] with setting group selector switch

3. **Telecommunications**
   Install channel and associated equipment supporting SCADA for WDT315 line.

4. **Environmental Health and Safety**
   Perform all required activities related to support the SCE portion of the WDT315 line.

5. **Licensing**
   Perform all required activities related to support the SCE portion of the WDT315 line.

6. **Real Properties**
   Perform all required activities related to support the SCE portion of the WDT315 line.

7. **Metering Services Organization**
   Install Revenue Meters required to meter the Retail load at the Generating Facility.

8. **Power System Control**
   Install [redacted] at the Generating Facility to monitor the typical Generation elements such as MW, MVAR, terminal Voltage and Circuit Breaker Status at each Generating Unit and the Plant Auxiliary Load and transmit this information to the SCE Grid Control Center.

   Upgrade [redacted] existing obsolete RTUs at [redacted] 33 kV Substation.

PLAN OF SERVICE RELIABILITY NETWORK UPGRADES

No Plan of Service Reliability Network Upgrades have been allocated to the Project.

RELIABILITY NETWORK UPGRADES

Below is a list of Reliability Network Upgrades with costs that have been allocated to the Project. See group report section 11 for scope details

- New East of Lugo Bulk System TC SPS4 (Llano Area)
- New East of Lugo Bulk System TC SPS5 (Kramer-Inyokern Area)
- Short-Circuit Duty (SCD) Mitigation

DELIVERY NETWORK UPGRADES

Below is a list of Delivery Network Upgrades with costs that have been allocated to the Project. See group report section 11 for scope details.

- South of Kramer Transmission Upgrades: Kramer Substation Expansion to 500 kV with [redacted] Transformer Banks, New Llano Switching Station and New Kramer-Llano 500 kV Transmission Line
- Inyokern-Kramer Corridor Reconfiguration Upgrades

NON-CAISO TRANSMISSION UPGRADES

BLM West – Kramer 220 kV T/L (Existing Non-CAISO T/L)
Loop the existing line into the expanded Inyokern Substation and form the two new Non-CAISO BLM West – Inyokern and CAISO Controlled Inyokern – Kramer No.1 220 kV T/L.

This work requires the installation of approximately 0.5 circuit mile of 1033 KCMIL ACSR conductors and OPGW, three new dead end 220 kV lattice steel structures and twenty one insulator / hardware assemblies and the removal [redacted] existing structures.

DISTRIBUTION UPGRADES

- Insta[redacted] new 33 kV Bus Dead-End Structures and extend the existing 33 kV Operating and Transfer Buses three positions
- Equip New 33 kV Bank Position for the existing 33/12kV Transformer Bank by installing the following equipment:
  - [redacted] CB
  - [redacted] ead-End Structure
  - [redacted] sets disconnect switches
- Equip New 33 kV position as a 33 kV underground circuit position by installing the following equipment:
  - [redacted] CB
  - [redacted] Dead-End Structure
  - [redacted] disconnect switches

- [redacted] Cable Risers
- [redacted] Potheads to terminate the U.G. cables

ADDITIONAL DISTRIBUTION UPGRADES

- Relocate Kramer-Rocket Test 115 kV Line
- Relocate Inyokern-McGen-Searless No.1 and No.2 115 kV Line

Table 12.1: Upgrades, Estimated Costs, and Estimated Time to Construct Summary

Type of Upgrade	Upgrade (May include the following)	Description	Estimated Cost x 1000	Estimated Time to Construct *(Note 3)*
PTO's Interconnection Facilities *(Note 1)*	Transmission, Substations, Metering Services Organization, Power System Control, Telecommunications, Real Properties, Transmission Projects Licensing, and Environmental Health and Safety	Non-network facilities needed to enable interconnection	$4,678	24 Months
Plan of Service Reliability Network Upgrades	None	Direct Assigned Network upgrades needed to enable interconnection.	N/A	N/A
Reliability Network Upgrades	SPS, Substation	Allocated Network upgrades needed to maintain system Reliability	$414	24 Months
Delivery Network Upgrades	Transmission, Substations, Power System Control, Telecommunications, Real Properties, Transmission Projects Licensing, and Environmental Health and Safety	Network upgrades needed to support Full Delivery, if requested	$43,289	84 Months
Non-CAISO Transmission Upgrades *(Note 2)*	BLM West – Kramer 220 kV T/L	Non-CAISO SCE Transmission Facilities	$349	48 Months
Distribution Upgrades *(Note 4)*	Relocate non-CAISO controlled 115 kV lines	Non-CAISO SCE Distribution Facilities	$3,088	84 Months
Total			**$51,818**	**84 Months**

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

Note 2: Non-CAISO Transmission Upgrades are not reimbursable.

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. 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.

Note 4: These upgrades are not identified in ISO tariff, and are not reimbursable. Allocated costs may change if all projects responsible for these upgrades do not execute LGIAs.

13. Study Caveats

13.1 Plan of Service

The Plan of Service developed for the Project is based on the data submittals provided for each specific project in the cluster group and will serve as the basis for developing the LGIA and for permitting purposes. However, the final Plan of Service is subject to change based upon completion of preliminary and final engineering, identification of field conditions, and compliance with applicable environmental and permitting requirements.

13.2 Customer's Technical Data

The study accuracy and results for the 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.

13.3 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 CAISO Controlled Grid, and sub-synchronous resonance (SSR).

13.4 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.

13.5 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.

13.6 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.

13.7 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

13.8 Standby Power and Temporary Construction Power

The 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.

13.9 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. 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.

13.10 Telecommunication Assumptions

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 SCE as opposed to the IC doing this work. In addition, the telecommunication requirements for SPS were assumed based on tripping of the generator breaker as opposed to tripping the circuit breakers at the SCE substation. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

Attachment 1

Generator Machine Dynamic Data

Attachment 2

Dynamic Stability Plots

Please Refer to Appendix F of the Group Report

Attachment 3

SCE Interconnection Handbook

Attachment 4

Short Circuit Calculation Study Results

Attachment 5

Deliverability Assessment Results

Please Refer to Appendix I of the Group Report

Attachment 6

Allocation of Network Upgrades for Cost Estimates