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0000143820

Jay I. Moyes, No. 007207
Jason Y. Moyes, No. 025864
MOYES SELLERS & HENDRICKS LTD.
1850 N. Central Avenue, Suite 1100
Phoenix, Arizona 85004
(602)-604-2106
jimoyes@law-msh.com
Attorneys for Tribal Solar, LLC

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BEFORE THE ARIZONA CORPORATION COMMISSION

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BOB BURNS

Arizona Corporation Commission
DOCKETED
MAR 28 2013
DOCKETED BY JM

IN THE MATTER OF TRIBAL SOLAR, LLC'S TEN YEAR PLAN

Docket No. E-00000D-13-0002

NOTICE OF FILING TEN YEAR PLAN

In accordance with Arizona's Eighth Biennial Transmission Assessment process, First Solar, through its wholly-owned subsidiary, Tribal Solar, LLC, files its Ten Year Plan for the substation and gen-tie transmission facilities associated with the proposed Fort Mojave Solar Project, including the System Impact Study prepared with respect to such facilities.

////

DATED this 27th day of March, 2013.

MOYES SELLERS & HENDRICKS LTD.

Jay I. Moyes
Jason Y. Moyes
Attorneys for Tribal Solar, LLC

Original and 13 copies filed this
27th day of March, 2013:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

TRIBAL SOLAR, LLC
Ten Year Plan
For Proposed Transmission Facilities
(in-service 2016)

Line Description	Fort Mojave Solar Project Substations and Gen-tie Line
Size	
• Voltage	34.5/230 kV step up transformers and up to approximately 25 miles of 230 kV double circuit transmission line from the high side of the step up transformer to a 230/500 kV transformer substation adjacent to the Mohave Generating Station Substation near Laughlin, NV.
• Capacity	TBD; Estimated 310 MW
• Point of Origin	A 34.5/230 kV substation to be constructed for the Fort Mojave Solar Project, a PV-only solar generating facility proposed for development on the Fort Mojave Indian Reservation in portions of Sections 20 to 22, 27, 28, 33 and 34 of T. 19 N., R. 22 W., G&SRB&M, Mohave County, AZ; and in portions of Sections 10, 11, 14, 15 and 22 to 27 of T. 10 N., R. 22 E., SBB&M in San Bernardino County, CA.
• Termination Point	The existing Mohave Generating Station Substation.
• Length	TBD. Up to 25 miles, depending upon the final project configurations.
General Route	TBD. See attached map. The gen-tie line will generally run from the Fort Mojave Solar Project substation along one of two main alternative routes (see map). The alternative route that travels in Arizona has the following path: east approximately 1.5 miles; then south approximately 2 miles; then east approximately 6 miles; then north approximately 11 miles; then west approximately 4 miles, crossing the Colorado River and into a 230/500 kV step up transformer substation which connects into the adjacent Mohave Generating Station Substation in Clark County, NV.
Purpose	The gen-tie line and substations will interconnect the proposed Fort Mojave Solar Project with the regional transmission grid at the Mohave Generating Station Substation.
Date	
• Estimated Construction Start	Q4 of 2014

- Estimated In-Service Date — Q4 of 2016
- Is Certificate Necessary? — Yes.

System Impact Study — See attached System Impact Study Report prepared by California ISO.

END

California ISO

California Independent
System Operator Corporation

August 26, 2010

Mr. James Filippi
First Solar
1111 Broadway, 4th Floor
Oakland, CA 94607

Subject: **Fort Mojave Solar Project**
Cluster Phase II Interconnection Study

Dear Mr. Filippi:

Attached is the Cluster 1 and Cluster 2 Phase II Interconnection Study Report for the interconnection of the proposed Fort Mojave Solar Project (Project) to the CAISO Controlled Grid. The CAISO and SCE performed the Phase II Interconnection Study in accordance with the CAISO's GIP tariff.

The study has identified that the Project contributes to the need for Network Upgrades in accordance with the CAISO's GIP tariff. A cost estimate of the Network Upgrades is provided in the study report. In addition, the study report provides a cost estimate of the Interconnection Facilities and Distribution System Upgrades to interconnect the Project to the CAISO Controlled Grid.

Please review the report and prepare comments and questions for the Results Meeting. The Phase II Interconnection Study Results Meeting will be coordinated and scheduled within 30 calendar days following receipt of this Phase II Interconnection Study report.

Sincerely,

Robert Sparks
Manager of Regional Transmission - South

Attachment

via e-mail:

Jim Filippi	james.filippi@firstsolar.com
Leanne Swanson	Leanne.Swanson@sce.com
Steve Mavis	Steven.Mavis@sce.com
Jorge Chacon	Jorge.Chacon@sce.com
Berry Curry	Berry.Curry@sce.com
Ying He	Ying.He@sce.com
Odet Bonilla	Odet.Bonilla@sce.com
Rabindra Kiran	Rabindra.Kiran@sce.com
Ayman Samaan	Ayman.Samaan@sce.com
Diane Llamas	Diane.llamas@sce.com
Gordon Brown	Gordon.Brown@sce.com
Robert Lugo	Robert.lugo@sce.com
Robert Sparks	RSparks@caiso.com
Songzhe Zhu	Szhu@caiso.com
Haifeng Liu	HLiu@caiso.com
Lyubov Kravchuk	LKravchuk@caiso.com
Yi Zhang	YZhang@caiso.com
Frank Chen	Fchen@caiso.com
Judy Brown	Jbrown@caiso.com
Linda Wright	LWright@caiso.com
Robert Emmert	remmert@caiso.com

Queue Cluster 1 & 2 Phase II Interconnection Study Report

Group Report in SCE's East of Lugo Bulk System

Final Report

California ISO
Shaping a Renewed Future

August 26, 2011

This study has been completed in coordination with Southern California Edison per CAISO Tariff Appendix Y, including Appendix 8 of the GIP ("Transition of Existing SGIP Interconnection Requests to the GIP") for Interconnection Requests in a Queue Cluster Window

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G. [Placeholder]
H. Short Circuit Calculation Study Results
I. Deliverability Assessment Results

Definitions

CAISO	California Independent System Operator Corporation
CFE	Comision Federal de Electricidad
COD	Commercial Operation Date
Deliverability Assessment	CAISO's Deliverability Assessment
EO	Energy Only Deliverability Status
EOP	East of Pisgah
EOP QC1&QC2	Group of QC1 and QC2 projects located East of Pisgah
FC	Full Capacity Deliverability Status
FERC	Federal Energy Regulatory Commission
IC	Interconnection Customer
IID	Imperial Irrigation District
LADWP	Los Angeles Department of Water and Power
LFBs	Local Furnishing Bonds
LGIA	Large Generator Interconnection Agreement
LGIP	Large Generator Interconnection Procedures
NOL	North of Lugo
Lugo Cluster	Group of QC1 and QC2 projects located within the Lugo Hub Area
PMax	Maximum generation output (based on interconnection requested amount)
NERC	North American Electric Reliability Corporation
NOK Cluster	Group of QC1 and QC2 projects located north of Kramer Substation
NQC	Net Qualified Capacity as modeled in the Deliverability Assessment:
PG&E	Pacific Gas and Electric Company
Phase I Study	Cluster 1 or Cluster 2 Phase I Study
Phase II Study	Cluster 1 and Cluster 2 Phase II Study
PTO	Participating Transmission Owner
RAS	Remedial Action Scheme (also known as SPS)
POI	Point of Interconnection
POS	Plan of Service
QC1	Queue Cluster 1
QC2	Queue Cluster 2
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SPS	Special Protection System (also known as RAS)
STC	SGIP Transition Cluster
SVC	Static VAr Compensator
SWPL	Southwest PowerLink
TPP	CAISO's Transmission Planning Process
WECC	Western Electricity Coordinating Council

1. Executive Summary

In accordance with Federal Energy Regulatory Commission (FERC) approved 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"), this study was performed to determine the combined impact of the Phase II projects in the CAISO Queue Cluster 1 (QC1), Queue Cluster 2 (QC2), and SGIP Transition Cluster (STC) on the CAISO Controlled Grid.

There are 50 generation projects in SCE's service territory for the Phase II study. Four general groups[1] are formed based on the electrical impact among the generation projects: Northern Bulk System, Eastern Bulk System, East of Lugo Bulk System and Metro System. The East of Lugo Bulk System covers the North of Lugo and the East of Pisgah sub-areas. This report provides the following:

1. Transmission system impacts caused by the addition of eight Phase II projects requesting interconnection in the East of Lugo Bulk System;

2. System reinforcements necessary to mitigate the adverse impacts of the eight Phase II projects requesting interconnection in the East of Lugo Bulk System under various system conditions and;

3. A list of required facilities, a Phase II cost estimate for Network Upgrades assigned to each Interconnection Request, and a non-binding, good faith estimate of the Interconnection Facilities cost and time to construct for each Interconnection Request.

To determine the system impacts caused by Phase II projects, the following studies were performed:

- Steady State Power Flow Analyses
- Short Circuit Duty Analyses
- Transient Stability Analyses
- Reactive Power Deficiency Analyses
- Deliverability Assessment
- Operational Studies

The results of above studies indicated that Phase II projects are responsible for the overloading of transmission facilities and overstressing of circuit breakers in SCE's service territory. Network Upgrades[2] and Distribution Upgrades to mitigate identified problems

[1] Precise electrical groupings were created during the deliverability study for Delivery Network Upgrade cost allocation purpose.

[2] 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. Network Upgrades do not include Distribution Upgrades.

corresponding to the Phase II projects requesting interconnection in the East of Lugo Bulk System have been proposed in this report. The following tables show a summary of the proposed Network Upgrades along with an estimated cost.

Table A – Plan of Service Reliability Network Upgrades ($ 1,000)

1	Various (see individual Appendix A for details)	
Total SCE Cost for SCE's East of Lugo Bulk System		**$56,021**

Table B– Reliability Network Upgrades ($ 1,000)*

1	Short-Circuit Duty (SCD) Mitigation Lugo Vincent Windhub	 $4,453 $10,846 $5,068
	North of Lugo Area	
2	SPS-4 (refer to Section 11)	$5,358
3	Expand Victor Area SPS (refer to Section 11)	$135
	East of Lugo	
4	SPS-1 (refer to Section 11)	$5,881
5	SPS-2 (refer to Section 11)	$5,769
6	SPS-3 (refer to Section 11)	$6,177
Total Cost		**$43,687**

Table C – Delivery Network Upgrades ($ 1,000)

	North of Lugo	
1	Cool Water-River 115 kV T/L Re-build	$66,732
2	No.3 500/220 kV Transformer Bank at Lugo Sub	$71,698
	East of Lugo	
3	No.2 500/220 kV Transformer Bank at Eldorado Sub	$57,319
4	Loop Lugo-Mohave 500 kV T/L into Pisgah Sub	$32,277
5	Add Series Cap Banks on Nipton-Pisgah & Mohave-Pisgah 500 kV T/Ls	$246,096
	Eastern Bulk System Upgrades	
6	New Red Bluff-Valley 500 kV T/L	$909,364
7	Colorado River-Red Bluff No.3 500 kV T/L	$158,158
Total Cost		**$1,541,644**

** Short Circuit Duty Mitigation costs are allocated across all projects as detailed in Section 8 of this Report.*

Table D – Distribution Upgrades ($ 1,000)

1	Short-Circuit Duty (SCD) Mitigation	$13,675
Total SCE Cost for SCE's East of Lugo Bulk System		**$13,675**

The upgrades in the Tables above do not include Interconnection Facilities, which are the obligation of each Interconnection Customer to fund. These interconnection facilities relating to each individual project are discussed in the corresponding Appendix A. Distribution Upgrades identified in Table D are non-refundable.

Given the magnitude of the above upgrades, a non-binding estimate to engineer, license, procure, and construct the facilities identified in the above Tables could be up to 84 months from LGIA execution. This Phase II Study evaluated potential operational constraints associated with the upgrades triggered by the queued ahead projects that were not allocated to the projects in the Phase II Study but which either help support or are required to interconnect the Phase II projects. These previous upgrades may impact the individual generation requested in-service dates. Facility in-service dates were evaluated as part of the Phase II Study in order to evaluate potential options for early interconnection of Phase II Projects.

2. Phase II Interconnection Information

Eight generation projects totaling a maximum output of 947 MW are included in Phase II in the East of Lugo Bulk System. Table 2.1 lists all the generator projects in QC1, QC2 and STC in the East of Lugo Bulk System with essential data obtained from the CAISO Generation queue and updated to reflect the most current information.

Table 2.1: Phase II Projects (East of Lugo Bulk System)

Project Number	Point of Interconnection	Full Capacity/ Energy Only	Fuel	Max MW
CAISO #488	Eldorado Substation	FC	Solar	92
CAISO #491	Cool Water-Dunn Siding 115 kV T/L	FC	Solar	230
CAISO #502	Eldorado-Ivanpah 220 kV T/L	FC	Solar	20
CAISO #503	Eldorado Substation 220 kV Bus	FC	Solar	155
CAISO #515	Kramer-Inyokern-Randsburg No.1 115 kV T/L	EO	Solar	20
CAISO #552	Lugo-Pisgah No.2 220 kV T/L	FC	Solar	60
CAISO #589	Victor Substation 115 kV	FC	Solar	60
CAISO #593	Mohave Generating Station 500 kV Bus	FC	Solar	310
			Total Phase II Generation	**947**

3. Study Objectives

This Phase II Interconnection study was performed in accordance with Section 7.1 of Appendix Y of the CAISO tariff, which states:

The Phase II Interconnection Study shall:

(i) update, as necessary, analyses performed in the Phase I Interconnection Studies to account for the withdrawal of Interconnection Requests,
(ii) identify final Reliability Network Upgrades needed to physically interconnect the Large Generating Facilities,
(iii) assign responsibility for financing the identified final Reliability Network Upgrades,
(iv) identify, following coordination with the CAISO's Transmission Planning Process, final Delivery Network Upgrades needed to interconnect those Large Generating Facilities selecting Full Capacity Deliverability Status;
(v) assign responsibility for financing Delivery Network Upgrades needed to interconnect those Large Generating Facilities selecting Full Capacity Deliverability Status;
(vi) identify for each Interconnection Request final Point of Interconnection and Participating TO's Interconnection Facilities;
(vii) provide a +/-20% estimate for each Interconnection Request of the final Participating TO's Interconnection Facilities;
(viii) optimize in-service timing requirements based on operational studies in order to maximize achievement of the Commercial Operation Dates of the Large Generating Facilities; and
(ix) if it is determined that the Delivery Network Upgrades cannot be completed by the Interconnection Customer's identified Commercial Operation Date, provide that operating procedures necessary to allow the Large Generating Facility to interconnect as an energy-only resource, on an interim-only basis, will be developed and utilized until the Delivery Network Upgrades for the Large Generating Facility are completed and placed into service.

This same section continues and further states that the Phase II Interconnection Study shall:

(x) specify and estimate the cost of the equipment, engineering, procurement and construction work, including the financial impacts (i.e., on Local Furnishing Bonds), if any, and schedule for effecting remedial measures that address such financial impacts, needed on the CAISO Controlled Grid to implement the conclusions of the updated Phase II Interconnection Study technical analyses in accordance with Good Utility Practice to physically and electrically connect the Interconnection Customer's Interconnection Facilities to the CAISO Controlled Grid; and
(xi) also identify the electrical switching configuration of the connection equipment, including, without limitation: the

transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Participating TO's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities.

The Phase II Study analysis was performed to identify the Interconnection Facilities, Plan of Service Reliability Network Upgrades, Reliability Network Upgrades, Delivery Network Upgrades and Distribution Upgrades necessary to safely and reliably interconnect the Phase II projects into the CAISO Controlled Grid. An estimated cost and construction schedule for these facilities has also been provided in this report.

4. Study Assumptions

4.1 Power flow base cases

The Phase II Study used power flow base cases representing 2014 summer peak and 2014 off-peak system conditions in the SCE service territory. These base cases included all CAISO approved transmission projects, as well as higher queued generation projects with associated Network Upgrades and Special Protection Systems.

4.2 Load and Import

The Deliverability Assessment On-Peak case modeled a 25,845 MW load in SCE system with an import target as shown in Table 4.1.

Table 4.1: On-Peak Deliverability Assessment Import Target

Branch Group (BG) Name	BG Import Direction	Net Import MW	Import Unused ETC MW
Lugo_victrville_BG	N-S	1138	171
COI_BG	N-S	3770	548
BLYTHE_BG	E-W	107	0
CASCADE_BG	N-S	1	0
CFE_BG	S-N	-55	0
ELDORADO_BG	E-W	1158	0
IID-SCE_BG	E-W	315	0
IID-SDGE_BG	E-W	-159	0
INYO_BG	E-W	0	0
LAUGHLIN_BG	E-W	0	0
MCCULLGH_BG	E-W	30	316
MEAD_BG	E-W	469	505
MERCHANT_BG	E-W	439	0
N.GILABK4_BG	E-W	-140	168
NOB_BG	N-S	1469	0
PALOVRDE_BG	E-W	3139	175
PARKER_BG	E-W	108	27
SILVERPK_BG	E-W	0	0
SUMMIT_BG	E-W	0	0
SYLMAR-AC_BG	E-W	0	471

While it is impractical to study all combinations of system load and generation levels during all seasons and at all times of the day, the base cases were developed to represent stressed scenarios of loading and generation conditions for the study group area.

4.3 Generation Assumptions

Generation assumptions for SCE's East of Lugo Bulk System[3] are shown below in Table 4.3.1 (existing), Table 4.3.2 (queued ahead serial LGIPs), Table 4.3.3 (Transition Cluster), and Table 4.3.4 (Pre Phase II SGIPs).

Generation dispatch assumptions in Deliverability Assessment can be found at http://www.caiso.com/1c44/1c44b5c31cce0.html.

On-peak Net Qualified Capacity (NQC) for proposed Full Capacity intermittent generation resources located in the Southern California region including the SCE and SDG&E service areas are estimated in the following methods:

Wind: 64% or 40% of net nameplate for Average Production During 12-6PM QC Period or Production Exceeded 20% of time During 12-6 PM QC Period

[3] Only SCE's East of Lugo Bulk System Generation is shown in the provided Tables.

Solar: 100% or 85% of net nameplate for Average Production During 12-6PM QC Period or Production Exceeded 20% of time During 12-6 PM QC Period

NQC of wind intermittent resource is set to 64% of the requested PMax for net maximum wind project output and 100% of the requested PMax for net solar project output initially. The on-peak NQC may be adjusted to 40% of the requested PMax for the wind output and 85% for the solar output if a mix of different fuel type generations is identified in the 5% DFAX group for a transmission limitation. Table 4.3.5 presents the estimated high and low Qualified Capacities for the Phase II projects in East Of Lugo, Eastern, and SDG&E subareas.

In the Reliability Assessment, the generation is dispatched at PMax.

Table 4.3.1
Existing Generation

Qualified Facilities	MW
BLM East (Units 7 & 8)	48
BLM West (Unit 9)	24
Borax	45
Calgen (Units 1, 2, & 3)	77.3
Kerrgen*	16.9
Kerr McGee*	55
Luz (Units 8 and 9) – SEGS 8 and 9	160
McGen	104.4
Mogen	51
Navy 2 (Units 4, 5, & 6)	75
Oxbow	50
SEGS 2	29.4
Sungen (Units 3, 4, 5, 6, & 7)	139.6
Subtotal:	**875.6**

*Note that the maximum net generation export as seen at Searles 115 kV (McGen + Kerrgen - Load) is limited to no more than 26 MW.

Edison Hydro	MW
Bishop Hydro Unit 2 & 6	13
Bishop Hydro Unit 3 & 4	16
Poole & Lundy	11
Rush Creek	11
Subtotal:	**51**

Alta Market Generation	MW
Alta Unit 1	65
Alta Unit 2	81
Alta Unit 3 (combustion turbines)	132
Alta Unit 3 (steam turbine)	108
Alta Unit 4 (combustion turbines)	132
Alta Unit 4 (steam turbine)	108
Subtotal:	**626**

HDPP Market Generation	MW
HDPP (Units 1, 2, & 3)	525
HDPP (Steam turbine)	325
Subtotal:	850
North of Lugo Total Area Generation:	**2402.6**

Table 4.3.2
Queued Ahead Serial Large Generation Interconnection Requests

#	CAISO Queue #	SCE Project ID	Interconnection Point	Size (MW)
1	33	TOT116	Control 115kV Bus	10
2	WDT	WDT164	Gale 115kV Bus	80
3	58	TOT127	Churchill-Bishop T/L	62
4	68	TOT131	Pisgah 220kV Bus	275 Phase 1 / 850 Full Build
5	125	TOT175	Kramer 220kV Bus	250
6	126	TOT176	New 500 kV[4]	500
7	131	TOT180	Ivanpah 220 kV Bus	100
8	135	TOT183	Pisgah-Lugo No.1 220 kV T/L	60
9	142	TOT192	Kramer 220kV Bus	80
10	156	TOT202	Pisgah-Lugo No.1 220kV T/L	201
11	162	TOT210	Ivanpah 115 kV Bus	114
12	233	TOT242	Mountain Pass 115kV Bus	200
13	240	TOT250	Pisgah 220kV Bus	400
14	241	TOT245	Pisgah 220kV Bus	400

Table 4.3.3
Transition Cluster Large Generation Interconnection Requests

#	CAISO Queue #	SCE Project ID	Interconnection Point	Size (MW)
1	163	TOT211	Ivanpah 220 kV Bus	300
2	205	TOT226	Eldorado 220 kV Bus	300
3	WDT	WDT285	Cottonwood-Savage 115 kV	100
4	WDT	WDT286	Victor-Phelan T/L	150
5	467	TOT381	New Primm Substation connected to Eldorado-Ivanpah 220 kV T/L	230
6	WDT	WDT315	Control	40.7

[4] The IC originally requested interconnection to the Eldorado 220 kV Substation. However, a different Method of Service was developed as part of the project's System Impact Study.

Table 4.3.4
Pre Phase II Serial Small Generation Interconnection Requests

#	CAISO Queue #	SCE Project ID	Interconnection Point	Size (MW)
1	474	TOT387	Cool Water-Baker-Dunn Siding-Mtn Pass-Ivanpah 115 kV	19.9
2	WDT	WDT325	Kramer Distribution	20
3	WDT	WDT326	Gale Distribution	20
4	WDT	WDT323	Cottonwood Distribution	20
5	WDT	WDT328	Cottonwood Distribution	20
6	WDT	WDT329	Kramer Distribution	20
8	WDT	WDT371	Savage-Cottonwood 115 kV line	19.99
9	WDT	WDT372	Victor Distribution	19.99
10	WDT	WDT409	Cottonwood Distribution	10
11	WDT	WDT417	Inyokern Distribution	5.5
12	WDT	WDT418	Cottonwood Distribution	10
13	WDT	WDT421	Cottonwood Distribution	20
14	WDT	WDT419	Randsburg 115 kV	20
15	WDT	WDT406	Cottonwood Distribution	3
16	WDT	WDT491	Victor Distribution	20
17	WDT	WDT508	Victor Distribution	2
18	WDT	WDT592	Cottonwood Distribution	20
19	WDT	WDT531	Apple Valley Distribution	1.942
20	WDT	WDT532	Apple Valley Distribution	1.942
21	WDT	WDT533	Apple Valley Distribution	0.757

Table 4.3.5: Qualified Capacities for the Phase II Projects In the EOL, Eastern, and SDG&E subareas

CAISO Queue	Area	Fuel	Net Nameplate Size	High Net Qualified Capacity	Low Net Qualified Capacity
			MW	MW	MW
C488	EOP	Solar	92	92	78
C491	NOL	Solar	230	230	196
C502	EOP	Solar	20	20	17
C503	EOP	Solar	155	155	132
C552	NOL	Solar	60	60	51
C589	NOL	Solar	60	60	51
C593	EOP	Solar	310	310	264
C576	Eastern	Solar	485	412	412
C588	Eastern	Solar	200	170	170
C493	SDG&E	Wind	299	191	120
C510	SDG&E	Solar	200	170	170
C555	SDG&E	Wind	92	59	37
C561	SDG&E	Solar	200	170	170
C565	SDG&E	Gas	100	100	100
C574	SDG&E	Solar	308	308	308

C590	SDG&E	Solar	150	128	128
C608	SDG&E	Solar	250	213	213
Total Phase II Generation			**3211**	**2847**	**2615**

4.4 New Transmission Projects

This Phase II Study included the modeling of all CAISO approved transmission projects in the East of Lugo Bulk System base cases. In addition, a number of transmission upgrades needed to support load growth and queued ahead generation projects in SCE's East of Lugo Bulk System were modeled in order to determine if additional facilities would be needed to support the projects in Phase II Study.

4.4.1 ELDORADO/MOHAVE/MOUNTAIN PASS/PISGAH AREAS

Several System Impact Studies (Serial Interconnection Requests) and Cluster Studies performed for queued ahead generation projects requesting interconnection to facilities at or near the Mountain Pass and Eldorado Substations and the Mohave Switchyard have identified the following facility upgrades needed to mitigate project impacts:

- Expansion of the existing SCE Pisgah 220 kV Substation to include 500 kV facilities (triggered by LGIA Serial Queued Project)
- Removal of the existing Lugo-Pisgah No. 2 220 kV transmission line and replacement with a new Lugo-Pisgah 500 kV transmission line[5] including an expansion of the Lugo 500 kV switchrack to support the new 500 kV transmission line (triggered by LGIA Serial Queued Project)
- Looping of the existing Eldorado-Lugo 500 kV transmission into the new 500 kV Pisgah Substation (triggered by LGIA Serial Queued Project)
- New "Nipton" 500/220 kV Substation to interconnect new generation in the Searchlight area and connected by looping the existing Eldorado-Lugo 500 kV transmission line (triggered by LGIA Serial Queued Project)
- New series compensation at "Nipton" on 500 kV line towards Pisgah Substation and removal of the existing of series compensation at Eldorado (triggered by LGIA Serial Queued Project)
- New "Ivanpah" 220/115 kV Substation with initially two 220/115 kV transformers installed to interconnect generation projects in the Ivanpah Dry Lake Area (triggered by LGIA Serial Queued Project)

[5] New right-of-way would be required west of the Mojave River to support a new 500 kV transmission line. A potential line routing alternative for this upgrade involves the use of existing right-of-way between the Mojave River and the Lugo Substation by removing both the existing Lugo-Pisgah No.1 and No.2 220 kV transmission lines and the construction of a new double-circuit 500 kV. One of the new 500 kV lines would be used to connect to Pisgah and the other 500 kV line would be initially operated at 220 kV and connected to Jasper 220 kV Substation.

- Removal of approximately 36 miles of a portion of the Eldorado leg of the existing Eldorado-Baker-Cool Water-Dunn Siding-Mountain Pass 115 kV line (triggered by LGIA Serial Queued Project)
- Removal of existing Eldorado 220/115 kV transformer bank (triggered by LGIA Serial Queued Project)
- Construction of approximately 36 miles of double-circuit 220 kV transmission line with one initial circuit between existing Eldorado Substation and new Ivanpah Substation (triggered by LGIA Serial Queued Project)
- Construction of a new "Primm" 220 kV Switching Station to interconnect new generation in the Primm, Nevada Area and connected by looping the planned Eldorado-Ivanpah No.1 220 kV transmission line (triggered by Transition Cluster)
- Construction of a new SCE-Owned Eldorado Substation facilities including 1) a new SCE-Owned 220 kV Switchrack located west of existing Eldorado 220 kV Switchrack and physically NOT connected to existing joint owned 220 kV switchrack, 2) installation of one new SCE-Owned 500/220 kV 1120 MVA transformer bank, and 3) reconfiguration of jointly owned 500 kV switchyard to enable connection of new AA-Bank (triggered by Transition Cluster)

4.4.2 LUGO-VICTOR-KRAMER-INYOKERN-CONTROL CORRIDOR

Several System Impact Studies (Serial Interconnection Requests) and Cluster Studies performed for queued ahead generation projects requesting interconnection to facilities at or near the Victor, Kramer, Cool Water, and Control Substations, and load growth studies have identified the following facility upgrades as necessary to maintain service to load reliability or to mitigate corresponding generation project impacts:

- New "Seaggett" 115 kV Switching Station to interconnect a queued ahead generation project in the Daggett Area and connected to reconfigured Victor-Black Mountain-Sopport-Southcap-Southdown 115 kV line (triggered by LGIA Serial Queued Project)
- Replacement of existing Inyo 115 kV phase-shift transformer (triggered by LGIA Serial Queued Project)
- Construction of new "Water Valley" (formerly "Lockhart") 220 kV Switching Station designed as a collector substation for new generation interconnections in the Kramer Area and connected by looping the existing Kramer-Cool Water No.1 220 kV transmission line (triggered by LGIA Serial Queued Project)
- Construction of new "Jasper" 220 kV Switching Station designed as a collector substation for new generation interconnections in the Lucerne Valley and initially connected by looping the existing Lugo-Pisgah No.1 220 kV transmission line (triggered by LGIA Serial Queued Project)

- Construction of a new 35-mile Cool Water-Jasper double-circuit 220 kV transmission line with one initial circuit (triggered by Serial Queued Project)
- Reconfiguration of transmission facilities at the existing Cool Water 220 kV Substation to enable connection of new Cool Water-Jasper 220 kV transmission line (triggered by Serial Queued Project)
- Removal of a 28-mile portion of Lugo-Pisgah No.1 220 kV transmission line between Lugo and Jasper Substation (triggered by Serial Queued Project)
- Construction of a new 28-mile Lugo-Jasper transmission line partially built with single-circuit 500 kV design standards and partially built with double-circuit 220 kV design standard (triggered by Serial Queued Project)
- Installation of the Victor No.3 220/115 kV transformer bank including rebuild of 115 kV switchrack (Triggered by SCE Load Growth and CAISO Approved)
- Construction of a new Victor-Savage No.3 115 kV Line (Not under ISO operational control. Triggered by SCE Load)

4.5 Other SPSs and Operator Actions

All new SPSs and modifications to existing ones will be designed with consideration of ISO SPS guidelines and are subject to review by Affected Parties and members of the WECC Remedial Action Scheme Reliability Subcommittee (RASRS).

4.5.1 Existing Kramer Special Protection System (SPS)

The Kramer SPS is designed to prevent transmission line or transformer bank overloads as well as system instability in the Kramer Junction area. These problems could occur during high generation conditions under certain transmission component outages. The following outlines the outages that can currently result in the potential operation of the Kramer SPS:

Single Outages

1. Loss of Kramer-Inyokern-Randsburg No.1 115 kV Line
2. Loss of Kramer-Lugo No.1 220 kV Transmission Line
3. Loss of Kramer-Lugo No.2 220 kV Transmission Line

Double Outages

1. Loss of Kramer-Lugo No.1 and No.2 220 kV Transmission Lines
2. Loss of Lugo 500/220 kV No.1 and No.2 Transformer Banks ("Safety Net")

New generation interconnection requests in the Kramer Subarea and new transmission upgrades triggered by such generation interconnections will require modification to the existing SPS. It should be noted that the serial Large Generation Interconnection Requests have resulted in the identification of an expansion of the existing Kramer SPS. Such expansion would result in a hardware limited SPS making further expansions untenable. As a result, additional generation interconnection in the Kramer Subarea beyond those in the serial interconnection process will necessitate physical transmission upgrades to facilitate such interconnections.

4.5.2 Existing High Desert Power Project SPS

This SPS is designed to prevent transmission line or transformer bank overloads as well as system instability. These problems could occur during high generation conditions under certain transmission component outages. The following outlines the outages that can result in the potential operation of the HDPP SPS:

Single Outages

1. Loss of Lugo-Victor No.1 220 kV Transmission Line
2. Loss of Lugo-Victor No.2 220 kV Transmission Line
3. Loss of Lugo 500/220 kV No.1 Transformer Bank (AA-Bank)
4. Loss of Lugo 500/220 kV No.2 Transformer Bank (AA-Bank)

Double Outages

1. Loss of Lugo-Victor No.1 and No.2 220 kV Transmission Lines
2. Loss of Lugo 500/220 kV No.1 and No.2 Transformer Banks ("Safety Net")

New generation interconnection requests in the Victor Subarea and new transmission upgrades triggered by such generation interconnections will require modification to the existing SPS. Additional generation interconnection in this Subarea may have to be added to the SPS as a participating generator in order to maintain system reliability.

4.5.3 Existing Bishop SPS

The Bishop SPS is currently designed to prevent system instability in the Bishop area, served by SCE's Control 115 kV Substation. System instability in this area could occur during high generation conditions under certain 115 kV line outages and in the Bishop area. Specifically, the existing SPS monitors the line flows on the two Control-Haiwee-Inyokern 115 kV lines and alarms for arming local area generation depending on the total flow level metered on these two transmission lines and status of the SCE-LADWP Inyo 220 kV system inter-tie. Generation tripping only occurs if an outage monitored as part of this SPS is detected and generation units were armed to trip if such and outage were to occur. The following outlines the outages that are currently monitored with this existing SPS.

<u>SCE-LADWP Inyo 220 kV System Inter-Tie Open</u>

1. Loss of Control-Coso-Haiwee-Inyokern 115 kV line

2. Loss of Control-Haiwee-Inyokern 115 kV line

SCE-LADWP Inyo 220 kV System Inter-Closed

3. Loss of Control-Coso-Haiwee-Inyokern and Control-Haiwee-Inyokern 115 kV lines

4.5.4 Existing South of Lugo SPS

In order to support flows on the three existing 500 kV transmission lines traveling from the Lugo Substation, near Victorville, to the Mira Loma area, a contingency based load tripping special protection system (SPS) is utilized. The South of Lugo SPS serves two operational purposes:

1. Protects electrical system against post-transient voltage instability; and
2. Protects electrical system against thermal overload conditions

The South of Lugo SPS monitors flows and status of the Lugo – Rancho Vista and two Lugo – Mira Loma 500 kV transmission lines and operates, if armed, under the loss of any two of these three (N-2) 500 kV transmission lines. Loads served from the Chino, Mira Loma, and Padua would be tripped if the SPS were to operate. Such operation would result in turning off customer loads in the communities of Chino, Chino Hills, Claremont, Corona, Diamond Bar, La Verne, Ontario, Pomona, Rancho Cucamonga, San Dimas, and Upland.

4.5.5 Proposed Jasper SPS

The need for new SPS in the Lugo Hub has been identified as part of studies performed for serial queued generation projects. Such SPS involves tripping the new generation projects under outage conditions associated with new transmission, between the existing Cool Water 220 kV Substation and a new substation (Jasper) to be located east of Lugo. Specifically, the new SPS is currently envisioned to monitor line status on a new Cool Water-Jasper 220 kV transmission line and Jasper-Lugo 220 kV transmission lines and trip new generation if outage of the monitored lines occurs.

4.5.6 Proposed Pisgah Area SPS

The proposed Pisgah Area SPS was identified in Serial Large Generation Interconnection Studies as a means to mitigate thermal overloads, transient instability, and localized system voltage collapse following loss of the proposed Lugo-Pisgah No.1 and No.2 500 kV transmission lines, upgrades triggered by a serial Interconnection Request.

4.5.7 Proposed Eldorado-Ivanpah and Ivanpah A-Bank SPS

The proposed Eldorado-Ivanpah SPS was identified in Serial Large Generation Interconnection Studies as a means to mitigate thermal overloads, transient instability, and localized system voltage collapse following loss of the planned Eldorado-Ivanpah 220 kV transmission line. As part of the serial interconnection studies, all three serial interconnection requests in this area were identified to require generation tripping under such outage condition.

The need to include two additional Transition Cluster generation projects and update the SPS design was identified in the Transition Cluster Phase II Study. In addition, studies performed for the third serial interconnection project identified the need to implement an SPS which would trip the third serial interconnection request following loss of one of two 220/115 kV transformer banks at the planned Ivanpah Substation.

4.5.8 Proposed Eldorado AA-Bank SPS

The proposed Eldorado SCE-Owned AA-Bank SPS was identified in the Transition Cluster Phase II Study as a means to mitigate transient stability, thermal overloads and the potential for a localized voltage collapse in the Ivanpah area following loss of a new Eldorado 500/220 kV transformer bank. Generation resources connecting to the Eldorado-Ivanpah 220 kV transmission line or directly to Eldorado will be tripped under such outage contingencies.

4.5.9 Proposed Eldorado Bulk System SPS

The proposed Eldorado Bulk System SPS was identified in the Transition Cluster Phase II Study as a means to mitigate overloads on the LADWP Eldorado-McCullough 500 kV Transmission Line following loss of both the Mohave-Lugo 500 kV (portion of existing Lugo-Mohave 500 kV) and one Lugo-Pisgah 500 kV (portion of existing Eldorado-Lugo 500 kV or new Lugo-Pisgah 500 kV) transmission lines. This SPS has not yet been designed and will require coordination with the Los Angeles Department of Water and Power (LADWP) since the overloaded facility for which this SPS is planned to be implemented is owned and operated by the LADWP and is not under the jurisdictional control of the CAISO.

4.5.10 Proposed Bishop SPS Modification

The East of Lugo Bulk System Transition Cluster project located within the North of Kramer Subarea identified the need for further expansion of the existing Bishop SPS. Such expansion will add one Transition Cluster Phase II project as a participant in this SPS as means to mitigate overloads, transient instability, and localized system voltage collapse following several single and simultaneous outages of 115 kV transmission lines around the Control Substation area.

4.5.11 Proposed Victor Area SPS Modification

The East of Lugo Bulk System Transition Cluster Phase II projects located within the Lugo Hub Subarea identified the need for further expansion of the existing High Desert Power Project SPS, beyond what was proposed for serial projects. Such expansion will add two Transition Cluster Phase II projects as participants in this SPS

in order to mitigate overloads, transient instability, and localized system voltage collapse following several single and simultaneous outages of 220 kV transmission lines around the Victor Substation area.

4.5.12 Operating Procedures

Operating procedures, which may include curtailing the output of the Phase II projects during planned or extended forced outages may be required for reliable operation of the transmission system. These procedures, if needed, will be developed before the projects' Commercial Operation Date.

4.6 Queued Ahead Triggered Circuit Breaker Upgrades, Replacement or Mitigation Requirements

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

A determination of such mitigation upgrade needs will be based on the study results of the Operational Studies undertaken for the Phase II generation projects. Should an impact to circuit breakers be identified in the Operational Study that requires the implementation of mitigation upgrades, such upgrades will need to be advanced by the corresponding projects in Operational Queue order to enable interconnection of the project.

The following provide the mitigation details of all previously triggered short-circuit duty impacts at locations where duty contributions are increased with the addition of these Phase II projects.

4.6.1 Antelope 220 kV

Upgrade or replace the following nine 40 kA 220 kV circuit breakers at Antelope Substation:

- Antelope CB4022 (Replace with 63kA) and CB6022 (Replace with 63kA)
- Antelope CB6032 (Replace with 63kA)
- Antelope CB4042 (Replace with 63kA) and CB6042 (Replace with 63kA)
- Antelope CB4062 (Replace with 63kA) and CB6062 (Replace with 63kA)
- Antelope CB4072 (Install TRV Caps)
- Antelope CB61X2 (Replace with 63kA)

4.6.2 Devers 220 kV

Upgrade or replace the following nine 220 kV circuit breakers at Devers Substation to 63 kA:

- Devers CB42X2 (Replace with 63 kA) and CB62X2 (Replace with 63 kA)
- Devers CB5022 (Replace with 63 kA) and CB6022 (Replace with 63 kA)
- Devers CB4032 (Install TRV Caps)
- Devers CB4082 (Replace with 63 kA) and CB6082 (Install TRV Caps)
- Devers CB4092 (Replace with 63 kA) and CB6092 (Replace with 63 kA)

4.6.3 Etiwanda 220 kV

Implement mitigation measures to address impacts on the following twenty-four 220 kV circuit breakers at the Etiwanda Substation:

- Etiwanda CB43E2 and Etiwanda CB63E2
- Etiwanda CB4022 and Etiwanda CB6022
- Etiwanda CB41E2 and Etiwanda CB42E2
- Etiwanda CB45E2 and Etiwanda CB61E2
- Etiwanda CB62E2 and Etiwanda CB65E2
- Etiwanda CB4032 and Etiwanda CB6032
- Etiwanda CB4042 and Etiwanda CB6042
- Etiwanda CB4052 and Etiwanda CB6052
- Etiwanda CB4092 and Etiwanda CB6092
- Etiwanda CB4102 and Etiwanda CB6102
- Etiwanda CB4072 and Etiwanda CB6072
- Etiwanda CB4082 and Etiwanda CB6082

4.6.4 Mira Loma East 220 kV

Implement mitigation measures to address impacts on the following twelve 220 kV circuit breakers at the Mira Loma Substation East Section:

- Mira Loma CB4102, CB6102 and CB4172
- Mira Loma CB4142, CB4152 and CB4162
- Mira Loma CB5142, CB5152 and CB5162
- Mira Loma CB6142, CB6152 and CB6162

4.6.5 Pisgah 220 kV

Replace the following four 220 kV circuit breakers at Pisgah Substation to 50 kA (upgradable to 63 kA):

- Pisgah CB442 and CB452
- Pisgah CB642 and CB652

4.6.6 Vincent 220 kV

Implement mitigation measures to address impacts on the following twenty-four 220 kV circuit breakers at the Vincent Substation:

- Vincent CB42X2, CB52X2 and CB62X2
- Vincent CB41X2, CB51X2 and CB61X2
- Vincent CB412, CB512 and CB612
- Vincent CB422, CB522 and CB622
- Vincent CB432, CB532 and CB632
- Vincent CB452 and CB652

- Vincent CB462, CB562 and CB662
- Vincent CB472, CB572 and CB672
- Vincent CB682

4.6.7 Windhub 220 kV

Implement mitigation measures to address impacts on the following twenty-four 220 kV circuit breakers at the Windhub Substation:

- Windhub 220 kV CB4012 and CB6012
- Windhub 220 kV CB4032 and CB6032
- Windhub 220 kV CB4042, CB5042 and CB6042
- Windhub 220 kV CB4062 and CB6062
- Windhub 220 kV CB4072 and CB6072
- Windhub 220 kV CB4092 and CB6092
- Windhub 220 kV CB4102, CB5102 and CB6102
- Windhub 220 kV CB4112 and CB6112
- Windhub 220 kV CB4122, CB5122 and CB6122
- Windhub 220 kV CB4132, CB5132 and CB6132

4.6.8 Cal Cement 66 kV

Replace the following three 66 kV circuit breakers at Cal Cement Substation to 31.5 kA:

- Cal Cement CB2
- Cal Cement CB4
- Cal Cement CB8

5. Study Criteria and Methodology

The applicable reliability criteria, which incorporate the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC) planning criteria and the CAISO planning standard, were used to evaluate the impact of Phase II projects on the CAISO Controlled Grid.

5.1 Steady State Study Criteria

5.1.1 Normal Overloads

Normal overloads are those that exceed 100 percent of normal facility ratings. The CAISO Controlled Grid Reliability Criteria requires the loading of all transmission system facilities be within their normal ratings. Normal overloads refer to overloads that occur during normal operating conditions (no contingency).

5.1.2 Emergency Overloads

Emergency overloads are those that exceed 100 percent of emergency ratings. Emergency overloads refer to overloads that occur during single element contingencies (Category "B") and multiple element contingencies (Category "C").

5.1.3 Voltage Violations

Voltage violations will occur if voltage deviations exceed +/- 5% of the pre-disturbance level for Category B contingencies and +/ -10% for Category C contingencies.

5.1.4 Contingencies

The contingencies used in this analysis are provided in Appendix C. Various categories of contingencies used are summarized in Table 5-1:

Table 5-1: Power Flow Contingencies

Contingencies	Description
CAISO Category "A" (No contingency)	All facilities in service – Normal Conditions
CAISO Category "B"	• B1 - All single generator outages. • B2 - All single transmission circuit outages. • B3 - All single transformer outages. • Selected overlapping single generator and transmission circuit outages.
CAISO Category "C"	• C1 - SLG Fault, with Normal Clearing: Bus outages (60-220 kV) • C2 - SLG Fault, with Normal Clearing: Breaker failures (excluding bus tie and sectionalizing breakers) at the same bus section above. • C3 - Combination of any two-generator/transmission line/transformer outages. • C4 - Bipolar (dc) Line • C5 - Outages of double circuit tower lines (60-220 kV) • C6 - SLG Fault, with Delayed Clearing: Generator • C7 - SLG Fault, with Delayed Clearing: Transmission Line • C8 - SLG Fault, with Delayed Clearing: Transformer • C9 - SLG Fault, with Delayed Clearing: Bus Section

As required under NERC standard TPL-003-0 R1.3.1, all of the relevant CAISO Category "C" contingencies were considered as part of this study.

5.2 Deliverability Assessment Methodology

The On-Peak Deliverability Assessment is performed according to the CAISO Generator On-Peak Deliverability Assessment Methodology (http://www.caiso.com/23d7/23d7e41c14580.pdf).

The goal of the ISO Generator deliverability study methodology is to determine if the aggregate of generation output in a given area can be simultaneously transferred to the remainder of ISO Control Area. Any generators requesting Full Capacity Deliverability Status in their interconnection request to the ISO Controlled Grid will be analyzed for "deliverability" in order to identify the Delivery Network Upgrades necessary to obtain this status and to ensure that capacity is not "bottled" from a resource adequacy perspective. The methodology is designed to ensure that facility enhancements and cost responsibilities can be identified in a fair and nondiscriminatory manner. The main steps of the on-peak deliverability assessment are described below.

Master Deliverability Assessment Base Case

A master base case is developed for the on-peak deliverability assessment which modeled all the queued generation projects up to Phase II. The resources in the master base case are dispatched as follows:

- Existing capacity resources are dispatched at 80% of summer peak net qualified capacity (NQC).
- Proposed full capacity resources are dispatched to balance load and maintain expected imports, but not exceeding 80% of summer peak NQC.
- Energy-only resources are set off-line.
- Imports are at the maximum summer peak simultaneous historical level by branch group as shown in Table 4.1.
- Non-pump load is at the 1 in 5 peak load level for CAISO.
- Pump load is dispatched within expected range for summer peak load hours.

East of Lugo Bulk Group Deliverability Assessment Base Case

The East of Lugo Bulk group deliverability assessment base case is developed from the master base case by dispatching all proposed full capacity resources in the East Of Lugo Bulk Transmission System to 80% of their NQCs.

Qualified Capacity of Wind and Intermittent Solar Generation

The Qualified Capacity of wind generation is calculated as the average production between the hours of 12PM-6PM, during the months of May through September (Qualified Capacity period). In order to ensure the deliverability of this generation during this entire QC period, this generation will be dispatched at the minimum level during this QC period in the base case but can be increased to its maximum value within that QC period during the analysis. If the intermittent generation is electrically clustered with other types of generation, then the cumulative availability of this generation will determine how much the intermittent generation can be increased during the deliverability analysis. For example, if only wind generation is in the group (scenario 1) then it will be increased to the production level expected to be exceeded less than 20% of the time for that group during the QC period. If 20 or more non-wind generation units are in the group (scenario 2) then the wind generation would not be increased above its average output during the QC period. The maximum wind generation output level would be interpolated for groups in between the two scenarios above. If both wind and intermittent solar generation are in the group, then a scenario with average production during the QC period, for both types will be assessed.

Qualified Capacity modeled in the On-Peak Deliverability Assessment for intermittent generation resources located in the Southern California region including the SCE and SDG&E service areas are presented below:

Wind:

- Production exceeded 20% of time during Qualified Capacity period: 64% of net nameplate capacity

- Average production during Qualified Capacity period: 40% of net nameplate capacity

Intermittent Solar:

- Production exceeded 20% of time during Qualified Capacity period: 100% of net nameplate capacity

- Average production during Qualified Capacity period: 85% of net nameplate capacity

Qualified Capacity is set to 64% of the requested PMax for wind generation and 100% of the requested PMax for solar generation initially. The Qualified Capacity may be adjusted to 40% of the requested PMax for wind generation and 85% for solar generation if a mix of different fuel type generations is identified in the 5% DFAX group for a transmission limitation.

Qualified Capacity of wind intermittent resource is set to 64% of the requested PMax for net maximum wind project output and 100% of the requested PMax for net solar project output initially. The on-peak Qualified Capacity may be adjusted to 40% of the requested PMax for the wind output and 85% for the solar output if a mix of different fuel type generations is identified in the 5% DFAX group for a transmission limitation.

Screening for Potential Deliverability Problems Using DC Power Flow Tool

A DC transfer capability/contingency analysis tool is used to identify potential deliverability problems. For each monitored facility, an electrical circle with 5% or greater Distribution Factor or Flow Impact is drawn under normal and each contingency, which includes all generators and the unused Existing Transmission Contract (ETC) injections

- Distribution Factor (DFAX) = Δ flow on monitored facility/Δ output of generating unit *100%

- Flow Impact = DFAX * NQC / Applicable rating of monitored facility *100%.

DC power flow simulations are performed using the PSS®MUST program to determine the transmission elements with loading over or near their applicable thermal ratings and the associated generators within the 5% Circle under normal condition and contingencies.

Verifying and Refining the Analysis Using AC Power Flow Tool

AC load flow analyses are carried out in GE/PSLF program to verify and refine the DC load flow results with limited assumption on generation re-dispatch. The generating units within the 5% Circle are re-dispatched by increasing their outputs starting from the group base case in order to stress flow on each monitored facility. No more than twenty units are re-dispatched to their maximum outputs starting from unit with largest flow impact to smallest one. In addition,

no more than 1500 MW of generation is increased in the AC load flow examination. To balance the loads and resources in the CAISO Control Area, all other generations are proportionally displaced.

If total of generation output is increased more than 1500 MW, the Facility Loading Adder, a DC load flow calculator, will be activated to estimate additional power flow impact on monitored facility for the rest of 20 units. The Facility Loading Adder calculates load flow impact by taking into consideration of both the rest 20 units with positive flow impact and up to 20 units with negative flow impact. If net impact leads to reduce flow on the monitored facility, the results from Facility Loading Adders will be set to zero and the AC load flow result on the monitored facility will be reported without applying Facility Loading Adder.

Network Mitigation Plan and Cost Allocation

A mitigation plan will be proposed and be verified to address the overload issues identified. The mitigation Plan needs to be reevaluated and the deliverability assessment will be repeated to demonstrate that all of the new generation is deliverable. If additional overloaded facilities are found, the mitigation plan will be modified or expanded, as needed, to ensure the deliverability of the new generation. All new generators in the 5% Circle are responsible for costs of network upgrades to mitigate the overload issues. The cost of each delivery network upgrade will be allocated to these new generators based on percentage of their load flow impact under transmission normal condition. The cost of reliability network upgrade triggered by the generators will be allocated based on the effectiveness to mitigate the issue and the weight of their PMax.

Method for Determining Deliverable Partial Capacity

Assuming the system conditions cannot accommodate the full deliverability of all generators in the study area that will be in commercial operation for the study year, the partial deliverability of each generator is determined from the amount of its power output that can be accommodated on a portion of the transmission constraint that is binding in the deliverability power flow. For each generator, the portion of the binding transmission constraint is calculated as a function of the queue position, generator's size and its flow impact on the constraint.

For each deliverability constraint facility, the available capacity without the generation projects being tested is allocated to projects in the order from higher queued projects to lower queued projects until it is depleted. The projects in the same cluster are considered to have the same queue position. If there is available partial capacity for projects in the same cluster, each project's partial deliverability capacity is determined based on the generator's size and its flow impact.

5.3 Short Circuit Duty Criteria

Short circuit studies are performed to determine the maximum fault duty on the adjacent buses to the Phase II projects in the SCE service territory. This study determines the impact of increased fault current resulting from Phase II projects and associated proposed Network Upgrades. Short circuit results will allocate costs for mitigating overstressed breakers to each project on a pro-rata basis based on project contribution to SCD at each location. The Computer Aided Protection Engineering (CAPE) software is used to conduct the detailed short circuit studies with three-phase (3PH) and single line-to-ground (SLG) faults.

To determine the impact on short-circuit duty within SCE's electrical system after inclusion of the Phase II generation projects and associated proposed Network Upgrades, the study calculated the maximum 3PH and SLG short-circuit duties. Generation, transformer, and generation tie line data provided by each Phase II Interconnection Customer was utilized. Bus locations where short-circuit duty is increased with the proposed Phase II projects by at least 0.1 kA and the duty is in excess of 60% of the minimum breaker nameplate rating are flagged for further review. Upon completion of the detailed circuit breaker review, circuit breakers exposed to fault currents in excess of 100 percent of their interrupting capacities will need to be replaced or upgraded, whichever is appropriate. It should be noted that other WECC entities may request specific information within the WECC process to evaluate potential impact within their respective systems of this project addition.

5.4 Transient Stability Criteria

Transient stability analysis is a time-domain simulation that assesses the performance of the power system during (and shortly following) a contingency. Transient stability studies are performed to ensure system stability following critical faults on the system.

The system is considered stable if the following conditions are met:

1. All machines in the WECC interconnected system must remain in synchronism as demonstrated by relative rotor angles (unless modeling problems are identified and concurrence is reached that a problem does not really exist);

2. A stability simulation will be deemed to exhibit positive damping if a line defined by the peaks of the machine relative rotor angle swing curves tends to intersect a second line connecting the valleys of the curves with the passing of time;

3. Corresponding lines on bus voltage swing curves will likewise tend to intersect. A stability simulation, which satisfies these conditions, will be defined as stable;

4. Duration of a stability simulation run will be ten seconds unless a longer time is required to ascertain damping;

5. The transient performance analysis will start immediately after the fault clearing and conclude at the end of the simulation and;

6. A case will be defined as marginally stable if it appears to have zero percent damping and the voltage dips are within (or at) the WECC Reliability Criteria limits.

Performance of the transmission system is measured against the WECC Reliability Criteria and the NERC Planning Standards.

Table 5.3 illustrates the NERC/WECC Reliability Criteria. The reliability and performance criteria are applied to the entire WECC transmission system.

Table 5.3
WECC Disturbance-Performance Table of Allowable Effects on Other Systems
(In addition to NERC requirements)

NERC and WECC Categories	Outage Frequency Associated with the Performance Category (Outage/Year)	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post-Transient Voltage Deviation Standard (See Note 2)
A	Not Applicable	Nothing in Addition to NERC		
B	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6 Hz** for 6 cycles or more at a load bus	Not to exceed **5%** at any bus
C	0.033 – 0.33	Not to exceed 30% at any bus. Not to exceed **20% for more than 40 cycles** at load buses.	Not below **59.0 Hz** for 6 cycles or more at a load bus	Not to exceed **10%** at any bus
D	< 0.033	Nothing in Addition to NERC		

Note 2: As an example in applying the WECC Disturbance-Performance Table, Category B disturbance in one system shall not cause a transient voltage dip in another system that is greater than 20% for more than 20 cycles at load buses, or exceed 25% at load buses or 30% at non-load buses at any time other than during the fault.

5.5 Post-Transient Voltage Stability Criteria

The last column of the above Table 5.3 illustrates the Post-Transient Voltage Stability Criteria. For some large generator contingencies, the governor power flow is utilized to test for the post-transient voltage deviation criteria.

5.6 Reactive Margin Criteria

Table 5.5 summarizes the voltage support and reactive power criteria in the NERC/WECC Planning Standards.

The system performance will be evaluated according to the NERC/WECC planning criteria where necessary.

Table 5.5: Reactive Margin Analysis Criteria Summary

Performance Level/Category	Disturbance	Reactive Power Deficiency Criteria
B	Generator One Circuit One Transformer DC Single Pole Block	Governor power flow to reach convergence at 105% of load level or operational transfer capability
C	Two Generators Two Circuits DC Bipolar Block	Governor power flow to reach convergence at 102.5% of load level or operational transfer capability

5.7 Power Factor Criteria

Table 5.6 summarizes the power factor criteria per the CAISO Tariff. The voltage at the POI must be within criteria under normal and contingency conditions. Additional requirements may also be imposed by the CAISO Tariff or by the SCE Interconnection Handbook. For wind generation and photovoltaic solar projects, FERC issued a decision requiring the identification of need for power factor correction, beyond unity power factor.

Table 5.6: Power Factor Analysis Criteria Summary

Generation Type	Power Factor Criteria
Asynchronous Generator	0.95 lagging to 0.95 leading at the POI if identified as needed in the study
All other Generator Types	0.90 lagging to 0.95 leading at Generator terminals

6. Deliverability Assessment

The on-peak deliverability assessment was performed to identify the transmission limitations and propose mitigation plan to ensure that the aggregate of generation in East of Lugo Bulk System can be simultaneously transferred to the remainder of the ISO Control Area, and that network facility enhancements and cost responsibilities can be identified in a fair and nondiscriminatory manner.

6.1 Delivery Thermal Overload Violations

This study covers on-peak deliverability assessments for the active Queue Cluster 1 and Queue Cluster 2 projects in the East of Lugo Bulk System. Both SCE and its vicinity bulk systems are monitored for any adverse impacts. Post-QC1&QC2 thermal overload violations without mitigation for the East of Pisgah Subarea are summarized in Table 6.1A. The study results for the North of Lugo Subarea are summarized in Table 6.1B.

More detailed deliverability assessment results for Category A, B and C contingencies are provided in Appendix I.

Table 6.1 Deliverability Assessment Results for East of Pisgah Subarea

Contingency	Overloaded Facilities	Applicable Rating	Overload Results
		MVA	%
Normal Condition	SCE Eldorado 500/220 kV AA Bank	1120	113%
PaloVerde-ColoradoRiver 500 kV Ckt 1	Lugo-Victorville 500 kV Ckt 1	2598	103%
Lugo-Pisgah 500 kV Ckt 1&2	Lugo-Victorville 500 kV Ckt 1	2598	120%
Lugo-Pisgah 500 kV Ckt 1&2	Lugo-Victorville 500 kV Ckt 1	2598	107%
ColoradoRiver-RedBluff 500 kV Ckt 1&2	N.Gila-ImperialValley 500 kV Ckt 1	2572	115%
ColoradoRiver-RedBluff 500 kV Ckt 1&2	Lugo-Victorville 500 kV Ckt 1	2598	119%
Devers-RedBluff 500 kV Ckt 1&2	N.Gila-ImperialValley 500 kV Ckt 1	2572	116%

Devers-RedBluff 500 kV Ckt 1&2	Lugo-Victorville 500 kV Ckt 1	2598	124%
Devers-RedBluff 500 kV Ckt 1	Devers-RedBluff 500 kV Ckt 2	2987	125%
Devers-RedBluff 500 kV Ckt 2	Devers-RedBluff 500 kV Ckt 1	2987	125%
Eldorado-Primm 220 kV Ckt 1	NA	load flow diverged	

Table 6.1B Deliverability Assessment Results for North of Lugo Subarea

Contingency	Overloaded Facilities	Applicable Rating	Overload Results
Base Case Overload	Cool Water-River 115 kV line	417 Amp (N)	217%
Base Case Overload	Lugo No.1 500/220 kV transformer	1120 MVA (N)	101%
Base Case Overload	Lugo No.2 500/220 kV transformer	1120 MVA (N)	102%
Loss of Cool Water-River 115 kV line	Diverged case	N/A	N/A
Loss of Jasper-Lugo 220 kV line	Kramer-Lugo No.1 220 kV line	1430 Amp (E)	117.8%
Loss of Jasper-Lugo 220 kV line	Kramer-Lugo No.2 220 kV line	1430 Amp (E)	117.8%
Loss of Cool Water-Jasper 220 kV line	Kramer-Lugo No.1 220 kV line	1430 Amp (E)	114.2%
Loss of Cool Water-Jasper 220 kV line	Kramer-Lugo No.2 220 kV line	1430 Amp (E)	114.2%
Loss of Kramer-Roadway-Victor 115 kV line and Kramer-Victor 115 kV line	Kramer No.1 230/115 kV transformer	287 MVA (E)	122.7%
Loss of Kramer-Roadway-Victor 115 kV line and Kramer-Victor 115 kV line	Kramer No.2 230/115 kV transformer	327 MVA (E)	105.7%

Loss of Kramer No.2 230/115 kV transformer	Kramer No.1 230/115 kV transformer	287 MVA (E)	118.7%
Loss of Kramer-Tortilla 115 kV line	Kramer-Cool Water 115 kV line	1280 Amp (E)	106.9%
Loss of Kramer-Cool Water 115 kV line	River-Dunn Siding 115 kV Tap	532 Amp (E)	100.1%
Loss of Kramer-Cool Water 115 kV line	Tortilla Tap of Cool Water-SEGS 2-Tortilla 115 kV line	1320 Amp (E)	120.1%
Loss of Kramer-Cool Water 115 kV line	Kramer-Tortilla 115 kV line	1320 Amp (E)	103.2%
Loss of Cool Water-SEGS 2-Tortilla 115 kV line	Kramer-Cool Water 115 kV line	1280 Amp (E)	114.4%
Loss of Lugo-Victor No.1 & No.2 220 kV lines	Kramer No.1 230/115 kV transformer	287 MVA (E)	116.8%
Loss of Lugo-Victor No.1 & No.2 220 kV lines	Kramer No.2 230/115 kV transformer	327 MVA (E)	100.1%
Loss of Lugo-Victor No.1 220 kV line	Lugo-Victor No.2 220 kV line	1430 Amp (E)	100.6%
Loss of Lugo-Victor No.2 220 kV line	Lugo-Victor No.1 220 kV line	1430 Amp (E)	100.6%

6.2 Deliverability Assessment Conclusions

Based on the thermal overloads identified in deliverability assessment, network upgrades including Delivery Network Upgrades and Reliability Network Upgrades are recommended to address the overloads identified in the North of Lugo, East of Pisgah, Eastern subareas, and the SDG&E system.

Figure 6.2A and Figure 6.2B present the SCE, SDG&E and PG&E Kern 500 kV transmission systems with and without the delivery network upgrades triggered by the QC1 & QC2 projects. The 500 kV transmission elements highlighted in red indicate the delivery network upgrades whose costs are allocated to the QC1 & QC2 projects in the East of Lugo area. Other 500 kV upgrades without cost allocated to the QC1 & QC2 projects in the East of Lugo area are highlighted in blue if any.

6.2.1 Proposed Network Upgrades in East of Pisgah Sub-area

The Delivery Network Upgrades and Reliability Network Upgrades identified in the East of Pisgah Sub-area studies are summarized in Table 6.2.1A and Table 6.2.1B respectively. The cost allocation factors are outlined without exposure of individual QC1 & QC2 project in Appendix I. The cost allocated to each QC1 & Qc2 project is presented in the individual project report.

Total of 4 Delivery Network Upgrades and various Special Protection Schemes are recommended, which are briefly described as follows:

Add 2nd AA Transformer Bank at SCE-owned Eldorado 220 kV Bus

The addition of the Phase II projects in the Eldorado area overloads the future SCE-owned Eldorado No.1AA 500/220 kV transformer bank under normal condition (Category "A"). Second new AA bank at SCE-owned Eldorado 220 kV Bus is required to eliminate the normal overload

Network Upgrades to Mitigate Impact on Neighboring Utility

The addition of Phase II projects in SCE's East of Lugo, Eastern subareas and SDG&E results in adverse impact on the joint-owned Lugo-Victorville 500 kV tie due to thermal rating limitation at Victorville 500 kV Substation, and creates thermal overloads on the tie line for the single outage of Palo Verde – Colorado River 500 kV line (Category "B") and the double contingency of Lugo – Pisgah 500 kV lines (Category "C"). There is no inexpensive solution to mitigate the advertise impacts on the tie between LADWP and SCE without exaggerating loop flow issues in the LADWP system. CAISO and SCE investigated various alternatives possible to avoid the adverse system impacts on the LADWP system under both normal condition and contingencies, such as network addition, phase shifter, or Unified Power Flow Controller (UPFC) installed on the Victorville – Lugo 500 kV tie line at the Lugo side. It remains unclear if there is any 500 kV phase shifter or UPFC devices available in market that can control load low as high as 2598 MVA. Three major network upgrades are recommended below to mitigate the impact on the Lugo – Victorville 500 kV transmission tie

- **Loop the Mohave – Lugo line into Pisgah 500 kV Substation**

To mitigate the thermal overloads for N-2 outage of Pisgah – Lugo 500 kV lines without exaggerating loop the flow issues in the neighboring utility, it is recommended to loop the Mohave–Lugo 500 kV line into Pisgah 500 kV Substation, and to install series capacitor banks on both Pisgah–Nipton and Pisgah–Mohave 500 kV lines. In addition, it is also required to modify the proposed Eldorado Bulk System SPS in order to trip the Phase II projects in the related subarea for the double.

The Pisgah Loop-in will also get rid of the overload on Lugo – Mohave 500 kV line for the double outage of the Pisgah – Lugo 500 kV lines.

- **Build a new Colorado River – Red Bluff No.3, and**
- **Build a New Red Bluff – Valley 500 kV lines**

The addition of the Phase II projects in the East of Lugo, Eastern and SDG&E areas triggers the overload on the Lugo – Victorville 500 kV 500 kV tie line for the N-2 outages of the Colorado River – Red Bluff or the Red Bluff – Devers 500 kV lines.

Two alternatives of transmission network addition are investigated in the Phase II study to mitigate the Lugo - Victorville 500 kV tie line overload under Category B and Category C outages, along with gen tripping Special Protection Schemes in order to minimize cost burden over the Phase II projects:

- Alternative A: build about 140 miles of new 500 kV line from Pisgah to Llano via Kramer, and a new 500 kV switching yard at Llano.

- Alternative B: build about 134 miles of new 500 kV transmission line connected between Colorado River and Valley with a tie at Red Bluff, which are also called the Colorado River – Red Bluff No.3 and the new Red Bluff – Valley 500 kV lines in the report.

Alternative B is considered as more effective and a least-cost solution to mitigate the overload on the Lugo – Victorville 500 kV tie line without exaggerating loop flow issues in the LADWP system. A 31 miles of new single-circle Colorado River – Red Bluff line and a 103 miles of new Red Bluff – Valley 500 kV transmission line with series capacitor banks compensation are recommended to built using single circuit structures equipped with 2-2156KCMIL ACSR Conductors. The both lines will be equipped with one Optical Ground Wire (OPGW).

Special Protection Schemes (as known as Remedial Action Schemes)

Various previous SPS triggered by high queued projects need to be modified to mitigate the rest of overloads since the Delivery Network Upgrades mentioned above are not adequate to mitigate all the overloads identified. As it is well known, these SPS are categorized as Reliability Network Upgrade. Below are described in detail:

- **SPS-1: Modify the gen tripping SPS triggered by higher queued projects in Ivanpah/Primm/Eldorado 220 kV system**

  Previously gen tripping Special Protection Scheme triggered by higher queued projects in the Ivanpah/Eldorado 220 kV system needs to be modified so as to mitigate the 500/220 kV AA bank overloads for the outage of other AA bank at the future SCE-owned Eldorado 220 kV bus due to the addition of the Phase II projects, C488, C491, C502 and C503.

- **SPS-2: Modify the gen tripping SPS triggered by higher queued projects in Ivanpah/Primm area 115/220 kV system**

  Previously gen tripping Special Protection Scheme triggered by higher queued projects in the Ivanpah 115/220 kV system needs to be modified to cover the Phase II C502 project and the single outage of the Ivanpah - Primm and Primm - Eldorado 220 kV lines so as to avoid the system instability issue in the 115 kV system.

- **SPS-3: Modify the gen tripping EOP SPS triggered by higher queued projects in the EOL area**

  Previously gen tripping Special Protection Scheme triggered by higher queued projects in the East of Pisgahsystem needs to be modified so as to mitigate the Lugo – Victorville 500 kV tie line for various N-1 or N-2 outages .

Table 6.2.1A Delivery Network Upgrades

Network Upgrade	Type	Overloaded Facilities
Add 2nd 500/220 kV AA bank at SCE Eldorado Sub	Delivery	SCE Eldorado 500/220 kV AA Bank overload under normal condition
Loop Mohave -Lugo 500 kV line into Pisgah 500 kV Sub	Delivery	Lugo-Victorville 500 kV Ckt 1 Overload for double-outage of the Lugo-Pisgah 500 kV Ckt 1&2
Build 3rd Colorado River - Redbluff 500 kV line	Delivery	1. Lugo-Victorville 500 kV Ckt 1 Overload for N-2 outage of the Colorado River - Red Bluff 500 kV Ckt 1&2 2. North-Gila-Imperial Valley 500 kV line overload for N-2 outage of the Colorado River - Red Bluff 500 kV Ckt 1&2
Build new Redbluff - Valley 500 kV line	Delivery	1. Overloads on the Lugo-Victorville and the North Gila-Imperial Valley 500 kV lines for N-2 outage of Devers-Red Bluff 500 kV Ckt 1 & 2 2. Devers-RedBluff 500 kV line overload for other Devers-Red Bluff 500 kV line outage

Table 6.2.1B Reliability Network Upgrades

Delivery Network Upgrade	Type	Overloaded Facilities
SPS-1: Modify previous SPS to trip gens in the Eldorado area	Reliability	Overload on the AA transformer bank for the other AA transformer bank at SCE-owned Eldorado 220 kV bus
SPS-2: Modify previous SPS to trip gens in the Ivanpah/Primm area	Reliability	Load flow diverded for Single Eldorado-Primm 220 kV line outage
SPS #3: Modify previous SPS to trip up to 1400 MW generation located in the EOL area	Reliability	1. Lugo-Victorville 500 kV Tie overload for N-2 outages of Pisgah-Lugo 500 kV lines 2. Lugo-Victorville 500 kV Tie overload for N-2 outages of Pisgah-Nipton 500 kV line and Eldorado-Pisgah 220 kV line 3. Lugo-Victorville 500 kV Tie overload for Palo Verde-Colorado River 500 kV line* N-1 outage

Note: * Facilities located in the SCE's Eastern subarea

6.2.2 Proposed Network Upgrades in North of Lugo Sub-area

Cool Water-River 115 kV Line Upgrade

The Cool Water-River 115 kV line is overloaded under the normal condition. It is proposed to re-build the Cool Water-River 115 kV line to mitigate the overload. The detailed description of the proposed upgrade is provided in Section 11.3.1.

New Lugo No.3 500/220 kV Transformer

The Lugo No.1 & No.2 500/220 kV transformers are overloaded under the normal condition. The Lugo No.3 500/220 kV transformer is proposed to mitigate the overload. The detailed description of the proposed upgrade is provided in Section 11.3.5.

Special Protection Schemes

Various overloads are identified under contingency conditions. SPSs are proposed to mitigate the overloads. The detailed description of the proposed SPSs is provided in Section 11.2.1.4 and 11.2.1.5.

Figure 6.2A SCE, SDG&E and PGE Kern Areas 500 kV Systems - QC1 & QC2 Pre-Mitigation

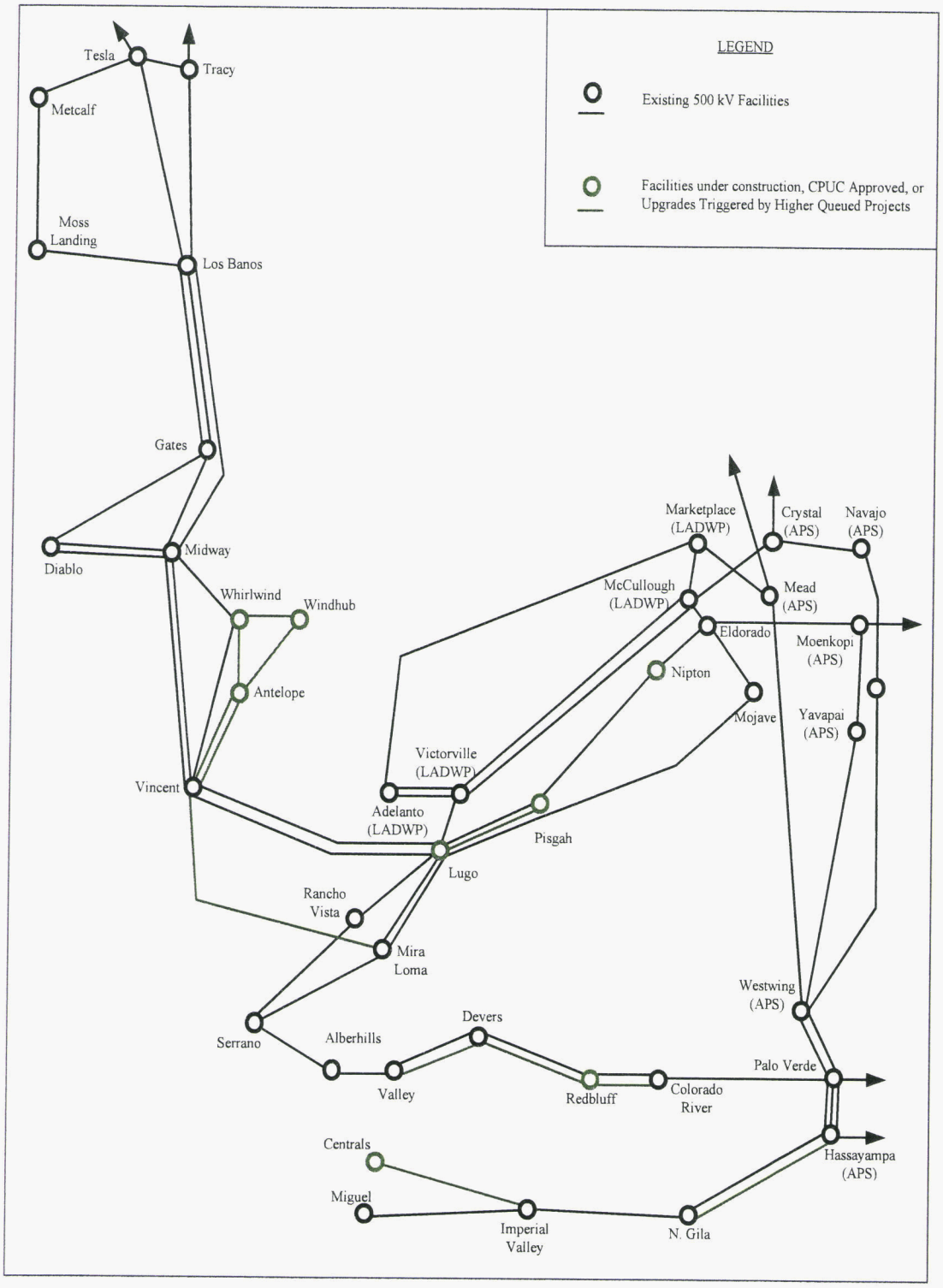
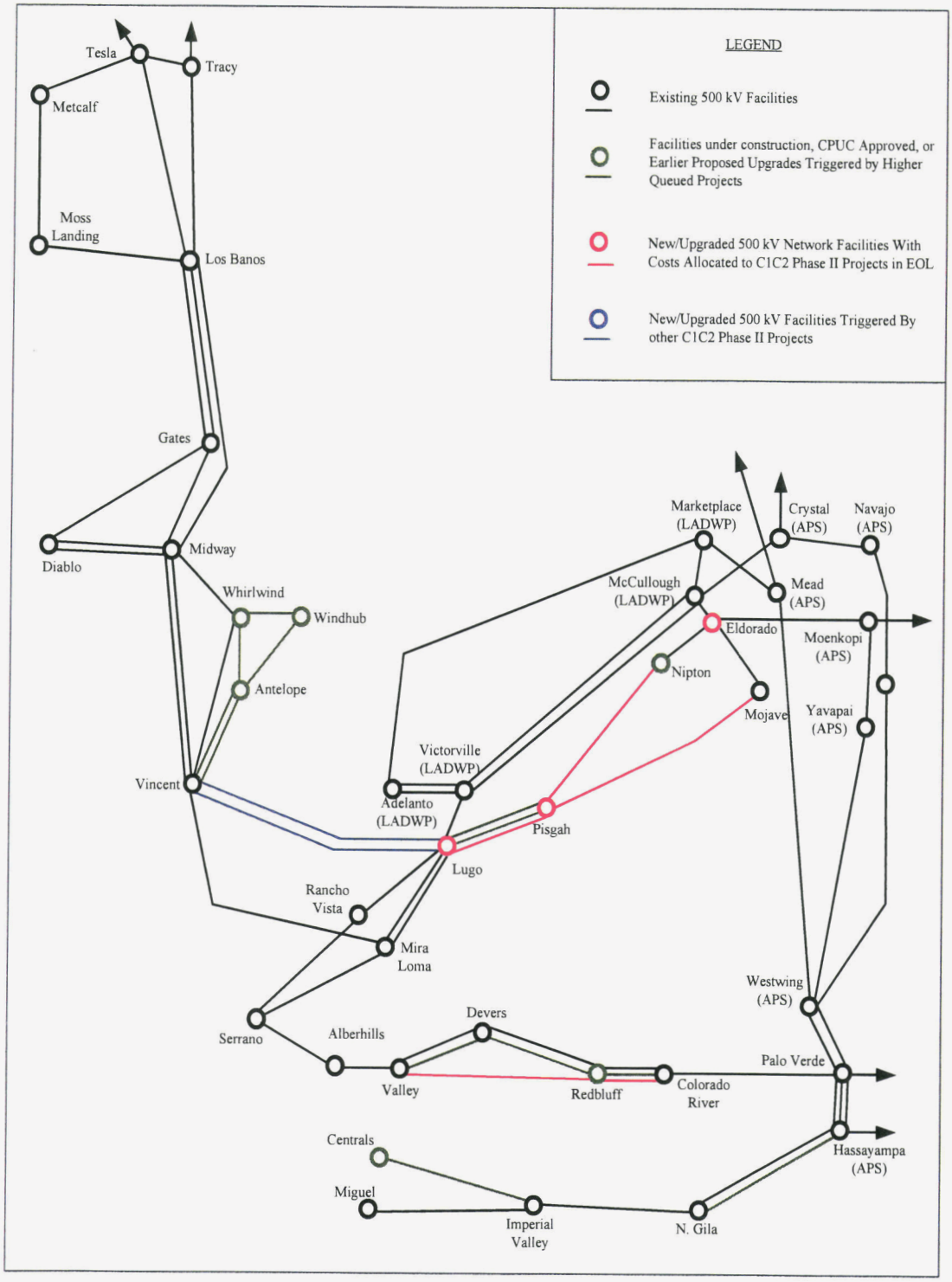


Figure 6.2B SCE, SDG&E and PGE Kern Areas 500 kV Systems - QC1 & QC2 Post-Mitigation



6.3 Operational Deliverability Assessment

The tariff allows the Generating Facilities to interconnect as an energy-only resource on an interim-only basis after all required Reliability Network Upgrades are completed and before all the required Delivery Network Upgrades are in service. In the Phase II study, ISO performed the operational deliverability assessment to provide information on the interim deliverability for the Phase II projects requesting Full Capacity deliverability status. Please note such interim and partial deliverability is an estimate based on the available information and is for information only.

In general, the operational deliverability assessment follows the same on-peak deliverability assessment methodology as described in Section 5. The key components of the operational deliverability assessments are discussed below.

Study Years

The assessment for the East of Lugo Bulk System was performed from 2013-2019.

Assumptions for Generation Interconnection Projects

The Phase II projects and generation projects queued ahead of Cluster 1 and Cluster 2 are modeled in the operational deliverability assessment according to the latest information available.

Table 6.3.1 Project In-Service-Year Modeled in Operational Deliverability Assessment

Queue Position	PMAX MW	Point of Interconnection	First Operational Deliverability Study Year
58	62	Control 115 kV	2016
68	850	Pisgah Sub 220 kV Bus	275MW in 2013; 850 MW in 2016
125	250	Cool Water-Kramer 220 kV	2014
126	500	Nipton 220 kV Substation	2016
131	100	Loop new sub connecting to Eldorado-Mtn Pass 115kV line	2013
135	60	Lugo-Pisgah 220 kV line	2014
142	80	Kramer 220 kV	2015
156	201	Lugo-Pisgah 220 kV line	2014
162	114	Loop new sub connecting Eldorado-Mtn Pass 115kV line	2013

163	300	Mountain Pass Substation 115kV	2016
205	300	El Dorado 220kV Switchyard	2016
233	200	Ivanpah Substation 220 kV	2013
240	400	Pisgah Sub 220 kV	2016
241	400	Pisgah Sub 220 kV	2016
467	230	Eldorado-Ivanpah 220 kV line	2016
488	92	Eldorado Substation 220 kV	2016
491	230	Cool Water-Dunn Siding	100 MW in 2013, 230 MW in 2014
502	20	Eldorado-Ivanpah 220 kV line	2016
503	155	Eldorado Substation 220 kV bus	2016
552	60	Lugo-Pisgah #1 220 kV	2014
589	60	Victor 115 kV	2013
593	310	Mohave Generating Station 500kV bus	2014
WDT164	80	Victor 115 kV	2013
WDT285	100	Victor 115 kV	2013
WDT286	150	Victor 115 kV	2013
WDT 315	40.7	Control 115 kV	2013

Assumptions for Transmission Upgrades

Transmission upgrades are modeled in the operational deliverability assessment based on their estimated CODs. All the required SPSs are assumed to be in-service when the associated generation project is in commercial operation.

Transmission Upgrade	First Operational Deliverability Study Year

Lugo – Vincent 500kV line terminal equipment	2014
Pisgah substation 500kV upgrade; Pisgah – Lugo 500kV line; Eldorado – Lugo 500kV line loops into Pisgah	2016
Eldorado 220 kV split	2016
Nipton 500kV switching station	2016
Ivanpah – Eldorado 220 kV single circuit line	2013
Loop Mohave –Lugo 500 kV lin into Pisgah with series cap banks added on the Nipton-Pisgah and the Mohave-Pisgah 500 kV lines	2018
SCE Eldorado 2nd AA Bank	2016
Inyo 115kV phase shiftor upgrade	2016
Jasper 220 kV substation	2014
Coolwater – Jasper – Lugo 220 kV line	2018
River-Cool Water 115 kV line	2018
Lugo No.3 500/220 kV transformer	2015
Colorado River – Red Bluff – Devers – Valley 500kV No. 2 line	2014
West of Devers 220 kV line upgrade	2017
New Colorado River - Red Bluff No.3 500kV line	2019
New Red Bluff - Valley No. 1 500kV line	2019

Operational Deliverability Assessment Results

The results of the operational deliverability assessment for each project requesting Full Capacity deliverability status are provided in the individual project report (Appendix A).

7. Steady State Assessment

This assessment is comprised of Power Flow Analysis and Reactive Power Deficiency Analysis.

Power flow analysis and **reactive power deficiency analysis** was performed to ensure that CAISO Control Grid in the SCE area remains in full compliance with North American Reliability Corporation (NERC) reliability standards TPL-001, 002, 003 and 004 with the proposed interconnection. The results of these power flow analyses will serve as documentation that an evaluation of the reliability impact of new facilities and their connections on interconnected transmission systems is performed.

The study results for this interconnection will be communicated to other neighboring entities that may be impacted, for coordination and incorporation of its transmission assessments. Input from other neighboring entities are solicited to ensure coordination of transmission systems.

While it is impractical to study all combinations of system load and generation levels during all seasons and at all times of the day, the base cases were developed to represent stressed scenarios of loading and generation conditions for the study group area. The CAISO and SCE cannot guarantee that these Phase II projects can operate at maximum rated output 24 hours a day, year round, without adverse system impacts, nor can the CAISO and SCE guarantee that these projects would not have adverse system impacts during the times and seasons not studied in the Phase II Study.

The following power flow base cases were used for the analysis in the Phase II Study:

- **Summer Peak Full Loop Base Case:**

  Power flow analyses were performed using SCE's summer peak full loop base case (in General Electric Power Flow format). This base case was developed from the 2014 Summer Peak WECC base case. It has a 1-in-10 year adverse weather load level for SCE Service Territory.

- **Off-Peak Full Loop Base Case:**

  Power flow analyses were also performed using the off-peak full loop 2014 WECC base case in order to evaluate system performance to the addition of Phase II Generation Projects during light load conditions. The off-peak load was modeled at about 65% of the 1 in 5 summer load level.

These base cases modeled all CAISO approved SCE transmission projects. The base cases also modeled all proposed generation projects that were higher than the Phase II projects in the CAISO generation queue. These generation projects were modeled along with the identified transmission upgrades necessary for their interconnection and/or delivery. All existing and planned generation in the East of Lugo System are dispatched to their maximum output in both peak and off-peak base cases except when noted.

In the Lugo Hub and North of Kramer Subareas of the Greater East of Lugo System, base case overloads were identified in the pre cases without the use of congestion

management to curtail non-deliverable and deliverable generation projects. The mitigation to address these previously identified overloads was reliant on the use of congestion management. The rationale behind not assigning upgrades to address the identified pre-project thermal overload problems to any generator, or group of generators, is associated with differences in study assumptions between the Reliability Studies and the Deliverability Studies. The Reliability Studies performed for queued ahead generation projects have identified the need for additional facilities to eliminate the identified pre-project base case overloads but such facilities were not determined to be needed in the Deliverability Studies.

Such conclusions are based on a determination that congestion management is a viable means of addressing the congestion identified in this study. Appropriate operating procedures may be needed to ensure safe and reliable transmission system operation.

Note that the Reliability Base Cases required curtailment of approximately 916 MW of generation in the off-peak case and 521 MW of generation in the summer peak case in the Lugo Hub and North of Kramer Subareas to eliminate these base case overloads.

The power flow study included a preliminary power flow study, which covered all Phase II projects in the East of Lugo System with plans of service as originally requested, as a "screening analysis" to identify potential reliability issues in the original plans of service requested by the developers in Phase II. The power flow study also included a modified power flow study, which reflected system changes based on the findings of the preliminary power flow study.

7.1 Preliminary Power Flow Study

The preliminary study modeled all East of Lugo Bulk System Phase II projects with the original requested plan of service for each project. This preliminary assessment was intended to determine if any plan of service issues with Phase II projects exist that would require modifications to the customer requested plans of service or points of interconnection.

7.1.1 Modeling and Generation Dispatch Assumptions

The preliminary reliability assessment was performed assuming all generation resources in the East of Lugo Bulk System were dispatched irrespective of the requested level of transmission service. This was done to identify if any new congestion exposure is created with the additional generation resources in Phase II.

7.1.2 Preliminary Power Flow Results (Category "A", "B", and "C")

7.1.2.1 East of Pisgah Subarea

In the East of Pisgah Subarea of the greater East of Lugo Bulk System with both Energy Only and Full Capacity generation resources dispatched at full output in the starting base case, the preliminary power flow analysis identified a base case overload (Category "A") thermal overload on the SCE-owned Eldorado No.1 500/220 kV transformer bank, as well as N-1 (Category "B") and N-2 (Category "C") overloads that were aggravated with the addition of the Phase II projects.

7.1.2.1 Lugo Hub and North of Kramer Subareas

With both Energy Only and Full Capacity generation resources in the Lugo Hub and North of Kramer Subareas dispatched in the starting base case, the preliminary power flow base cases identified that the addition of the Phase II Projects trigger numerous base case (Category "A") thermal overloads on the Lugo No.1AA and No.2AA 500/220 kV transformer banks, the Kramer-Lugo No.1 & No.2 220 kV transmission lines, and the Cool Water-River 115 kV transmission line in both the summer and off-peak cases. Additionally, in the off-peak case there was also a thermal overload on the Kramer-Q515 (TOT413) Sub 115 kV transmission line and a low voltage at the Mountain Pass 115 kV bus.

Additionally, the use of congestion management to curtail generation resources consistent with the pre-Phase II base case did not mitigate the thermal overloads or the low voltage condition.

The overloads and associated power flow plots are shown in Appendix D. The worst overloads for each facility are summarized in Table 7-3-1 and Table 7-3-2 for the East of Pisgah Substation Subarea and in Table 7-3-3 and Table 7-3-4 for the Lugo Hub and North of Kramer Subareas respectively.

EAST OF PISGAH SUBAREA

Table 7-3-1: Preliminary Power Flow Overloads – Summer Peak Conditions

Over Loaded Component	Rating Amps (MVA)	Pre- Project Loading(Amps |%Rating)		Post- Project Loading(Amps |%Rating)		% Change from Pre-Project Loading	Comment
Category A (N-0) Overloads							
Future SCE Eldorado 500/220 kV Transformer at future SCE owned Eldorado Bus	(1120)	977	87%	1295	115%	28%	Base Case

Table 7-3-2: Preliminary Power Flow Overloads – Off-Peak Conditions

Over Loaded Component	Rating Amps (MVA)	Pre- Project Loading(Amps |%Rating)		Post- Project Loading(Amps |%Rating)		% Change from Pre-Project Loading	Comment
Category A (N-0) Overloads							
Future SCE Eldorado 500/220 kV Transformer at future SCE owned Eldorado Bus	(1120)	978	87%	1279	114%	27%	Base Case

LUGO HUB AND NORTH OF KRAMER SUBAREAS

Table 7-3-3: Preliminary Power Flow Overloads – Summer Peak Conditions with Congestion Management

Over Loaded Component	Rating Amps (MVA)	Pre- Project Loading(Amps %Rating)		Post- Project Loading(Amps %Rating)		% Change from Pre-Project Loading	Comment
Category A Normal Overloads							
Lugo No.1AA 500/220 kV Transformer	1120	1106.7	98.8%	1242.3	110.9%	12.1%	See note
Lugo No.2AA 500/220 kV Transformer	1120	1114.6	99.5%	1251.2	111.7%	12.2%	See note
Kramer-Lugo No.1 & No. 2 220 kV T/Ls	1240	1141.2	92.0%	1279.4	103.2%	11.2%	See note
Cool Water-River 115 kV T/L	415	55.2	13.3%	717.7	172.9%	159.6%	See note
Kramer-TOT413 Sub	828	772.7	93.3%	842.5	101.7%	8.4%	See note

Note: With 521MW of congestion management

Table 7-3-4: Preliminary Power Flow Overloads – Off-Peak Conditions with Congestion Management

Over Loaded Component	Rating Amps (MVA)	Pre- Project Loading(Amps %Rating)		Post- Project Loading(Amps %Rating)		% Change from Pre-Project Loading	Comment
Category A Normal Overloads							
Lugo No.1AA 500/220 kV Transformer	1120	1111.4	99.2%	1253.0	111.9%	12.7%	See note
Lugo No.2AA 500/220 kV Transformer	1120	1119.3	99.9%	1264.0	112.7%	12.8%	See note
Kramer-Lugo No.1 & No. 2 220 kV T/Ls	1240	1162.6	93.8%	1306.4	105.4%	11.6%	See note
Cool Water-River 115 kV T/L	415	95.0	22.9%	684.7	164.9%	142.0%	See note

Note: With 916 MW of congestion management

7.2 Preliminary Power Flow Conclusions

Based on the findings of the preliminary power flow study, the following conclusions were reached.

7.2.1 Transformer Capacity is Constrained at the SCE-owned Eldorado 220 kV Bus

The addition of the Phase II projects, in the Eldorado area, overloads the SCE-owned Eldorado No.1AA 500/220 kV transformer bank.

The East of Lugo Bulk System Phase II generation projects with ultimate delivery to the CAISO at the SCE-owned Eldorado 220 kV Bus requires significant transformer capacity upgrades. To provide such additional capacity, the following upgrade is proposed:

- Install new SCE-owned Eldorado No.2AA 500/220 transformer bank at the SCE-owned Eldorado 220 kV bus.

7.2.2 Transformer Capacity is Constrained at SCE's Lugo Substation

The existing Lugo No.1AA and No.2 AA 500/220 kV transformer banks at Lugo Substation do not have sufficient transmission capability to support the Phase II projects in the North of Kramer and Lugo Hub Subareas.

East of Lugo Bulk System Phase II projects in the North of Kramer and Lugo Hub Subareas require additional transformer capacity at Lugo Substation.

To address the transformer capacity short-fall at Lugo Substation, the following mitigation is proposed:

- Install new Lugo No.3AA 500/220 kV transformer bank

7.2.3 Existing Transmission is Constrained South of SCE's Kramer Substation

The existing 220 kV lines connecting the Kramer Substation to the Lugo Substation do not have sufficient transmission capability to support the Phase II projects in the North of Kramer Subarea.

East of Lugo Bulk System Phase II projects in the North of Kramer Subarea require additional south of Kramer transmission capacity or additional congestion management. To address the capacity short-fall between Kramer Substation and Lugo Substation, the following mitigation is proposed:

- Increase congestion management in the North of Kramer area to avoid overloading the Kramer-Lugo No.1 & No.2 220 kV transmission lines.

7.2.4 Transmission is Constrained East of the Cool Water 115 kV Bus

Notwithstanding the severe low voltage problems identified at the Mountain Pass 115 kV bus, the addition of the Phase II project by looping the existing Eldorado-Baker-Cool Water-Dunn Siding-Mt. Pass 115 kV transmission line causes a base case overload on the reconfigured Cool Water-River 115 kV transmission line segment.

The East of Lugo Bulk System Phase II generation project with ultimate delivery to the CAISO at the Cool Water 115 kV Bus requires significant capacity upgrades. To provide such additional capacity, the following upgrade is proposed:

- Reconductor (rebuild) the 16 mile Cool Water-River 115 kV transmission line with 954 SAC conductor

7.2.5 Transmission South of TOT413 to Kramer 115 kV Bus is Constrained

The existing 115 kV line segment between Kramer and TOT413 does not have sufficient transmission capability to support the Phase II projects in the North of Kramer Subarea.

East of Lugo Bulk System Phase II projects in the North of Kramer Subarea require additional transmission capacity or additional congestion management. To address the capacity short-fall between Kramer Substation and TOT413, the following mitigation is proposed:

- Increase congestion management to avoid overloading this 115 kV transmission line.

7.3 Modified Power Flow Study

A modified power flow study was performed based on updated base cases that address the preliminary power flow study findings.

7.3.1 Modeling and Generation Dispatch Assumptions

For the modified power flow study analysis, the preliminary power flow cases were modified to reflect the findings of the preliminary power flow study and the mitigation requirements discussed above.

- Generation dispatch was modified to reflect the implicit additional curtailment of generation resources in the East of Lugo Bulk System, specifically the Lugo Hub and North of Kramer Subareas. This curtailment included energy only projects as well as full capacity projects that were previously studied at full generation dispatch in previous cluster studies.
- Modeled a new reconductored Cool Water-River 115 kV transmission line (rebuild with 954 SAC), approximately 16 miles.
- Modeled a new Lugo No.3AA 500/220 kV transformer bank.
- Modeled 2nd Eldorado 500/220 kV transformer bank at the SCE-owned Eldorado bus.
- Modeled the loop-in of the Lugo-Mohave 500 kV transmission line into Pisgah Substation.
- Modeled adding series capacitor banks on the Nipton-Pisgah and Mohave-Pisgah 500 kV transmission lines.
- Modeled new and modified SPSs in the East of Lugo area to trip generation resources for thermal and stability concerns.

7.3.2 Power Flow Results (Category "A", "B", and "C")

LUGO HUB AND NORTH OF KRAMER SUBAREAS

Table 7-3-7: Modified Power Flow Overloads – Summer Conditions

Over Loaded Component	Rating Amps (MVA)	Pre- Project Loading(Amps |%Rating)		Post- Project Loading(Amps |%Rating)		% Change from Pre-Project Loading	Comment
Category B (N-1) Overloads – Summer with Additional Congestion Management in Post Case							
Remaining Kramer-Lugo 220 kV T/L under loss of Kramer-Lugo No.1 or No.2 220 kV T/L	1430	1663.2	134.1%	1802.1	145.3%	11.2%	Modify Existing SPS
Kramer-Roadway-Victor 115 kV T/L under loss of Kramer-Lugo No.1 or No.2 220 kV T/L	1160	1104.3	95.2%	1211	104.5%	9.3%	Modify Existing SPS
Kramer-Lugo No.1 & No.2 220 kV T/Ls under loss of Jasper-Lugo 220 kV T/L	1240	1885.4	152.0%	2113.4	170.4%	18.4%	New SPS to trip C491 & C552 + Existing SPS
Kramer-Lockhart 220 kV T/L under loss of Jasper-Lugo 220 kV T/L	1614	1597.4	99.0%	1729.5	107.2%	8.2%	New SPS to trip C491 & C552 + Existing SPS
Kramer-Victor 115 kV T/L under loss of Jasper-Lugo 220 kV T/L	1150	1220.4	106.2%	1381.6	120.2%	14.0%	New SPS to trip C491 & C552 + Existing SPS
Kramer-Roadway-Victor 115 kV T/L under loss of Jasper-Lugo 220 kV T/L	1160	1240.3	107.0%	1401.9	120.9%	13.9%	New SPS to trip C491 & C552 + Existing SPS
Kramer-Lugo No.1 & No.2 220 kV T/Ls under loss of Cool Water-Jasper 220 kV T/L	1240	1562.2	126.0%	1676.8	135.2%	9.2%	New SPS to trip C491 + Existing SPS
Remaining Lugo-Victor 220 kV T/L under loss of Lugo-Victor No.1 or No.2 220 kV T/L	1240	1711.6	138.0%	1916.8	154.6%	16.6%	Previously identified SPS will mitigate (trip C589)
Inyokern-Randsburg-TOT413 Sub 115 kV T/L under loss of Inyokern-Kramer 115 kV T/L	828	1355.4	163.6%	1122.4	135.5%	28.1%	Previously identified SPS will mitigate
Kramer-TOT413 Sub 115 kV T/L under loss of Inyokern-Kramer 115 kV T/L	828	1314.7	158.7%	1166.4	140.8%	17.9%	Previously identified SPS will mitigate
Control-Coso-Haiwee-Inyokern 115 kV T/L under loss of the Control-Haiwee-Inyokern 115 kV T/L	402	512.4	127.6%	434.2	108.1%	19.5%	Previously identified SPS will mitigate
Control-Haiwee-Inyokern 115 kV T/L under loss of the Control-Coso-Haiwee-Inyokern 115 kV T/L	402	509.9	127.0%	433.2	107.9	19.1%	Previously identified SPS will mitigate
Cool Water-SEGS2-Tortilla 115 kV T/L under loss of Cool Water-Kramer 115 kV T/L	974	697.3	71.6%	1467.4	150.7%	79.1%	New SPS to trip C491

Kramer-Tortilla 115 kV T/L under loss of Cool Water-Kramer 115 kV T/L	974	498.1	51.1%	1247.8	128.1%	77.0%	New SPS to trip C491
Cool Water-Kramer 115 kV T/L under loss of Cool Water-SEGS2-Tortilla 115 kV T/L	949	567.3	59.8%	1324.6	139.6%	79.8%	New SPS to trip C491
Case Divergence under loss of Cool Water-River 115 kV T/L	N/A	N/A	N/A	N/A	N/A	N/A	New SPS to trip C491
Case Divergence under loss of Afton Sub-River 115 kV T/L	N/A	N/A	N/A	N/A	N/A	N/A	New SPS to trip C491
Case Divergence under loss of Afton Sub-Baker-Mountain Pass-Ivanpah 115 kV T/L	Case Convergence	N/A	N/A	N/A	N/A	N/A	New SPS to trip C491
Kramer-Roadway-Victor 115 kV T/L under loss of Kramer-Victor 115 kV T/L	1430	1097.2	94.6%	1206.4	104.0%	9.4%	Congestion management
Kramer No.1 220/115 kV Transformer under loss of Kramer No.2 220/115 kV transformer	(250)	235.6	94.2%	321.4	128.5%	34.3%	New SPS to trip C491
Category C (N-2) Overloads – Summer with Additional Congestion Management in Post Case							
Case Divergence under loss of Kramer-Lugo No.1 & No.2 220 kV T/Ls	N/A	N/A	N/A	N/A	N/A	N/A	Existing SPS
Case Divergence under loss of Lugo-Victor No.1 & No.2 220 kV T/Ls	Case Convergence	N/A	N/A	N/A	N/A	N/A	Previously identified SPS will mitigate (trip C589)
Case Divergence under loss of Inyokern-Kramer & Inyokern Randsburg-TOT413 Sub 115 kV T/Ls	N/A	N/A	N/A	N/A	N/A	N/A	Previously identified SPS will mitigate
Case Divergence under loss of Kramer-TOT413 Sub and Inyokern-Kramer 115 kV T/Ls	N/A	N/A	N/A	N/A	N/A	N/A	Previously identified SPS will mitigate
Case Divergence under of Control-Haiwee-Inyokern & Control-Coso-Haiwee-Inyokern 115 kV T/Ls	N/A	N/A	N/A	N/A	N/A	N/A	Previously identified SPS will mitigate
Kramer No.1 220/115 kV transformer under loss of Kramer-Victor & Kramer-Roadway-Victor 115 kV T/Ls	(250)	272.6	109.0%	348.9	139.6%	30.6%	New SPS to trip C491
Kramer No.2 220/115 kV transformer under loss of Kramer-Victor & Kramer-Roadway-Victor 115 kV T/Ls	(280)	267.6	95.6%	342.5	122.3%	26.7%	New SPS to trip C491

Table 7-3-8: Modified Power Flow Overloads – Off-Peak Conditions

Over Loaded Component	Rating Amps (MVA)	Pre- Project Loading(Amps |%Rating)		Post- Project Loading(Amps |%Rating)		% Change from Pre-Project Loading	Comment
Category B (N-1) Overloads – with Additional Congestion Management in Post Case							
Remaining Kramer-Lugo 220 kV T/L under loss of Kramer-Lugo No.1 or No.2 220 kV T/L	1430	1696.8	136.8%	1811.0	146.0%	9.2%	Modify Existing SPS
Kramer-Lugo No.1 & No.2 220 kV T/Ls under loss of Jasper-Lugo 220 kV T/L	1240	1896.7	153.0%	2071.8	167.1%	14.1%	New SPS to trip C491 & C552 + Existing SPS
Kramer-Lockhart 220 kV T/L under loss of Jasper-Lugo 220 kV T/L	1614	1561.8	96.8%	1689.3	104.7%	7.9%	New SPS to trip C491 & C552 + Existing SPS
Kramer-Victor 115 kV T/L under loss of Jasper-Lugo 220 kV T/L	1150	1153.5	100.3%	1297.3	112.8%	12.5%	New SPS to trip C491 & C552 + Existing SPS
Kramer-Roadway-Victor 115 kV T/L under loss of Jasper-Lugo 220 kV T/L	1160	1166.0	100.5%	1309.7	112.9%	12.4%	New SPS to trip C491 & C552 + Existing SPS
Kramer-Lugo No.1 & No.2 220 kV T/Ls under loss of Cool Water-Jasper 220 kV T/L	1240	1593.0	128.5%	1677.0	135.2%	6.7%	New SPS to trip C491 + Existing SPS
Remaining Lugo-Victor 220 kV T/L under loss of Lugo-Victor No.1 or No.2 220 kV T/L	1240	1266.0	102.1%	1472.4	118.7%	16.6%	Previously identified SPS will mitigate (trip C589)
Inyokern-Randsburg-TOT413 Sub 115 kV T/L under loss of Inyokern-Kramer 115 kV T/L	828	1288.6	155.6%	1184.0	142.9%	12.7%	Previously identified SPS will mitigate
Kramer-TOT413 Sub 115 kV T/L under loss of Inyokern-Kramer 115 kV T/L	828	1255.5	151.6%	1233.2	148.9%	2.7%	Previously identified SPS will mitigate
Control-Coso-Haiwee-Inyokern 115 kV T/L under loss of the Control-Haiwee-Inyokern 115 kV T/L	402	408.3	101.7%	409.0	101.8%	0.1%	Previously identified SPS will mitigate
Inyo Phase Shift 115 kV transformer under loss of the Control-Haiwee-Inyokern 115 kV T/L	(56)	75.3	134.4%	75.4	134.6%	0.2%	Previously identified SPS will mitigate
Control-Haiwee-Inyokern 115 kV T/L under loss of the Control-Coso-Haiwee-Inyokern 115 kV T/L	402	406.5	101.2%	407.3	101.4%	0.2%	Previously identified SPS will mitigate
Inyo Phase Shift 115 kV Transformer under loss of Control-Coso-Haiwee-Inyokern 115 kV T/L	(56)	75.6	135.0%	75.7	135.2%	0.2%	Previously identified SPS will mitigate
Case Divergence under loss of Cool Water-Kramer 115 kV T/L	Case Convergence	N/A	N/A	N/A	N/A	N/A	New SPS to trip C491

Cool Water-Kramer 115 kV T/L under loss of Cool Water-SEGS2-Tortilla 115 kV T/L	949	120.2	61.3%	1352.3	142.5%	81.2%	New SPS to trip C491
Case Divergence under loss of Cool Water-River 115 kV T/L	N/A	N/A	N/A	N/A	N/A	N/A	New SPS to trip C491
Case Divergence under loss of Afton Sub-River 115 kV T/L	N/A	N/A	N/A	N/A	N/A	N/A	New SPS to trip C491
Case Divergence under loss of Afton Sub-Baker-Mountain Pass-Ivanpah 115 kV T/L	Case Convergence	N/A	N/A	N/A	N/A	N/A	New SPS to trip C491
Kramer No.1 220/115 kV Transformer under loss of Kramer No.2 220/115 kV transformer	(250)	277.3	110.9%	386.7	154.7%	43.8%	New SPS to trip C491
Category C (N-2) Overloads – with Additional Congestion Management in Post Case							
Case Divergence under loss of Kramer-Lugo No.1 & No.2 220 kV T/Ls	Case Convergence	N/A	N/A	N/A	N/A	N/A	Existing SPS
Kramer-Lugo No.1 & No.2 220 kV T/L under loss of Lugo-Victor No.1 & No.2 220 kV T/Ls	1240	1678.6	135.4%	1872.2	151.0%	15.6%	Expand Victor area SPS to include C589
Kramer No.1 220/115 kV Transformer under loss of Lugo-Victor No.1 & No.2 220 kV T/Ls	(250)	393.3	157.3%	493.4	197.3%	40%	Expand Victor area SPS to include C589
Kramer No.2 220/115 kV Transformer under loss of Lugo-Victor No.1 & No.2 220 kV T/Ls	(280)	386.1	137.9%	484.4	173.0%	35.1%	Expand Victor area SPS to include C589
Inyo Phase Shifter 115 kV transformer under loss of Lugo-Victor No.1 & No.2 220 kV T/Ls	(56)	69.0	123.2%	76.0	135.8	12.6%	Expand Victor area SPS to include C589
Case Divergence under loss of Inyokern-Kramer & Inyokern Randsburg-TOT413 Sub 115 kV T/Ls	N/A	N/A	N/A	N/A	N/A	N/A	Previously identified SPS will mitigate
Case Divergence under loss of Kramer-TOT413 Sub and Inyokern-Kramer 115 kV T/Ls	N/A	N/A	N/A	N/A	N/A	N/A	Previously identified SPS will mitigate
Case Divergence under of Control-Haiwee-Inyokern & Control-Coso-Haiwee-Inyokern 115 kV T/Ls	N/A	N/A	N/A	N/A	N/A	N/A	Previously identified SPS will mitigate
Kramer No.1 220/115 kV transformer under loss of Kramer-Victor & Kramer-Roadway-Victor 115 kV T/Ls	(250)	286.0	114.4%	374.7	149.9%	35.5%	New SPS to trip C491
Kramer No.2 220/115 kV transformer under loss of Kramer-Victor & Kramer-Roadway-Victor 115 kV T/Ls	(280)	280.8	100.3%	367.9	131.4%	31.1%	New SPS to trip C491

7.4 Modified Power Flow Study Conclusions

Based on the study findings, *the power flow problems identified in the preliminary power flow study were eliminated based on the mitigation measures identified in Section 7.2 above.*

7.4.1 Existing and Proposed North of Kramer & Lugo Hub SPS is insufficient

The addition of the Phase II generation projects interconnecting in the North of Kramer and Lugo Hub Subareas create a potential for insufficient SPS arming to address thermal overloads and stability concerns following outages on the following transmission facilities:

- Cool Water-Jasper 220 kV T/L
- Kramer-Cool Water 115 kV T/L
- Cool Water-SEGS-Tortilla 115 kV T/L
- Jasper-Lugo 220 kV T/L
- Kramer No.2 220/115 kV transformer bank
- Kramer-Tortilla 115 kV T/L
- Kramer-Roadway-Victor & Kramer-Victor 115 kV T/Ls
- Cool Water-River 115 kV T/L

To address such potential insufficient SPS arming, the Phase II generation projects interconnecting in the North of Kramer and Lugo Hub Subareas will need to participate in SPS that trips these resources under various single and double-contingency conditions.

East of Lugo Bulk System Phase II generation projects requesting Interconnection in the North of Kramer and Lugo Hub Subareas create a potential for insufficient SPS arming. An existing SPS will be expanded and a new SPS will be required in order to address various single and double-contingency outages.

7.5 Network Upgrades Identified in Deliverability Assessment

In addition to the reliability power flow study results and conclusions, additional mitigation requirements were identified in the Deliverability Study as discussed above in Section 6. These conclusions are summarized below:

7.5.1 Transmission is Constrained East of the Pisgah Substation

Phase II projects connecting in the East of Pisgah Subarea cause significant transmission constraints on transmission lines east of Pisgah Substation.

The East of Lugo Bulk System Phase II generation projects in the East of Pisgah Subarea require significant transmission capacity upgrades. To provide such additional capacity, the following upgrade is proposed:

- Add SCE-own Eldorado 500/230 AA transformer
- Loop the Lugo-Mohave 500 kV transmission line into the proposed Pisgah 500 kV bus
- Add series capacitor banks on the Nipton-Pisgah and Mohave-Pisgah 500 kV transmission lines

7.5.2 Existing and Proposed East of Pisgah Subarea SPS is insufficient

The addition of the Phase II generation projects interconnecting in the East of Pisgah Subarea create a potential for insufficient SPS arming to address thermal overloads and stability concerns following outages on the following transmission facilities:

- Colorado River-Palo Verde 500 kV transmission line
- Lugo-Pisgah No.1 and No.2 500 kV transmission lines
- Eldorado-Cima-Pisgah No.1 and No.2 220 kV transmission lines and the Nipton-Pisgah 500 kV transmission line

To address such potential insufficient SPS arming, the Phase II generation projects interconnecting in the East of Pisgah Subarea will need to participate in SPS that trips these resources under various single and double-contingency conditions.

East of Lugo Bulk System Phase II generation projects requesting Interconnection in the East of Pisgah Subarea create a potential for insufficient SPS arming. An existing SPS will be expanded and new SPSs will be required in order to address various single and double-contingency outages.

7.5.3 Impacts on Neighboring Utilities

The addition of the Phase II generation projects interconnecting to the East of Pisgah Subarea create thermal overloads under N-2 (Category "C") conditions. These overloads were identified on the LADWP owned Lugo-Victorville 500 kV transmission line.

Phase II generation projects located in the East of Lugo, Eastern, and SDG&E Subareas are identified to impact neighboring utilities on the SCE and LADWP joint owned Lugo – Victorville 500 kV transmission tie line. The following upgrades are proposed along with the modification of previously identified Eldorado Area SPSin order to address such impacts:

- Build a new 31 miles of single-circuit Colorado River – Red Bluff No.3 transmission line in 2-2156KCMIL ACSR Conductors. The line will be equipped with one Optical Ground Wire (OPGW).

- Build a new 103 miles of new Red Bluff – Valley 500 kV transmission line with series capacitor banks compensation in 2-2156KCMIL ACSR Conductors. The line will be equipped with one Optical Ground Wire (OPGW).

7.6 Reactive Power Deficiency Analysis

Reactive Power Deficiency Analysis was performed to evaluate impacts of generation projects not satisfying the ISO Tariff power factor requirements and SCE's Interconnection Handbook requirements (see Attachment 3 of Appendix A). Based on these additional studies, potential case non-convergence scenarios were identified which would not exist with compliance with the ISO Tariff power factor requirements and SCE's Interconnection Handbook. For project specific details see the Individual Appendix A reports.

8. Short Circuit Duty Assessment

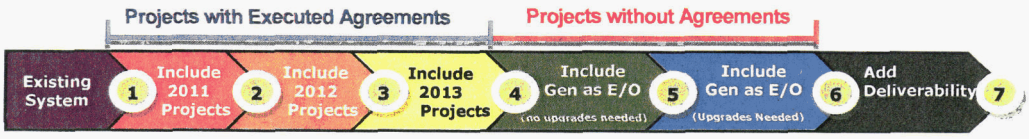
8.1 Application Queue Analysis

Application queue short circuit duty studies were performed to determine the impact on circuit breakers with the interconnection of Phase II projects to the transmission system. The application queue considered all existing and higher queued generation interconnection projects and corresponding upgrades into the starting base cases as a pre-condition prior to adding the Phase II projects. In addition, the application queue included all CAISO approved transmission projects and all SCE approved non-CAISO upgrades into the starting base case as a pre-condition prior to adding the Phase II projects. The fault duties were calculated to identify any equipment overstress conditions. Three-phase (3PH) and single-line-to-ground (SLG) faults were simulated without the Phase II projects to establish the starting base line. The Phase II projects including the identified Reliability and Delivery Network Upgrades from the power flow and stability analysis were then added and the fault duties were recalculated to identify the incremental impacts associated with the inclusion of the Phase II projects. 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 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. The pro rata allocation of each Phase II project to the circuit breaker upgrades listed above is provided in each individual report (Appendix A).

8.2 Operational Queue Analysis

The Operational short-circuit duty studies were performed to identify timing of need for short-circuit duty mitigations. The operational study considered seven different scenarios as shown below in Figure 8.2.1. These scenarios were selected as the most appropriate operational study conditions.

Figure 8.2.1 – Short Circuit Duty Operational Study



8.2.1 Projects with Executed Agreements

Three-phase (3PH) and single-line-to-ground (SLG) faults were simulated for the existing system condition to establish the starting operational base line conditions. Generation projects with an active executed agreement (LGIA, SGIA, or Letter Agreement) were then added for years 2011, 2012 and 2013. In addition, transmission upgrades already permitted which are under construction or scheduled to be in-service by the end of 2013 were included into these operational studies. The list of new generation projects with executed agreements are summarized below in Table 8.2.1, Table 8.2.2 and Table 8.2.3 for years 2011, 2012, and 2013 respectively

and the list of transmission upgrades scheduled to be in-service by the end of 2013 is summarized below in Table 8.2.4.

Table 8.2.1
Generation Projects with Executed Agreement Expected to be In-Service in End of 2011

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
WDAT	WDT042	01/07/00	Devers-Banning-Windpark 115 kV line	40
WDAT	WDT213	11/02/05	Garnett-Banning-Windfarm 115 kV line	49
95	TOT162	03/01/06	Windhub 220 kV	150[6]
96	TOT163	03/01/06	Windhub 220 kV	150[7]
WDAT	WDT323	12/16/08	Cottonwood 33 kV (Victor System)	20

Table 8.2.2
Generation Projects with Executed Agreement Expected to be In-Service in End 2012

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
7	TOT041	10/06/00	El Segundo 220 kV	630
66	TOT135	05/06/05	Walnut 220 kV	500.5
20	TOT108	09/04/03	Whirlwind 220 kV	300
73	TOT148	06/27/05	Whirlwind 220 kV	250
79	TOT146	09/07/05	Windhub 66 kV	51
91	TOT153	02/22/06	Windhub 66 kV	51
95	TOT162	03/01/06	Windhub 220 kV	130[8]
131	TOT180	09/25/06	Ivanpah 115 kV	100
132	TOT179	09/27/06	Highwind 220 kV	297
WDAT	WDT240	10/19/06	Brea 66 kV (Olinda System)	25
WDAT	WDT273	03/26/08	Saugus 66 kV System	20
WDAT	WDT268	04/02/08	Brea 66 kV (Olinda System)	9
297	TOT278	07/31/08	Neenach 66 kV	66
412	TOT345	07/31/08	Whirlwind 220 kV	125[9]

Table 8.2.3
Generation Projects with Executed Agreement Expected to be In-Service by End 2013

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
3	TOT032	06/14/00	Devers 220 kV (Sentinel Project)	850
93	TOT161	03/01/06	Windhub 220 kV	220
100	TOT167	04/17/06	Vincent 220 kV (via Sagebrush Gen-Tie)	120
119	TOT173	08/08/06	Windhub 220 kV	500
125	TOT175	08/22/06	Water Valley 220 kV	250
135	TOT183	10/10/06	Jasper 220 kV (Looping Lugo-Pisgah No.2)	60
146	TOT198	11/16/06	New Red Bluff 220 kV	150
147	TOT199	11/16/06	New Red Bluff 220 kV	400
162	TOT210	01/05/07	Ivanpah 115 kV	114
233	TOT242	06/27/07	Ivanpah 115 kV	200
188	TOT219	07/31/08	Windhub 220 kV	200

[6] This figure reflects partial interconnection of 150 MW in 2011 for a total of 420 MW by end of 2011.
[7] This figure reflects interconnection the balance of 150 MW in 2011 for a total project of 600 MW by end of 2011.
[8] This figure reflects interconnection of balance of 130 MW in 2012 for a total project of 550 MW in 2012.
[9] This figure reflects partial interconnection of 125 MW in 2012.

294	TOT276	07/31/08	Colorado River 220 kV	500[10]
365	TOT321	07/31/08	Red Bluff 220 kV	500
412	TOT345	07/31/08	Whirlwind 220 kV	125

Table 8.2.4
Transmission Upgrades with a Well Defined In-Service Date Prior to End of 2013

System Upgrade	OD
Acton 66 kV Loop-In	2011
Chino-Mira Loma No.1 and No.2 220 kV (Segment 8C)	2011
Devers-Mirage 115 kV System Split	2012
Mirage No.3 230/115 kV Transformer Bank (third bank)	2012
Devers-Coachella 220 kV Loop into Mirage	2012
Highwind 220 kV Substation (TRTP Segment 3B)	2012
Windhub-Highwind 220 kV T/L (TRTP Segment 3B)	2012
Antelope 500/220 kV Substation (TRTP Segment 9) with 2 AA-Banks	2012
Windhub No.3 and No.4 500/220 kV Transformer Banks (Segment 9)	2012
Whirlwind 500/220 kV Substation (TRTP Segment 9) with 1 AA-Bank	2012
Antelope-Vincent No.2 Operation to 500 kV (TRTP Segment 3C)	2012
Antelope-Windhub Operation to 500 kV (TRTP Segment 3C)	2012
Antelope-Whirlwind 500 kV (TRTP Segment 4)	2012
Antelope-Vincent No.1 500 kV (TRTP Segment 5)	2012
Midway-Vincent 500 kV Loop-In Whirlwind 500 kV (TRTP Segment 9)	2012
Whirlwind-Windhub 500 kV T/L (TRTP Segment 10)	2012
Victor No.3 230/115 kV Bank and Bus Rebuild	2012
Victor-Savage No.3 115 kV Line	2012
New Eldorado-Merchant No.2 with Merchant Tie CBs Operated as Normally Open	2012
Chino-Mira Loma No.3 500 kV Operated at 220 kV (Segment 8B)	2013
Colorado River 500/220 kV Substation with one AA-Bank	2013
Devers-Colorado River 500 kV	2013
Devers-Valley No.2 500 kV	2013
Eldorado-Ivanpah 220 kV	2013
Ivanpah 220 kV Substation with two A-Banks	2013
Rio Hondo-Vincent No.2 220 kV Replacement (TRTP 6, 7)	2013
Red Bluff 500/220 kV Substation with one AA-Bank	2013
Saugus No.3 220/66 kV Transformer Bank	2013

[10] This figure reflects partial 500 MW interconnection (1,000 MW Project) in 2013

8.2.2 Projects without Executed Agreements Assumed To Be Interconnected as Energy Only and No Transmission Upgrades

In order to provide a preview of additional circuit breaker upgrade or replacement requirements that could materialize as more and more generation projects are interconnected, the operational study considered the inclusion of all other generation projects that do not yet have an executed agreement in place assuming they could be interconnected as Energy Only. This excludes generation projects that require transmission upgrades beyond the method of service and telecomm needed to support the Energy Only interconnection. These projects were added to the 2013 operational study scenario. While the interconnection customers may be requesting an earlier in-service dates, this operational study method will define all of the circuit breaker upgrades and/or replacements needed to interconnect every single generation project that can be interconnected as Energy Only without any additional transmission upgrades beyond the method of service and telecomm needed to support the Energy Only interconnection.

The study did not take into account permitting timeframes associated with construction of the facilities needed to support the Energy Only interconnection and simply assumed such facilities would be in place. The objective of this Operational Study scenario is to identify locations where additional circuit breaker upgrade or replacement requirements could materialize as interconnection agreements are executed so that resource requirements could be identified in order to enable interconnection of any generation project which does not yet have an executed interconnection agreement. While some of these generation projects have articulated a desire for an earlier in-service date, there is no executed agreement in place committing to such interconnection timeframes. Consequently, the study performed grouped these projects together with all other projects which do not yet have an active interconnection agreement. The list of the generation projects modeled in this operational study scenario is summarized below in Table 8.2.5.

Table 8.2.5
Generation Project without an Executed Agreement Assumed To Be Interconnected as Energy Only without Additional Transmission Upgrades

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
WDAT	WDT011	03/23/98	Renwind 12 kV (Out of Devers System)	9
WDAT	WDT016	07/09/98	Garnet 33 kV (Out of Devers System)	11.57
1	TOT022	09/30/98	Buckwind 115 kV (Out of Devers System)	16.5
N/A	TOT023	01/22/99	Buckwind 115 kV (Out of Devers System)	2.4[11]
17	TOT079	04/22/03	Colorado River 500 kV	520
49	TOT120	12/14/04	Devers 115 kV	100.5
58	TOT127	02/22/05	Control 115 kV	62
WDAT	WDT179	03/18/05	Colton-Bloomington 66 kV Line	49.9
WDAT	WDT182	05/06/05	Valley 115 kV	507.5
68	TOT131	05/11/05	Pisgah 220 kV	575[12]
72	TOT132	06/16/05	Alberhill 500 kV (Previously Lee Lake)	500

[11] 2.4 MW (Solar) of the total 3.82 MW Interconnection Request requires Agreement Amendment
[12] This figure reflects the balance of an 850 MW project (275 MW assumed in-service by 2013).

WDAT	WDT190	06/17/05	Tap into 66kV line into Browning Substation	49.9
41	TOT119	11/18/04	Pastoria 220 kV	158.8
84	TOT151	12/01/05	Whirlwind 220 kV	340
219	TOT237	05/23/07	Colorado River 500 kV	50
240	TOT250	07/12/07	Pisgah 220 kV	400
241	TOT245	07/12/07	Pisgah 220 kV	400
WDAT	WDT292	04/10/08	Irvine Substation (Out of Santiago System)	19.6
WDAT	WDT314	06/30/08	Pan Aero 115 kV	20
154	TOT203	07/31/08	Windhub 220 kV	250
163	TOT211	07/31/08	Ivanpah 220 kV	300
175	TOT215	07/31/08	Whirlwind 220 kV	650
193	TOT233	07/31/08	Colorado River 220 kV	500
205	TOT226	07/31/08	Eldorado 220 kV	300
294	TOT276	07/31/08	Colorado River 220 kV	500[13]
342	TOT307	07/31/08	Del Sur 66 kV	50
383	TOT327	07/31/08	Arco-Hinson 220 kV	85
407	TOT340	07/31/08	Whirlwind 220 kV	325
408	TOT341	07/31/08	Whirlwind 220 kV	325
409	TOT342	07/31/08	Highwind 220 kV	150
421	TOT349	07/31/08	Blythe-Eagle Mountain 161 kV T/L	49.5
467	TOT381	07/31/08	Primm 220 kV (Loop Eldorado-Ivanpah)	230
WDAT	WDT285	07/31/08	Cottonwood-Savage 115 kV	100
WDAT	WDT286	07/31/08	Victor-Phelan 115 kV	150
WDAT	WDT270	07/31/08	Little Rock-Wilsona 66 kV	33
WDAT	WDT315	07/31/08	Casa Diablo 115 kV	40.7
WDAT	WDT401	10/08/08	Venwind 115 kV	20
WDAT	WDT328	01/27/09	Cottonwood 115 kV Distribution	20
483	TOT389	04/29/09	Tehachapi 66 kV (Sagebrush Line)	10
WDAT	WDT334	06/09/09	Hi Desert 115 kV Distribution	18.5
485	TOT390	06/18/09	Highwind 220 kV	20
486	TOT393	06/29/09	Neenach 66 kV	20
488	TOT394	07/31/09	Eldorado 220 kV	92
490	TOT412	07/31/09	San Onofre 220 kV	48
494	TOT398	07/31/09	Windhub 220 kV	350
502	TOT405	07/31/09	Primm 220 kV (Loop Eldorado-Ivanpah)	20
503	TOT404	07/31/09	Eldorado 220 kV	155
506	TOT411	07/31/09	Whirlwind 220 kV	300
512	TOT410	07/31/09	Antelope 66 kV	94
513	TOT409	07/31/09	Whirlwind 220 kV	141
WDAT	WDT345	07/31/09	Highgrove 115 kV	49.9
WDAT	WDT357	08/17/09	Blythe 33 kV Distribution	20
WDAT	WDT371	08/25/09	Cottonwood-Savage 115 kV	20

[13] This figure reflects the balance of the 1,000 MW Interconnection Request.

WDAT	WDT372	08/25/09	Victor 115/33 kV	20
WDAT	WDT390	10/19/09	Vestal 66 kV Subtransmission	20
WDAT	WDT391	10/19/09	Vestal 66 kV Subtransmission	20
WDAT	WDT392	10/19/09	Vestal 66 kV Subtransmission	20
WDAT	WDT394	10/19/09	Vestal 66 kV Subtransmission	20
531A	TOT427	10/29/09	Antelope-Del Sur 66 kV	20
537A	TOT430	11/23/09	Highwind 220 kV	19.5
WDAT	WDT403	11/30/09	Little Rock 66/12 kV	2
WDAT	WDT404	11/30/09	Little Rock-Wilsona 66 kV	10
WDAT	WDT353	12/03/09	Vestal 66 kV Subtransmission	20
WDAT	WDT409	12/09/09	Cottonwood 115/33 kV	20
540	TOT431	12/22/09	Lancaster-Little Rock-Piute 66 kV Line	20
546	TOT437	01/06/10	Piute-Redman 66 kV Line	15
547	TOT436	01/06/10	Lancaster-Purify-Redman 66 kV Line	20
WDAT	WDT421	01/25/10	Cottonwood 115/33 kV	20
WDAT	WDT407	01/31/10*	Rector Distribution	20
WDAT	WDT435	01/31/10*	Windhub 66 kV	20
WDAT	WDT453	01/31/10*	Palmdale 66/12 kV	5
WDAT	WDT458	01/31/10*	Hi Desert 115/33 kV	10
WDAT	WDT459	01/31/10*	Hi Desert 115/33 kV	9
552	TOT438	02/01/10	Jasper 220 kV	60
585	TOT443	02/01/10	Antelope 220 kV	150
576	TOT446	02/01/10	Colorado River 220 kV	485
593	TOT448	02/01/10	Mohave 500 kV	310
589	TOT452	02/01/10	Victor 115 kV	60
588	TOT453	02/01/10	Red Bluff 220 kV	200
602	TOT455	02/01/10	Whirlwind 220 kV	150
628	TOT471	02/01/10	Del Sur 66 kV	20
632AA	TOT476	02/01/10	Mountwind 115 kV	10
651A	TOT508	02/01/10	Antelope 66 kV	20
653H	TOT516	02/01/10	Antelope 66 kV	20
650A	TOT521	02/01/10	Antelope 66 kV	20
661	TOT525	02/01/10	Antelope 66 kV	20
663	TOT527	02/01/10	Antelope 66 kV	20
WDAT	WDT425	02/01/10	Weldon 66 kV	60
WDAT	WDT433	02/01/10	Vestal-Glenville 66 kV	40
WDAT	WDT400	02/01/10	Pan Aero 115 kV	30

* Date adjusted as a result of the recently FERC approved Generation Interconnection Procedure modifications

8.2.3 Projects without Executed Agreements That Require Transmission Upgrades to Interconnected as Energy Only

The operational study included a scenario that added the transmission upgrades needed to enable Energy Only interconnection of specific number of projects. This scenario also included transmission upgrades already permitted but scheduled to be in-service after 2013. The list of the transmission upgrades included in this scenario is provided below in Table 8.2.6. The list of the generation projects modeled in this operational study scenario is summarized below in Table 8.2.7.

The study did not take into account permitting timeframes associated with construction of the facilities needed to support the Energy Only interconnection of these remaining generation project and simply assumed such facilities would be in place. The objective of this Operational Study scenario is to identify locations where additional circuit breaker upgrade or replacement requirements not yet defined could materialize as interconnection agreements are executed. This would ensure that resource requirements could be identified in order to enable interconnection of the remaining generation projects which do not have an executed interconnection agreement. While some of these generation projects have articulated a desire for an earlier in-service date, there is no executed agreement in place committing to such interconnection timeframes.

Table 8.2.6
Transmission Upgrades with an In-Service Date After End of 2013 or an In-Service Date prior to the End of 2013 which is dependent on ongoing Environmental Review Modeled in This Operational Scenario

System Upgrade	OD
East Kern Renewable Wind Area (EKWRA)	2013
Colorado River No.2 500/220 kV Transformer Bank	2014[14]
Loop Magnolia-NSO 220 kV T/L into Eldorado and reconfigure to operated Merchant No.1 and No.2 220 kV T/L as radial gen-ties	2014
Mira Loma-Vincent 500 kV (TRTP 6, 7, 8)	2014
San Bernardino-Vista 220 kV Reconductor	2014
San Joaquin Cross Valley Loop	2014
Whirlwind No.2 500/220 kV Transformer Bank	2014[15]
Wildlife 220 kV Substation (City of Riverside MOS)	2015
Mesa-Vincent No.2 220 kV (TRTP 11)	2015
Whirlwind No.3 500/220 kV Transformer Bank	2016

[14] Installation of second AA-Bank at Colorado River Substation is required when total amount of generation projects interconnecting exceed initial bank capability. Based on executed or near executed agreements (Serial and Transition Cluster), this date is currently identified to be 2014.

[15] Installation of second AA-Bank at Whirlwind Substation is required when total amount of generation projects interconnecting exceed initial bank capability. Based on executed or near executed agreements (Serial and Transition Cluster), this date is currently identified to be 2014.

Table 8.2.7
Generation Project without an Executed Agreement That Require Additional Transmission Upgrades to Interconnect as Energy Only

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
348	TOT313	07/31/08	Corum-Goldtown 66 kV	40
349	TOT314	07/31/08	Goldtown 66 kV	100
522A	TOT416	08/19/09	Rosamond 66 kV	20
522B	TOT417	08/19/09	Antelope-Cal Cement-Rosamond 66 kV Line	20
WDAT	WDT361	08/20/09	Great Lakes 66/12 kV	5
WDAT	WDT368	08/20/09	Goldtown 66/12 kV	4.9
474	TOT387	09/15/08	Cool Water-Dunn Siding-Baker 115 kV Line	20
WDAT	WDT325	11/17/08	Kramer 11 kV Distribution	20
WDAT	WDT326	12/10/08	Gale 11 kV Distribution	20
WDAT	WDT329	02/13/09	Kramer 11 kV Distribution	20
491	TOT396	07/31/09	Cool Water-Dunn Siding-Baker 115 kV Line	230
WDAT	WDT402	11/25/09	Goldtown 66/12 kV	10
WDAT	WDT417	01/19/10	Inyokern 115/33 kV	5.5
609	TOT456	01/31/10*	Rosamond 66 kV	20
617A	TOT465	01/31/10*	Piute-Redman 66 kV	20
WDAT	WDT419	01/31/10*	Randsburg 115/33 kV	20
515	TOT413	02/01/10**	Kramer-Inyokern-Randsburg No.1 115 kV	20
522C	TOT415	02/01/10**	Correction-Cummings-Kern River 1-Monolith 66 kV Line	20
521	TOT419	02/01/10**	Corum-Goldtown 66 kV Line	19.9
522	TOT420	02/01/10**	Corum-Goldtown-Rosamond 66 kV Line	20
613A	TOT461	02/01/10	Monolith 66 kV	19.5
614A	TOT462	02/01/10	Coram-Goldtown-Rosamond 66 kV Line	20
639	TOT472	02/01/10	Piute 66 kV	20
640	TOT473	02/01/10	Antelope-Cal Cement-Rosamond 66 kV Line	20
649C	TOT499	02/01/10	Antelope-Cal Cement-Rosamond 66 kV Line	20
650AA	TOT501	02/01/10	Antelope-Del Sur-Rosamond 66 kV Line	15
649B	TOT502	02/01/10	Antelope-Del Sur-Rosamond 66 kV Line	20
640A	TOT503	02/01/10	Lancaster-Purify-Redman 66 kV Line	20
653EF	TOT512	02/01/10	Monolith 66 kV	20
653BA	TOT513	02/01/10	Correction-Cummings-Kern River 1-Monolith 66 kV Line	20
653FB	TOT514	02/01/10	Lancaster-Little Rock-Piute 66 kV Line	20
653FA	TOT515	02/01/10	Lancaster-Little Rock-Piute 66 kV Line	20
657A	TOT518	02/01/10	Antelope-Neenach 66 kV	20
657B	TOT519	02/01/10	Corum-Goldtown 66 kV	20
660	TOT522	02/01/10	Lancaster-Purify-Redman 66 kV Line	20
658	TOT523	02/01/10	Piute 66 kV	20
659	TOT524	02/01/10	Antelope-Rosamond 66 kV	20
664	TOT526	02/01/10	Antelope-Lancaster-Lanpri-Shuttle 66 kV Line	20

8.2.4 Inclusion of All Long-Term Deliverability Network Upgrades

The operational study included a final scenario that added all of the long-term Deliverability Upgrades needed to provide for the requested Full Capacity level of service to all generation projects in queue including the Phase II project requests.

8.3 Application Queue SCD Results

All bus locations where the Phase II Projects increased 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 Table H.1.1 (three-phase-to-ground) and Table H.1.2 (single-phase-to-ground). These values have been used to determine if any *additional* equipment, beyond what has previously been identified to be overstressed due to queued ahead projects, is triggered with the addition of the Phase II interconnections and corresponding network upgrades.

The Phase II breaker evaluation identified that the inclusion of the Phase II Projects triggers the need for SCD mitigation Vincent 500 kV, Lugo 220 kV, Antelope 66 kV, and Windhub 66 kV. The effective three-phase-to-ground and single-phase-to-ground duties are shown below in Table 8.3.1 and Table 8.3.2 respectively.

Table 8.3.1
Effective Three-Phase-to-Ground Duties at Locations Requiring Phase II Triggered SCD Mitigation

Substation	Voltage	Pre-Phase II			Post-Phase II			Phase II Impact	
		kA	X/R	Eff kA*	kA	X/R	Eff kA*	kA	Eff kA*
Vincent	500	48.8	21.4	49.8	50.0	21.6	51.1	1.2	1.3
Lugo	230	41.5	33.6	46.1	50.9	33.2	56.5	9.4	10.4
Vista	115	20.1	28.7	22.9	20.4	29.2	23.3	0.3	0.4
Antelope	66	34.8	28.4	34.8	36.6	46.8	42.1	1.8	7.3
Windhub	66	34.4	50.2	39.3	35.6	49.1	40.9	1.4	1.6

* Effective kA is the value that is used to determine breaker adequacy consistent with IEEE Standards

Table 8.3.2
Effective Single-Phase-to-Ground Duties at Locations Requiring Phase II Triggered SCD Mitigation

Substation	Voltage	Pre-Phase II			Post-Phase II			Phase II Impact	
		kA	X/R	Eff kA*	kA	X/R	Eff kA*	kA	Eff kA*
Vincent	500	39.1	15.4	39.1	39.7	15.3	39.7	0.6	0.6
Lugo	230	41.9	25.5	44.4	52.4	25.2	55.5	10.5	11.1
Vista	115	22.4	26.3	25.1	22.7	26.6	25.4	0.3	0.3
Antelope	66	22.8	22.5	22.8	24.4	25.3	24.4	1.6	1.6
Windhub	66	25.5	23.8	25.5	26.6	23.7	26.6	1.1	1.1

* Effective kA is the value that is used to determine breaker adequacy consistent with IEEE Standards

A detailed discussion of the upgrade requirements is provided below.

8.3.1 Vincent 500 kV Substation

The study identified that the addition of the Phase II projects results in increasing SCD at SCE's Vincent 500 kV Substation beyond the breaker capabilities. Such duty increases were identified to impact a total of four 500 kV circuit breakers.

- Vincent 500 kV CB722
- Vincent 500 kV CB852 and CB952
- Vincent 500 kV CB862

To mitigate these identified overstressed circuit breakers, replacement of these four CBs with 63 kA rating is recommended.

8.3.2 Lugo 220 kV Substation

The study identified that the addition of the Phase II projects results in increasing SCD at SCE's Lugo 220 kV Substation beyond the breaker capabilities. Such duty increases were identified to impact a total of six220 kV circuit breakers.

- Lugo 220 kV CB4032 and CB6032
- Lugo 220 kV CB4052, CB5052, and CB6052
- Lugo 220 kV CB4062

To mitigate these identified overstressed circuit breakers, replacement of six CBs with 63 kA rating is recommended.

8.3.3 Antelope 66 kV Substation

The study identified that the addition of the Phase II projects results in increasing SCD at SCE's Antelope 66 kV Substation beyond the 40 kA standard design breaker capabilities with the Antelope Substation operating with three 220/66 kV transformer banks in parallel. Such duty increases were identified to impact a total of forty 66 kV circuit breakers.

To address this problem, the use of an Operating procedure[16] to reduce duty to within circuit breaker limits will be required.

8.3.4 Windhub 66 kV Substation

The study identified that the addition of the Phase II projects results in increasing SCD at SCE's Windhub 66 kV Substation beyond the 40 kA standard design breaker capabilities with the Windhub Substation operating with three 220/66 kV transformer banks in parallel.

To mitigate this problem the Windhub 66 kV switchrack will need to be operated in a split bus configuration. This configuration will necessitate the installation of the fourth 220/66 kV transformer bank at Windhub.

[16] SCE anticipates that the appropriate long-term mitigation of the Antelope 66 kV SCD problem involves sectionalizing the Antelope 66 kV bus. For this Phase II study, an operating procedure to de-loop or de-energize sufficient transmission facilities to keep Antelope 66 kV SCD below 40 KA will be required.

8.4 Operational Study SCD Results

8.4.1 Existing System with the inclusion of projects in 2011

All bus locations where the inclusion of projects in 2011 increased 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 Table H.2.1 (three-phase-to-ground) and Table H.2.2 (single-phase-to-ground). These values were used to determine which SCD mitigation needs to be placed into service by the end of 2011.

The 2011 Operational Study breaker evaluation identified the need for SCD mitigation at the following location:

8.4.1.1 Vincent 220 kV

The following 220 kV circuit breaker at Vincent Substation, rated at 40 kA, requires mitigation. This breaker is subject to a multiplier factor as defined by IEEE Standards. As a result, three-phase-to-ground duties identified in this operational study determined that the duty on this specific breaker was increased from an effective 55.9 kA to an effective 56.1 kA. To mitigate the overstressed breaker, it is recommended to replace it with a new 63 kA rated breaker.

- Vincent CB682

8.4.2 Inclusion of projects in 2012

All bus locations where the inclusion of projects in 2012 increased 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 Table H.3.1 (three-phase-to-ground) and Table H.3.2 (single-phase-to-ground). These values were used to determine which incremental SCD mitigation needs to be placed into service by the end of 2012.

The 2012 Operational Study breaker evaluation identified the need for SCD mitigation at the following locations:

8.4.2.1 Antelope 220 kV

The following nine 220 kV circuit breakers at Antelope Substation, rated at 40 kA, require mitigation. These breakers are subject to a multiplier factor as defined by IEEE Standards. The study results identified this station to have greater single-phase-to-ground fault duties so these were used as the determination of need for upgrade. The operational studies identified that the single-phase-to-ground duty on these specific breakers was increased from an effective 23.6 kA to an effective 45.1 kA. To mitigate the overstressed breakers, it is recommended to replace eight of the following circuit breakers with 63 kA rated breakers and install TRV capacitors on one to increase duty to 50 kA.

- Antelope CB 4022 (Replace with 63kA) and CB 6022 (Replace with 63kA)
- Antelope CB 6032 (Replace with 63kA)
- Antelope CB 4042 (Replace with 63kA) and CB 6042 (Replace with 63kA)

- Antelope CB 61X2 (Replace with 63kA)
- Antelope CB 4062 (Replace with 63kA) and CB 6062 (Replace with 63kA)
- Antelope CB 4072 (Install TRV Caps)

8.4.3 Inclusion of projects in 2013

All bus locations where the inclusion of projects in 2013 increased 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 Table H.4.1 (three-phase-to-ground) and Table H.4.2 (single-phase-to-ground). These values were used to determine which incremental SCD mitigation needs to be placed into service by the end of 2013.

8.4.3.1 Devers 220 kV

The following seven 220 kV circuit breakers at Devers Substation, rated at 40 kA, require mitigation. These breakers are subject to a multiplier factor as defined by IEEE Standards. As a result, three-phase-to-ground duties identified in this operational study determined that the three-phase-to-ground duty on these specific breakers was increased from an effective 29.5 kA to an effective 41.5 kA. Replacement of these breakers with new 63 kA rated breakers will be implemented prior to the commercial operating date of the generation project identified to require the upgrades.

- Devers CB 5022 and CB 6022
- Devers CB 4082
- Devers CB 4092 and CB 6092
- Devers CB Cap 1
- Devers CB Cap 3

8.4.3.2 Mira Loma 220 kV

The following 220 kV circuit breaker at Mira Loma Substation, rated at 63 kA, requires mitigation. This breaker is subject to a multiplier factor as defined by IEEE Standards. As a result, three-phase-to-ground duties identified in this operational study determined that the three-phase-to-ground duty on this specific breaker was increased from an effective 62.5 kA to an effective 63.1 kA. To mitigate the overstressed breakers, it is recommended to implement an operational procedure as a means of reducing short-circuit duty. The operational procedure would involve operating one of the Mira Loma 500/220 kV transformer bank (AA-Bank) connected to the eastern section of the 220 kV bus as normally open.

- Mira Loma CB 4172

8.4.4 Inclusion of Generation Projects Assuming Energy Only Interconnection (excluding Generation projects requiring EKWRA to enable Energy Only Interconnection)

All bus locations where the inclusion of generation projects that do not yet have an executed interconnection agreement assuming interconnection can be implemented as Energy Only without transmission upgrades increased 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 Table H.5.1 (three-phase-to-ground) and Table H.5.2 (single-phase-to-ground). These values were used to determine which incremental SCD mitigation needs to be placed into service to enable such Energy Only Interconnections.

8.4.4.1 Vista 115 kV

The following ten 115 kV circuit breakers at Vista Substation, rated at 25 kA, require mitigation. These breakers are subject to a multiplier factor as defined by IEEE Standards. As a result, single-phase-to-ground duties identified in this operational study determined that the single-phase-to-ground duty on these specific breakers was increased from an effective 25.2 kA to an effective 25.7 kA. Replacement of these breakers with new 40 kA rated breakers will need to be implemented prior to the commercial operating date of additional generation projects seeking interconnection on the Vista 115 kV System.

- Vista CB 29 and CB 30
- Vista CB 31 and CB 32
- Vista CB 33 and CB 34
- Vista CB 35 and CB 36
- Vista CB 39 and CB 40

8.4.5 Inclusion of EKWRA and all Generation Projects that required EKWRA to enable Energy Only Interconnection

All bus locations where the inclusion of the remaining generation projects that do not yet have an executed interconnection agreement, assuming interconnection can be implemented as Energy Only but require transmission upgrades for interconnection, increased 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 Table H.6.1 (three-phase-to-ground) and Table H.6.2 (single-phase-to-ground). These values were used to determine which incremental SCD mitigation needs to be placed into service to enable such Energy Only Interconnections.

8.4.5.1 Antelope 66 kV

The study identified that the inclusion of all projects and corresponding upgrades needed to enable "Energy Only" interconnection results in increasing short-circuit duty at SCE's Antelope 66 kV Substation. These breakers are subject to a multiplier factor as defined by IEEE Standards. With the subtransmission upgrades modeled to interconnect these projects, the X/R ratio

was found to be increased from 25.3 to 46.8 resulting in a multiplier change from 1.00 to 1.15. This multiplier results in increasing the effective duty at Antelope beyond the 40 kA ratings of the Antelope 66 kV breakers thus impacting a total of forty 66 kV circuit breakers. To address this problem, the use of an Operating procedure[17] to reduce duty to within circuit breaker limits will be required. This operating procedure involves operating one of the Antelope 500/220 kV transformer banks, being installed as part of TRTP, normally open.

8.4.5.2 Cal Cement 66 kV

The following three 66 kV circuit breakers at Cal Cement Substation, rated at 13 kA, require mitigation. These breakers are subject to a multiplier factor as defined by IEEE Standards. As a result, three-phase-to-ground duties identified in this operational study determined that the three-phase-to-ground duty on these specific breakers was increased from an effective 7.4 kA to an effective 18.0 kA. Replacement of these breakers with new 31.5 kA rated breakers will need to be implemented prior to the commercial operating date of EKWRA and additional generation projects seeking interconnection on the northern portion of the SCE Antelope-Bailey 66 kV System (future Windhub 66 kV System).

- Cal Cement CB 2
- Cal Cement CB 4
- Cal Cement CB 8

8.4.6 System with Generation Projects Assuming Energy Only Interconnection (without and with upgrades) and inclusion of the Deliverability Network Upgrades

All bus locations where the inclusion of the Deliverability Network Upgrades increased 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 Table H.7.1 (three-phase-to-ground) and Table H.7.2 (single-phase-to-ground). These values were used to determine which incremental SCD mitigation needs to be placed into service to provide for the requested Full Capacity Deliverability service.

8.4.6.1 Vincent 500 kV

As discussed above in Section 8.3, Phase II Projects were identified to trigger the need for Vincent 500 kV breaker replacements (four breakers). This need, however, is not required until the identified Deliverability Network Upgrades are placed in-service. In evaluating the timing for the need of the breaker upgrades, all sources of incremental short-circuit duty contribution were reviewed. Based on the review, the total incremental short-circuit duty contribution associated with Phase II was an effective 1.2 kA to the limiting circuit breakers. The study identified that the net delta could be broken into

[17] SCE anticipates that the appropriate long-term mitigation of the Antelope 66 kV SCD problem involves sectionalizing the Antelope 66 kV bus. For this Phase II study, an operating procedure to de-loop or de-energize sufficient transmission facilities to keep Antelope 66 kV SCD below 40 KA will be required.

three basic categories, each contributing 0.4 kA to the Vincent 500 kV limiting circuit breakers. The first involves the inclusion of all Phase II generation projects, assuming Energy Only Interconnection. The second involves the inclusion of Network Delivery Upgrades identified in the East of Lugo area and the third involves the inclusion of the Network Delivery Upgrades identified in the other two areas. Because the breakers in question are within 0.2 kA of their maximum ratings, any one of these three would drive the need for the breaker upgrades. Consequently, the timing for replacement of these four circuit breakers will be tied actual development of both generation and Network Deliverability Upgrades. Additional review of these circuit breakers will be performed three times a year to evaluate timing of these breaker replacements as projects execute Generation Interconnection Agreements.

8.4.6.2 Etiwanda 220 kV

Short-circuit duty mitigation will be required to address overstressing all twenty-four 220 kV circuit breakers at Etiwanda outlined in Section 4.6.4. The mitigation will involve reconfiguration of the 220 kV System as a means to lower short-circuit duties at both Mira Loma and Etiwanda. As a first step, one of the Mira Loma 500/220 kV transformer banks connecting to the eastern bus section will need to be operated as normally open and close only when the remaining bank is being serviced. This will result in lowering short-circuit duty contributions to below the maximum rating of the breakers.

8.4.6.3 Lugo 220 kV

As discussed above in Section 8.3, Phase II Projects were identified to trigger the need for Lugo 220 kV breaker replacements (six breakers). This need, however, is not required until the identified Deliverability Network Upgrades are placed in-service. In evaluating the timing for the need of the breaker upgrades, all sources of incremental short-circuit duty contribution were reviewed. Based on the review, the total incremental short-circuit duty contribution associated with Phase II was an effective 10.4 kA to the limiting circuit breakers. The study identified that the installation of the third Lugo AA-Bank alone increases duty by 7.1 kA and the remaining 3.3 kA is the result of all generation projects and all other Deliverability Upgrades. Consequently, the timing for replacement of these six circuit breakers should be tied with the in-service date of the third Lugo AA-Bank.

8.4.6.4 Mira Loma East 220 kV

Short-circuit duty mitigation will be required to address overstressing all twelve 220 kV circuit breakers at Mira Loma East 220 kV bus-section outlined in Section 4.6.4. The mitigation will involve reconfiguration of the 220 kV System as a means to lower short-circuit duties at both Mira Loma and Etiwanda. As a first step, one of the Mira Loma 500/220 kV transformer banks connecting to the eastern bus section will need to be operated as normally open and close only when the remaining bank is being serviced. This will result in lowering short-circuit duty contributions to within the maximum rating of the circuit

breakers for a period of time. To further reduce duties, the 220 kV lines at Mira Loma will need to be reconfigured.

8.4.6.5 Pisgah 220 kV

Replacement of the following four 220 kV circuit breakers at Pisgah Substation from 40 kA to 50 kA (upgradable to 63 kA) will be required to address overstressing these breakers.

- Pisgah CB442 and CB452
- Pisgah CB642 and CB652

8.4.6.6 Vincent 220 kV

Short-circuit duty mitigation will be required to address overstressing all twenty-four 220 kV circuit breakers at Vincent outlined in Section 4.6.4. The mitigation will involve reconfiguration of the 220 kV System and splitting the bus as a means to lower short-circuit duty. The actual need for this work will be based on the number of projects that ultimately interconnect and the corresponding fault duty contributions.

8.4.6.7 Windhub 220 kV

As part of TRTP, the Windhub 220 kV Substation is being constructed in a split-bus configuration. This design addresses the short-circuit duty impacts identified in this study. As a result, no additional mitigation will be required.

8.5 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. It is strongly recommended that Phase II generation projects, to the extent possible, install transformers that limit each project's contribution to SLG SCD on the SCE system. This may be accomplished by installing transformers with delta-connected high side windings or with "impedance-grounded" wye-connected high side windings.

9. Transient Stability Analysis

Transient stability analysis was conducted using both the summer peak and off-peak full loop base cases to ensure that the transmission system remains stable with the addition of Phase II Generation Projects. The generator dynamic data used for the study is confidential in nature and is provided with each individual project report.

9.1 Transient Stability Study Scenarios

Disturbance simulations were performed for a study period of 10 seconds to determine whether the Phase II projects will create any system instability during a variety of line and

generator outages. For SCE's East of Lugo Bulk System, selected line and generator outages within this local area were evaluated. The outages were consistent with Category B and Category C requirements (single element and multiple element outages).

9.2 Transient Stability Results

The study identified that with the addition of Phase II projects and upgrades in place to mitigate base case and outage related overload problems, no new transient instability problems were identified in the East of Pisgah Subarea. However, in the North of Kramer and Lugo Hub Subareas, multiple N-1 and N-2 outages required new SPS to mitigate against stability concerns. The North of Kramer Subarea SPSs are detailed in Section 11.2.

The study concluded that the Phase II Projects in SCE's East of Lugo Bulk System would not cause the transmission system to go unstable under Category B and Category C Outages. Transient stability plots for summer peak and off-peak load conditions are provided in Appendix F.

10. Post-Transient Voltage Stability Analysis

A limited Phase II post-transient voltage stability analysis was performed. This post-transient analysis focused on evaluating the system after the inclusion of all transmission upgrades including the use of the identified SPS and with the implementation of the proposed congestion management. With such upgrades in place as well as the use of SPS and congestion management, the study did not identify any East of Lugo Bulk system post-transient stability problems.

11. Mitigation of Overloaded Facilities

The mitigation requirements triggered by Phase II projects, based on the results described in Sections 6-10 above, are as follows.

11.1 Plan of Service Reliability Network Upgrades

Plan of Service Reliability Network Upgrades for Phase II projects in the East of Lugo Bulk System are discussed in detail in each individual project report (Appendix A).

11.2 Reliability Network Upgrades

11.2.1 Special Protection Systems (SPS)

Note: The SPS Relays to be installed at each Generating Facility have been addressed as part of the Interconnection Facilities Elements of this report. The required diverse – route telecommunication channels and related terminal equipment at each Generating Facility have been addressed as part of the Interconnection Facilities Elements of this report.

11.2.1.1 SPS – 1

Trip Interconnections Queue #488 and Queue #503, interconnected at the SCE owned segment of the Eldorado 220kV Bus, Queue #502, interconnected at the Primm 220kV Bus and Queue #593, interconnected to the Mohave Switchyard 500kV Bus, under the Single Contingency outage of the Colorado River – Palo Verde 500kV T/L.

Substations:

Colorado River Substation – SPS Central Processing Location
Install three N60 Relays for each SPS A and SPS B (Total of six relays) for line monitoring, logic processing and sending of generator tripping signals.

Install one SEL-2407 Satellite Synchronized Clock.

Palo Verde G. S. 500kV Switchyard – Non SCE Facility (For Information Only)
Install two N60 Relays for each SPS A and SPS B (Total of four relays) for line monitoring.

Install one SEL-2407 Satellite Synchronized Clock.

Telecommunications:

Use existing infrastructure to provide all diverse – route telecommunications channels required.

Install all required light-wave, channel and related terminal equipment at the Colorado River Substation and the Alhambra Communications Site and microwave equipment at the Mohave Switchyard and the existing Christmas Tree, Opal and Red Mountain Communications Sites to provide the required interface between the existing channels and the SPS Relays.

Also install a new Antenna Tower at the Red mountain Communications Site.

Power System Control:
Install two "Twin RTU's" at Colorado River Substation to support the SPS.

11.2.1.2 SPS – 2

Incorporate the Interconnections addressed on SPS – 1 into the existing (Pre Queues 1 and 2) SPS tripping Serial Projects Queues #68, #240 and #242 under the Double Contingency outages of the Lugo – Pisgah No.1 and No.2 500kV T/L's.

Substations:

Pisgah Substation – SPS Central Processing Location
Install four N60 Relays for each SPS A and SPS B (Total of eight relays) for line monitoring, logic processing and sending of generator tripping signals.
Install one SEL-2407 Satellite Synchronized Clock.

Lugo Substation
Install one N60 Relays for each SPS A and SPS B (Total of two relays) for line monitoring.
Install one SEL-2407 Satellite Synchronized Clock.

Telecommunications:

Use existing infrastructure to provide all diverse – route telecommunications channels required.

Install all required light-wave, channel and related terminal equipment at the Pisgah Substation and the Alhambra Communications Site and microwave equipment at the Mohave Switchyard and the existing Christmas Tree, Opal and Red Mountain Communications Sites to provide the required interface between the existing channels and the SPS Relays.

Also install a new Antenna Tower at the Red Mountain Communications Site.

Power System Control:
Install two "Twin RTU's" at Pisgah Substation to support the SPS,

11.2.1.3 SPS – 3

Trip the Interconnections addressed on SPS – 1 under the following Double Contingency outages:

- N – 2 Outages of Cima – Eldorado – Pisgah No.1 220kV and Nipton – Pisgah 500kV T/L's
- N – 2 Outages of Cima – Eldorado – Pisgah No.2 220kV and Nipton – Pisgah 500kV T/L's

Substations:

Pisgah Substation – SPS Central Processing Location
Install three N60 Relays for each SPS A and SPS B (Total of six relays) for line monitoring, logic processing and sending of generator tripping signals.

Install one SEL-2407 Satellite Synchronized Clock.

Nipton Substation
Install one N60 Relays for each SPS A and SPS B (Total of two relays) for line monitoring.

Install one SEL-2407 Satellite Synchronized Clock.

Eldorado Substation
Install one N60 Relays for each SPS A and SPS B (Total of two relays) for line monitoring.

Install one SEL-2407 Satellite Synchronized Clock.

Telecommunications:

Use existing infrastructure to provide all diverse – route telecommunications channels required.

Install all required light-wave, channel and related terminal equipment at the Eldorado, Nipton and Pisgah Substations and the Alhambra Communications Site and microwave equipment at the Mohave Switchyard and the existing Christmas Tree, Opal and Red Mountain Communications Sites to provide the required interface between the existing channels and the SPS Relays.

Also install a new Antenna Tower at the Red mountain Communications Site.

Power System Control:

Install two "Twin RTU's" at Pisgah Substation to support the SPS,

11.2.1.4 SPS – 4

Trip Queue #491 under the following Single and Double Contingency outages:

- N – 1 Outage of Cool Water – River 115kV Line
- N – 1 Outage of Kramer – Tortilla 115kV Line
- N – 1 Outage of Kramer – Cool Water 115kV Line
- N – 1 Outage of Cool Water – SEGS – Tortilla 115kV Line
- N – 1 Outage of Jasper – Lugo 220kV T/L – SEE NOTE BELOW
- N – 1 Outage of Kramer No.2A 220/115 kV Transformer Bank
- N – 1 Outage of Cool Water – Jasper 220 kV T/L
- N – 2 Outages of Kramer – Roadway and Kramer – Roadway – Victor 115kV Lines

Note: Include the tripping of Interconnection CAISO Q552 under the Single Contingency outage of the Jasper – Lugo 220kV T/L

Substations:

Kramer Substation – SPS Central Processing Location

Install six N60 Relays for each SPS A and SPS B (Total of twelve relays) for line monitoring, logic processing and sending of generator tripping signals.

Install one SEL-2407 Satellite Synchronized Clock.

Cool Water G.S. 115kV Switchyard

Install two N60 Relays for each SPS A and SPS B (Total of four relays) for line monitoring.

Install one SEL-2407 Satellite Synchronized Clock.

Jasper Substation

Install one N60 Relays for each SPS A and SPS B (Total of two relays) for line monitoring.

Install one SEL-2407 Satellite Synchronized Clock.

River Substation

Install one N60 Relays for each SPS A and SPS B (Total of two relays) for line monitoring.

Install one SEL-2407 Satellite Synchronized Clock.

Roadway Substation
Install one N60 Relays for each SPS A and SPS B (Total of two relays) for line monitoring.

Install one SEL-2407 Satellite Synchronized Clock.

Tortilla Substation
Install one N60 Relays for each SPS A and SPS B (Total of two relays) for line monitoring.

Install one SEL-2407 Satellite Synchronized Clock.

Victor Substation
Install one N60 Relays for each SPS A and SPS B (Total of two relays) for line monitoring.

Install one SEL-2407 Satellite Synchronized Clock.

Telecommunications:

Use existing infrastructure to provide all diverse – route telecommunications channels required.

Install all required light-wave, channel and related terminal equipment at the Kramer, Lugo, Tortilla, Roadway, Jasper, and Victor substations and the Alhambra Communications Site to provide the required interface between the existing channels and the SPS Relays.

Power System Control:
Install two "Twin RTU's" at Kramer Substation to support the SPS.

11.2.1.5 Expand Victor Area SPS

Expand the existing Victor Area SPS to include Q589 project. The SPS is monitoring the existing Lugo – Victor No.1 and No.2 220 kV T/Ls and trips generation under for loss of one or both lines.

NOTE: The SPS Relays to be installed at the Generating Facility have been already addressed as part of the Interconnection Facilities Elements of this report.

Power System Control
Expand existing RTU's at Victor Substation to add the project to the SPS as the project interconnects.

11.2.1.6 Short Circuit Duty Mitigation (SCD)

Vincent Substation
Upgrade four (4) 500 kV circuit breakers.

Lugo Substation
Upgrade six (6) 220 kV circuit breakers.

Windhub Substation
Split the bus by performing the following:

1. Equip one (1) 220 kV position

11.3 Delivery Network Upgrades

11.3.1 Cool Water – River 115kV Line – Line Upgrade to 1,090A Rating

The existing structures are not adequate for the 954SAC Conductor that would be needed for the required line rating.

Dismantle approximately sixteen miles of single circuit lattice structures and related conductors and re-build using new light-weight poles within the existing Right of Way.

Telecommunications
Install two diverse – path telecommunications channels between the Cool Water G.S. 115kV Switchyard and the new River Substation to support the new Line Protection Relays.

The Primary Circuit requires the installation of approximately 89,500 Ft. of new Fiber Optic Cable supported by the new 115kV Structures except for a 3,835 Ft. segment of underground construction with nine 4 Ft. by 6 Ft. by 7 Ft. Manholes.

The Secondary Circuit will be installed away from the existing 115kV Corridor and requires the installation of approximately 117,415 Ft. of Fiber Optic Pole Line using mostly existing poles plus the addition of six new ones and a 3,585 Ft. segment of underground construction with eleven 4 Ft. by 6 Ft. by 7 Ft. Manholes.

Also install all required light-wave, channel and related terminal equipment at each station to provide the required interface between the fiber optic channels and the Line Protection Relays.

Power System Control
Install new RTU at River Substation

Real Properties, Transmission Projects Licensing, and Corporate Environmental Health and Safety
Perform all required activities to acquire permits and licensing and conduct all required environmental studies to install the new River Substation and also dismantle and rebuild the new Cool Water – River 115kV Line within the existing Right of Way.

11.3.2 Lugo – Mohave 500 kV T/L Loop-in to Pisgah

Transmission Line:
Install approximately 0.5 Circuit Miles of 500kV Double and Single Circuit Structures equipped with 2-2156KCMIL ACSR Conductors to loop the existing line into Pisgah Substation and form the two new Lugo – Pisgah No.3 and Mohave – Pisgah 500kV T/L's.

Substations:

Pisgah Substation
Install two new dedicated Double Breaker 500kV Line Positions to terminate the new Lugo No.3 and Mohave 500kV Transmission Lines.

This work requires the installation of the following Reliability Network Upgrade Elements at each position:

- One 108 Ft. High by 90 Ft, Wide Dead-End Structure
- Two 500kV 4000A – 50kA Circuit Breakers
- Four 500kV 4000A – 80kA Horizontal-Mounted Group-Operated Disconnect Switches
- One 500kV Line Grounding Switch Attachment
- Twenty Seven 500kV Bus Supports with associated steel pedestals
- Three 0.003MFD 500kV Coupling Capacitor Voltage Transformers with steel pedestals
- Three 500kV Surge Arresters with associated steel pedestals
- Two 500kV 4,000A Wave Traps
- Three 108 Ft. Line Tie-Downs with 3-2500KCMIL SAC Conductors
- 2-2156KCMIL ACSR Conductors as required
- Install the following equipment at the existing MEER Building:
- Two G.E. L90 Current Differential Relays with dual dedicated digital communication channels.
- One SEL 421 Current Differential Relay on RFL 9780 PLCC.
- One RFL 9745 Direct Transfer trip
- One RFL 9780 Direct Transfer trip

Telecommunications:
Install all required light-wave, channel and related terminal equipment at Pisgah Substation to provide the required interface between the fiber optic channels and the Line Protection Relays.

Power System Control:
Expand existing RTU at Pisgah Substation to include monitoring and control of the new Lugo No.3 and Mohave 500kV T/L's Circuit Breakers.

Real Properties, Transmission Projects Licensing, and Corporate Environmental Health and Safety:

Perform all required activities to obtain property and / or easements, acquire permits and licensing and conduct all required environmental studies to install the new segments of 500kV T/L's from the existing 500kV Corridor into Pisgah Substation.

11.3.3 Mohave – Pisgah 500 kV Line Series Capacitor Banks

Substations:
Pisgah Substation
Install one 500kV Line Series Capacitors Bank outside the new Mohave 500kV T/L Line Position equipped as follows:

- Two 110 Ft. High by 90 Ft. Wide 500kV Line Dead End Structure.
- Six Line Drops equipped with 2-2156KCMIL ACSR Conductors.
- Two 500kV Horizontal Mounted – Group Operated Disconnect Switches.
- One 500kV Pantograph Type – Group Operated Capacitor By-Pass 500kV Disconnect Switch.
- The installation above requires an approximate area of 350 Ft. by 250 Ft.

11.3.4 Nipton – Pisgah 500 kV Line Series Capacitor Banks

Substations:
Nipton Substation:
Install one 500kV Line Series Capacitors Banks outside the new Pisgah 500kV T/L Line Position equipped as follows:

- Two 110 Ft. High by 90 Ft. Wide 500kV Line Dead End Structure.
- Six Line Drops equipped with 2-2156KCMIL ACSR Conductors.
- Two 500kV Horizontal Mounted – Group Operated Disconnect Switches.
- One 500kV Pantograph Type – Group Operated Capacitor By-Pass 500kV Disconnect Switch.
- The installation above requires an approximate area of 350 Ft. by 250 Ft.

Pisgah Substation:
Install one 500kV Line Series Capacitors Banks outside the new Mohave 500kV T/L Line Position equipped as follows:

- Two 110 Ft. High by 90 Ft. Wide 500kV Line Dead End Structure.
- Six Line Drops equipped with 2-2156KCMIL ACSR Conductors.
- Two 500kV Horizontal Mounted – Group Operated Disconnect Switches.
- One 500kV Pantograph Type – Group Operated Capacitor By-Pass 500kV Disconnect Switch.
- The installation above requires an approximate area of 350 Ft. by 250 Ft.

11.3.5 Lugo Substation – 500/220 kV Capacity Increase

Lugo Substation:
Increase the 500/220kV station capacity from 2,240MVA to 3,360MVA by installing a new No.3AA 1120MVA 500/220kV Transformer Bank with corresponding 500kV and 220kV Bank Positions.

This expansion requires the following work:

- Extend the existing 500kV North and South Buses
- Extend the existing 220kV North and South Buses
- Install a 500kV Double Breaker Bank Position to connect the new 500/220kV Transformer Bank.
- Install a 220kV Double Breaker Bank Position to connect the new 500/220kV Transformer Bank.
- Install the No.3AA 1,120MVA 500/220kV Transformer Bank equipped with four 373MVA Single Phase Units (Includes one Spare unit) and 13.8kV Tertiary Buses.

Power System Control:

- Expand existing RTU at Lugo Substation to include monitoring and control of the new 500kV and 220kV Transformer Bank Circuit Breakers.

11.3.6 Eldorado Substation – SCE Owned 500/220 kV Capacity Increase

Eldorado Substation – SCE Owned Transformer Banks Area:
Increase the SCE owned 500/220kV station capacity from 1,120MVA to 2,240MVA by installing a new No.3AA 1120MVA 500/220kV Transformer Bank with corresponding 500kV and 220kV Bank Positions.

This expansion requires the following work:

- Extend the existing 500kV North and South Buses
- Extend the existing 220kV North and South Buses
- Install a 500kV Double Breaker Bank Position to connect the new 500/220kV Transformer Bank.
- Install a 220kV Double Breaker Bank Position to connect the new 500/220kV Transformer Bank.
- Install the No.3AA 1,120MVA 500/220kV Transformer Bank equipped with three 373MVA Single Phase Units and 13.8kV Tertiary Buses.

Power System Control:
Expand existing RTU at Eldorado Substation to include monitoring and control of the new 500kV and 220kV Transformer Bank Circuit Breakers

11.3.7 Colorado River – Red Bluff No.3 500kV T/L

Transmission Line:

- Install approximately 31 miles of double-circuit transmission towers (except where elevation restrictions would require two single-circuit)
- Install only one circuit equipped with bundled 2156KCMIL ACSR Conductors

- Install one ½-inch steel OHGW and one OPGW

  NOTE: This line right-of-way (ROW) should be away from the existing ROW supporting existing DPV1 and planned DC-R (Colorado River – Red Bluff No.1 and No.2 500kV T/L Corridor).

Substations:

Colorado River Substation:

- Install a new dedicated Double Breaker 500kV Line Position to terminate the new Red Bluff No.3 500kV Transmission Line. This work requires the installation of the following Network Upgrade Elements:
  - One 108 Ft. High by 90 Ft, Wide Dead-End Structure
  - Two 4000A – 50kA Circuit Breakers
  - Four 4000A – 80kA Horizontal-Mounted Group-Operated Disconnect Switches
  - One Line Grounding Switch Attachment
  - Twenty Seven Bus Supports with associated steel pedestals
  - Three 0.003MFD Coupling Capacitor Voltage Transformers with steel pedestals
  - Three Surge Arresters with associated steel pedestals
  - Two 4,000A Wave Traps
  - Three 108 Ft. Line Tie-Downs with 3-2500KCMIL SAC Conductors
  - 2-2156KCMIL ACSR Conductors as required

- Install the following equipment at the existing MEER Building:
  - Two G.E. L90 Current Differential Relays with dual dedicated digital communication channels
  - One SEL 421 Current Differential Relay on RFL 9780 PLCC
  - One RFL 9745 Direct Transfer trip
  - One RFL 9780 Direct Transfer trip

Red Bluff Substation:

- Install a new dedicated Double Breaker 500kV Line Position to terminate the new Colorado River No.3 500kV Transmission Line. This work requires the installation of the following Network Upgrade Elements:
  - One 108 Ft. High by 90 Ft, Wide Dead-End Structure
  - Two 4000A – 50kA Circuit Breakers
  - Four 4000A – 80kA Horizontal-Mounted Group-Operated Disconnect Switches
  - One Line Grounding Switch Attachment
  - Twenty Seven Bus Supports with associated steel pedestals
  - Three 0.003MFD Coupling Capacitor Voltage Transformers with steel pedestals

- Three Surge Arresters with associated steel pedestals
- Two 4,000A Wave Traps
- Three 108 Ft. Line Tie-Downs with 3-2500KCMIL SAC Conductors
- 2-2156KCMIL ACSR Conductors as required

- Install the following equipment at the existing MEER Building:
  - Two G.E. L90 Current Differential Relays with dual dedicated digital communication channels
  - One SEL 421 Current Differential Relay on RFL 9780 PLCC
  - One RFL 9745 Direct Transfer trip
  - One RFL 9780 Direct Transfer trip

Telecommunications:

- Extend the Colorado River – Red Bluff 500kV T/L OPGW into the Telecommunications Rooms at each of the substations. This work requires:
  - approximately 3,660 ft. of Underground Fiber Optic Cable inside 5-inch conduit and one 4 ft. by 6 ft. by 7 ft. Manhole at Colorado River Substation
  - approximately 3,750 ft. of Underground Fiber Optic Cable inside 5-inch conduit and one 4 ft. by 6 ft. by 7 ft. Manhole at Red Bluff Substation
- **Equipment** - install all required light-wave, channel and related terminal equipment at each station to provide the required interface between the fiber optic channels and the Line Protection Relays.

Power System Control

- Expand existing RTU at Colorado River Substation to include monitoring and control of the new Red Bluff 500kV T/L Circuit Breakers
- Expand existing RTU at Red Bluff Substation to include monitoring and control of the new Colorado River 500kV T/L Circuit Breakers

Real Properties, Transmission Projects Licensing, and Corporate Environmental Health and Safety

Perform all required activities to obtain property and / or easements, acquire permits and licensing and conduct all required environmental studies to install the new Colorado River – Red Bluff 500kV T/L on a dedicated Right of Way separate from the existing No.1 and No.2 T/L's Corridor.

11.3.8 Red Bluff – Valley 500kV T/L

Transmission Line:

- Install approximately 103 miles of double-circuit transmission towers (except where elevation restrictions would require two single-circuit)
- Install only one circuit equipped with bundled 2156KCMIL ACSR Conductors
- Install one ½-inch steel OHGW and one OPGW

NOTE: This line right-of-way (ROW) should be away from the existing ROW supporting existing DPV1 and planned DC-R (Colorado River – Red Bluff No.1 and No.2 500kV T/L Corridor).

Substations:

Red Bluff Substation:

- Install a new dedicated Double Breaker 500kV Line Position to terminate the new Valley 500kV Transmission Line. This work requires the installation of the following Network Upgrade Elements:
  - One 108 Ft. High by 90 Ft, Wide Dead-End Structure
  - Two 4000A – 50kA Circuit Breakers
  - Four 4000A – 80kA Horizontal-Mounted Group-Operated Disconnect Switches
  - One Line Grounding Switch Attachment
  - Twenty Seven Bus Supports with associated steel pedestals
  - Three 0.003MFD Coupling Capacitor Voltage Transformers with steel pedestals
  - Three Surge Arresters with associated steel pedestals
  - Two 4,000A Wave Traps
  - Three 108 Ft. Line Tie-Downs with 3-2500KCMIL SAC Conductors
  - 2-2156KCMIL ACSR Conductors as required

- Install the following equipment at the existing MEER Building:
  - Two G.E. L90 Current Differential Relays with dual dedicated digital communication channels
  - One SEL 421 Current Differential Relay on RFL 9780 PLCC
  - One RFL 9745 Direct Transfer trip
  - One RFL 9780 Direct Transfer trip

Valley Substation:

- Install a new dedicated Double Breaker 500kV Line Position to terminate the new Red Bluff 500kV Transmission Line. This work requires the installation of the following Network Upgrade Elements:
  - One 108 Ft. High by 90 Ft, Wide Dead-End Structure
  - Two 4000A – 50kA Circuit Breakers

- Four 4000A – 80kA Horizontal-Mounted Group-Operated Disconnect Switches
- One Line Grounding Switch Attachment
- Twenty Seven Bus Supports with associated steel pedestals
- Three 0.003MFD Coupling Capacitor Voltage Transformers with steel pedestals
- Three Surge Arresters with associated steel pedestals
- Two 4,000A Wave Traps
- Three 108 Ft. Line Tie-Downs with 3-2500KCMIL SAC Conductors
- 2-2156KCMIL ACSR Conductors as required

- Install the following equipment at the existing MEER Building:
  - Two G.E. L90 Current Differential Relays with dual dedicated digital communication channels
  - One SEL 421 Current Differential Relay on RFL 9780 PLCC
  - One RFL 9745 Direct Transfer trip
  - One RFL 9780 Direct Transfer trip

500kV Line Series Capacitors (Red Bluff – Valley Corridor)

- Grade and site prepare areas for line series capacitors
- Install new grounding grid, interior driveways and control cable trenches
- Install two 500kV Line Series Capacitors Banks on the new Red Bluff – Valley 500kV T/L. Each Capacitor Bank will be equipped as follows:
  - Two 110 Ft. High by 90 Ft. Wide 500kV Line Dead End Structure
  - Six Line Drops equipped with 2-2156KCMIL ACSR Conductors
  - Two Horizontal Mounted – Group Operated Disconnect Switches
  - One Pantograph Type – Group Operated Capacitor By-Pass 500kV Disconnect Switch
  - One Mechanical-Electrical Equipment Room (MEER)
  - The installation above requires an approximate area of 350 Ft. by 250 Ft.

Telecommunications:

- Extend OPGW at each substation and series capacitor site from the dead-end structure inside each substation and capacitor site into the MEER/Communications Room at each location with FO cable. This requires approximately 1665' of new conduit inside the switchyard at each location

- **Equipment** - install all required light-wave, channel and related terminal equipment at each station and series capacitor site to provide the required interface between the fiber optic channels and the Line Protection Relays.

Power System Control

- Expand existing RTU at Red Bluff Substation to include monitoring and control of the new Valley 500kV T/L Circuit Breakers
- Expand existing RTU at Valley Substation to include monitoring and control of the new Red Bluff 500kV T/L Circuit Breakers

Real Properties, Transmission Projects Licensing, and Corporate Environmental Health and Safety

Perform all required activities to obtain property and / or easements, acquire permits and licensing and conduct all required environmental studies for the two 500kV Line Series Capacitor sites.

11.3.9 Red Bluff Substation 500/220kV Capacity Increase

Red Bluff No.2 500/220 kV Transformer Banks

- Increase the 500/220kV station capacity from 1,120MVA to 2,240MVA by installing a new No.2AA 1120MVA 500/220kV Transformer Bank with corresponding 500kV and 220kV Bank Positions. This expansion requires the following work:
    - Extend the existing 500kV North and South Buses
    - Extend the existing 220kV North and South Buses
    - Install a 500kV Double Breaker Bank Position to connect the new 500/220kV Transformer Bank
    - Install a 220kV Double Breaker Bank Position to connect the new 500/220kV Transformer Bank
    - Install the No.2AA 1,120MVA 500/220kV Transformer Bank equipped with three 373MVA Single Phase Units and 13.8kV Tertiary Buses

Power System Control

Expand existing RTU at Red Bluff Substation to include monitoring and control of the new 500kV and 220kV Transformer Bank T/L Circuit Breakers.

11.4 Distribution Upgrades

Short-Circuit Duty (SCD) Mitigations
Windhub Substation

Split the bus by performing the following:

1. Equip one (1) 66 kV position
2. Install one (1) 220/66 kV transformer

Refer to the individual Appendix As for Distribution Upgrades.

12. Environmental Evaluation / Permitting

12.1 CPUC General Order 131-D

The California Public Utilities Commission's (CPUC) General Order 131-D (GO 131-D) sets for the permitting requirements for certain electrical and generation facilities. GO 131-D was established by the CPUC to be responsive to: the requirements of the California Environmental Quality Act (CEQA); the need for public notice and the opportunity for affected parties to be heard by the CPUC; and the obligations of the utilities to serve their customers in a timely and efficient manner.

Electric facilities between 50 and 200 kV are subject to the CPUC's Permit to Construct (PTC) review specified in GO 131-D, Section III.B. For facilities subject to PTC review, or for over 200 kV electric facilities subject to Certificate of Public Convenience and Necessity (CPCN) requirements specified in GO 131-D, Section III.A, the CPUC reviews utility PTC or CPCN applications pursuant to CEQA and serves as Lead Agency under CEQA. Section IX of GO 131-D discusses the requirements for PTC and CPCN applications.

Generally, SCE takes approximately a minimum of 6-18 months to assemble a CPCN or PTC application, the majority of which time involves developing the required Proponent's Environmental Assessment (PEA). The CPUC review of such applications may take anywhere from 8 – 36 months depending on the specific project.

12.2 CPUC General Order 131-D – Permit to Construct/Exemptions

GO 131-D provides for certain exemptions from the CPUC PTC requirements for facilities between 50 and 200 kV. For example, Exemption f of GO 131-D (Section III.B.1.f) exempts from CPUC PTC permitting requirements power lines or substations between 50 - 200 kV to be constructed or relocated that have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA document (Environmental Impact Report or Negative Declaration) finds no significant unavoidable environmental impacts caused by the proposed line or substation. Note, GO 131-D, Section III.B.2, discusses the conditions under which PTC exemption shall not apply (consistent with CEQA Guidelines).

After lead agency approval of the final CEQA document which confirms there are no significant environmental impacts associated with the SCE scope of work, SCE may be eligible to use Exemption f, and in doing so would follow certain limited public noticing requirements, including filing an informational Advice Letter at the CPUC, posting the project site/route, providing notice to the local jurisdicition(s) planning director and the executive director of the California Energy Commission (CEC), and advertising the project notice, for once a week for two weeks successively in a local newspaper. As part of an agreement with the CPUC Energy Division, SCE informally provides a copy of the final CEQA document to the CPUC Energy Division for reference when the Advice Letter is pending before the CPUC.

Note, the CPUC rules for Advice Letters consider an Advice Letter to be in effect on 30th calendar day after the date filed, and GO 131-D specifies a minimum period of 45-days between advertising the notice for the project and when construction can occur.

Typically, SCE may proceed with construction 45-days after it has filed its Advice Letter and has posted and advertised the project notice unless a protest is filed and/or CPUC staff suspends the Advice Letter. If protests are filed, they must address whether SCE has properly claimed the exemption. SCE has 5 business days to respond to the protest and the CPUC will typically take a minimum of 30 days to review the protest and SCE's response, and either dismiss the protests or require SCE to file a Permit to Construct. SCE has no control over the time it takes the CPUC to respond when issues arise. If the protest is granted, SCE may then need to apply for a formal permit to construct the project (i.e., Permit to Construct).

If SCE facilities are not included in the larger project's CEQA review, or if the project does not qualify for the exemption due to significant, unavoidable environmental impacts, or if the exemption is subject to the "override" provision in GO 131-D, Section III.B.2, SCE may need to seek approval from the CPUC (i.e., Permit to Construct) taking as much as 18 months or more since the CPUC would need to conduct its own environmental evaluation (i.e., Mitigated Negative Declaration or Environmental Impact Report).

Note, for projects undergoing no CEQA review but instead only undergoing a review under the National Environmental Policy Act (NEPA) due to the lead agency being a federal agency (such as the BLM), GO 131-D technically does not allow for the use of Exemption f when the environmental review is conducted only pursuant to NEPA and does not have a CEQA component. As such, SCE would need to review such projects on a case-by-case basis with the CPUC to determine if the CPUC would allow the project to proceed under Exemption f or instead allow SCE to proceed under an "expedited" PTC application by attaching the NEPA document in lieu of a PEA.

For projects that are not eligible for Exemption f, but have already undergone CEQA or NEPA review, SCE may be able to file an "expedited" PTC application, which typically takes the CPUC approximately 4-6 months to process.

12.3 CPUC General Order 131-D – Certificate of Public Convenience & Necessity (CPCN) Exceptions

When SCE's transmission lines are designed for immediate or eventual operation at 200 kV or more, GO 131-D requires SCE to obtain a Certificate of Pubic Convenience and Necessity (CPCN) from the CPUC unless one of the following exceptions applies: the replacement of existing power line facilities or supporting structures with equivalent facilities or structures, the minor relocation of existing facilities, the conversion of existing overhead lines (greater than 200 kV) to underground, or the placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built.

Unlike Exemption f relating to the exemptions allowed from a Permit to Construct for electric facilities between 50 – and 200 kV, no such exemption exists for electric facilities over 200 kV transmission lines that have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA document finds no significant unavoidable environmental impacts caused by the proposed line or substation. Accordingly, SCE would

need to consult on a case-by-case basis with the CPUC for such projects CPUC would allow the project to proceed "exempt" or instead allow SCE to proceed under an "expedited" CPCN application by attaching the final CEQA document in lieu of a SCE Proponent's Environmental Assessment. Such an expedited CPCN with the environmental review already completed by the lead agency that permitted the Interconnection Customer's generator project typically may take from only 4-6 months for the CPUC to process.

12.4 CPUC General Order 131-D – General Comments Relating to Environmental Review of SCE Scope of Work as Part of the Larger Generator Project

For the benefits and reasons stated above, It is assumed that the Interconnection Customer will include SCE's Interconnection Facilities and Network Upgrades work scope (including facilities to be constructed by others and deeded to SCE) in the Interconnection Customer's environmental reports/applications submitted to the lead agency permitting the Interconnection Customer's larger generator project (e.g., California Energy Commission or applicable local, state or federal permitting agency, such as the Bureau of Land Management), and that such agencies will review the potential environmental impacts associated with SCE's work scope in any environmental document issued. This may enable SCE to proceed "exempt" from CPUC permitting requirements or under an "expedited" PTC or CPCN. However, depending on certain circumstances, the CPUC may still require SCE to undergo a standard PTC or CPCN for the generator tie line and Network Upgrades work associated with the Interconnection Customer's Project. SCE may also be required to obtain other authorizations for its interconnection facilities and network upgrades. Hence, the SCE's facilities needed for the project interconnection could require an additional two years, or more, to license and permit. The cost for obtaining any of this type of permitting is not included in the cost estimates.

Please see General Order 131-D. This document can be found in the CPUC's web page at:

http://www.cpuc.ca.gov/PUBLISHED/GENERAL_ORDER/589.htm

12.5 CPUC Section 851

Because SCE is subject to the jurisdiction of the CPUC, it must also comply with Public Utilities Code Section 851. Among other things, this code provision requires SCE to obtain CPUC approval of leases and licenses to use SCE property, including rights-of-way granted to third parties for Interconnection Facilities. Obtaining CPUC approval for a Section 851 application can take several months, and requires compliance with the California Environmental Quality Act (CEQA). SCE recommends that Section 851 issues be identified as early as possible so that the necessary application can be prepared and processed. As with GO 131-D compliance, SCE recommends that the project proponent include any facilities that may be affected by Section 851 in the lead agency CEQA review so that the CPUC does not need to undertake additional CEQA review in connection with its Section 851 approval.

12.6 SCE scope of work NOT subject to CPUC General Order 131-D

Certain SCE facilities and scope of work may not be subject to CPUC's GO 131-D. In such instances, SCE will follow the requirements of all applicable environmental laws and regulations. In some cases, SCE will be required to obtain permits for SCE facilities and

scope of work from state and federal agencies under other environmental laws and regulations, such as California Fish and Game Code, Clean Water Act, and Endangered Species Act. State and federal agencies may be required to comply with CEQA and NEPA prior to issuing their permits. Your lead agency may also be required to evaluate SCE's facilities and scope of work as part of your project.

For these reasons, SCE recommends that the Interconnection Customer coordinates with SCE early in its environmental review process to identify the potential need to obtain certain permits for SCE facilities and scope of work. SCE recommends that the Interconnection Customer addresses SCE scope of work and anticipated impacts that would be subject to various environmental laws in its submittals to its lead agency, enabling the lead agency to analyze such impacts during its environmental review process as appropriate. In this manner, the lead agency may coordinate with responsible agencies (under CEQA) or with cooperating agencies (under NEPA) to appropriately analyze impacts of the other agencies' actions and reduce the need for supplemental analyses and amendments to circulated environmental documents. In addition, SCE recommends that the Interconnection Customer coordinates with SCE when obtaining environmental permits to simplify the permit process in case both SCE and the Interconnection Customer require permits issued under the same authorities.

For facilities that are not subject to GO 131-D, once all pre-construction requirements of applicable environmental laws and regulations are complied with, SCE would issue an in-house Environmental Clearance before commencement of its construction activities.

13. Upgrades, Cost and Time to Construct Estimates

The cost estimates are based on the published unit costs, when applicable. Customized costs were developed when the unit costs did not reflect the unique circumstances of a project. The customized costs may include: anticipated purchase of land rights, licensing, environmental mitigation, looping lines into substations, new switchyards, substation upgrades not included in unit costs, and SCE's Interconnection Facilities.

Regardless of the requested Commercial Operating Date, the actual Commercial Operation Dates of the generation projects in Phase II are dependent on the completed construction and energizing of the identified Network Upgrades. Without these upgrades, the new generators may be subject to CAISO's congestion management, including generation tripping. Based on the needed time for permitting, design, and construction, it may not be feasible to complete all the upgrades needed for this cluster before the requested Commercial Operation Dates.

Costs for each generation project are confidential and are not published in the main body of this report. Each IC is receiving a separate Appendix A report, specific only to that generation project, containing the details of the IC's cost responsibilities.

The estimated cost of **Reliability Network Upgrades** identified in this Group Study is assigned to all Interconnection Requests in that Group Study according to the following rules: (a) short circuit related Reliability Network Upgrades will be assigned pro rata on the basis of the short circuit duty contribution of each Large Generating Facility and associated proposed Network Upgrades, (b) for all other Reliability Network Upgrades, the cost will be assigned 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 as listed by the Interconnection Customer in its Interconnection Request. **Plan of Service Reliability Upgrades** are 100% allocated to the particular IC and are detailed in each IC's Appendix A report.

The estimated cost of all **Delivery Network Upgrades** identified in the Deliverability Assessment are assigned to all Interconnection Requests selecting Full Capacity Deliverability Status based on the flow impact of each such Large Generating Facility on the Delivery Network Upgrades as determined by the generation distribution factor methodology.

The estimated cost of all **Interconnection Facilities** is assigned to each Interconnection Request individually. The cost estimates for the Interconnection Facilities are all site specific and details are provided in each individual project report.

The estimated cost of **Distribution Upgrades** is developed by SCE and is not mandated by ISO Tariff. These non-CAISO, non-network costs are not reimbursable.

Table 13.1 Total SCE Cost Allocated to Phase II projects in SCE's East of Lugo System 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	Description	Estimated Cost x 1,000 Constant Dollar (2011) *(Note 3)*	Estimated Cost x 1,000 Constant Dollar (OD Year) *(Note 3)*		Estimated Time to Construct *(Note 1)*
Plan of Service Reliability Network Upgrades	Plan of Service Reliability Network Upgrades for QC1 and QC2 projects in the East of Lugo Bulk System are discussed in detail in each individual project report (Appendix A).					See Appendix A
Reliability Network Upgrades	SPS-4	Trip Queue #491 under the Single and Double Contingency outages (refer to Section 11 for multiple outage conditions)	$5,358	$5,858	2014	24 Months
	Expand Existing Victor Area SPS	Add Q589 to Victor Area SPS	$135	$148	2014	24 Months
	SPS-1	Trip Interconnections under the Single Contingency outage of the Colorado River – Palo Verde 500kV T/L	$5,881	$6,430	2014	24 Months
	SPS-2	Incorporate the Interconnections under the Double Contingency outages of the Lugo – Pisgah No.1 and No.2 500kV T/Ls	$5,769	$6,307	2014	24 Months
	SPS-3	Trip the Interconnections under the following Double Contingency outages: -N – 2 Outages of Cima – Eldorado – Pisgah No.1 220kV and Nipton – Pisgah 500kV T/Ls -N – 2 Outages of Cima – Eldorado – Pisgah No.2 220kV and Nipton – Pisgah 500kV T/Ls	$6,177	$6,754	2014	24 Months
	Short-Circuit Duty (SCD) Mitigation	See Section 11 for description	$20,367	$22,280	2014	24 Months

Delivery Network Upgrades	Cool Water-River 115 kV T/L Re-build	Install approximately 16.0 Miles of new Single Circuit Line equipped with 954 SAC Conductor, one ½-In Steel OHGW and one OPGW.	$66,732	$79,061	2018	72 Months
	No.3 500/220 kV Transformer Bank at Lugo Sub	Install new Lugo No.3AA 500/220 kV transformer bank	$71,698	$80,875	2015	36 Months
	No.2 500/220 kV Transformer Bank at Eldorado Sub	Install new Eldorado No.2AA 500/220 kV transformer bank at SCE-owned Eldorado 220 kV bus	$57,319	$64,656	2015	36 Months
	Loop Lugo-Mohave 500 kV T/L into Pisgah Sub	Loop Lugo-Mohave 500 kV T/L into Pisgah Substation	$32,277	$39,223	2018	72 Months
	Add Series Cap Banks on Nipton-Pisgah & Mohave-Pisgah 500 kV T/Ls	Add series caps on the Nipton-Pisgah & Mohave-Pisgah 500 kV T/Ls	$246,096	$299,058	2018	72 Months
Eastern Delivery Network Upgrades Allocated to EOL Projects	New Red Bluff-Valley 500 kV T/L	Build new Red Bluff-Valley 500 kV T/L	$909,364	$1,135,897	2019	84 Months
	New Colorado River-Red Bluff No.3 500 kV T/L	Build new Colorado River-Red Bluff No.3 500 kV T/L	$158,158	$197,557	2019	84 Months
Distribution Upgrades	SCD Mitigation	See Section 11 for description	$13,675	$14,992	2014	24 Months

Total Cost	**$1,599,006**			**84 Months**

Note1: 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 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 LGIAs

Note 3: SCE's Phase II cost estimating is done in 'constant' dollars 2011 and then escalated to the estimated O.D.year. For the Phase II Phase II study, the estimated O.D. is derived by assuming the duration of the work element will begin approximately in January 2012, which is roughly the CAISO tariff scheduled completion date of the Phase II study plus 90 days for the LGIA 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 2014. 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.

14. Coordination with Affected Systems

CAISO LGIP Tariff Appendix Y section 3.7 requires CAISO to coordinate with any affected systems that are potentially impacted by the projects in Phase II Study.

The East of Lugo Bulk System Phase II projects located within the East of Pisgah Subarea were found to impact neighboring utilities in the vicinity of Eldorado. In particular, these projects were found to result in thermal overload conditions for which system upgrades were recommended. The upgrades involve both transmission line upgrades as well as use of SPS under outage conditions. Because typical SPS design requires line monitoring, coordination with the affected systems may be required to ensure SPS design can be appropriately developed.

Appendix A – Q#593

Nextlight Renewable Power, LLC

Fort Mojave Solar Project

Queue Cluster 1 & 2 Phase II Final Report

California ISO
Your Link to Power

August 26, 2011

This study has been completed in coordination with Southern California Edison per CAISO Tariff Appendix Y), including Appendix 8 of the GIP ("Transition of Existing SGIP Interconnection Requests to the GIP") for Interconnection Requests in a Queue Cluster Window

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Attachments:

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

1. Executive Summary

Nextlight Renewable Power, LLC an Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to the California Independent System Operator Corporation (CAISO) for their proposed Fort Mojave Solar Project (the Project), interconnecting to the CAISO Controlled Grid. The Project is a Full Delivery solar plant using photovoltaic inverter technology with an output of 310 MW to the proposed Point of Interconnection (POI) at the jointly-owned Mohave 500 kV Switchyard[1] in Laughlin, Nevada. The customer has requested an In-Service date of April 15, 2013 and a Commercial Operation Date of July 7, 2014.

In accordance with Federal Energy Regulatory Commission (FERC) approved 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"), the Project was grouped with the Queue Cluster 1 (QC1) and Queue Cluster 2 (QC2) 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.

The group report has been prepared separately identifying the combined impacts of all projects in the group on the CAISO Controlled Grid. This report focuses only on the impacts of this Project.

The report provides the following:

1. Transmission 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 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 11 of this report.

The non-binding cost estimate of Interconnection Facilities[2] to interconnect the Project is approximately **$12,966,000** including ITCC[3]. The maximum cost responsibility for the SCE Network Upgrades[4] to interconnect the Project is **$140,646,000** and the cost of the SCE Distribution Upgrades[5] is **$561,000**.

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[1] The Mohave 500 kV Switchyard is owned in varying amounts by SCE, NV Energy, Salt River Project, and LADWP.

[2] The transmission facilities necessary to physically and electrically interconnect the Project to the CAISO Controlled Grid at the point of interconnection.

[3] 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.

[4] The SCE transmission facilities, other than Interconnection Facilities, beyond the point of interconnection necessary to physically and electrically interconnect the Project safely and reliably to the CAISO Controlled Grid

[5] These upgrades are not identified in ISO tariff, and are not reimbursable.

The estimated costs above have been provided in 2011 constant dollars. Table 11.1 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 facilities is approximately 84 months from the signing of the Generator Interconnection Agreement (GIA).

2. Project and Interconnection Information

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

Table 2-1: Fort Mojave Solar Project General Information

Project Location	Near the intersection of River Rd. and Capri Rd. in Needles, California, San Bernardino County, 92363
SCE Planning Area	East of Lugo-East of Pisgah
Number and Type of Generators	160 NextLight Renewable Power PV Inverter Units
Interconnection Voltage	500 kV
Maximum Generator Output	320 MW
Generator Auxiliary Load	10 MW
Maximum Net Output to Grid	310 MW
Power Factor Regulation Range	0.95 (leading) to 0.90 (lagging) per the IR
Step-up Transformer(s)	One three phase 500/230/13.8 kV transformer, rated for 300 MVA with 4.3% (H-X) Z @ 180 MVA, 2.6% (H-Y) Z @ 33 MVA, and 1.4% (X-Y) Z @ 33 MVA, two three phase 230/34.5/13.8 kV transformers rated for 150 MVA with 9% (H-X) Z @ 90 MVA, 5% (H-Y) @ 90 MVA, 8% (X-Y) @ 90 MVA
Point of Interconnection	Jointly-owned Mohave 500 kV switchyard
Commercial Operation Date	April 15, 2013 (customer requested date)

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.

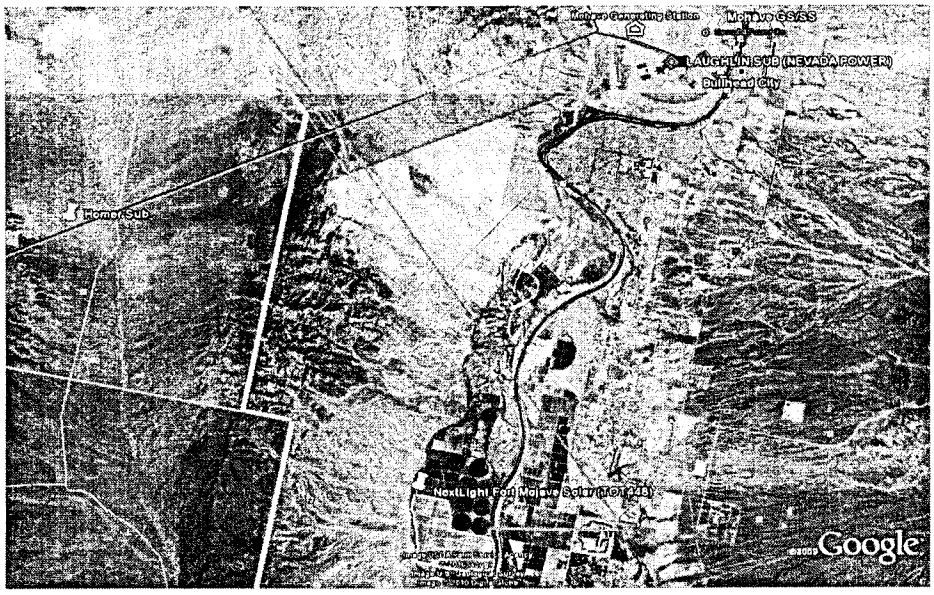

Figure 2-1 : Map of the Project

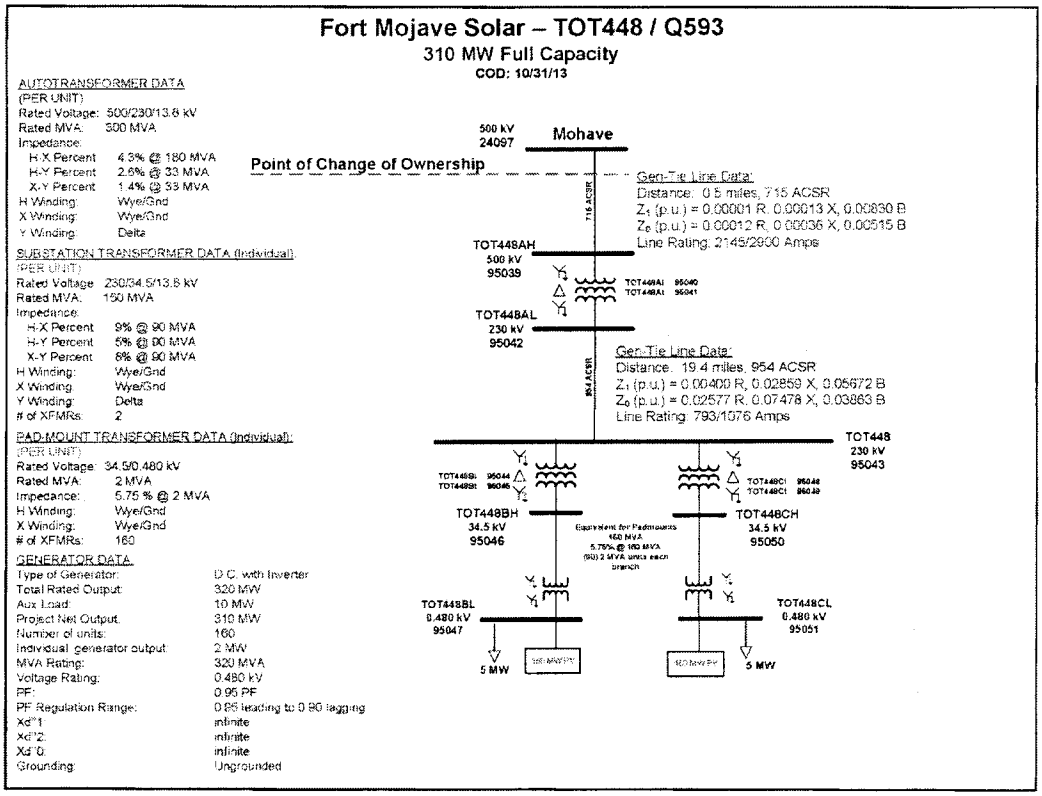

Figure 2-2: Proposed Single Line Diagram

3. Study Assumptions

For detailed assumptions, please refer to the main report. The following assumptions are only specific to the Project:

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

- The segment of 500kV Gen Tie Line inside the Mohave Switchyard Property Line.
- The segments of each one of the two generator – owned telecommunications channels inside the Mohave Switchyard Property Line.
- The location of this Project is not within SCE service territory for retail service. The IC is responsible for making all retail service arrangements with the local retail service provider.
- The SCE Meters will be connected to the generator – owned voltage and current transformers to be installed for their CAISO metering.

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

- The 500kV Gen Tie Line from the Generating Facility to the last structure outside the Mohave Switchyard Property Line.
- The 500kV Gen Tie Line Optical Ground Wire (OPGW) and an additional Fiber Optic Pole Line to provide two diverse – route telecommunication paths required for the Line Protection Relays and the Special Protection System (SPS).
- The required CAISO Metering Equipment (Voltage and Current Transformers and CAISO Meters.

  NOTE: The Metering Voltage and Current Transformers installed for the CAISO Metering will also be used for the SCE owned Retail Meters.

The following Line Protection Relays to be installed at the Generating Facility end of the 500kV Gen Tie Line:

- Two G.E. L90 Current Differential Relays with dual dedicated digital communication channels to the Mohave Switchyard.
- One SEL 421 Current Differential Relay on RFL 9780 PLCC.
- One RFL 9745 Direct Transfer trip
- One RFL 9780 Direct Transfer trip

The following SPS Relays to be installed at the Generating Facility:

- Two N60 relays (One each for SPS A and B) to trip the Main Generator Breaker.
- One SEL – 2407 Satellite Synchronized Clock.

4. Power Flow Analysis

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

4.1 Overloaded Transmission Facilities

Category "A"

- SCE-owned Eldorado 500/220 kV transformer

Category "B"

- Lugo-Victorville 500 kV T/L

Category "C"

- Lugo-Victorville 500 kV T/L

4.2 Power Flow Non-Convergence

There were no non-convergence issues identified by the addition of this project with all proposed system upgrades.

4.3 Recommended Mitigations

A combination of congestion management and SPS to trip the Project under identified contingency outage conditions is required to mitigate the power flow impacts of the Project described above. See the group report for additional details.

The scope of the mitigations assigned to the Project are as follows:
(Refer to Section 11 for a brief description of the upgrades)

Reliability Network Upgrades

- New SPS – 1
- New SPS – 2
- New SPS – 3
- Short Circuit Duty (SCD) Mitigation

Delivery Network Upgrades

- Lugo-Mohave 500 kV T/L looped into Pisgah 500 kV substation
- Add series capacitors banks at the Pisgah end of the new Nipton-Pisgah 500 kV T/L and Mohave-Pisgah 500 kV T/L
- New Red Bluff – Valley 500 kV T/L
- Build Colorado River-Red Bluff No.3 500 kV T/L

Distribution Upgrades

- Short Circuit Duty (SCD) Mitigation

5. Short Circuit Analysis

Short circuit studies were performed to determine the fault duty impact of adding the 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 Phase II is determined. Each project in Phase II will be responsible for its share of the upgrade cost based on the rules set forth in CAISO Tariff Appendix Y.

5.1 Short Circuit Study Input Data

The following input data provided by the Applicant of the Project was used in this study:

NextLight Renewable Power PV Inverters:

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

Generation Step-up Transformers (total of one)

Three-phase 500/220/13.8 kV transformer, rated for 180/240/300 MVA OA/FA/FA @ 65 degree C temperature rise with 4.3% (H-X) Z @ 180 MVA, 2.6% (H-Y) Z @ 33 MVA, and 1.4% (X-Y) Z @ 33 MVA

Station Step-up Transformers (total of two)

Three-phase 230/34.5/13.8 kV transformers each rated for 150 MVA OA/FA/FA @ 65 degree C temperature rise with 9% (H-X) Z @ 90 MVA, 5% (H-Y) @ 90 MVA, 8% (X-Y) @ 90 MVA

Generation Tie Line

The generation tie line from the Project to the 500 kV autotransformer was assumed to be 19.4 miles of 954 ACSR conductor.

The generation tie line from the 500 kV autotransformer to the Mohave 500 kV Switchyard was assumed to be 0.5 miles of 715 ACSR conductor

5.2 Results

All bus locations where the Phase II 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 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. In addition, the SCD impact of the associated proposed Network Upgrades was allocated to each Generating Facility using the same percentage assigned for the triggered Network Upgrade.

As discussed in the Group Report, the Phase II 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:

- Upgrade four (4) 500 kV circuit breakers at Vincent Substation
- Upgrade six (6) 220 kV circuit breakers at Lugo Substation
- Split the 66 kV bus at Windhub Substation

Table 5.1 SCD Allocation

Project Name	Vincent		Lugo		Windhub (Reliability)		Total (x1,000)
	% Allocated	Cost (x1,000)	% Allocated	Cost (x1,000)	% Allocated	Cost (x1,000)	
Q593	14.1	$ 1,531	7.4	$ 330	4.1	$ 208	$ 2,068

5.3 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. Reactive Power Deficiency Analysis

Reactive power deficiency analysis was performed with the N-1 loss of the Eldorado-McCullough 500 kV transmission line.

With all proposed system upgrades listed above and in Section 4.3, the power flow studies for Category "B" and Category "C" contingencies indicated that this Phase II project did not cause voltage drops of 5% or more from the pre-project levels, or cause the SCE system to fail to meet applicable voltage criteria. This project, therefore, did not cause any adverse voltage impacts on the CAISO Controlled Grid with the proposed upgrades in place.

Additionally, the interconnection requirements for large asynchronous generation facilities, i.e., wind and solar PV facilities have been modified by FERC. Under the modified requirements, an asynchronous generating facility must operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in the LGIA in order to maintain a specified voltage schedule, but only if the Phase II Interconnection Study shows that such a requirement is necessary to ensure safety or reliability.

A simplified "QV" analysis was performed as part of this Phase II study for the East of Pisgah Subarea. Figure 6-1 shows that the addition of the Phase II projects at unity power factor resulted in an upward shift of the nose of the QV curve by approximately 30 MVAR of reactive reserve margin at the Ivanpah substation under the N-1 outage of the Eldorado-McCullough 500 kV transmission line – indicating a decrease in the reactive margin. The study also indicated that modeling the Phase II projects with 0.95 pf correction capability helped increase the reactive margin at Ivanpah substation as seen by the downward shift closer to the pre-project levels.

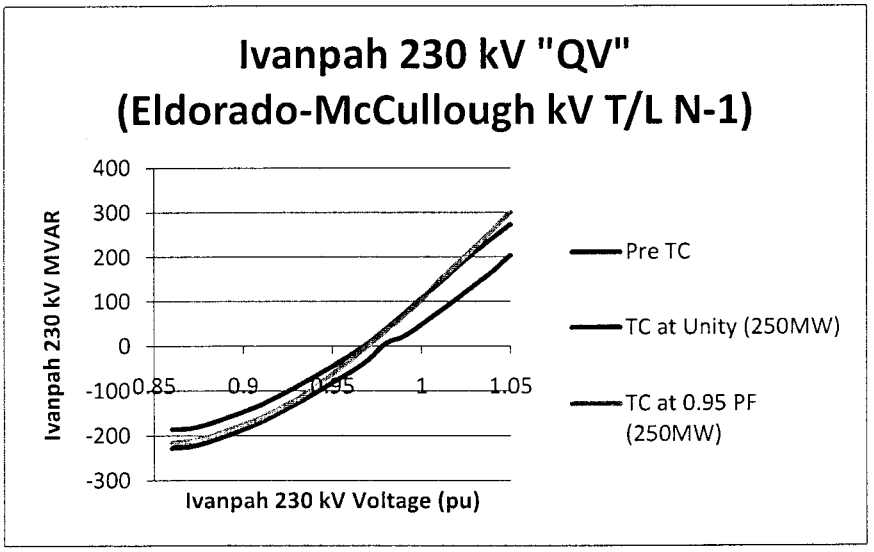

Figure 6-1: Ivanpah 230 kV "QV" (Eldorado-McCullough 500 kV N-1)

In addition, the reactive power flow exchange with neighboring utilities was evaluated to identify incremental reactive demand associated with the Phase II projects located in the East of Pisgah subarea. Based on the load flow results with all transmission elements in-service, the reactive power flow taken in from LADWP on the Eldorado – McCullough 500 kV line increases to 485 MVAR from 317 MVAR, by incrementally 168 MVAR, with the addition of the Phase II projects under the unity power factor assumption. This exceeds the limit of 0 ~ ±200 MVAR range suggested in SCE's System Operating Bulletin No. 0017 (SOB 17), which establishes guidelines on reasonable VAR flow between interconnected utilities and may lead to reliability concerns in LADWP/SCE. To address this significant incremental reactive power exchange, Phase II projects locating in the East of Pisgah area will be required to operate within a power factor range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection.

The power factor correction requirements are for steady state or post-transient and not dynamic conditions, as long as the ultimate dynamic characteristics of each Phase II project remains consistent with the transient stability characteristics exhibited by the models provided by each interconnection customer.

7. Transient Stability Evaluation

Transient stability studies were conducted using 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 Phase II projects begin operation. The generator dynamic data used in the study for the Project is shown in Attachment 1.

7.1 Transient Stability Study Scenarios

Disturbance simulations were performed for a study period of 10 seconds to determine whether the 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 East of Lugo Bulk System were evaluated. For the list of specific line and generator outages evaluated, see the group report.

7.2 Results

Stability analysis was performed for the North and East of Lugo Bulk system to identify "relative" as opposed to "absolute" conclusions regarding the stability impacts of this Phase II queued generation project. In the stability analysis performed in the 500 kV, 220 kV and 115 kV systems with the upgrades in place to mitigate base case and outage related overload problems, no significant transmission system stability problems relative to existing stability criteria were identified.

With all proposed system upgrades listed above and in Section 4.3, the Phase II Projects in SCE's East of Lugo Bulk System would not cause the transmission system to go unstable under Category B and Category C outages. Stability plots are shown in Appendix F of the Group Report.

8. Deliverability Assessment

8.1 On Peak Deliverability Assessment

CAISO performed an On-Peak Deliverability Assessment. The Deliverability Assessment results for Category "A", "B", and "C" are detailed in the East Of Lugo group report. The project contributes to the following overloads.

Category "A"
None

Category "B"
Lugo - Victorville No.1 500 kV Transmission Tie
Devers – Red Bluff No.1 or No.2 500 kV T/L
SCE-owned new Eldorado 500/230 kV AA transformers

Category "C"
Lugo - Victorville No.1 500 kV Transmission Tie
Mohave – Lugo No.1 500 kV T/L
North Gila – Imperial Valley No.1 500 kV T/L

8.2 Recommended Mitigations

Add 2nd AA Transformer Bank at SCE-owned Eldorado 220 kV Bus

The addition of the Phase II projects in the Eldorado area overloads the future SCE-owned Eldorado No.1AA 500/220 kV transformer bank under normal condition (Category "A"). Second new AA bank at SCE-owned Eldorado 220 kV Bus is required to eliminate the normal overload

Loop the Mohave – Lugo line into Pisgah 500 kV Substation

To mitigate the thermal overloads for N-2 outage of Pisgah – Lugo 500 kV lines without exaggerating loop the flow issues in the neighboring utility, it is recommended to loop the Mohave–Lugo 500 kV line into Pisgah 500 kV Substation, and to install series capacitor banks on both Pisgah–Nipton and Pisgah–Mohave 500 kV lines. In addition, it is also required to modify the proposed Eldorado Bulk System SPS in order to trip the Phase II projects in the related subarea for the double line outage.

Build a new Colorado River – Red Bluff No.3 500 kV Transmission line

To mitigate the overloads on the Lugo – Victorville 500 kV tie line and the North Gila – Imperial Valley 500 kV line for the N-2 outage of Colorado River – Red Bluff 500 kV lines without exaggerating loop flow issues in the LADWP system, a 31 miles of new Colorado River – Red Bluff 500 kV No.3 line is recommended to be built using single circuit structures equipped with 2-2156KCMIL ACSR Conductors.

Build a new Red Bluff – Valley No.1 500 kV Transmission line

To mitigate the overloads on the Lugo – Victorville 500 kV tie line for the N-2 outages of the Red Bluff – Devers 500 kV lines without exaggerating loop flow issues in the

LADWP system, a 103 miles of new 500 kV transmission line from Red Bluff to Valley with 50% series capacitor banks compensation is recommended. This upgrade will also get rid of the overloads on the North Gila – Imperial Valley 500 kV line for the double outage of the Devers – Red Bluff 500 kV lines, and the overload on the Red Bluff – Devers 500 kV line for the other Red Bluff – Devers 500 kV line

Modify various previous Special Protection Schemes

Various previous SPS triggered by high queued projects need to be modified to accommodate the Project since the Delivery Network Upgrades mentioned above are not adequate to mitigate all the overloads identified.

- **SPS-1: Modify the gen tripping SPS triggered by higher queued projects in Ivanpah/Primm/Eldorado 220 kV system**

  Previously gen tripping Special Protection Scheme triggered by higher queued projects in the Ivanpah/Eldorado 220 kV system needs to be modified so as to mitigate the 500/220 kV AA bank overloads for the outage of other AA bank at the future SCE-owned Eldorado 220 kV bus due to the addition of the Phase II projects, C488, C491, C502 and C503

- **SPS-2: Modify the gen tripping SPS triggered by higher queued projects in Ivanpah/Primm area 115/220 kV system**

  Previously gen tripping Special Protection Scheme triggered by higher queued projects in the Ivanpah 115/220 kV system needs to be modified to cover the Phase II C502 project and the single outage of the Ivanpah - Primm and Primm - Eldorado 220 kV lines so as to avoid the system instability issue in the 115 kV system

- **SPS-4: Modify the East Of Pisgah SPS triggered by higher queued projects in the East Of Lugo area**

  Previously gen tripping Special Protection Scheme triggered by higher queued projects in the East of Pisgahsystem needs to be modified so as to mitigate the Lugo – Victorville 500 kV tie line for various N-1 or N-2 outages

8.3 Operational Deliverability Assessment

The assumptions used to perform the operational Deliverability Assessment are presented in the Group Report. The table below shows the identified deliverability constraints and partial deliverability amounts for the Project.

Table 8.3: Deliverability Constraint and Partial Deliverability Estimate

Overloaded Facility									
Lugo - Victorville 500 kV Tie Line									
Partial Deliverability Percentage	Year								
	2012	2013	2014	2015	2016	2017	2018	2019	2020
			100%	100%	4%	4%	4%	100%	100%

The requested generator In-Service date of September 30, 2012 can't be met due to the anticipated duration of 48 months for the Eldorado 220 kV bus split required to enable Energy Only Interconnection. The requested Full Delivery will not be available until the appropriate Deliverability Network Upgrades are placed into service. Based on the Phase II Study, the estimated date to meet full deliverability is 2019. There is about 4% of its 92 MW Pmax estimated to be deliverable during the years between 2016 and 2019.

9. Operational Studies

9.1 IC Proposed Project Timelines

The latest information provided by the IC has indicated that the proposed In-Service date is April 15, 2013.

9.2 System Upgrade Timelines

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

9.2.1 PTO's Interconnection Facilities

See Section 11

9.2.2 Plan of Service Reliability Network Upgrades

See Section 11

9.2.3 Reliability Network Upgrades

9.2.3.1 Special Protection System (SPS)

This Project is in an area which has a previously identified SPS (Eldorado Area SPS). As a result, this Project will be subjected to the same SPS.

9.2.3.2 Short-Circuit Duty (SCD) Mitigation

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. Timing for breaker upgrades at each of the substations identified as queued ahead is shown below in Table 9.2.1:

Table 9.2.1
Timing of Previously Triggered SCD Mitigation Requirements

Substation	Breakers	Timing Need
Antelope 220 kV	CB4022, CB6022, CB632, CB4042, CB6042, CB61X2, CB4062, CB6062 and CB4072	2012 – Replacement or Operating Procedure required upon in-servicing the second Antelope 500/220 kV Transformer Bank as part of TRTP
Devers 220 kV	CB5022, CB6022, CB4082, CB4092, CB6092, CB Cap1 and CB Cap3	2013 – Will be replaced as part of generation project that operationally triggers the need for breaker replacement
Mira Loma	All East 220 kV Bus Section (Total of 12 circuit breakers)	Operating Procedure when Mira Loma-Vincent 500 kV line is placed into service (estimated 2014)
Etiwanda	All 220 (Total of 24 circuit breakers)	Operating Procedure when Mira Loma-Vincent 500 kV line is placed into service (estimated 2014)
Vincent 220 kV	CB682	2011
Cal Cement 66 kV	CB2, CB4, and CB8	Required when EKWRA Project is placed into service (estimated 2013)

All of the above short-circuit duty impacts have an existing project or appropriate Operating Procedure identified that would address the duty impacts. As a result, these breaker upgrades will not adversely impact the operating date of this project for Energy Only Interconnection.

Timing for breaker upgrades at each of the substations identified as triggered with the inclusion of all Phase II Projects that are part of this Phase II Study is as follows:

Table 9.2.2
Timing of Phase II Triggered SCD Mitigation Requirements

Substation	Breakers	Timing Need
Vincent 500 kV	CB722, CB852, CB952, and CB862	Timing of replacement of these four breakers is tied to actual development of generation projects and completion Deliverability Network Upgrades. Additional review of these breakers will be performed as projects execute interconnection agreements to identify actual timing of these breaker replacements
Lugo 220 kV	CB4032, CB6032, CB4052, CB5052, CB6052, and CB4062	Required when third Lugo 500/220 kV transformer bank is placed into service
Antelope 66 kV	All 66 kV Breakers	Operating Procedure will provide mitigation to all 40 66 kV circuit breakers rated at 40 kA
Windhub 66 kV	All 66 kV Breakers	Network portion of Split Bus Mitigation (including 4th A-Bank) will be needed based on the in-service date of the third Windhub 220/66 kV transformer bank and all generation projects seeking interconnection to SCE's Northern Antelope-Bailey 66 kV System

The timing of need of the above short-circuit duty impacts triggered by the inclusion of the Phase II Projects and all corresponding upgrades is described in the table above. Because the timing of need for the mitigation is dependent on actual timing of generation projects and corresponding upgrades, these breaker upgrades will not adversely impact the operating date of this project for Energy Only Interconnection. Additional review of these circuit breakers will be performed three times a year to evaluate timing of these breaker replacements as projects execute Generation Interconnection Agreements.

9.2.3.3 Subtransmission Upgrades

None

9.2.4 Distribution Upgrades

Timing of the Distribution Upgrades allocated to this project is tied to the timing of the short-circuit duty mitigation at Windhub 66 kV. Refer to Table 9.2.2 for additional details.

9.2.5 Other Energy Only Operational Issues

The requested interconnection point is a joint-owned facility. Consequently, interconnection agreement will require approval by all participating owners of the joint-owned facility.

9.3 System Upgrades Required for Full Capacity Service

9.3.1 Triggered Deliverability Upgrades

To provide for the requested Full Delivery, the Phase II study identified the need for significant Delivery Network Upgrades. Specifically, the project has been identified to need the following to achieve full delivery:

a. Loop of the Existing Mohave-Lugo 500 kV T/L into future Pisgah 500 kV forming new Lugo-Pisgah No.3 500 kV and new Mohave-Pisgah 500 kV T/L's

b. New series capacitors on Mohave-Pisgah 500 kV T/L

c. New series capacitor on Nipton-Pisgah 500 kV T/L

d. New Colorado River – Red Bluff No.3 500 kV T/L

e. New Red Bluff – Valley No.1 500 kV T/L

f. Modifications on EOP SPS triggered by high queued projects

The anticipated time to construct all of these Delivery Network Upgrades associated with "Full Delivery" Interconnection is 96 months upon execution of LGIA. Construction of such delivery network upgrades cannot commence until SCE receives all appropriate permitting approvals and licenses.

9.3.2 Previously Triggered Deliverability Upgrades

Previous studies identified the following upgrades which will impact the timing of achieving Deliverability:

Lugo-Pisgah 500 kV Transmission Project

As part of this project, the Pisgah substation will be expanded to 500 kV. Until the Pisgah 500 kV expansion is in service, the existing Mohave-Lugo 500 kV T/L cannot be looped into Pisgah. In addition, the series compensation identified cannot be installed at Pisgah.

Nipton 500 kV Substation

A queued ahead generation interconnection request resulted in the identification of a new Nipton 500 kV Substation which would be connected by looping the existing Eldorado-Lugo 500 kV Transmission line (will also be looped into Pisgah as part of the Lugo-Pisgah 500 kV Transmission Project. Until the Nipton Substation is constructed, series compensation at Nipton cannot be installed.

SCE Owned Eldorado 220 kV Switchrack and 500 kV Transformation

As part of the Transition Cluster, the need for an SCE owned Eldorado 220 kV switchrack was identified as well as installation of one new SCE-owned 500/220 kV transformation. This upgrade will be required to enable installation of a second SCE-owned Eldorado 500/220 kV transformer bank. The operating date for this work will be driven by the execution of interconnection agreements for the projects triggering the need.

9.4 Conclusion

The requested generator In-Service date of July 7, 2014 could be met after the completion of the required Reliability Network Upgrade project to be needed to enable Energy Only Interconnection under the assumptions described in Section 6.3 of the group report. Based on the Operational Deliverbility Assessment, the requested Full Delivery will be available for the first two years after the Project is inserice. But there is about 4% of its Pmax anticipated to be deliverable during the years between 2016 and 2019. The Project will be fully deliverable by the time the appropriate Deliverability Network Upgrades are placed into service. The estimated date to meet full deliverability is 2019.

10. Environmental Evaluation/Permitting

Please see Section 12 of group report.

11. Upgrades, Cost Estimates and Construction schedule estimates

To determine the cost responsibility of each generation project in Phase II, 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. **Transmission:**

   500kV Generation Tie Line

   Install three 500kV Structures and four spans of conductors and OPGW between the last generator – owned structure and the Substation Dead – End Rack at the Mohave Switchyard 500kV Switchyard.

2. **Substations:**

   Mohave Switchyard

   Install the following Interconnection Facilities Components for the termination of the new 500kV Gen Tie Line.

   - One Dead-End Structure.
   - 500kV Line Drop Conductors from the top of the dead End Structure down to the substation terminal equipment.
   - Three 500kV Coupling Capacitor Voltage Transformers.
   - Three 500kV Surge Arresters.
   - Two 500kV Wave Traps and Line Tuners
   - Two G.E. L90 Current Differential Relays with dual dedicated digital communication channels to the Generating Facility.
   - One SEL 421 Current Differential Relay on RFL 9780 PLCC.
   - One RFL 9745 Direct Transfer trip
   - One RFL 9780 Direct Transfer trip

3. **Telecommunications:**

   Install the following equipment to bring the two telecommunication channels to be provided by the Generator into the Mohave Switchyard Telecommunications Room:

   Primary Circuit: From last generator – owned 500kV Gen Tie Line Structure:

   - Approximately 700 Ft. of Underground Fiber Optic Cable inside 5-In. Conduit and two 4 Ft. by 6 Ft. by 7 Ft. Manholes

   Also install all required light-wave, channel and related terminal equipment at each end of both fiber optic channels to interface with the required line Protection and SPS Relays.

4. **Metering Services Organization**

Install a Revenue Metering Cabinet and Revenue Meters required to meter the Retail load at the Generating Facility.

The Generator will provide the required Metering Equipment (Voltage and Current Transformers).

5. **Power System Control**

   Install one RTU 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.

6. **Real Properties, Transmission Project Licensing, Corporate Environmental Health and Safety Organization**

   Obtain easements and / or acquire land, obtain licensing and permits and perform all required environmental activities for the installation of the following project elements if applicable:

   - Segment of 500kV Gen Tie Line within the Mohave Switchyard Property.
   - Segments of underground fiber optic cables within the Mohave Switchyard Property

7. **Other Required Interconnection Facilities that the IC may elect to self-build**

   Install new ADSS Fiber Optic Cable from the Generating Facility to Colorado River Substation to meet the diverse routing requirements for the 220 kV Gen Tie Line Protection and SPS Relays.

   Obtain easements and / or acquire land, obtain licensing and permits and perform all required environmental activities for the installation of the following project element:

   - Approximately 900 Ft. of Underground Fiber Optic Cable inside 5-In. Conduit and two 4 Ft. by 6 Ft. by 7 Ft. Manholes

   The cost of this required scope is included in this study.

PLAN OF SERVICE RELIABILITY NETWORK UPGRADES

Mohave Switchyard – 500kV Switchyard

Install a new dedicated Double Breaker 500kV Line Position to terminate the new 500kV Gen Tie Line.

This work requires the installation of the following Reliability Network Upgrade Elements:

- Two 500kV 4000A – 50kA Circuit Breakers
- Four 500kV 4000A – 80kA Horizontal-Mounted Group-Operated Disconnect Switches
- One 500kV Line Grounding Switch Attachment
- Eighteen 500kV Bus Supports with associated steel pedestals
- 2-1590KCMIL ACSR Conductors as required
- Two GE C60 Breaker Management Relays (Breaker Failure)

All remaining elements of the Line Position not described above have already been addressed as Interconnection Facilities Elements of this same Line Position.

Power System Control
Expand existing RTU at the Mohave Switchyard to include monitoring and control of the new Gen Tie Line Circuit Breakers.

RELIABILITY NETWORK UPGRADES

SPS-1

Trip Interconnections Queue #488 and Queue #503, interconnected at the SCE owned segment of the Eldorado 220kV Bus, Queue #502, interconnected at the Primm 220kV Bus and Queue #592, interconnected to the Mohave Switchyard 500kV Bus, under the Single Contingency outage of the Colorado River – Palo Verde 500kV T/L.

SPS-2

Incorporate the Interconnections addressed on SPS – 1 into the existing (Pre Queues 1 and 2) SPS tripping Serial Projects Queues #68, #240 and #242 under the Double Contingency outages of the Lugo – Pisgah No.1 and No.2 500kV T/L's.

SPS-3

Trip the Interconnections addressed on SPS – 1 under the following Double Contingency outages:

- N – 2 Outages of Cima – Eldorado – Pisgah No.1 220kV and Nipton – Pisgah 500kV T/L's
- N – 2 Outages of Cima – Eldorado – Pisgah No.2 220kV and Nipton – Pisgah 500kV T/L's

Short Circuit Duty (SCD) Mitigation

Transmission Network Circuit Breaker Upgrades

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

Vincent Substation
Upgrade four (4) 500 kV circuit breakers.

Lugo Substation
Upgrade six (6) 220 kV circuit breakers.

Windhub Substation
Split the bus by performing the following:
Equip one (1) 220 kV position

See the Group Report for additional details.

DELIVERY NETWORK UPGRADES

Lugo – Mohave 500 kV T/L and Associated Upgrades

Install approximately 0.5 Circuit Miles of 500kV Double and Single Circuit Structures equipped with 2-2156KCMIL ACSR Conductors to loop the existing line into Pisgah Substation and form the two new Lugo – Pisgah No.3 and Mohave – Pisgah 500kV T/L's.

Install one 500 kV Line Series Capacitors Bank outside the new Mohave 500 kV T/L line position at Pisgah Sub.
Install one 500 kV Line Series Capacitors Banks outside the new Pisgah 500 kV T/L line position at Nipton Sub.

See the Group Report for additional details.

DISTRIBUTION UPGRADES

Short-Circuit Duty (SCD) Mitigations

The following Distribution Upgrades are required to mitigate the SCD on the Distribution system:

Windhub Substation
Split the bus by performing the following:
1. Equip one (1) 66 kV position
2. Install one (1) 220/66 kV transformer

Table 11.1: 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 *(Note 3)*
PTO's Interconnection Facilities *(Note 1)*	See Section 11 - PTO'S Interconnection Facilities	Non-network facilities needed to enable interconnection	$12,966	$14,176 (2014)	24 Months
Plan of Service Reliability Network Upgrades	See Section 11 – Plan of Service Reliability Network Upgrades	Direct Assigned Network Upgrades needed to enable interconnection.	$10,793	$11,800 (2014)	24 Months
Reliability Network Upgrades	See Section 11 - Reliability Network Upgrades in the East of Lugo Group Report	Allocated Network Upgrades needed to maintain system Reliability	$9,578	$10,472 (2014)	24 Months
Reliability Network Upgrades	See Section 11 - Short-Circuit Duty (SCD) Mitigation in the East of Lugo Group Report	SCD Mitigation Allocated to maintain system Reliability	$2,068	$2,261 (2014)	24 Months
Delivery Network Upgrades	See Section 11 - Delivery Network Upgrades in the East of Lugo Group Report	Network Upgrades needed to support Full Delivery, if requested	$118,207	$144,417 (2018)	84 Months
Distribution Upgrades *(Note 2)*	See Section 11 – Distribution Upgrades	Non-CAISO SCE Distribution Facilities	$561	$613 (2014)	24 Months
Total Cost			**$154,173**		**84 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 LGIAs.

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: SCE's Phase II cost estimating is done in 'constant' dollars 2011 and then escalated to the estimated O.D.year. For the Phase II study, the estimated O.D. is derived by assuming the duration of the work element will begin approximately in January 2012, which is roughly the CAISO tariff scheduled completion date of the Phase II study plus 90 days for the LGIA 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 2014. 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.

Q593 TRIBAL-FORT MOJAVE SOLAR

Cost Estimate Summary (2011 Dollars)

Scope: Install all Interconnection Facilities and Plan of Service Reliability Upgrades to interconnect 310MW of Generation to the CAISO Grid at the Mojave Switchyard 500kV Bus

No.	ELEMENT	INTERCONNECTION FACILITIES (Subject to ITCC)***	ITCC ** (35%)	TOTAL	TOTAL CONSTANT $ (ESTIMATED YEAR O.D.)****
					2014
	SUB-TRANSMISSION				
1	500kV Gen Tie Line segment into Mojave Substation	$ 4,392,000	$ 1,537,000	$ 5,929,000	
	MOJAVE SUBSTATION				
2	500kV Gen Tie Line Position - Line Drop (dead end structure, line protection related equipment and relays	$ 2,376,000	$ 832,000	$ 3,212,000	
3	Network Portion - One 500kV Double Breaker Position	$ -	$ -	$ -	
	TELECOM				
4	Install FO cable, lightwave, channel, and associated equipment supporting SCADA	$ 924,000	$ 323,000	$ 1,247,000	
5	Telecom facilities needed to support RTU at Generating Facility - N/A	$ -	$ -	$ -	
6	ECS - install 700' of 48/SMF FO cable, primary route	$ 119,000	$ 42,000	$ 161,000	
7	ECS - install 900' of 48/SMF FO cable, secondary route	$ 145,000	$ 51,000	$ 196,000	
	CORPORATE ENVIRONMENTAL HEALTH AND SAFETY				
8	CEH&S activites related to new segment of 500kV gen-tie connection (3 structure, 4 spans) from the Mojave Substation Switchyard to the first generator-owned transmission structure outside of the SCE Substation property line.	$ 864,000	$ 302,000	$ 1,166,000	
9	CEH&S activities related to telecom to support gen-tie connection	$ 296,000	$ 104,000	$ 400,000	
10	CEH&S activites related to telecom to support RTU at generating facility	$ 298,000	$ 104,000	$ 402,000	
11	CEH&S activites related to new dedicated Double Breaker 500kV Line Position at the Mojave Substation to terminate the new 500kV Gen Tie Line	$ -	$ -	$ -	
	LICENSING				
12	Licensing - N/A	$ -	$ -	$ -	
	REAL PROPERTIES				
13	RP activites related to 500kV Gen Tie Line and related Telecommunication Channels	$ 65,000	$ 23,000	$ 88,000	
	METERING SERVICES				
14	Retail metering equipment, metering cabinets and retail meters at the Generation Facility	$ 29,000	$ 10,000	$ 39,000	
	POWER SYSTEM CONTROL				
15	RTU at Generating Facility	$ 93,000	$ 33,000	$ 126,000	
16	Add points to existing RTU at the Mojave Switchyard	$ -	$ -	$ -	
	Totals	$ 9,604,000	$ 3,362,000	$ 12,966,000	$ 14,176,000

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

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

*** 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 CIAC 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 II cost estimating is done in 'constant' dollars 2011 and then escalated to the estimated O.D.year. For the Phase II study, the estimated O.D. is derived by assuming the duration of the work element will begin approximately in January 2012, which is roughly the CAISO tariff scheduled completion date of the Phase II study plus 90 days for the LGIA 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 2014. 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.

[illegible]

12. Items Not Covered In This Study

12.1 Conceptual Plan 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 II Interconnection Study.

12.2 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.

12.3 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).

12.4 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.

12.5 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.

12.6 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.

12.7 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 18.

12.8 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.

12.9 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.

12.10 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 (IC may own, operate, maintain, and construct diverse telecommunication paths associated with the IC's gen tie, excluding terminal equipment at both ends). 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. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of Phase II, telecommunication upgrades for higher queued projects were not considered in this study. Depending on the outcome of interconnection studies for higher queued projects, the telecommunication upgrades identified for Phase II may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

Attachment 1

Generator Machine Dynamic Data

The following data was submitted by the Interconnection Customer for Dynamic simulation:

```
epcgen   99401 "G1      "   0.48 "1 " : #7 mva=160.0000  "nextlight.p" 3.0000  "rsrc"
0.0000  "xsrc" 0.0000  "Vratio" 1.2000  "Iratio" 1.1000  "Tdc" 0.0100  "Ilim" 1.1000
"Kpdc" 2.0000  "Kidc" 20.0000  "Kpac" 0.1000  /
 "Kiac" 1.0000  "Tcm" 1.0000  "MOD" 0.0000  "PFLGmin" 0.9500  "PFLDmin" 0.9500
"OV1L" 1.2000  "OV1T" 0.2000  "OV2L" 1.1500  "OV2T" 0.5000  "OV3L" 1.1000  /
 "OV3T" 1.0000  "UV1L" 0.2000  "UV1T" 0.3000  "UV2L" 0.5000  "UV2T" 2.0000  "UV3L"
0.7500  "UV3T" 3.0000  "OF1L" 63.0000  "OF1T" 1.0000  "OF2L" 62.0000  /
 "OF2T" 3.0000  "UF1L" 57.0000  "UF1T" 1.0000  "UF2L" 58.0000  "UF2T" 3.0000

epcgen   99402 "G2      "   0.48 "1 " : #7 mva=160.0000  "nextlight.p" 3.0000  "rsrc"
0.0000  "xsrc" 0.0000  "Vratio" 1.2000  "Iratio" 1.1000  "Tdc" 0.0100  "Ilim" 1.1000
"Kpdc" 2.0000  "Kidc" 20.0000  "Kpac" 0.1000  /
 "Kiac" 1.0000  "Tcm" 1.0000  "MOD" 0.0000  "PFLGmin" 0.9500  "PFLDmin" 0.9500
"OV1L" 1.2000  "OV1T" 0.2000  "OV2L" 1.1500  "OV2T" 0.5000  "OV3L" 1.1000  /
 "OV3T" 1.0000  "UV1L" 0.2000  "UV1T" 0.3000  "UV2L" 0.5000  "UV2T" 2.0000  "UV3L"
0.7500  "UV3T" 3.0000  "OF1L" 63.0000  "OF1T" 1.0000  "OF2L" 62.0000  /
 "OF2T" 3.0000  "UF1L" 57.0000  "UF1T" 1.0000  "UF2L" 58.0000  "UF2T" 3.0000
```

Attachment 2

Dynamic Stability Plots

Please refer to Appendix F of the Group Report.

Attachment 3

SCE Interconnection Handbook

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

(This will be included in the final report)

Attachment 4

Short Circuit Calculation Study Results

Please refer to the Appendix H of the Group report.

Attachment 5

Deliverability Assessment Results

Please refer to the Appendix I of the Group report.

Attachment 6

Allocation of Network Upgrades for Cost Estimates

Transmission & Distribution Business Unit, Transmission & Interconnection Planning	**NERC Reliability Compliance Program**	Document No.	1
		Version No.	3
INTERCONNECTION HANDBOOK		Effective Date	10/02/09

SOUTHERN CALIFORNIA
EDISON®
An EDISON INTERNATIONAL® Company

Southern California Edison Company

Approved by:

Original Signed by — ***10/02/09***
Patricia Arons, Manager — ***Date***
Transmission & Interconnection Planning

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Section 1: Summary of Technical Requirements

1.1 Introduction

1.1.1 Minimum Requirements

Southern California Edison Company's (SCE) Interconnection Technical Requirements (Requirements) specify the typical minimum technical requirements to interconnect facilities with SCE's electric system. These requirements are necessary to ensure safe and reliable operation of SCE's electric system.

Applicable to Generation Facilities

Throughout the Requirements, the owner, its agents, or the operator of only a generation facility to be interconnected with SCE that includes performing the functions of supplying energy and a service (exclusive of basic energy and transmission services) to support the reliable operation of the transmission system shall be referred to as the "Producer."

These Requirements apply to the following types of interconnections of wholesale generating facilities to SCE's electric grid:

1) New wholesale generation interconnections (i.e. those interconnections not currently or previously connected to SCE's electric system).

2) Material changes to existing wholesale generating facilities including, but not limited to, changes in plant generating capacity, changes in plant load, and/or modifications to related equipment.

3) Existing generating facilities entering the wholesale energy market for the first time. This would include existing Qualifying Facilities (non-wholesale) converting to the wholesale market.

Applicable to Transmission Facilities

Throughout the Requirements, facilities that include interconnection of a group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems shall be referred to as "Transmission Facilities."

Applicable to End-User Facilities

Throughout the Requirements, an interconnection that includes retail service, wholesale service, load (dynamic and static) and reactive devices (capacitors and reactors), shall be referred to as "End-User Facilities."

Applicable to Generation, Transmission and End-User Facilities

Throughout the Requirements, if an entry is applicable to all facilities, such as generation, transmission and end-user facilities, the requirements will address each type of facility interconnection as one entity referred to as "Interconnected Facility (INTFAC)."

The Requirements do not, and cannot, address all the technical requirements applicable to a specific facility interconnection. Each interconnection is unique. Once sufficient facility information is provided by the INTFAC, SCE will determine and communicate the additional project-specific technical requirements to the INTFAC. INTFACs should discuss their project plans with SCE before purchasing or installing equipment or making other major financial commitments. SCE will follow notification procedures for new or modified facilities in the Transmission Control Agreement (TCA) per Section 4.2.3, with respect to the California Independent System Operator (CAISO) Register. In addition, INTFACs may inquire about procedures for notification of new or modified generation, transmission and end-user facilities from the following contact:

Contact	Mailing Address
Manager, Grid Interconnection & Contract Development	P.O. Box 800 2244 Walnut Grove Avenue Rosemead, California 91770

Nothing contained in this document is intended to modify the parties' rights and obligations under SCE or CAISO tariffs, or interconnection agreements with the INTFAC. The provisions of those tariffs and agreements supersede any provisions contained in this document that may appear to be inconsistent or contrary.

1.1.2 Purpose of Interconnection Handbook

Applicable to Generation, Transmission and End-User Facilities

This document has been prepared to identify the technical requirements for connecting new facilities to the SCE transmission system. This document provides an overview of the technical and reliability requirements to address interconnection requests. The interconnections include facility additions and modifications to accommodate generation, transmission and end-user facilities that are being connected to or planned to be connected to the SCE transmission system. This document is written to support compliance with NERC Standards, FAC-001 Facility Connection Requirements, which requires entities responsible for the reliability of the interconnected transmission systems to maintain and publish a Facility Connections Requirements document. The North American Electric Reliability Corporation (NERC) standards require those entities seeking to add facilities or connect to the interconnected transmission system to comply with the Facility Connection Requirements document. This document is not intended to be used as a design specification. SCE's Requirements are intended to provide a simple-to-use source for determining the minimum technical requirements necessary to interconnect a facility with SCE's electrical system. Although interconnections may be technically complex, it is SCE's intent to make the interconnection process as straightforward as possible.

In support of this intent, SCE is providing INTFACs with general technical information needed to properly interconnect facilities with the SCE grid, and provides descriptive examples of the electrical equipment they may need for their interconnection. This document does not address procedural information related to facility interconnections, nor cover all possible technical details. Other requirements and documents such as interconnection contracts, rules, tariffs, and additional reliability criteria, provide additional information to the INTFAC. The final design of facility connections to the SCE transmission system will be subject to SCE review and approval on a case-by-case basis.

This document also provides a means to facilitate communication of technical information to SCE regarding the INTFAC.

SCE's Requirements do not cover all aspects of applicable technical criteria that may apply to an INTFAC's project. The INTFAC is responsible for familiarity and compliance with all standards and criteria applicable to its specific project. A listing of technical standards and criteria referenced in these Requirements is provided for information as Appendix A.

These Requirements do not address the administrative or commercial requirements for INTFACs to SCE owned transmission or distribution systems.

1.1.3 Conformity

Applicable to Generation, Transmission and End-User Facilities

The INTFAC shall comply with all applicable reliability standards for its facilities. SCE will not assume any responsibility for complying with mandatory reliability standards for such facilities and offers no opinion whether the Interconnection Customer must register with NERC pursuant to Section 215 of the Federal Power Act. If required to register with NERC, the INTFAC shall be responsible for complying with all applicable reliability standards for its facilities up to the Point of Change of Ownership as described in Appendix A of each project's Large Generator Interconnection Agreement (LGIA).

The INTFAC is responsible for conforming to applicable joint NERC and Western Electricity Coordinating Council (WECC) standards, California Independent System Operator (CAISO) and SCE reliability criteria, Federal Energy Regulatory Commission (FERC) regulation, as well as good engineering and utility practice.

1.1.4 Requirements are Subject to Change

Applicable to Generation, Transmission and End-User Facilities

These Requirements are subject to change. INTFACs have the responsibility to ensure that they comply with the most recent version of the Interconnection Requirements. The current version may be accessed at SCE's internet site:

http://www.sce.com/AboutSCE/Regulatory/openaccess/

Each page of SCE's Interconnection Handbook displays its effective date in the lower right hand corner.

1.1.5 Applicability

Applicable to Generation, Transmission and End-User Facilities

Nothing in this document is intended to supersede Interconnection Agreements agreed to by SCE and the INTFAC, and, if there is a conflict, the Interconnection Agreement, as applicable, will control.

Upon execution of an Interconnection Agreement per its appropriate tariff, the INTFAC should make reference to this document in its entirety during the construction process.

Section 2: Parallel Systems

Applicable to Generation Facilities

These Requirements apply to interconnecting wholesale generating facilities that intend to operate in parallel with SCE's system, and ultimately deliver power to the CAISO grid (directly to the transmission system, or via SCE's Distribution system).

Subject to FERC and California Public Utilities Commission (CPUC) regulations and SCE approval, an INTFAC may elect to operate a wholesale generating facility in parallel with SCE or as a separate system with the capability of non-parallel load transfer between the two independent electrical systems. Induction generators, and some systems using inverter devices, must be operated in parallel to produce energy. Synchronous generators may be operated either in parallel or as a separate system. However, please note that the Requirements provided in this document are applicable to interconnecting generators intending to operate in parallel.

2.1 Parallel Operation

2.1.1 Definition

Applicable to Generation Facilities

A parallel system is one in which the Producer's wholesale generating facilities can be operated while connected to SCE's system. A consequence of such parallel operation is that the parallel generator becomes a part of SCE's electrical system, and must, therefore, be considered in planning the protection of SCE's system.

2.1.2 Need for Protective Devices

Applicable to Generation Facilities

Prudent electrical practices require that certain protective devices (relays, circuit breakers, etc.) specified by SCE must be installed at any location where a Producer desires to operate its wholesale generating facilities in parallel with the SCE system. The purpose of these devices is to promptly disconnect the Producer's wholesale generating equipment from the SCE system when faults

or abnormal operation jeopardize the reliable operation of equipment or the safety of personnel. Other modifications to electrical system configuration or protective relays may also be required in order to accommodate parallel generation. SCE assumes no responsibility for determining protective equipment needed to protect Producer's facilities.

2.1.3 Hazards

Applicable to Generation Facilities

SCE's transmission and distribution lines are subject to a variety of natural and man-made hazards. Among these are lightning, earthquakes, wind, animals, automobiles, mischief and human error. Producer's electric systems are subject to these same hazards but not nearly to the same degree because SCE's system has greater exposure to these hazards.

The electric problems that can result from these hazards are principally short circuits, grounded conductors, and broken conductors. These fault conditions require that damaged equipment be de-energized as soon as possible to ensure public safety and continued operation of the remainder of SCE's system.

Where SCE controls the only source of supply to a given transmission or distribution line, it has the sole responsibility to install protective equipment to detect faulted equipment or other operating abnormalities and to isolate the problem from the remainder of SCE's electrical system. A non-SCE generating facility connected to and operated in parallel with an SCE line represents another source of power to energize the line. Accordingly, SCE requires that such facilities also have adequate protective devices installed to react to abnormal electric system conditions and isolate from SCE's electric system.

2.1.4 Islanding

Applicable to Generation Facilities

Wholesale generating facilities operating in parallel with SCE's electric system must also be equipped to detect another condition referred to as "islanding." Islanding is the abnormal operating condition where a portion of SCE's electric system and loads become isolated from the remainder of SCE's electric system while still connected to and receiving energy from generating facilities within an electrical island. When islanding occurs, all generating facilities within the electrical island must be disconnected to prevent continued operation.

The protective devices and other Requirements established by SCE in Section 3 are intended to provide protection against hazards, such as those noted above, by ensuring that parallel wholesale generating facilities are disconnected when abnormal operating conditions occur. The following sections reflect the fact that these Requirements are typically minimal for small installations, but increase in scope and/or complexity as the size of the generation installation increases. SCE may require voltage and frequency protective functions or relays to detect islanding and shut down generation during periods of islanding.

2.1.5 UPS

Applicable to Generation Facilities

Uninterruptible Power Supply (UPS) systems will be classified as either a separate or a parallel system depending on the following criteria. If such UPS systems are not capable of transfer of electric power from the emergency source to SCE's electric system, they will be classified as a separate system generating facility. If such UPS systems are capable of transfer of power, they must meet the Requirements for parallel generation.

Section 3: Protection Requirements

Applicable to Generation, Transmission and End-User Facilities

Protective devices (relays, circuit breakers, synchronizing equipment, etc.) must be installed for the protection of SCE's system as required by SCE. Generally, the protective devices may differ with the relative electrical capacity of the installation. The larger the installation, the greater the effect it may have on SCE's electrical system. For instance, a manual disconnecting device must be provided by the INTFAC, but the form of this device will vary with the service voltage and wholesale generating facility capacity. For voltage classes 200 kV and above, primary relay protection for network transmission circuits will be designed to clear transmission line faults within a maximum of 6 cycles. Project stability studies may indicate that faster clearing times are necessary.

Categories: SCE's Requirements identify three different categories for Producer wholesale generating facilities connecting to the SCE system each with distinctive protection Requirements. These categories are:

1. Interconnection voltage above 34.5 kV
2. 200 kVA and above capacity, interconnection voltage 34.5 kV or below
3. Less than 200 kVA capacity, interconnection voltage 34.5 kV or below

Aggregation: Where multiple generating facilities (with a single owner) are allowed to connect to SCE's system through a single point of interconnection, the interconnection is said to have aggregated generating facilities. The appropriate category of aggregated generating facilities is calculated by summing the KVA ratings of the multiple generators.

Disclaimer: The categories above have been established for convenience and are based on urban/suburban circuits with normal load density. The final decision as to the specific requirements for each installation will be made by SCE depending on several factors that could include Producer load magnitude, the magnitude of other load connected to that circuit/system, available short circuit duty contribution, and other conditions SCE deems prudent.

The Protection Requirements of the above three categories are described in Sections 3.1 to 3.3. These sections include Figures 3a through 3f to illustrate typical installations of protection equipment. The following is a legend of device numbers referred to in these figures:

Legend

Protective Device Numbers and Description

4	Master Contactor
25	Synchronizing or Synchronism Check
27	Under-voltage
32	Power Direction
40	Loss of Field Detection
46	Current Balance
47	Voltage Phase Sequence
51	Time Over-current
51G	Ground Time Over-current
51N	Neutral Time Over-current
51V	Voltage Restrained/Controlled Time Over-current
59	Over-voltage
59G	Over-voltage Type Ground Detector
67V	Voltage Restrained/Controlled Directional Time Over-current
78	Loss of Synchronism (Out-of-Step)
79	Reclosing Relay
810	Over-frequency
81U	Under-frequency
87	Current Differential

NOTE: For additional information on device numbers, refer to ANSI C37.2.

3.1 Category 1: Voltage Over 34.5 kV

Applicable to Generation Facilities

This Category is limited to wholesale generating facilities interconnecting at a single point with interconnection voltage above 34.5 kV. This requirement applies to all interconnections to the CAISO controlled grid, and to interconnections to SCE owned and operated facilities above 34.5 kV.

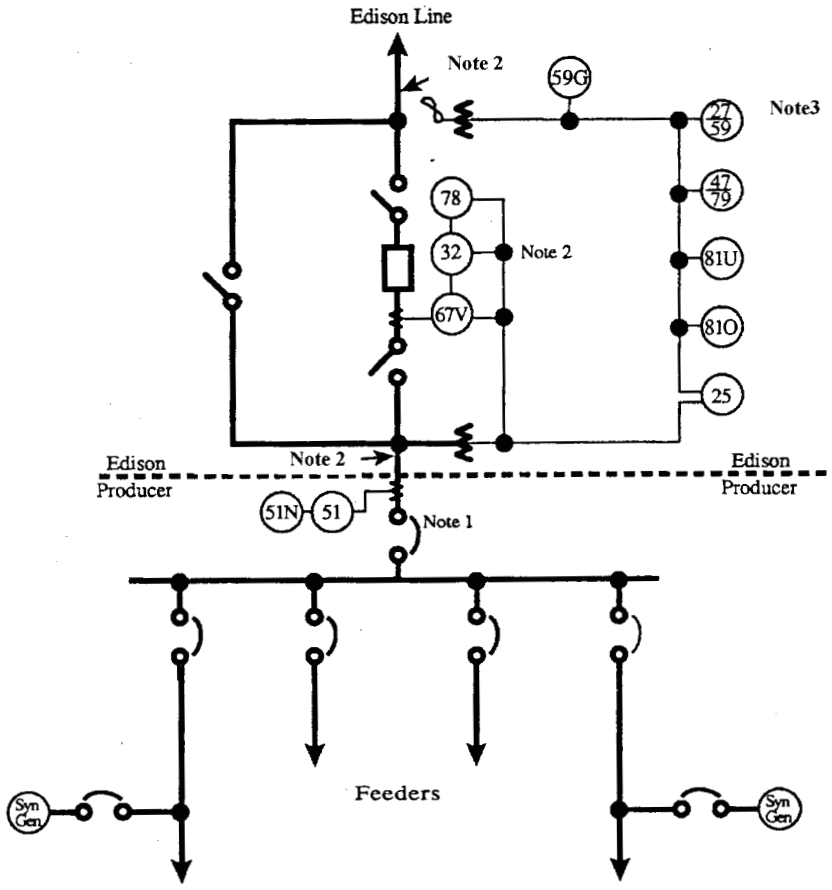
3.1.1 Typical Installations

Applicable to Generation Facilities

Figures 3a and 3b show typical installations with the SCE interface.

Figure 3a

Typical Synchronous Parallel Generation with Assumed SCE Owned Protection (> 34.5 kV)

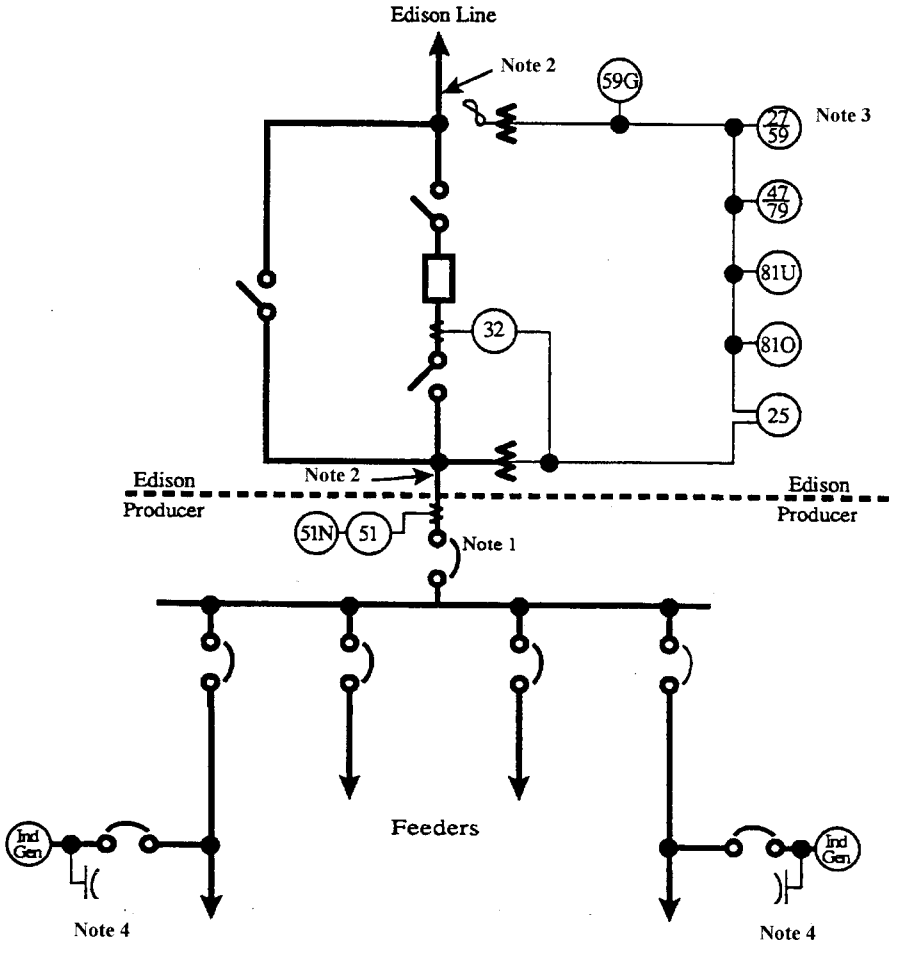


NOTES:
1. Producer's main breaker or switch.
2. Transformation, if required, may be by SCE or the Producer.
3. Two relays connected to different phase pairs.

Not all Producer-side protective relaying is shown.

Figure 3b

Typical Induction Parallel Generation with Assumed SCE Owned Protection (>34.5 kV)



NOTES:
1. Producer's main breaker or switch.
2. Transformation may be by SCE or the Producer as required.
3. Two relays connected to different phase pairs.
4. See Section 5.8.

Not all Producer-side protective relaying is shown.

For induction generation interconnection facilities, the Producer is responsible for installing the appropriate VAR supporting equipment at its facility to maintain unity power factor at the point of interconnection.

3.1.2 The specific Requirements for this Category of wholesale generating facilities are

Applicable to Generation Facilities

a) Typically SCE-owned and controlled circuit breaker to disconnect generating facilities during SCE system trouble.

b) Producer-owned and controlled circuit breaker or disconnect switch (as required – refer to section 5.11 Switching and Tagging Rules) at the main to disconnect for Producer system trouble. If desired, SCE may permit the Producer to trip and/or close the SCE breaker by remote control. If synchronizing is to be done with SCE, SCE will install synchronizing supervision relays and telecommunications as required.

c) Producer to provide synchronizing relays or equipment at the main, generator and other breakers as appropriate. Either induction starting, automatic synchronizing or manual synchronizing supervised by a synchronizing relay must be provided by the Producer.

d) Induction starting will be permitted only where the inrush will not exceed SCE prescribed limits. Producer shall never attempt to parallel its system with SCE's system when the Producer's synchronizing facilities are malfunctioning or inoperative. Manual synchronizing without a supervising relay is not permitted. Automatic synchronizing may be required for synchronous generators which contribute short circuit current exceeding 5 (%) percent of the pre-existing short circuit current at the point of interconnection with SCE's distribution system.

e) Protection related telecommunications may be required as determined by SCE Protection Engineering.

3.1.3 SCE-owned and maintained protective relays which perform the following functions

Applicable to Generation Facilities

a) **Short Circuit Protection** (Devices 51V or 67V, 51N or 59G)

The designated relays will detect faults on the SCE electric system to which the Producer's generating facility is connected. Generally, the phase relays are voltage restrained overcurrent type or impedance torque controlled overcurrent type. Occasionally, pilot relays or transferred tripping relays may be required. In ground fault protection, a directional overcurrent relay or ground fault voltage detector may be used. A grounding transformer may be required to avoid dangerous overvoltages which could occur during accidental isolation of the line from the main system while the generator is in operation. Adequate grounding can be provided either by the use of a wye-grounded-delta main power transformer or by installing an appropriate grounding transformer. To limit the effects of such grounding on SCE's ground relay sensitivity, SCE may require that the grounding impedance be limited to the highest value suitable for neutral stabilization. Devices 51V or 67V are normally omitted for induction generator installations because of the absence of sustained fault currents from these generators.

b) **Islanding Protection** (Devices 27/59, 81-0, 81-U)

During the course of fault clearing or due to accident, equipment malfunction, or malicious mischief, it is possible for an SCE circuit/system to become separated from the main system, leaving customers on the circuit supplied from the Producer's generator. In order to protect customers from abnormal voltage or frequency excursions under these conditions, and to facilitate rapid restoration of normal service, relays for islanding protection are required. Generally, these relays will provide over and under frequency functions and three phase over and under voltage functions with instantaneous overvoltage tripping. For wholesale generating facilities aggregating 10 MW and greater, SCE may elect to

use a voltage phase comparison system (Telesync) for islanding protection while retaining the voltage and frequency relays for backup.

c) **Breaker Closing/Reclosing Control** (Devices 25, 47, 79)

It is important that the closing of the SCE circuit breaker be controlled so that it can only be closed when it is safe to do so. Inadvertent closing of the circuit breaker could result in paralleling out of synchronism or energizing of de-energized facilities, and hazardous conditions could result. The required logic for manual closing of the SCE breaker is:

i. The line side of the breaker is energized with proper voltage and phase sequence, the load side of the breaker is de-energized and the Producer's main breaker (or generator breaker) is open, or
ii. Synchronism check across the breaker is satisfactory which, in most cases, indicates that either the breaker bypass switch is closed or interconnection with the Producer already exists elsewhere.

In order to provide the best continuity of service to the Producer, automatic reclosing of the SCE breaker subsequent to fault clearing is engineered into the control circuitry. If the trouble is permanent, the breaker will trip again and lockout. No further reclosing will take place until the breaker has been reclosed manually. The required conditions for automatic reclosing are the same as for manual closing. Where provision is made for closing of the SCE circuit breaker by the Producer, the required conditions for closing will be the same as for manual closing by SCE. The Producer's closing control will enable SCE's synchronizing relay to close the breaker.

d) **Loss of Synchronism** (Device 78)

Operation of the Producer's synchronous generator out of synchronism with SCE may cause large voltage fluctuations to SCE's customers and may cause severe damage to the generator. If SCE determines that the relative capacities of its system and of the Producer's wholesale generating facility are such that this situation is likely to occur or for those installations which have experienced such voltage fluctuations, specific relays for detection of loss-of-synchronism (out-of-step) will be required.

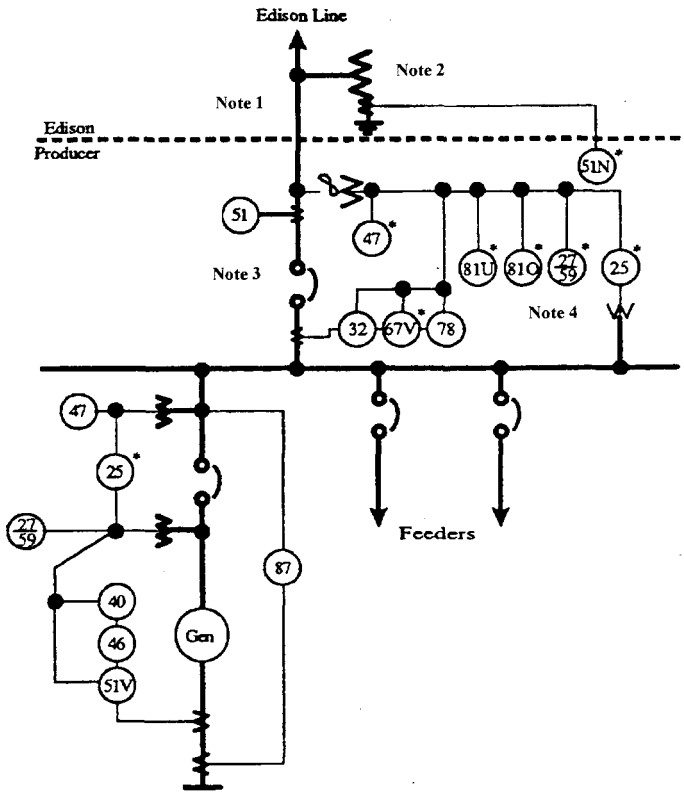
3.2 Category 2: Total Generation 200 kVA and Above, Voltage at 34.5 kV or Below

Applicable to Generation Facilities

All installations in this Category require SCE review of the protective functions to be provided by the Producer. Refer to Figures 3c and 3d for typical installations. Producers must ensure their compliance to SCE's telemetering Requirements as stated in Section 7 of these Requirements.

Figure 3c

Typical Synchronous Parallel Generation, with Assumed Producer Owned Protection (≥ 200 kVA, ≤ 34.5 kV)

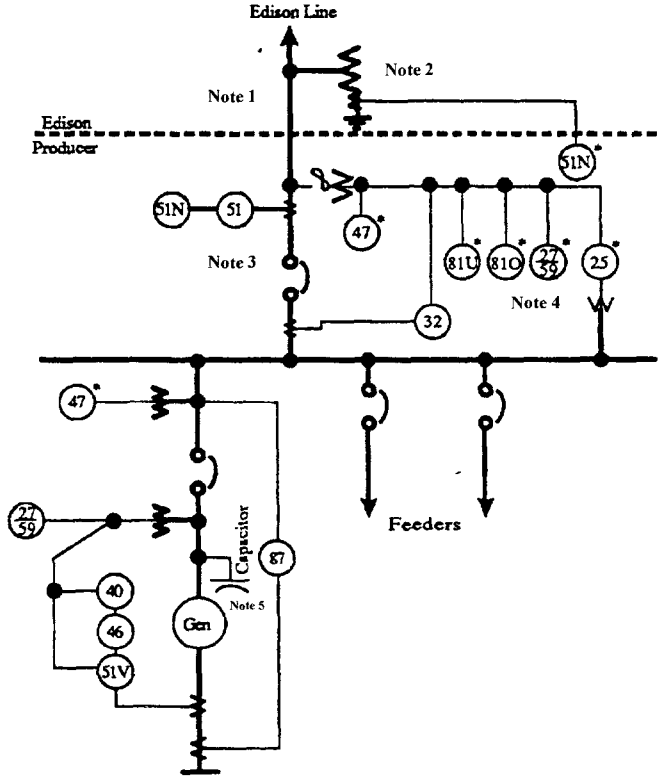


NOTES:
1. Transformation (as required) by SCE or the Producer.
2. Grounding transformer or ground detector is required to be supplied by SCE unless the main transformer is wye grounded/delta. (See 3.2.3.d for requirements)
3. Protective and synchronizing relays required if the Producer desires to serve isolated load during SCE outage. If not provided at main circuit breaker, these functions should be provided at generator breaker.
4. Two phase-to-phase connected or three phase-to-neutral connected relays required.

"*" indicates devices required by SCE. Others are shown as conventional practice.

Figure 3d

Typical Induction Parallel Generation with Assumed Producer Owned Protection (≥ 200 kVA, ≤ 34.5 kV)



NOTES:
1. Transformation (as required) by SCE or the Producer.
2. Grounding transformer or ground detector is required to be supplied by SCE unless the main transformer is wye grounded/delta. (See 3.2.3.d for requirements)
3. Protective and synchronizing relays required if the Producer desires to serve isolated load during SCE outage. If not provided at main circuit breaker, these functions should be provided at generator breaker.
4. Two phase-to-phase connected or three phase-to-neutral connected relays required.
5. Refer to Section 5.7.

"*" indicates devices required by SCE. Others are shown as conventional practice.

For induction generation interconnection facilities, the Producer is responsible for installing the appropriate VAR supporting equipment at its facility to maintain unity power factor at the point of interconnection.

3.2.1 The Producer shall provide adequate protective devices to

Applicable to Generation Facilities

a) Detect and clear the generator(s) from short circuits or grounds on the SCE system serving the Producer.

b) Detect the voltage and frequency changes that can occur if the SCE system serving the Producer is disconnected from the main system, and clear the Producer's generating facilities from the islanded system.

c) Prevent reparalleling the Producer's generation, after an incident of trouble, unless the SCE service voltage has been of normal magnitude and frequency continuously for a pre-determined period of time (typically five minutes).

3.2.2 Protection devices which may be required to satisfy the above Requirements are

Applicable to Generation Facilities

a) **Phase over-current trip devices** (Device 51, 51V, or 67V)

In most cases these will have to be voltage-restrained or voltage-controlled over-current relays in order to provide coordination with SCE relays.

b) **Residual over-current or over-voltage relays to trip for ground faults on the SCE system** (Devices 51N or 59G)

The required type of device (51N or 59G) depends on the characteristic of SCE's interconnecting system. Contact SCE for information for a specific location.

c) **Under/over voltage relays** (Device 27/59)

Two over/under voltage relays measuring different phase-to-phase voltages or three over/under voltage relays each measuring a phase-to-neutral voltage is required. A single multiphase over/under voltage relay is acceptable if it has separate voltage measurement elements for each

phase or phase pair. Under voltage relays should be adjustable from 75-90% of nominal voltage and have time delay to prevent unnecessary tripping on external faults. Over voltage relays should be adjustable from 110-120% of nominal voltage and be instantaneous or a combination of instantaneous and time delayed. Setting changes with temperature variation should not exceed ±2 volts over the expected temperature range.

d) **Under/over frequency relays** (Device 81)

The under-frequency relay should be adjustable from 56.4 -59.5 Hz and the over-frequency relay from 60.5 to 61.7 Hz. Setting change with temperature variation over the expected range, or voltage variation over ±10%, should not exceed ±0.05 Hz.

e) **Phase sequence under-voltage relay** (Device 47/27)

To permit paralleling only when SCE voltage and phase sequence are normal.

f) **Automatic Separation:** In some cases, protective devices supplied with the wholesale generating equipment will meet some or all of these Requirements, provided that it is acceptable to trip the generator whenever the SCE source is lost. If the Producer desires to automatically separate from SCE and commence isolated operation upon loss of the SCE source, additional devices will be necessary to effect the separation.

g) **Large Generators:** In specific installations, particularly with large generators (over 10,000 kVA), SCE may require specific additional protection functions such as loss of excitation, loss of synchronism and over-excitation protection, if these conditions would have an impact on SCE's system.

3.2.3 Other protection devices for Category 2 Generation are

Applicable to Generation Facilities

a) **Utility Quality Relays:** Depending on the size of the wholesale generating facility and the size of the distribution or subtransmission system to which it is connected, SCE may require the Producer to utilize "utility quality" protective relays. Such relays have more stringent tolerances and more widely published characteristics than "industrial quality" relays and have the ability to coordinate protective settings with utility settings. This Requirement will be invoked only if the wholesale generating facility is large enough to require close coordination with SCE relays. In general, installations aggregating less than 1,000 kVA will not be subject to this Requirement.

b) **Relay Operation Recorders:** All protective devices supplied to satisfy the Requirements in Category 2 wholesale generating facilities shall be equipped with operation indicators (targets) or shall be connected to an annunciator or event recorder so that it will be possible to determine, after the fact, which devices caused a particular trip.

c) **Relay Testing:** All protective devices supplied to satisfy the Requirements in this Category shall be tested by qualified personnel prior to SCE approving parallel operation, and at intervals at least as frequent as those used by SCE for the relays protecting the line(s) serving the Producer. These intervals are given in Table 5.3, in Section 5. Lines traversing fire hazardous areas are required to have their relays tested annually before May 1st. Special tests may also be requested by SCE to investigate apparent misoperations. Each routine or special test shall include both a calibration check and an actual trip of the circuit breaker from the device being tested. For each test a report shall be prepared and sent to SCE listing the tests made and the "as found" and "as left" calibration values.

d) **Four-wire Multi-grounded Neutral Distribution Circuits:** In projects where the Producer is served from an SCE four-wire multi-grounded

neutral distribution circuit, adequate grounding must be provided to ensure neutral stability during accidental isolation of the line from the main system. This is necessary to avoid dangerous over-voltages on other customers served from phase-to-neutral connected distribution transformers. Adequate grounding can be provided either by the use of a wye-delta main power transformer or by installing an appropriate grounding transformer. In order to limit the effects of such grounding on SCE's ground relay sensitivity, SCE may require that the grounding impedance be limited to the highest value suitable for neutral stabilization.

3.2.4 Exemption For Installing Phase Over-current Protective Devices

Applicable to Generation Facilities

Where induction generators or static inverters are employed rather than synchronous machines, the phase over-current protective devices required by SCE generally will be waived since these generation sources will not deliver sustained over-currents. All other specified protective devices are required.

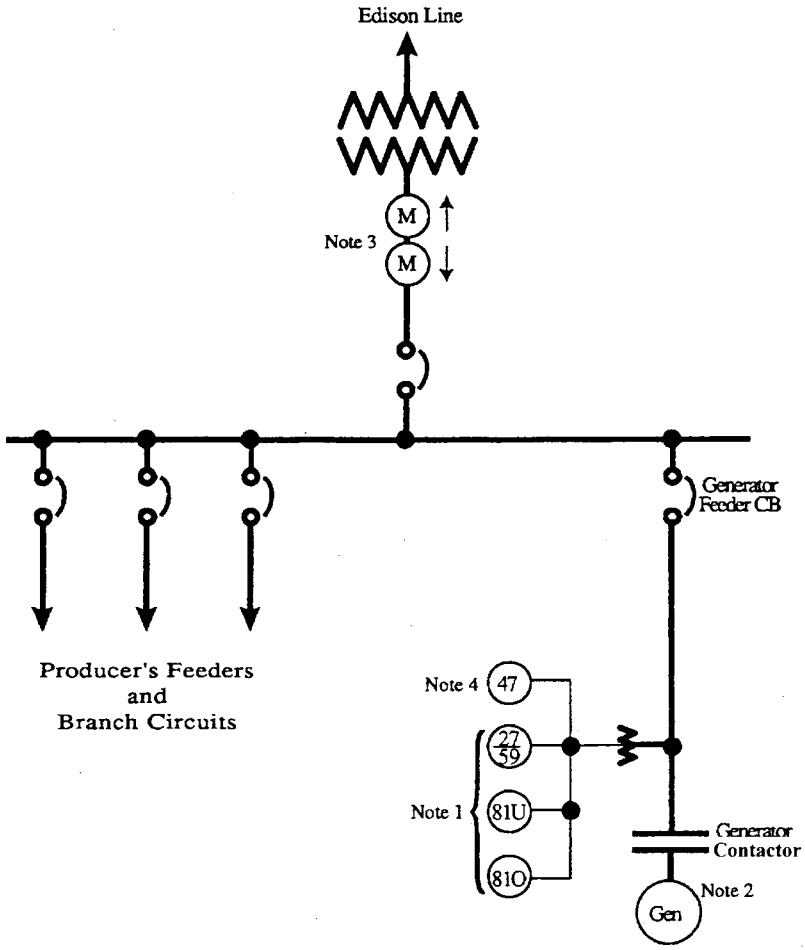
3.3 Category 3: Total Generation Less Than 200 kVA

Applicable to Generation Facilities

The following Requirements for small wholesale generating facilities are based on an assumed low density of parallel generation on the serving circuit. Other Requirements may be imposed should the density exceed a tolerable limit. Refer to Figure 3e.

Figure 3e

Typical Parallel Generation Under 200 kVA



NOTES:
1. Protective devices required by SCE for all installations.
2. Other protective devices for generator not shown because of large variations with type of generator.
3. Self-contained metering is typical.
4. Required for three phase generators.

a) **Line Voltage Relay or Contactor:** Producer generator controls are to be equipped with a line voltage relay or contactor which will prevent the generator from being connected to a de-energized or single-phased (if normally three-phase) source. This relay is to disconnect the generator from a de-energized utility line and prevent its reconnection until the line has been re-energized by SCE and has maintained nominal voltage and frequency continuously for a pre-determined period of time (typically five minutes).

b) **Relays to Detect Islanding:** Producer generators are to be equipped with over/under frequency and over/under voltage relays for islanding detection. These relays must meet the specifications listed in Section 3.2.2, paragraphs (c) and (d). The relays may be arranged to de-energize the contactor as shown in Figure 3f. The Producer generator islanding protection must be able to detect an islanded condition and cease to energize SCE's distribution system within two seconds. Other requirements may be imposed on those installations unable to meet this requirement.

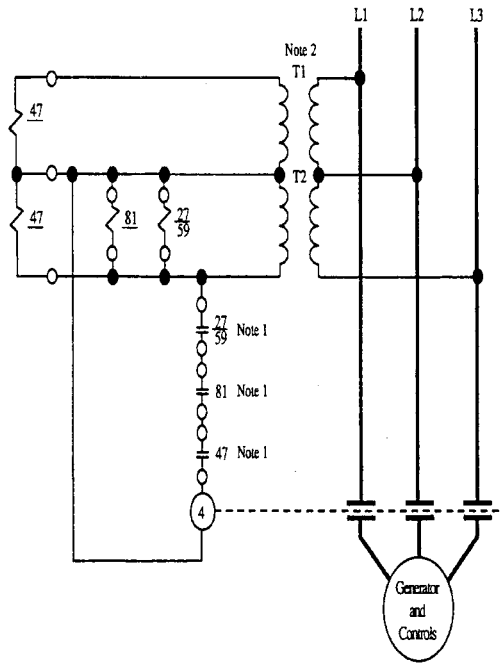
c) **Fault Detection:** The Producer shall provide adequate protective relays to detect and clear the generator(s) from short circuits or grounds on the SCE system serving the Producer.

d) **Four-wire Multi-grounded Neutral Distribution Circuits:** In projects where the Producer is served from an SCE four-wire multi-grounded neutral distribution circuit, adequate grounding must be provided to ensure neutral stability during accidental isolation of the line from the main system.

Figure 3f

Typical Relay/Contactor Arrangement Under 200 kVA

This drawing is intended to show the relay/contactor arrangement only. Other over-current or switching devices may be required by local authorities.



NOTES:
1. Contacts closed with normal voltage, frequency and phase sequence.
2. Control transformers as required to match relay/contactor voltage to supply voltage. Arrangement shown is for three phase system. For single phase omit L3, T1, Dev. 47.

f) **Dedicated Distribution Transformer:** SCE may require the Producer to be served through a dedicated distribution transformer which serves no other customers. The purpose of the dedicated transformer is to confine any voltage fluctuations or harmonics produced by the generators to the Producer's own system.

g) **Harmonic Requirements for inverters**, see "Voltage Imbalance and Abnormal Waveforms" Section 5.10.

h) **SCE Telecommunications** are typically not required for protective purposes in Category 3 wholesale generating facilities except as required to coordinate with SCE's protective relays.

i) **Exception to Protection Devices:** Producers wholesale generating facilities may, as an alternative to the Requirements specified in this Category 3 wholesale generating facility section above, utilize an approved inverter/interface device meeting applicable safety and performance standards established by the National Electrical Code, the Institute of Electrical and Electronics Engineers ("IEEE"), and accredited testing laboratories such as Underwriters Laboratories ("UL"). These Requirements include, but are not limited to, the provisions of IEEE Standard 929, IEEE Standard 1547, and UL Standard 1741.

3.4 Breaker Duty and Surge Protection

Applicable to Generation, Transmission and End-User Facilities

3.4.1 SCE Duty Analysis

The recognized standard for circuit breakers rated on a symmetrical current basis is IEEE Standard C37.010-1999 "IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis," and ANSI/IEEE Standard C37.5 for circuit breakers rated on a total current basis. SCE will review breaker duty and surge protection to identify any additions required to maintain an acceptable level of SCE system availability, reliability, equipment insulation margins and safety. Also, the management of increasing short-circuit duty of the transmission system involves selecting the alternative that provides the best balance between cost and capability. System arrangements must be designed so that the interrupting capability of available equipment is not exceeded.

When studies of planned future system arrangements indicate that the short-circuit duty will reach the capability of existing breakers, consideration should be given to the following factors:

A. Methods of limiting duty to the circuit breaker capability, or less:

1. Delooping or rearranging transmission lines at substations;
2. Split bus arrangements.

B. Magnitude of short circuit duty.

C. The effect of future projects on the duty.

D. Increasing the interrupting capability of equipment.

E. The ability of a particular breaker to interrupt short circuits considering applicable operating experience and prior test data.

Please note that SCE performs an annual short circuit duty analysis, which may include reevaluation of the facility breakers.

3.4.2 Customer Owned Duty/Surge Protection Equipment

In compliance with Good Utility Practice and, if applicable, the Requirements of SCE's Interconnection Handbook, the INTFAC owner shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the INTFAC to any short circuit occurring on the SCE system not otherwise isolated by SCE's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the SCE system. Such protective equipment shall include, but not limited to, a disconnecting device and a fault current-interrupting device located between the facility and the SCE system at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. The facility owner shall be responsible for protection of the facility and other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. The facility owner shall be solely responsible to disconnect their facility if conditions on the SCE system are impacted by the INTFAC.

Section 4: Miscellaneous Requirements:

4.1 Transmission Facilities Requirements

Applicable to Transmission Facilities

The INTFAC shall ensure that its overhead transmission facilities are constructed to a minimum of General Order 95 **Rules for Overhead Electric Line Construction** standards when facilities are built within California and to **National Electric Safety Code** standards when facilities are built outside of California. The INTFAC shall ensure that its underground transmission facilities are constructed to a minimum of General Order 128 **Rules for Construction of Underground Electric Supply and Communication Systems** when facilities are built within California and to National Electric Safety Code standards when facilities are built outside of California. Where facilities are intended to be owned by SCE, additional design requirements apply and must be consistent with SCE's design standards.

4.2 Power System Stabilizers (PSS)

Applicable to Generation Facilities

All new Producers' synchronous generators, larger than 30 MVA and interconnecting at a voltage 60 kV or higher are required to install PSS with a suitable excitation system, unless an exemption has been obtained from the Western Electricity Coordinating Council (WECC). Suitable excitation systems are defined in the WECC report; "Criteria to Determine Excitation System Suitability for PSS," dated December 1992.

Unless an exemption has been received from the WECC, all new generators are assumed suitable for PSS, and must abide by the following Requirements:

a) The generator excitation system must be equipped with a power system stabilizer (PSS). The PSS improves stability in the electrical system when system power disturbances occur.

b) The PSS equipment must be approved by SCE prior to installation and operation.

c) The PSS must be calibrated and operated in accordance with WECC standard procedures for calibration, testing, and operation of PSS equipment.

d) Calibration and test reports must be submitted to SCE for review and approval. The wholesale generating facility shall not be considered operational until calibration of the PSS has been performed to SCE's satisfaction.

e) The PSS shall be properly maintained and in service when the wholesale generator is on line for power production.

In addition to the foregoing Requirements, Producers must conform to all applicable current or future WECC Criteria. Specific to PSS, these Criteria currently include "WECC Power System Stabilizer Design and Performance Criteria", approved by the Technical Operations Subcommittee, September 15, 2003.

4.3 Governor "Droop" Shall Be Set At 5%

Applicable to Generation Facilities

All new Producers' generators having suitable systems must comply with the WECC minimum operating reliability criteria for governor droop.

These Requirements are necessary to provide an equitable and coordinated system response to load/generation imbalances. Governor droop shall be set at 5%. Governors shall not be operated with excessive dead-bands, and governors shall not be blocked unless required by regulatory mandates.

4.4 Wind Turbine Wholesale Generating Facilities

Applicable to Generation Facilities

4.4.1 Wind Turbine Set-Back Criteria

a) The Producer shall locate its wind-driven wholesale generating unit such that it does not encroach onto SCE transmission right of way or edge of any electric operating property.

b) The Producer shall be responsible for performing its appropriate grounding requirements for its wind-driven generating units.

4.4.2 Generator Electric Grid Fault Ride-Through Capability Criteria and Power Factor Criteria

SCE currently supports a Low Voltage Ride-Through Criteria the WECC has adopted to ensure continued reliable service. The Criteria are summarized as follows:

1. Generator is to remain in-service during system faults (three phase faults with normal clearing and single-line-to-ground with delayed clearing) unless clearing the fault effectively disconnects the generator from the system.
2. During the transient period, generator is required to remain in-service for the low voltage and frequency excursions specified in WECC Disturbance-Performance Table of Allowable Effects on Other Systems as applied to load bus constraint. These performance criteria are applied to the generator interconnection point, not the generator terminals.
3. Generators may be tripped after the fault period if this action is intended as part of a Special Protection Scheme.
4. This Standard will not apply to individual units or to a site where the sum of the installed capabilities of all machines is less than 10MVA, unless it can be proven that reliability concerns exist.
5. The performance criteria of this Standard may be satisfied with performance of the generators or by installing equipment to satisfy the performance criteria.

6. The performance criterion of this Standard applies to any generation independent of the interconnected voltage level.
7. No exemption from this Standard will be given because of minor impact to the interconnected system.

This criterion also applies to existing generators that go through any refurbishments or any replacements.

4.5 Reclosing Circuit Breakers and Hot Line Reclose Blocking

Applicable to Generation Facilities

Because most short circuits on overhead lines are of a temporary nature, it is SCE's practice to reclose the circuit breakers on such lines within a few seconds after they have automatically tripped. This practice improves continuity of service to all SCE's customers. The protective relays specified by SCE for parallel generation interfaces are intended to disconnect the wholesale generating facilities from faulty or isolated lines before reclosing occurs. Should the Producer desire additional protection against the possibility that reclosing might occur with his generator still connected to the line (a potentially damaging occurrence for synchronous generators), SCE can provide, at the Producer's expense, "Hot Line Reclose Blocking" at the necessary points on its system. Transfer trip protection may be required to facilitate restoration of service to SCE's customers. SCE's preference is to avoid such equipment because of the possible adverse effects on service continuity and the problems of moving or rearranging the equipment to accommodate system changes. Costs for installing, maintaining, and/or rearranging such equipment will be borne by the Producer(s) requesting the equipment.

4.6 Unbalanced Currents

Applicable to Generation Facilities

Producers with three-phase generators should be aware that certain conditions in the utility system may cause negative sequence currents to flow in the generator. It is the sole responsibility of the Producer to protect its equipment from excessive negative sequence currents.

4.7 Sub-Synchronous Resonance Studies

Applicable to Generation and Transmission Facilities

Generators installed near series compensated lines or Flexible AC Transmission Systems (FACTS) may be exposed to Sub-Synchronous Resonance (SSR) conditions which must be evaluated by the Producer. SSR occurs when the network natural frequencies (below fundamental frequencies) coincide with the turbine-generator torsional-mode frequencies causing the turbine-generator to stress that may result in shaft failure. The turbine-generator and the system may interact with SSR into two main ways: Torsional Interaction (TI) and Torque Amplification (TA). In order to evaluate a potential SSR condition on a new generator installation near series compensated lines or FACTS devices a screening study needs to be conducted to identify any TA or TI impact on the series compensation level or FACTS devices controls. If a case is identified by the initial screening process (Frequency Scanning Study) a more detailed time domain study is required to quantify the potential damage and provide with mitigation measures. Customer owned transmission lines that have a series capacitor attached to the line and wish to interconnect to SCE, must demonstrate to SCE that SSR studies have been performed on their line.

4.8 Automatic Voltage Regulators (AVR)

Applicable to Generation Facilities

Generating units 10 MVA and larger shall be equipped with automatic voltage control equipment. All generating units with automatic voltage control equipment shall normally be operated in voltage control mode. These generating units shall not be operated in other control modes (e.g., constant power factor control) unless authorized to do so by the balancing authority. The control mode of generating units shall be accurately represented in operating studies.

All new Producers' synchronous generators, regardless of size and interconnecting at a voltage 60 kV or higher, must abide by the following Requirements:

a) The synchronous generator shall have an excitation system with a continuously acting Automatic Voltage Regulator (AVR).

b) The AVR equipment must be approved by SCE prior to installation and operation.

c) The AVR must be calibrated and operated in accordance with WECC standard procedures for calibration, testing, and operation of AVR equipment.

d) Calibration and test reports must be submitted to SCE for review and approval. The wholesale generating facility shall not be considered operational until calibration of the AVR has been performed to SCE's satisfaction.

e) The AVR shall be properly maintained and in service when the generator is on line for power production.

Applicable to Generation, Transmission and End-User Facilities

Automatic voltage control equipment on generating units, synchronous condensers, and Flexible Alternating Current Transmission System (FACTS) shall be kept in service to the maximum extent possible with outages coordinated to minimize the number out of service at any one time. Such voltage control equipment shall operate at voltages specified by the balancing authority operator.

4.9 Underfrequency Relays

Applicable to Generation Facilities

For voltage classes 161 kV and above, it is essential that the underfrequency protection of generating units and any other manual or automatic actions are coordinated with underfrequency load shedding relay settings. For further information, please refer to Section 3.2.2.d.

Applicable to Transmission and End-User Facilities

Since the facilities of the SCE system may be vital to the secure operation of the Interconnection, CAISO/SCE shall make every effort to remain connected to the Interconnection. However, if the system or control area determines that it is endangered by remaining interconnected, it may take such action as it deems necessary to protect the system.

Intentional tripping of tie lines due to underfrequency is permitted at the discretion of SCE's system, providing that the separation frequency is no higher than 57.9 Hz with a one second time delay. While acknowledging the right to trip tie lines at 57.9 Hz, the preference is that intentional tripping not be implemented.

4.10 Insulation Coordination

Applicable to Generation, Transmission and End-User Facilities

Insulation coordination is the selection of insulation strength and practice of correlating insulation levels of equipment and circuits with the characteristics of surge-protective devices such that the insulation is protected from excessive overvoltages. Insulation coordination must be done properly to ensure electrical system reliability and personnel safety.

The INTFAC shall be responsible for an insulation coordination study to determine appropriate surge arrester class and rating on the INTFAC equipment. In addition, the INTFAC is responsible for the proper selection of substation equipment and their arrangements from an insulation coordination standpoint.

Basic Surge Level (BSLs), surge arrester, conductor spacing and gap application, substation and transmission line insulation strength, protection, and shielding shall be documented and submitted for evaluation as part of the interconnection plan.

4.11 Ratings

4.11.1 Facility Ratings

Applicable to Generation, Transmission and End-User Facilities

The ratings of facilities are the responsibility of the owner of those facilities. Ratings of facilities must conform to NERC Standard FAC-008-1 Facility Ratings Methodology.

4.11.2 Ratings Provided by Equipment Manufacturers

Applicable to Generation, Transmission and End-User Facilities

Equipment installed on the SCE system is rated according to the manufacturer's nameplate or certifications, and ANSI/IEEE standards. The manufacturer's nameplate rating is the normal rating of the equipment. ANSI/IEEE standards may allow for emergency overloads above the normal rating under specified conditions and often according to an engineering calculation. Emergency loading may impact the service life of the equipment. In some cases the manufacturer has certified equipment for operation at different normal or emergency loads based on site specific operation conditions. Older technology equipment is rated according to the standards under

which it was built unless the manufacturer, ANSI/IEEE standards, or SCE's determination indicates that a reduced rating is prudent or an increase rating is justified.

4.11.3 Rating Practice

Applicable to Generation, Transmission and End-User Facilities

The normal and emergency ratings of transmission lines or the transformation facilities shall equal the least rated component in the path of power flow.

4.11.4 Ambient Conditions

Applicable to Generation, Transmission and End-User Facilities

Since SCE's territory is in a year-round moderate climate, SCE does not establish equipment ratings based on seasonal temperatures. That is, SCE standard ratings for normal and emergency ratings are the same throughout the year and reflect summer ambient temperatures coincident with ANSI/IEEE standards, i.e., 40°C (104°F). However, in some cases SCE may calculate site-specific ratings that consider the local ambient conditions based on ANSI/IEEE rating methods.

4.11.5 Transmission Lines

Applicable to Generation, Transmission and End-User Facilities

The transmission circuit rating is determined according to the least rated component in the path of power flow. This comprises of the transmission line conductor, the series devices in the line, the allowable current that will not cause the conductors to sag below allowable clearance limits, and the termination equipment.

4.11.6 Conductors

Applicable to Generation, Transmission and End-User Facilities

The transmission line conductor ratings are calculated in accordance with ANSI/IEEE 738-1993. For Aluminum Conductor Steel Reinforced (ACSR) conductor the normal conductor rating allows a total temperature of 90°C and the emergency rating allows 135°C. Similarly, for aluminum and copper conductors SCE permits 85°C and 130°C. For Aluminum Conductor Steel Supported (ACSS), SCE base the normal rating at 120°C, and 200°C for the emergency rating. Higher or lower temperature limits may be permitted as appropriate depending on engineering justification.

4.11.7 Series and Shunt Compensation Devices

Applicable to Generation, Transmission and End-User Facilities

Series capacitor and reactors are only permitted to be loaded to ANSI/IEEE limits or as specified by the manufacturer. VAR compensators shall be rated according to the ANSI/IEEE standards where applicable and according to the manufacturer's limitations. These ratings are reported to CAISO Transmission Register. Shunt capacitors and reactors are not in the path of power flow so they are not directly a "limiting component." However, their reactive power capacity is reported to CAISO Transmission Register.

4.11.8 Terminal Equipment

Applicable to Generation, Transmission and End-User Facilities

Terminal equipment comprises: circuit breakers, disconnect switches, jumpers, drops, conductors, buses, and wave-traps, i.e., all equipment in the path of power flow that might limit the capacity of the transmission line or transformer bank to which it is connected. The normal and emergency ampere rating for each termination device is reported to CAISO in its Transmission Register.

4.11.9 Transformer Bays

Applicable to Generation, Transmission and End-User Facilities

The rating of a transformer bay is determined by the least rated device in the path of power flow. This comprises ratings of the transformer, the transformer leads, the termination equipment, and reduced parallel capacity where applicable. The transformer rating is compared to the termination equipment ratings and lead conductors to establish the final transformation rating based on the least rated component. All of the above ratings are reported to the CAISO Transmission Register.

4.11.10 Transformer Normal Ratings

Applicable to Generation, Transmission and End-User Facilities

The "normal" rating is the transformer's highest continuous nameplate rating with all of its cooling equipment operating. The only exception is when a special "load capability study" has been performed showing that a specific transformer is capable of higher than nameplate loading and for which the test data or calculations are available.

4.11.11 Transformer Emergency Ratings

Applicable to Generation, Transmission and End-User Facilities

A transformer's emergency rating is arrived at by one of two methods. First, if no overload tests are available then a 10% overload is allowed. Second, if a factory heat-run or a load capability study has been performed, the emergency rating may be as high as 20% above normal as revealed by the test. For transformers on the transmission system, i.e., primary voltage of 500 kV, the allowed duration of the emergency loading is 24-hours. For transformers with primary voltage of 161 kV to 230 kV, the allow duration is thirty days.

4.11.12 Parallel Operation of Transformers

Applicable to Generation, Transmission and End-User Facilities

When two or more transformers are operated in parallel, consideration is given to load split due to their relative impedances such that full parallel capacity is not usually realized. The permissible parallel loading is calculated according to ANSI/IEEE standards.

4.11.13 Relays Protective Devices

Applicable to Generation, Transmission and End-User Facilities

In cases where protection systems constitute a loading limit on a facility, this limit is the rating for that facility. These limiting factors are reported to the CAISO Transmission Register and are so noted as to the specific reason, e.g., "limited to 725A by relay setting."

4.11.14 Path Ratings

Applicable to Generation, Transmission and End-User Facilities

As stated in Section 2 of the WECC Procedures for Project Rating Review, new facilities and facility modifications should not adversely impact accepted or existing ratings regardless of whether the facility is being rated. New or modified facilities can include transmission lines, generating plants, substations, series capacitor stations, remedial action schemes or any other facilities affecting the capacity or use of the interconnected electric system.

4.12 Synchronizing of Facilities

Applicable to Generation, Transmission and End-User Facilities

Testing and synchronizing of an INTFAC may be required depending on SCE system conditions, ownership or policy, and will be determined based on facility operating parameters. Such procedures should provide for alternative action to be taken if lack of information or loss of communication channels would affect synchronization.

Appropriate operating procedures and equipment designs are needed to guard against out-of-sync closure or uncontrolled energization. (Note: SCE's transmission lines utilize ACB phase rotation, which is different than the national standard phase rotation). The INTFAC is responsible to know and follow all applicable regulations, industry guidelines, safety requirements, and accepted practice for the design, operation and maintenance of the facility.

Synchronizing locations shall be determined ahead of time; required procedures shall be in place and be coordinated with SCE. SCE and the INTFAC shall mutually agree and select the initial synchronization date. The initial synchronization date shall mean the date upon which a facility is initially synchronized to the SCE transmission system and upon which trial operation begins.

For additional technical information regarding the synchronizing of wholesale generators refer to section 3 Protection Requirements.

4.13 Maintenance Coordination and Inspection

Applicable to Generation, Transmission and End-User Facilities

The security and reliability of the interconnected power system depends upon periodic inspection and adequate maintenance of the INTFAC and associated equipment, including but not limited to control equipment, communication equipment, relaying equipment and other system facilities. Entities and coordinated groups of entities shall follow CAISO procedures and are responsible for disseminating information on scheduled outages and for coordinating scheduled outages of major facilities which affect the security and reliability of the interconnected power system.

4.14 Abnormal Frequency and Voltages

4.14.1 Joint Reliability Procedures

Applicable to Generation, Transmission and End-User Facilities

Where specific transmission issues have been identified, those entities affected by and those entities contributing to the problem shall develop joint procedures for maintaining reliability.

4.14.2 Voltage and Reactive Flows

Applicable to Generation, Transmission and End-User Facilities

CAISO shall coordinate the control of voltage levels and reactive flows during normal and emergency conditions. All operating entities shall assist with the CAISO's coordination efforts.

4.14.3 Transfer Limits Under Outage and Abnormal System Conditions

Applicable to Generation, Transmission and End-User Facilities

In addition to establishing total transfer capability limits under normal system conditions, transmission providers and balancing authority shall establish total transfer capability limits for facility outages and any other conditions such as unusual loads and resource patterns or power flows that affect the transfer capability limits.

4.15 Communications and Procedures

4.15.1 Use of Communication System

Applicable to Generation, Transmission and End-User Facilities

It is essential to establish and maintain communications with the SCE Grid Control Center (GCC), the Alternate Grid Control Center (AGCC) or a jurisdictional Switching Center should a temporarily attended station or area of jurisdiction become involved in a case of system trouble. It is equally important that communication services be kept clear of nonessential use during times of system trouble to facilitate system restoration or other emergency operations.

4.15.2 Special Protection Schemes Communication Equipment Requirements

Applicable to Generation, Transmission and End-User Facilities

INTFACs will require the necessary communication equipment for implementation of Special Protection Systems (SPS). This equipment provides line monitoring and high speed communications between the INTFAC breaker and the central control facility, utilizing IEC61850 protocols. This Centralized Remedial Action Scheme (C-RAS) may also be applied to generators that may be required to trip in order to relieve congestion on transmission facilities. This will allow SPS to incorporate disconnection into their automatic control algorithms under contingency conditions, as needed.

The C-RAS is a fully redundant system consisting of equipment that includes, but is not limited to, fiber optic cable, line monitoring/tripping relays and a switch/router at the point of connection to the SCE owned grid. For example, two independent lightwave transmission systems can utilize different strands in common cables. A hardware failure of one system does not result in failure of the other system.

4.15.3 Critical System Voltage Operation

Applicable to Generation, Transmission and End-User Facilities

Voltage control during abnormal system configurations requires close attention with consideration given to what operations will be necessary following loss of the next component. Voltages approaching 10% above or below the normal value are considered critical with rate of change being of principal importance.

Section 5: General Operating Requirements:

Applicable to Generation, Transmission and End-User Facilities

a) **System Operating Bulletins:** The INTFAC connecting into the SCE system may be subject to operating requirements established by SCE, the CAISO or both. SCE's general operating Requirements are discussed in the sections below. SCE may also require additional operating Requirements specific to an INTFAC. If so, these Requirements will be documented in SCE's System Operating Bulletins (SOB), Substation Standard Instructions (SSI), and/or interconnection and power purchase agreements. SCE's SOBs and/or SSIs specific to the INTFAC and any subsequent revisions will be provided by SCE to the INTFAC as they are made available.

b) **INTFAC's Responsibility:** It is the INTFAC's responsibility to comply with applicable operating requirements. Operating procedures are subject to change as system conditions and system needs change. Therefore it is advisable for the INTFAC to regularly monitor operating procedures that apply to its wholesale generating facilities. The CAISO publishes its operating procedures on its internet site, but it is prudent for the INTFAC to contact the CAISO for specific Requirements.

c) **Quality of Service:** The interconnection of the INTFAC's equipment with the SCE system shall not cause any reduction in the quality of service being provided to SCE's customers. If complaints result from operation of the INTFAC, such equipment shall be disconnected until the problem is resolved.

d) **SCE Circuits:** INTFACs are not permitted to energize any de-energized SCE circuit.

e) **Operate Prudently:** The INTFAC will be required to operate its facility in accordance with prudent electrical practices.

f) **Protection in Service:** The wholesale generating facility shall be operated with all of required protective apparatus in service whenever the wholesale generating facility is connected to, or is operated in parallel with, the SCE electric system. Redundant protective devices may be provided at the Producer's expense if the generator is to be operated in parallel during routine testing of or failure of a protective device. Any deviation for brief periods of emergency may only be by agreement of SCE and is not to be interpreted as permission for subsequent incidents.

Applicable to Generation Facilities

g) **Added Facilities Documentation:** The Producer may not commence parallel operation of generator(s) until final written approval has been given by SCE. As part of the approval process, the Producer shall provide, prior to the commencement of parallel operation, all documents required by SCE to establish the value of any facilities installed by the Producer and deeded to SCE for use as added facilities. SCE reserves the right to inspect the Producer's facility and witness testing of any equipment or devices associated with the interconnection.

5.1 Wholesale Generating Facility Records and Data

Applicable to Generation Facilities

SCE requires generating facility operating records and data from the Producer in order for SCE to plan and reliably operate its electrical system. Some Producers may be subject to similar record and data obligations from the CAISO. If so, the Producer may satisfy many of SCE's operating record and data requirements by giving SCE permission to access the Producer's information held by the CAISO.

Table 5.1 illustrates typical sizes of wholesale generating facilities and typical means of communicating generating facility operating records and data to SCE. Typically, large and medium sized generating facilities are required to install real-time telemetering, but small generating facilities may be excluded from many record and data requirements. Section 7 of this document describes the real-time telemetering[1] hardware requirements. The following two sub-sections describe wholesale generating facility operating records and data Producers are required to submit to SCE by real-time telemetering, voice communication or equivalent means.

SCE will require submission of additional records if such records are necessary for SCE to reliably operate and plan its electrical system.

1 Generation up to 10 MW may rely on the Public Switched Telephone Network (PSTN) as the primary means of maintaining operating communications. Generation greater than 10 MW should provide an alternate means of communication in addition to the PSTN to insure availability in the event of unplanned outage or emergency.

Table 5.1

Aggregate Generation Facility Size	Real-time Telemetering	Voice
Gen. ≥ 1 MW	Required	Required
Gen. < 1 MW	Maybe	Maybe

5.2 Operating Records and Data the Producer Must Provide to SCE

Applicable to Generation Facilities

a) SCE requires some Producers to maintain operating communications with an SCE designated switching center. These communications provide SCE operating records and data about the Producer's generating facilities in order for SCE to reliably operate its electrical system. Generally, Producers with wholesale generating facility capacity of 1 MW or greater will have these Requirements, but it may be necessary for SCE to receive generating facility records for smaller generators if needed for reliability. Table 5.2 illustrates typical required generating facility records and data. SCE may require Producers to provide additional records than those shown in Table 5.2.

Table 5.2

	Wholesale Generation Facility Record	Typical Size of Aggregate Generation[2] Facility	Delivery Date or Primary Communication Mode	Delivery Location
1	System Parallel Operation Or Separation	> 200 kW	Timely by Voice	Designated SCE Switching Center
2	Scheduled And Unscheduled Outages	> 200 kW	Scheduled Outages Outage Duration Adv. Notice < 1 day 24 Hours 1 day or more 1 Week Major overhaul 6 Months Unscheduled Outages Timely Communication Mode Voice	Designated SCE Switching Center
3	Levels Of Real And Reactive Power	≥ 1 MW	Real-time Telemetering	SCADA
4	Equipment Clearance	≥ 10 MW	Timely by Voice	Designated SCE Switching Center
5	Interruption event	> 200 kW	Timely after event by Voice	Designated SCE Switching Center
6	Gen. Circuit Breaker Status	≥ 10 MW	Real-time Telemetering	SCADA
7	Gen. on/off Status	≥ 10 MW	Real-time Telemetering	SCADA
8	Generator Terminal Voltage	≥ 10 MW	Real-time Telemetering	SCADA

b) An interruption event is said to occur on an interconnection circuit when its closed energized circuit breaker has opened or trips and interrupts powerflow to/from SCE facilities. After experiencing an event, the Producer is required to submit the following event information to their Designated Switching Center in order for SCE to assess relay operations and system integrity.

i. Date and time of trips by the interconnection circuit breaker
ii. Generation facility status at time of incident (real & reactive power generation)
iii. Relay operation indicator (target) operations
iv. Oscillograph or Sequence of Event recorder records.

5.3 Operating Data and Records the Producer Must Provide SCE Upon Request

Applicable to Generation Facilities

a) The Producer will be required to keep a daily operations log (records) for the generating facility which must include levels of operating voltage, relay operations, information on maintenance outages, maintenance performed, availability, and

2 Aggregate generation is the total nameplate capacity of generating facilities at the generation site being interconnected or the total generation under one SCE account.

circuit breaker trip operations requiring a manual reset. Producers with the necessary metering[3] will be required to log fuel consumption, cogeneration fuel efficiency kilowatts, kilovars, and kilowatt-hours generated and settings or adjustments of the generator control equipment and protective devices, and any significant events related to the operation of the generating facility, including but not limited to real and reactive power production; changes in operating status and protective apparatus operations; and any unusual conditions found during inspections. Changes in settings shall also be logged for Producer's generator(s) if it is "block-loaded" to a specific kW capacity.

b) SCE, after giving written notice to the Producer, shall have the right to review and obtain copies of metering records and operations and maintenance logs of the wholesale generating facility.

c) If a Producer's wholesale generating facility has a Nameplate Rating greater than one (1) megawatt, SCE may require the Producer to report to a designated SCE Switching Center, twice a day at agreed upon times for the current day's operation, the hourly readings in kW of capacity delivered and the energy in kWh delivered since the last report.

5.4 Calibration of Producer Owned Protective Apparatus

Applicable to Generation Facilities

The Producer must test the protective apparatus it owns on a routine basis in order to provide correct calibration and operation of the devices. Required test intervals of these protective apparatus have been established as shown in Table 5.3.

These test intervals are based on the nominal system voltage at the point of interconnection to SCE. SCE may require the Producer, at the Producer's expense, to demonstrate to SCE's satisfaction the correct calibration and operation of the Producer's protective apparatus at any time SCE reasonably believes that the Producer's protective apparatus may impair the SCE electric system integrity.

3 Generators operating under the FERC QF status have additional metering installed.

Table 5.3

	Interconnection Voltage	Test Interval	Delivery Location
1	≥200 kV	Every two years[1]	mail to: Manager, Grid Contracts, P.O. Box 800, 2244 Walnut Grove Avenue, Rosemead, California 91770
2	55 - 200 kV	Every four years[1]	mail to: Same
3	less than 55 kV	Every eight years[2]	mail to: Same
4	Frequency relays (all voltage levels) Electromechanical: Electronic:	Every two years four years	mail to: Same

1 The test interval may be extended by 2 years for self-monitoring microprocessor relays provided with failure alarms, e.g. from four years to six years.

2 Interconnection protective relays on interconnections to lines listed in System Operating Bulletin 22 (fire hazard areas) must be tested *annually* before May 1 of each year.

5.5 Disconnecting Service to a Generation Facility

Applicable to Generation Facilities

Applicable agreements and tariffs may state criteria for disconnection of generating facilities which are interconnected to SCE's system. In general, generating facilities may be curtailed or disconnected if SCE determines that their operation creates a threat to personnel or the electric system.

5.6 Voltage Variations

Applicable to Generation Facilities

a) **Voltage Regulation:** Operation of the Producer's wholesale generating facility shall not adversely affect the voltage regulation of that portion of the SCE system to which it is connected. Adequate voltage control shall be provided by the Producer to minimize voltage regulation on the SCE system caused by changing generator loading conditions. The step-up transformer ratio must be chosen such that the Producer can meet its voltage regulation obligations over the expected range of SCE system voltages. Step-up transformers must be equipped with no-load taps which provide ±5% adjustment of the transformer ratio in 2.5% steps.

b) **Exception:** The tap Requirement will be waived if the Producer submits a study to SCE which demonstrates to SCE's satisfaction that the Producer can meet its voltage regulation obligations over the expected range of system voltages specified by SCE.

Generator voltage schedule and transformer tap settings will be specified by SCE, as necessary, or the CAISO to ensure proper coordination of voltages and regulator action. It is the Producer's responsibility to ensure voltage-VAR schedule compliance. The following table illustrates whether SCE or the CAISO specifies these schedules.

Table 5.4

Wholesale Generating Facility Connected to:	CAISO Controlled Transmission System	SCE Controlled Subtransmission or Distribution
Voltage Schedule	Specified by CAISO	Specified by SCE, as needed
Transformer Tap Settings	Specified by SCE ±5% in 2.5% steps	Specified by SCE ±5% in 2.5% steps

c) **Transmission Voltages:** Expected transmission system operating voltages range from 160 to 164 kV for 161 kV nominal voltage, 220 to 240 kV for 220 kV nominal voltage, and 515 to 535 kV for 500 kV nominal voltage. Voltage regulation at a given location on the transmission system must follow the CAISO and SCE voltage schedules.

d) **Distribution and Subtransmission Voltages:** In order to supply and maintain proper voltages for SCE's customers as required by the CPUC, SCE's primary distribution voltages (2.4 to 34.5 kV) and subtransmission voltages (55 to 115 kV) may fluctuate by as much as ±5% from the nominal values (e.g., 12 kV ±5%; 34.5 kV ±5%; etc.). SCE uses various voltage regulation techniques to raise or lower primary distribution and subtransmission voltages in order to maintain the customer's service voltage at the desired level. Producers interconnected at primary distribution or subtransmission voltage levels must be able to withstand such voltage changes and to respond with proper power factor adjustment in order not to oppose or interfere with SCE's or the CAISO's voltage regulation processes.

5.7 VAR Correction

Applicable to Generation, Transmission and End-User Facilities

VAR correction will normally be planned for light load, heavy load and for system normal and contingency conditions. This is to be accomplished by providing transmission system VAR correction to minimize VAR flow and to maintain proper voltage levels. The planning of transmission system VAR requirements should consider the installation of shunt capacitors, shunt reactors and tertiary shunt reactors, synchronous condensers, FACTS and transformer tap changers. The guidelines for reactive planning are as follows:

5.7.1 Interconnection

Applicable to Generation, Transmission and End-User Facilities

Interconnection with other utilities will normally be designed with the capability of maintaining near-zero VAR exchange between systems. Entities interconnecting their transmission system with SCE's transmission system shall endeavor to supply the reactive power required on their own system, except as otherwise mutually agreed. SCE shall not be obligated to supply or absorb reactive power for the INTFAC when it interferes with operation of the SCE transmission system, limits the use of SCE interconnections, or requires the use of generating equipment that would not otherwise be required.

5.7.2 Subtransmission System

Applicable to End-User Facilities

VAR correction will normally be planned for connection to 55 kV through 160 kV buses to correct for large customer VAR deficit, subtransmission line VAR deficit, and transformer A-Bank VAR losses, the objective being zero VAR flow at the high side of the A-Banks with VAR flow toward the transmission system on the high side of the A-Banks, if required. Adequate VAR correction shall be provided for maximum coincident customer loads (one-in-five year heat storm conditions), after adjusting for dependable local generation and loss of the largest local bypass generator.

5.8 Voltage Regulation/Reactive Power Supply Requirements

Applicable to Generation, Transmission and End-User Facilities

Operating entities shall ensure that reactive reserves are adequate to maintain minimum acceptable voltage limits under facility outage conditions. Reactive reserves required for acceptable response to contingencies shall be automatically applied when contingencies occur. Operation of static and dynamic reactive devices shall be coordinated such that static devices are switched in or out of service so that the maximum reactive reserves are maintained on generators, synchronous condensers and other dynamic reactive devices.

Applicable to Transmission and End-User Facilities

To ensure secure and reliable operation of the interconnected power system, reactive supply and reactive generation shall be properly controlled and adequate reactive reserves shall be provided. If power factor correction equipment is necessary, it may be installed by the INTFAC at the facility, or by SCE at SCE's facilities at the INTFAC's expense.

Applicable to Generation Facilities

Generator VAR schedules, as needed, will be specified by SCE or the CAISO to ensure proper coordination of voltages. It is the Producer's responsibility to ensure voltage-VAR schedule compliance. If power factor correction equipment is necessary, it must be installed by the Producer at its facility at the Producer's expense to ensure the power factor at the point of interconnection meets the criteria in Table 5.5.

Note that the generator power factor capability for WDAT service is likely to require equipment capable of operating over the range of 0.9 lag to 0.95 lead in order to meet the Tariff Point of Delivery requirements.

Table 5.5

Wholesale Generating Facility Connected to:	CAISO Controlled Transmission System	SCE Controlled Subtransmission or Distribution
Power Factor	Generator has the capability of 0.90 lagging to 0.95 leading.	At point of delivery, 0.95 lagging to 0.95 leading.

5.8.1 Reactive Power Equipment – Induction Generators (in aggregate)

5.8.1.1 Facility Reactive Power Equipment Design - generally

Applicable to Generation, Transmission and End-User Facilities

INTFACs shall provide for the supply of its reactive requirements, including appropriate reactive reserves, and its share of the reactive requirements to support power transfers on interconnecting transmission circuits.

The reactive power equipment utilized by the INTFAC to meet SCE's Requirements must be designed to minimize the exposure of SCE's customers, SCE's electric system, and the electric facilities of others (i.e., other facilities and utilities in the vicinity) to:

1. severe overvoltages that could result from self-excitation of induction generators,
2. transients that result from switching of shunt capacitors,
3. voltage regulation problems associated with switching of inductive and capacitive devices.
4. unacceptable harmonics or voltage waveforms, which may include the effect of power electronic switching, and
5. Voltage flicker exceeding SCE Voltage Flicker limits as indicated in SCE Transmission Planning Criteria and Guidelines Figure 4-1 "VOLTAGE FLUCTUATION DESIGN LIMITS".

5.8.1.2 Facility Reactive Power Equipment Design - provide variable source

Applicable to Generation, Transmission and End-User Facilities

The reactive power equipment utilized by the INTFAC to meet SCE's Requirements must be designed to provide a variable source of reactive power (either continuously variable or switched in discrete steps). For discrete step changes, the size of any discrete step change in reactive output shall be limited by the following criteria:

a) the maximum allowable voltage rise or drop (measured at the point of interconnection with the SCE system) associated with a step change in the output of the INTFAC's reactive power equipment must be less than or equal to 1%; and
b) the maximum allowable deviation from an INTFAC's reactive power schedule (measured at the point of interconnection with the SCE system) must be less than or equal to 10% of the INTFAC's maximum (boost) reactive capability.

5.8.2 Reactive Power Supply Requirements - Synchronous Generators

Applicable to Generation Facilities

Producers connected to the SCE system and utilizing synchronous generators are required to generate or supply reactive power so that the generating facility does not impose any additional reactive power demand upon SCE other than the demand of loads within the facility. The Producer will not be permitted to deliver excess reactive power to SCE under normal operating conditions unless otherwise agreed to by SCE. Under emergency operating conditions, the Producer is permitted to deliver excess reactive power to SCE to ensure voltage schedule compliance.

Producers connected to the subtransmission system or bulk power system (above 34.5 kV) must have the voltage regulation equipment and generator reactive power capability to maintain a voltage schedule or reactive power schedule prescribed by SCE or, if applicable, the CAISO. Generators must be capable of operation over the power factor ranges designated in Table 5.5.

5.8.3 Reactive Power Supply Requirements - Inverter Systems

Applicable to Generation Facilities

Forced-commutated inverters must meet SCE's reactive power supply Requirements of synchronous generators in 5.8.2. Line commutated inverters must be corrected to satisfy SCE's reactive power supply Requirements of induction generators in 5.8.1.

Inverters must also meet SCE's harmonic load limits based on IEEE Standard 519-1992. For further information on the assessment and mitigation of harmonics due to inverters, refer to "SCE Transmission Planning Criteria and Guidelines, Appendix F, HARMONIC LOAD LIMITS, APPLICATION OF IEEE STANDARD 519-1992 TO TRANSMISSION AND SUBTRANSMISSION PLANNING".

5.8.3.1 IEEE and UL Standards for Inverter Systems 200 kVA or Less

Applicable to Generation Facilities

Inverter systems which conform to the recommended practices in IEEE Standard 929-19 and which have been tested and approved for conformance to UL Subject 1741, are considered to have met all SCE's reactive power supply Requirements.

5.8.4 Voltage and Reactive Control

5.8.4.1 Coordination

Applicable to Generation, Transmission and End-User Facilities

Operating entities shall coordinate the use of voltage control equipment to maintain transmission voltages and reactive flows at optimum levels for system stability within the operating range of electrical equipment. Operating strategies for distribution capacitors and other reactive control equipment shall be coordinated with transmission system requirements.

5.8.4.2 Transmission Lines

Applicable to Transmission Facilities

Although transmission lines should be kept in service as much as possible, during over-voltage system conditions a customer's transmission line(s) may be subject to removal from operation as a means to mitigate voltage problems in the local area. SCE will notify CAISO when removing such facilities from and returning them back to service.

5.8.4.3 Switchable Devices

Applicable to Transmission and End-User Facilities

Devices frequently switched to regulate transmission voltage and reactive flow shall be switchable without de-energizing other facilities.

5.9 Off-Nominal Frequency Requirements

Applicable to Generation Facilities

Producer wholesale generating facilities that protect for off-nominal frequency operation should have relaying protection and generating equipment that accommodates, at a minimum, under frequency and over frequency operation for the following specified time frames in the table below.

Table 5.6
WECC Off Nominal Frequency Limits

Under Frequency Limit	Over Frequency Limit	Minimum Time
> 59.4 Hz	60.0 to < 60.6 Hz	continuous operating range
≤ 59.4 Hz	≥ 60.6 Hz	3 minutes
≤ 58.4 Hz	≥ 61.6 Hz	30 seconds
≤ 57.8 Hz	N/A	7.5 seconds
≤ 57.3 Hz	N/A	45 cycles
≤ 57.0 Hz	> 61.7 Hz	instantaneous trip

Frequency relay settings must not allow less stringent operation of the wholesale generating facility than specified in the WECC Off Nominal Generation Requirements shown in Table 5.6, unless agreed to in writing by SCE and coordinated with SCE's abnormal frequency operation plan. It is the Producer's responsibility to ensure conformance with the latest approved WECC Off Nominal Generation Requirements.

The CAISO is responsible for frequency control and therefore SCE can assume no responsibility for damage that occurs due to off nominal frequency operation. It is possible that the electrical network including SCE's system may operate outside of the limits stated above. It is the responsibility of all Producers connected to SCE's electrical system to install equipment to protect against damage to Producer owned equipment from off-nominal frequency operation.

Wholesale generators that are required to use under-frequency detection for islanding must coordinate frequency threshold settings to ensure conformance with SCE's abnormal frequency operation plan. In general, detection and separation of wholesale generators under islanded conditions take precedence over sustained operation of these particular generators through system frequency deviation events.

5.10 Voltage Imbalance and Abnormal Voltage or Current Waveforms (harmonics)

Applicable to Generation Facilities, Transmission and End-User Facilities

Power quality problems are caused when voltage imbalances and harmonic currents result in abnormal voltage and/or current waveforms. Generally, if an INTFAC's output degrades power quality to SCE's customers' facilities, other INTFACs, or SCE's facilities, SCE may require the facility to install equipment to eliminate the power quality problem.

5.10.1 Voltage Imbalance

Applicable to Generation, Transmission and End-User Facilities

The unbalanced voltage level (magnitude and phase), due to the INTFAC to be connected at the transmission or subtransmission system level, may not exceed 1% at the Point of Common Connection[4] (PCC), under steady state system conditions. Under certain conditions (contingency conditions), SCE may allow higher levels of voltage imbalance if justified after a study conducted by SCE. In any event, the unbalanced voltage level created by an INTFAC shall not exceed 1.5%.

4 The PCC will generally be at the location of the revenue meter or the point of ownership change in the electrical system between SCE and the Producer. For customers served by dedicated facilities, the location of the PCC will be determined by mutual agreement between the Producer and SCE.

It is the responsibility of INTFACs, connected to the SCE electrical system, to install the adequate mitigation devices to protect their own equipment from damage that maybe caused by voltage imbalance condition.

5.10.2 Harmonics

Applicable to Generation, Transmission and End-User Facilities

INTFACs are required to limit harmonic voltage and current distortion produced by static power converters or similar equipment in accordance to good engineering practice used at their facility to comply with the limits set by the current IEEE Standards.

5.10.3 Disconnection

Applicable to Generation, Transmission and End-User Facilities

SCE may disconnect any INTFAC until the above Requirements are met.

5.10.4 Photovoltaic Inverter Systems

Applicable to Generation, Transmission and End-User Facilities

Photovoltaic inverter systems which conform to the recommended practices in IEEE Standard 929-1999 and which have been tested and approved for conformance to UL Subject 1741 are considered to have met SCE's Requirements for voltage imbalance and abnormal waveforms.

5.11 Switching and Tagging Rules

Applicable to Generation Facilities

SCE and Producer shall provide the other Party a copy of its switching and tagging rules that are applicable to the other Party's activities. In accordance with SCE's switching and tagging rules to ensure the safety of SCE's personnel, the Producer shall allow SCE to place its locks on the Producer's Interconnection Facilities (specifically disconnect switches and/or circuit breakers on the Producer's terminus of the Producer's generation tie line) to prevent inadvertent energization of the Producer's generation tie line while SCE personnel are performing maintenance and/or repair work on

SCE's Interconnection Facilities, as may be required.

The Producer's substation facilities must incorporate a 3 phase gang operated disconnect with a common operating handle for 230 kV and below; 500 kV shall require a disconnect operating handle for each phase. The disconnect shall be placed in the LINE DISCONNECT position on the high side of the Producer's generation tie line. The operating handle of the disconnect/disconnects must include a provision for locking the disconnect control handle/handles in the open positions. The locking feature may be utilized by either party when inter-company clearances are issued on the Producer's generation tie line.

The Producer's substation facilities must incorporate a 3 phase gang operated GROUND disconnect with a common operating handle for 230 kV and below; 500 kV shall require a GROUND disconnect operating handle for each phase. The disconnect shall be placed in the line position on the high side of the Producer's generation tie line. The operating handle of the disconnect/disconnects must include a provision for locking the disconnect control handle/handles in the closed positions. The locking feature may be utilized by either party when inter-company clearances are issued on the Producer's generation tie line.

5.11.1 Manual Disconnects

Applicable to Generation Facilities

The producer shall furnish and install a ganged, manually-operated isolating switch near the point of Interconnection to isolate the Generation Facility from the SCE's Distribution System.

The device must:

1. Allow visible verification that separation has been accomplished.
2. Include marking or signage that clearly indicates open and closed positions.
3. Be capable of being reached quickly and conveniently 24 hours a day by SCE personnel.
4. Be capable of being locked in the open position.
5. Be clearly labeled with permanent signage.

Section 6: Revenue Metering Requirements

Applicable to Generation and End-User Facilities

6.1 General Information

Revenue metering is required to measure the energy and capacity delivered and consumed by a Producer's station load. While functionally similar, there are varying Requirements for Producers depending on the nature and purpose of their wholesale generating facility and varying rules established by the authorities having jurisdiction over a Producer and SCE. Metering Requirements for Producers taking service under a FERC tariff, and retail service under CPUC regulations are set forth in Section 6.2.

In general, all ISO revenue metering and associated equipment used to measure a generator's energy, and capacity output, shall be provided, owned, and maintained at the Producer's expense.

6.1.1 Retail Service

The retail metering requirements for retail service will be owned, operated, and maintained by SCE under SCE's Electrical Service Requirements (ESR) and in accordance with SCE approved tariffs.

6.2 Revenue Metering Requirements for Wholesale Generators

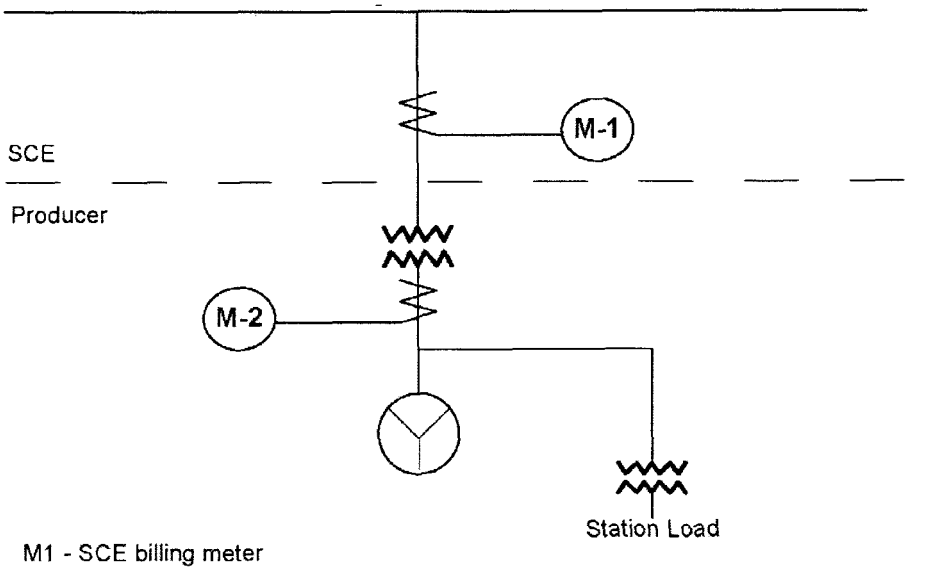
6.2.1 General Information

In order to measure energy and capacity delivered and scheduled with the CAISO, a Producer shall install all necessary meters, routers, telecommunications, and associated equipment to comply with the metering standards and requirements of the CAISO Tariff and Metering Protocol. As required by the CAISO Tariff, a Producer's metering facilities shall be certified by the CAISO. Further, retail service will be measured using an SCE owned meter including SCE owned metering PT's and CT's. However, a producer may install the required ISO metering in tandem with the SCE owned metering Figure 6a shows a typical SCE metering installation for a wholesale generating facility without departing load and Figure 6b also shows a typical

CAISO customer owned meter and SCE owned meter in tandem on the customers side of the fence and an SCE metering installation for SCE retail billing purposes on SCE property of a wholesale generating facility with departing load.

Figure 6a

Typical metering configuration for Generators taking service under the CAISO Tariff with CAISO metering installed on Producer's side of the interconnection with no departing load showing placement of SCE metering at M-1 or M-2.

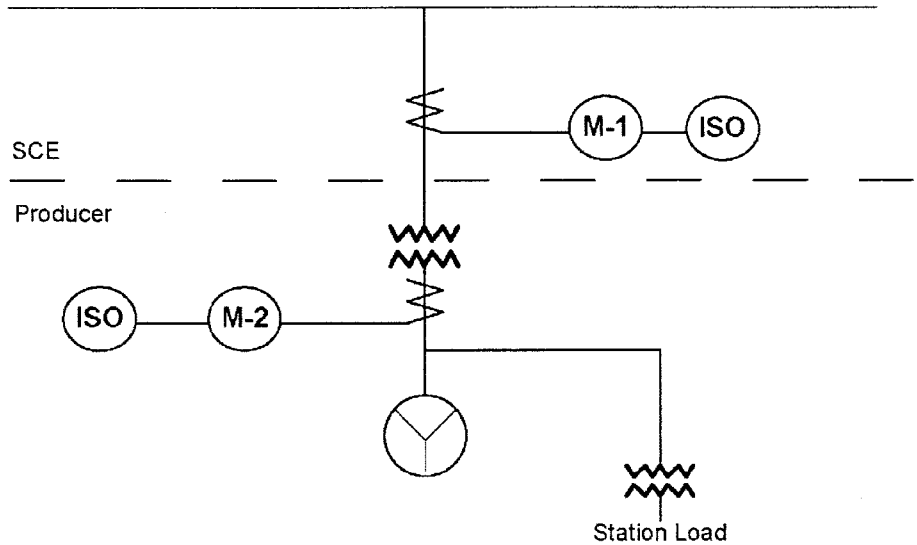


M1 - SCE billing meter

M2 - SCE billing meter in an ESR compliant meter cubicle

Figure 6b

Typical metering configuration for Generators taking service under the CAISO Tariff with CAISO metering installed on SCE's or Producer's side of the interconnection with departing load showing placement of SCE metering at M-1 or M-2, respectively.



M1 - SCE billing meter

M2 - SCE billing meter in an ESR compliant meter cubicle

If a Producer elects Direct Access service pursuant to SCE's Rule 22, it must comply with Rule 22 metering requirements for retail billing.

6.2.2 Location/Ownership of CAISO Metering Equipment

a) **Metering Installed on a Producer's Side of Interconnection**

A Producer shall, at its expense, install, own, and maintain all CAISO metering equipment, including metering CTs/PTs, meters, routers, and telecommunication's equipment providing such equipment is installed on its assets and located on its side of the point of interconnection with SCE (Figure 6a).

Section 7: Telemetering Requirements (Hardware)

7.1 Telemetering Requirements

Applicable to Generation, Transmission and End-User Facilities

For a high degree of service reliability under normal and emergency operation, it is essential that the INTFAC have adequate and reliable telecommunication facilities.

The INTFAC shall specify the following at the point of connection: the requested voltage level, MW/MVAR capacity, and/or demand.

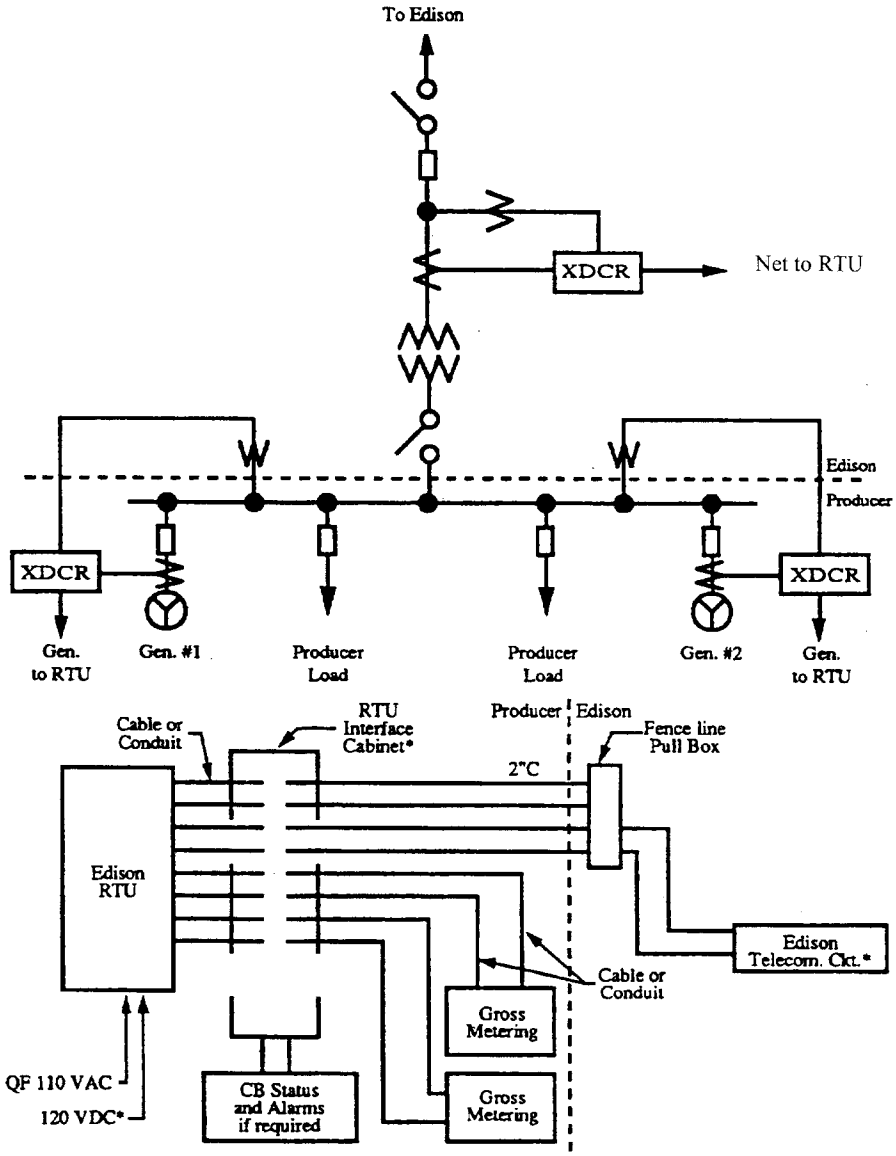
Applicable to Generation Facilities

Producers with wholesale generating facilities 1 MVA nameplate or larger will require telemetering equipment and telecommunications at Producer's expense. For projects equal to or greater than 1 MVA but less than 10 MVA, real time SCADA telemetry of watts and vars only are required for total generation and customer load. For projects greater than 10 MVA, the telemetering equipment must transmit at minimum generator unit gross MW and MVAR, generator status, generator circuit breaker status and generator terminal voltage. In addition, real time telemetering of project net MW and MVAR is required.

(Refer to the following Figure 7). Wind generation facilities equal to or greater than 1MVA nameplate will require real-time monitoring in most cases. It is the Producer's responsibility to comply with any CAISO telemetry requirements.

Figure 7

Typical Remote Terminal Unit (RTU) Installation
1 MVA nameplate OR MORE Wholesale Generating Facility



* For generation 1 MVA or more.

7.2 Total Generation 1 MVA Nameplate or More

Applicable to Generation Facilities

The following is a list of Requirements for the installation of a Real-Time Remote Terminal Unit (RTU) or equivalent device at the Producer's wholesale generating facility. Unless otherwise specified, all the facilities listed below are to be provided by the Producer.

The typical RTU utilized by SCE is the DAQ Callisto RTU, GE-Harris D20, or equivalent. The size and point count of the RTU is determined based on the generation nameplate capacity as well as the number of data points to be monitored. SCE will install, own, operate, maintain, repair, inspect, use, control, alter, replace and upgrade the RTU.

The following specifications are to be used as informational guidelines to facilitate the RTU installation at the Generation Facility:

a) An interior location suitable for floor or wall mounting the RTU cabinet is required. The location should be reasonably close to the origin of telemetering signals. A control room or relay house is acceptable as long as the temperature range is within 0C to 70C. Cable access can be either through the top or bottom of the RTU cabinet.

- Wall space for a single door cabinet 24 inches wide by 20 inches deep by 30 inches high. The wall mount cabinet weighs 125 pounds and is mounted with a ½ inch bolt through mounting tabs at each corner.
- Floor space for a single door cabinet 30 inches wide by 24 inches deep and 72 inches tall with a minimum of 30 inches of front access for door. The floor-mount cabinets weigh approximately 500 pounds. The floor cabinet is anchored to the floor with four bolts and concrete anchors.

b) Provide a 120 VAC 15 Amp convenience power source to the RTU cabinet. This source will utilize a dedicated breaker labeled "SCE-RTU". A 4 foot coil is to be left at the RTU location and will be terminated by SCE inside the RTU cabinet.

c) Station DC power (48VDC or 125VDC) on a dedicated 5 Amp circuit breaker (not shared with other equipment) run to the RTU cabinet for RTU power. Breaker to

be labeled SCE-RTU. If DC power is not available, a 120 VAC circuit may be used as long as this circuit is sourced from an Uninterruptible Power System with a minimum of 4 hour backup.

d) One stranded AWG #8 conductor will be connected to station ground and run to the RTU cabinet by the customer.

e) The customer will run all data signal cables to the RTU cabinet or to a near-by (6 feet or less) interface cabinet for termination. Data cables must be shielded with shield grounded at RTU end only. Twisted-pair stranded wire between AWG#16 and AWG#22 or twisted-pair solid wire between AWG#18 and AWG#24 may be used. 6,12,25 and 32 pair cables are typical. A 10 foot coil is to be left at the RTU location and will be terminated by SCE inside the RTU cabinet.

f) Data signals will include 2 of the three quantity pairs listed below[5].

- Gross MWatts and MVars for each unit.
- Net MWatts and MVars for each unit.
- Auxiliary MWatts and MVars for each unit.

Data signals will also include:

- KVolts for each unit (terminal voltage).
- Circuit breaker open/closed status for each unit CB.
- Online status for each unit.

All analog quantities will be represented by a + / – 1 milliamp or 4 to 20 milliamp current loop. The current loop may be shared as long as there are no grounds and it is not driven beyond the manufacturers specified limits. Circuit breaker and unit on/off line status will be represented by a dry contact available at the interface cabinet. All status points will utilize the Normally Open contacts of the customer provided isolation relay. The RTU will provide the contact wetting voltage.

SCE's Grid Control Center (GCC) on a site-to-site basis may deem other status, protection alarms, or controls necessary.

g) Two communication methods are supported to connect the RTU to the SCE's EMS Remote Port Servers at one of SCE's Substations.

- Dedicated 3002-type voice grade 4-wire communications circuit. SCE's IT Infrastructure group will provide coordination for the installation of landline communications facilities.
- SCE satellite communications package may be provided if a landline circuit is not feasible. A suitable location for the satellite antenna is any wall or pole that provides an unobstructed view of the sky directed to 130 degrees (South-East) with an angle to the horizon of 40 degrees. The customer must run a ¾ -inch or 1-in conduit from the RTU to within 24 inches of the satellite antenna for the communications and antenna power cables. A weather head is required at the antenna end of the conduit. Currently, Satellite Communication method is **not available** and to be revised at a latter date due to design issues with hub capacity and data protocol.

h) The RTU cabinet can be delivered to the customer premises for mounting and conveniences to the customer.

i) 24-hour access to the RTU for maintenance by SCE's Power System Controls technicians.

j) Ground Mats

See Section 8.2: Ground Mats.

[5] For project equal to or greater than 1 MVA but less than 10 MVA, real time SCADA telemetry of watts and vars only are required for total generation and customer load.

Section 8: Grounding Circuits and Substations

8.1 Nominal Voltage and Grounding

Applicable to Generation, Transmission and End-User Facilities

SCE's most common primary distribution voltages are 4, 12 and 16 kV depending on the geographic area. Other voltages are also used in specific areas. Subtransmission voltages are nominally 66 kV to 115 kV. Transmission system voltages are nominally 161 kV, 220 kV and 500 kV. The majority of the 4, 12, and 16 kV circuits are effectively grounded, but some are operated with high impedance grounding. A substantial number of the effectively grounded circuits are used for four-wire distribution (phase to neutral connected loads). SCE will provide the INTFAC necessary information on the specific circuit serving the INTFAC for proper grounding.

8.2 Ground Mats

Applicable to Generation, Transmission and End-User Facilities

If the INTFAC and SCE substation ground mats are tied together, all cables may be landed without any protection. If the INTFAC and SCE substation ground mats are not tied together, all cables shall have protection at both ends. The design of cable protection, if any, on circuits used for protective relaying purposes shall be such that the operation of the protective relaying is not hampered when the cable protection operates or fails.

All INTFAC ground mats shall be designed in accordance with good engineering practice and judgment. Presently the recognized standard for grounding is IEEE 80 "IEEE Guide For Safety in AC Substation Grounding." All ground mat designs should meet or exceed the requirements listed in this standard. If local governmental requirements are more stringent, building codes for example, they shall prevail. All INTFACs shall perform appropriate tests, including soil resistivity tests, to demonstrate that their ground grid design meets the standard. Mats shall be tested at regular intervals to ensure their effectiveness.

Grounding studies shall be performed with industry recognized software to determine if INTFAC and SCE ground grids should be separate or tied together. This study will determine the maximum safe fault current for the ground grid design. It is suggested that the grid be designed for the maximum fault currents expected over the life of the facility.

If for any reason the worst-case fault current exceeds the design maximum fault current value due to changes in the producer's facility or changes on the SCE system, the INTFAC shall conduct new grounding studies. Any changes required to meet safety limits and protect equipment shall be borne by the INTFAC.

The INTFAC is responsible to ensure that the GPR (Ground Potential Rise) of the Producer's or interconnected mat does not negatively affect nearby structures or buildings. The cost of mitigation for GPR and other grounding problems shall be borne by the INTFAC. If it is elected to install separate ground grids for SCE and the INTFAC, the facility shall be responsible to mitigate any transfer voltages and GPR that occur to SCE's grid due to faults on the INTFACs.

Any ground grid design, which results in a GPR that exceeds 3,000 volts RMS for the worst-case fault or has a calculated or measured ground grid resistance in excess of 1 ohm, will require special approval by SCE.

8.3 Substation Grounding

Applicable to Generation, Transmission and End-User Facilities

The INTFAC shall follow practices outlined in IEEE 80 "IEEE Guide for Safety in AC Substation Grounding." Substation grounding is necessary to protect personnel and property against dangerous potentials and currents during both normal and abnormal conditions of operation. Also, it provides a path to ground for the discharge of lightning strikes, a path to ground for the neutral currents of grounded neutral circuits and apparatus, the facilities for relaying to clear ground faults, the stability of circuit potentials with respect to ground and a means of discharging current-carrying parts to be handled by personnel.

Section 9: Property Requirements

Applicable to Generation, Transmission and End-User Facilities

The INTFAC must acquire the necessary Rights of Way requirements for their gen-tie or transmission line, along with the Access requirements to the point of interconnection with SCE's facilities. The use of SCE Rights of Ways and/or property shall not be included in any interconnection proposals.

The Interconnection Transmission line or Access Rights of Way that are proposed to cross SCE Transmission line or Access easements or fee owned property must be submitted to SCE Corporate Real Estate organization for a separate review request and approval.

9.1 Infrastructure Property Requirements

Applicable to Generation, Transmission and End-User Facilities

Substation: The following approximate land requirements are needed for typical interconnection facilities (SCE owned substation) on the customer's property:

- 66kV Tap: 90 ft by 110 ft
- 66kV Loop: 110 ft by 150 ft
- 115kV Tap: 100 ft by 120 ft
- 115kV Loop: 120 ft by 180 ft
- 220kV Loop: 290 ft by 480 ft
- 500kV Loop: 420 ft by 780 ft

Minimum substation land requirements are subject to change according to engineering studies and interaction with SCE is required for final determination. The dimensions above include a required 10 ft easement bordering the interconnection facility under the assumption that the customer owns the transformer and the land needed for the incoming line(s) is not included.

Revision History Table:

Revision	Date	Comments
1	11/3/04	Document Created
2	03/19/09	Revised to incorporate interconnection requirements for new Generation, Transmission, and End User facilities.
3	10/2/09	Revised to incorporate the new wind-turbines set-back criteria.

Appendix A

Following is a list of the technical standards and criteria referenced within SCE's Interconnection Technical Requirements.

NERC/WECC Planning Standards

WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan

CAISO Large Generator Interconnection Procedures, in response to FERC Order No. 2003

IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems

IEEE 80 Guide for Safety in AC Substation Grounding

IEEE 929 Recommended Practice for Utility Interface of Residential and Intermediate Photovoltaic (PV) Systems

IEEE 519 IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems

IEEE C37.010-1999 IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

ANSI C84.1 Voltage Ratings for Electric Power Systems and Equipment

SCE Transmission Planning Criteria and Guidelines

WECC Minimum Operating Reliability Criteria

Overview of Policies and Procedures for Regional Planning Project Review, Project Rating Review, and Progress Reports

Next Review Date

This document shall be reviewed upon a change in the referenced documents that may impact this document.

Data Retention

This document shall be retained a minimum of 4 years from last WECC on-site audit and is stored in/on the Reliability Standards and Compliance Group document library.

Approval

TDBU Business Line	Signature	Date
Transmission & Interconnection Planning	Original Copy signed by Pat Arons	10/02/09

Revision History

Revision No.	Date	Description of Revision	By	Next Review Date
1	03/19/09	Revised the Interconnection Handbook, Wholesale Generators to incorporate interconnection requirements for new Generation, Transmission, and End User facilities	---	---
2	03/19/09	Replaces all remaining referenced documents in Version 1, so that, this Interconnection Handbook will be used for new Generation, Transmission, and End User facilities	---	---

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Revision No.	Date	Description of Revision	By	Next Review Date
3	10/02/09	Revised to incorporate new SCE approved wind turbines set-back criteria.	---	---

Attachments

None

Distribution

Transmission and Interconnection Planning

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Addendum to Appendix A – Q#593

Nextlight Renewable Power, LLC

Fort Mojave Solar Project

Addendum To The

Cluster 1 & 2 Phase II Final Report

California ISO
Shaping a Renewed Future

February 15, 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

Executive Summary

Nextlight Renewable Power, LLC an Interconnection Customer (IC), received a Cluster 1 and 2 Phase II (C1C2 Phase II) study report dated August 26, 2011 for its Interconnection Request (IR) to the California Independent System Operator Corporation (CAISO) for their proposed Fort Mojave Solar Project (Project), queue position Q593.

Subsequent to the distribution of the report, the CAISO performed additional studies (C1C2 Phase II Re-assessment) to re-assess certain upgrades by applying the criteria in the Technical Bulletin issued on January 31, 2012 entitled "Generation Interconnection Procedures: Deliverability Requirements for Clusters 1-4."[1] This addendum to the C1C2 Phase II report contains a revised identification of network upgrades resulting from the re-assessment. The underlying assumptions and results of the C1C2 Phase II reassessment are set forth in the C1C2 Phase II Re-assessment report, which is available on the CAISO website at the following location:
http://www.caiso.com/Documents/TechnicalReport_cluster1_2DeliverabilityRe-Assessment.pdf

The following identified sections and corresponding changes replace and supersede those same sections in the IC's C1C2 Phase II study report dated August 26, 2011.

Summary of changes:

A. Replace the cost estimates in the Executive Summary on page 2 with the following to reflect the removal of the delivery network upgrades:

The non-binding cost estimate of Interconnection Facilities[2] to interconnect the Project is approximately **$12,966,000** including ITCC[3]. The maximum cost responsibility for the SCE Network Upgrades[4] to interconnect the Project is **$22,439,000** and the cost of the SCE Distribution Upgrades[5] is **$561,000**.

B. Replace Section 8.3 on Page 13 with the following:

8.3 Operational deliverability assessment results

The assumptions used to perform the operational Deliverability Assessment are presented in the Group Report.

[1] The Technical Bulletin can be accessed on the ISO website at http://www.caiso.com/Documents/TechnicalBulletin-GeneratorInterconnectionProcedures-DeliverabilityRequirements-Clusters1-4Jan31_2012.pdf

[2] The transmission facilities necessary to physically and electrically interconnect the Project to the CAISO Controlled Grid at the point of interconnection.

[3] 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.

[4] The SCE transmission facilities, other than Interconnection Facilities, beyond the point of interconnection necessary to physically and electrically interconnect the Project safely and reliably to the CAISO Controlled Grid

[5] These upgrades are not part of the CAISO Controlled Grid, and are not reimbursable.

The Project will have FC deliverability status (FCDS) after the SCE area upgrades in Table 11.1 are completed, subject to the constraints and potential limitations identified in the C1C2 Phase II Re-assessment.

C. Replace Section 9.3.1 on Page 17 with the following:

9.3.1 Triggered Deliverability Upgrades

To provide for the requested Full Delivery, the Phase II study identified the need for significant Delivery Network Upgrades. Specifically, the project has been identified to need the following to achieve full delivery:

a. Loop of the Existing Mohave-Lugo 500 kV T/L into future Pisgah 500 kV forming new Lugo-Pisgah No.3 500 kV and new Mohave-Pisgah 500 kV T/L's

b. New series capacitors on Mohave-Pisgah 500 kV T/L

c. New series capacitor on Nipton-Pisgah 500 kV T/L

d. New Colorado River – Red Bluff No.3 500 kV T/L

e. New Red Bluff – Valley No.1 500 kV T/L

f. Modifications on EOP SPS triggered by high queued projects

The anticipated time to construct all of these Delivery Network Upgrades associated with "Full Delivery" Interconnection is 96 months upon execution of LGIA. Construction of such delivery network upgrades cannot commence until SCE receives all appropriate permitting approvals and licenses. **– Per the C1C2 Phase II Re-assessment, upgrades a, b, c, d, and e are no longer being assigned to the Project.**

D. Replace Delivery Network Upgrades in Section 11 on page 22 with the following:

DELIVERY NETWORK UPGRADES

Lugo – Mohave 500 kV T/L and Associated Upgrades
Install approximately 0.5 Circuit Miles of 500kV Double and Single Circuit Structures equipped with 2-2156KCMIL ACSR Conductors to loop the existing line into Pisgah Substation and form the two new Lugo – Pisgah No.3 and Mohave – Pisgah 500kV T/L's.
Install one 500 kV Line Series Capacitors Bank outside the new Mohave 500 kV T/L line position at Pisgah Sub.
Install one 500 kV Line Series Capacitors Banks outside the new Pisgah 500 kV T/L line position at Nipton Sub. **– Per the C1C2 Phase II Re-assessment, this upgrade is no longer being assigned to the Project.**

See the Group Report for additional details.

E. Replace Table 11.1 on page 24 with the following to reflect the removal of the delivery network upgrades:

Table 11.1: 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 *(Note 3)*
PTO's Interconnection Facilities *(Note 1)*	See Section 11 - PTO'S Interconnection Facilities	Non-network facilities needed to enable interconnection	$12,966	$14,176 (2014)	24 Months
Plan of Service Reliability Network Upgrades	See Section 11 – Plan of Service Reliability Network Upgrades	Direct Assigned Network Upgrades needed to enable interconnection.	$10,793	$11,800 (2014)	24 Months
Reliability Network Upgrades	See Section 11 - Reliability Network Upgrades in the East of Lugo Group Report	Allocated Network Upgrades needed to maintain system Reliability	$9,578	$10,472 (2014)	24 Months
Reliability Network Upgrades	See Section 11 - Short-Circuit Duty (SCD) Mitigation in the East of Lugo Group Report	SCD Mitigation Allocated to maintain system Reliability	$2,068	$2,261 (2014)	24 Months
Distribution Upgrades *(Note 2)*	See Section 11 – Distribution Upgrades	Non-CAISO SCE Distribution Facilities	$561	$613 (2014)	24 Months
Total Cost			**$35,966**		**24 Months**

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

Note 2: These upgrades are not part of the CAISO Controlled Grid, and are not reimbursable. Allocated costs may change if all projects responsible for these upgrades do not execute LGIAs.

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: SCE's Phase II cost estimating is done in 'constant' dollars 2011 and then escalated to the estimated O.D.year. For the Phase II study, the estimated O.D. is derived by assuming the duration of the work element will begin approximately in January 2012, which is roughly the CAISO tariff scheduled completion date of the Phase II study plus 90 days for the LGIA 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 2014. 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.

F. Replace Attachment 6 on page 33 with the following to reflect the removal of the delivery network upgrades:

Attachment 6

Allocation of Network Upgrades for Cost Estimates

Type	Upgrades	Needed For	Cost factor	Cost Share ($1000) Constant
Reliability	SPS #1: to trip 700 MW generation located in the EOL area	LUGO - VICTORVL 500 kV Tie Overload for PalaVerde - Colorado River 500 kV line outage	54%	$3,160
Reliability	SPS #2: to trip 1400 MW generation located in the EOL area	LUGO - VICTORVL 500 kV Tie Overload for any Pisgah - Lugo 500 kV lines N-2 outages	54%	$3,100
Reliability	SPS #3: to trip about 200 MW generations located in the Eldorado area	LUGO - VICTORVL 500 kV Tie Overload for the Pisgah - Nipton 500 kV line and Eldorado-Pisgah 220 kV N-2 outages	54%	$3,319
Reliability	POS			$10,793
Reliability	Short circuit duty			$2,068
			Total:	$22,439

The remainder of the Phase II study is unaffected by the re-assessment.

```
#East of Pisgah-Cluster 3
#N-1 AND N-2 CONTINGENCIES FOR NORTH AND EAST OF LUGO AREAS:
line 8001          "line MOENKOPI    to ELDORADO     500 ck 1"
 line     14002     24042   "1 "  1 0
0
line 8002          "line ELDORADO    to MCCULLOUGH   500 ck 1"
 line     24042     26048   "1 "  1 0
0
line 8003          "line MARKETPLACE to MCCULLOUGH   500 ck 1"
 line     26044     26048   "1 "  1 0
0
line 8004          "line CRYSTAL     to MCCULLOUGH   500 ck 1"
 line     26123     26048   "1 "  1 0
0
line 8005          "line MCCULLOGH   to VICTORVILLE  500 ck 1"
 line     26048     26105   "1 "  1 0
0
line 8006          "line MCCULLOGH   to VICTORVILLE  500 ck 2"
 line     26048     26105   "2 "  1 0
0
line 8007          "line MARKETPLACE to MCCULLOUGH   500 ck 1"
 line     26044     26048   "1 "  1 0
0
line 8008          "line MOHAVE      to ELDORADO     500 ck 1"
 line     24097     24042   "1 "  1 0
0
line 8009          "line ELDORADO    to NIPTON       500 ck 1"
 line     24042     29415   "1 "  1 0
0
line 8010          "line PISGAH      to NIPTON       500 ck 1"
 line     24226     29415   "1 "  1 0
0
line 8011          "line NIPTON      to SEARCHLT     500 ck 1"
 line     29415     29413   "1 "  1 0
0
line 8012          "line HOMER       to SEARCHLT     500 ck 1"
 line     29414     29413   "1 "  1 0
0
line 8013          "line HOMER       to MOHAVE       500 ck 1"
 line     29414     24097   "1 "  1 0
0
line 8014          "line LUGO        to HOMER        500 ck 1"
 line     24086     29414   "1 "  1 0
0
line 8015          "line PISGAH      to LUGO         500 ck 1"
 line     24226     24086   "1 "  1 0
0
line 8016          "line PISGAH      to LUGO         500 ck 2"
 line     24226     24086   "2 "  1 0
0
line 8017          "line LUGO        to VICTORVILLE  500 ck 1"
 line     24086     26105   "1 "  1 0
0
line 8018          "line LUGO        to VINCENT      500 ck 1"
 line     24086     24156   "1 "  1 0
0
line 8019          "line LUGO        to VINCENT      500 ck 2"
 line     24086     24156   "2 "  1 0
0
line 8020          "line LUGO        to MIRALOMA     500 ck 2"
 line     24086     24092   "2 "  1 0
0
line 8021          "line LUGO        to MIRALOMA     500 ck 3"
 line     24086     24092   "3 "  1 0
0
line 8022          "line LUGO        to RANCHO VISTA 500 ck 1"
 line     24086     24236   "1 "  1 0
```

```
0
line 8023          "line VINCENT     to MIRA LOMA    500 ck 1"
 line     24156     24092   "1 "  1 0
0
line 8024          "line PISGAH      to ELDORADO     230 ck 1"
 line     24219     24041   "2 "  1 0
0
line 8025          "line PISGAH      to CIMA/ELDORAD 230 ck 1"
 line     24219     24627   "1 "  1 0
 line     24627     24041   "1 "  1 0
0
line 8026          "line VICTOR      to LUGO         230 ck 1"
 line     24601     24085   "1 "  1 0
0
line 8027          "line VICTOR      to LUGO         230 ck 2"
 line     24601     24085   "2 "  1 0
0
line 8028          "line VICTOR      to LUGO         230 ck 3"
 line     24601     24085   "3 "  1 0
0
line_8029          "line LUGO        to JASPER   230 ck 1"
line     94250     24085   "1 "  1 0
0
line 8030          "line COOLWATER   to JASPER   230 ck 1"
 line     24717     94250   "1 "  1 0
0
#line 8031          "line DESERTVIEW  to CHARRO       230 ck 1"
# line     94250     94084   "1 "  1 0
#0
#line 8032          "line COOLWATER   to CHARRO       230 ck 1"
# line     24717     94084   "1 "  1 0
#0
line 8033          "line KRAMER      to COOLWATER    230 ck 2"
 line     24701     24717   "2 "  1 0
0
line 8034          "line LOCKHART    to COOLWATER    230 ck 1"
 line     28691     24717   "1 "  1 0
0
line 8035          "line LOCKHART    to KRAMER       230 ck 1"
 line     28691     24701   "1 "  1 0
0
line 8036          "line KRAMER      to LUGO         230 ck 1"
 line     24701     24085   "1 "  1 0
0
line 8037          "line KRAMER      to LUGO         230 ck 2"
 line     24701     24085   "2 "  1 0
0
line 8038          "line KRAMER      to INYOKERN     230 ck 1"
 line     24701     24787   "1 "  1 0
0
line 8039          "line KRAMER      to INYOKERN     230 ck 1"
 line     24701     24787   "2 "  1 0
0
line 8040          "line IVANPAH     to ELDORADO     230 ck 1"
 line     28726     24041   "1 "  1 0
0
line 8041          "line PARDEE      to SYLMAR S 230 ck 1"
 line     24114     24147   "1 "  1 0
0
line 8042          "line PARDEE      to SYLMAR S 230 ck 2"
 line     24114     24147   "2 "  1 0
0
line 8043          "line PARDEE      to VINCENT 230 ck 1"
 line     24114     24155   "1 "  1 0
0
line 8044          "line VINCENT     to PARDEE  230 ck 2"
 line     24155     24114   "2 "  1 0
```

```
0
line 8045          "line VINCENT     to RIO HONDO 230 ck 1"
 line     24155     24126   "2 "  1 0
0
line 8046          "line RIO HONDO   to VINCENT 230 ck 2"
 line     24126     24155   "2 "  1 0
0
line 8047          "line VINCENT     to MESA CAL 230 ck 1"
 line     24155     24091   "1 "  1 0
0
line 8048          "line MESA CAL    to VINCENT 230 ck 2"
 line     24091     24155   "2 "  1 0
0
line 8049          "line MESA CAL    to RIO HONDO 230 ck 1"
 line     24091     24126   "1 "  1 0
0
line 8050          "line LAGUBELL    to RIO HONDO 230 ck 1"
 line     24076     24126   "1 "  1 0
0
tran 8051          "tran LUGO      500/230 kV TRANS NO.1"
 tran     24086     24085   "1 "  0
0
tran 8052          "tran PISGAH    500/230 kV TRANS NO.1"
 tran     24226     24219   "1 "  0
0
line_8053          "line PISGAH      to LUGO       500 ck 1 & PISGAH    to
LUGO         500 ck 2"
 line     24226     24086   "1 "  1 0
 line     24226     24086   "2 "  1 0
0
line 8054          "line PISGAH      to LUGO       500 ck 1 & LUGO      to
HOMER        500 ck 1"
 line     24226     24086   "1 "  1 0
 line     24086     29414   "1 "  1 0
0
line 8055          "line PISGAH      to LUGO       500 ck 2 & LUGO      to
HOMER        500 ck 1"
 line     24226     24086   "2 "  1 0
 line     24086     29414   "1 "  1 0
0
line 8056          "line LUGO        to VINCENT    500 ck 1 & LUGO      to
VINCENT      500 ck 2"
 line     24086     24156   "1 "  1 0
 line     24086     24156   "2 "  1 0
0
line_8057          "line LUGO        to MIRA LOMA  500 ck 2 & LUGO      to
MIRA LOMA    500 ck 3"
 line     24086     24092   "2 "  1 0
 line     24086     24092   "3 "  1 0
0
line 8058          "line LUGO        to MIRA LOMA  500 ck 2 & LUGO      to
RANCHO VISTA 500 ck 1"
 line     24086     24092   "2 "  1 0
 line     24086     24236   "1 "  1 0
0
line 8059          "line LUGO        to MIRA LOMA  500 ck 3 & LUGO      to
RANCHO VISTA 500 ck 1"
 line     24086     24092   "3 "  1 0
 line     24086     24236   "1 "  1 0
0
line 8060          "line ELDORADO    to NIPTON     230 ck 1 & PISGAH    to
CIMA/ELDORAD 230 ck 1"
 line     24042     29415   "1 "  1 0
 line     24219     24627   "1 "  1 0
 line     24627     24041   "1 "  1 0
0
line_8061          "line ELDORADO    to NIPTON     500 ck 1 & PISGAH    to
```

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ELDORADO     230 ck 1"
 line     24042     29415   "1 "  1 0
 line     24219     24041   "2 "  1 0
0
line 8062          "line PISGAH      to ELDORADO   230 ck 1 & PISGAH    to
CIMA/ELDORAD 230 ck 1"
 line     24219     24041   "2 "  1 0
 line     24219     24627   "1 "  1 0
 line     24627     24041   "1 "  1 0
0
line_8063          "line VICTOR      to LUGO        230 ck 1 & VICTOR   to
LUGO        230 ck 2"
 line     24601     24085   "1 "  1 0
 line     24601     24085   "2 "  1 0
0
line_8064          "line VICTOR      to LUGO        230 ck 1 & VICTOR   to
LUGO        230 ck 3"
 line     24601     24085   "1 "  1 0
 line     24601     24085   "3 "  1 0
0
line_8065          "line VICTOR      to LUGO        230 ck 2 & VICTOR   to
LUGO        230 ck 3"
 line     24601     24085   "2 "  1 0
 line     24601     24085   "3 "  1 0
0
line 8066          "line COOLWATER   to CHARRO     230 ck 1 & COOLWATER to
JASPER  230 ck 1"
 line     24717     94084   "1 "  1 0
 line     24717     94250   "1 "  1 0
0
line 8067          "line DESERTVIEW  to CHARRO     230 ck 1 & COOLWATER to
JASPER  230 ck 1"
 line     94250     94084   "1 "  1 0
 line     24717     94250   "1 "  1 0
0
line 8068          "line KRAMER      to COOLWATER  230 ck 2 & LOCKHART  to
KRAMER       230 ck 1"
 line     24701     24717   "2 "  1 0
 line     28691     24701   "1 "  1 0
0
line 8069          "line KRAMER      to COOLWATER  230 ck 2 & LOCKHART  to
COOLWATER    230 ck 1"
 line     24701     24717   "2 "  1 0
 line     28691     24717   "1 "  1 0
0
line_8070          "line KRAMER      to LUGO       230 ck 1 & KRAMER    to
LUGO         230 ck 2"
 line     24701     24085   "1 "  1 0
 line     24701     24085   "2 "  1 0
0
line 8071          "line KRAMER      to INYOKERN   230 ck 1 & KRAMER    to
INYOKERN     230 ck 2"
 line     24701     24787   "1 "  1 0
 line     24701     24787   "2 "  1 0
0
line 8072          "line PARDEE      to SYLMAR S 230 ck 1 & PARDEE      to
SYLMAR S 230 ck 2"
 line     24114     24147   "1 "  1 0
 line     24114     24147   "2 "  1 0
0
line 8073          "line PARDEE      to VINCENT 230 ck 1 & VINCENT     to
PARDEE  230 ck 2"
 line     24114     24155   "1 "  1 0
 line     24155     24114   "2 "  1 0
0
line 8074          "line VINCENT     to RIO HONDO 230 ck 1 & RIO HONDO   to
VINCENT 230 ck 2"
```

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 line     24155     24126   "1 "  1 0
 line     24126     24155   "2 "  1 0
0
line 8075          "line VINCENT     to MESA CAL 230 ck 1 & MESA CAL    to
VINCENT 230 ck 2"
 line     24155     24091   "1 "  1 0
 line     24091     24155   "2 "  1 0
0
line 8076       "Line COOLWATER-AftonSub-115 kV "
 line     24716     94830   "1 "  1 0
0
line 8077       "Line Afton SUB-BAKER-MTN PASS-IVANPAH 115 kV "
 line     94830     24777   "1 "  1 0
 line     24777     24778   "1 "  1 0
 line     24778     28727   "1 "  1 0
0
line 8078       "Line VICTOR-NEW VIC   115.0 kV "
 line     24602     24632   "1 "  1 0
0
line 8079       "Line VICTOR-NEW VIC NO.1 AND 2  115.0 kV "
 line     24602     24632   "1 "  1 0
 line     24602     24632   "2 "  1 0
0
line 8080       "Line NEW SUB2-coolwater N-1 115 kV "
 line     94414     24716   "1 "  1 0
0
line 8081       "Line NEW SUB2-coolwater N-2 115 kV "
 line     94414     24716   "1 "  1 0
 line     94414     24716   "2 "  1 0
0
line 8082     "Line SAVAGE-Del Oro 115.0 kV "
 line     24608     94693   "1 "  1 0
0
line 8083     "Line Del Oro-wdt28tp-cottonwood 115.0 kV "
 line     24613     94734   "1 "  1 0
 line     94734     94693   "1 "  1 0
0
tran 8084          "tran WestDorado    500/230 kV TRANS NO.1"
 tran     24042     94764   "1 "  0
0
line 8085          "line IVANPAH  to Primm  230 ck 1"
 line     94828     28726   "1 "  1 0
0
line 8086          "line primm to EL DORADO 230 ck 1
 line     94764     94828   "1 "  1 0
0
line8_8087          "line primm to EL DORADO 230 ck 1 & primm to ElDorado 230
ck 2"
 line     94764     94828   "1 "  1 0
 line     94764     94828   "2 "  1 0
0
line 8088       "Line Afton-River Subs N-1 115 kV "
 line     94414     94830   "1 "  1 0
0
line 8089          "Line KRAMER   500.0 to LLANO    500.0 Circuit 1"
 line     94768     94995   "1 "  1 0
0
line 8090          "Line VINCENT  500.0 to LLANO    500.0 Circuit 1"
 line     24156     94995   "1 "  1 0
0
line 8091          "Line LLANO    500.0 to LUGO     500.0 Circuit 1"
 line     94995     24086   "1 "  1 0
0
line 8092          "Line Lugo-Pisgah No.3 Ckt.1 & Homer-Pisgah Ckt. 1"
 line     24226     29414   "1 "  1 0
 line     24226     24086   "3 "  1 0
0
```

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# N-1 AND N-2 CONTINGENCIES FOR NORTH AND EAST OF LUGO AREAS (115kV): PRE
TRANSITIONAL CLUSTER BASE CASE
# 02/02/09
# 115 kV SINGLE OUTAGES (N-1)
line 100001        "Line VICTOR-PHELAN   115.0 kV "
 line     24602     24606   "1 "  1 0
0
line 100002        "Line VICTOR-SAVAGE 115.0 kV No. 1"
 line     24602     24608   "1 "  1 0
0
line 100003        "Line VICTOR-SAVAGE 115.0 kV No. 2"
 line     24602     24608   "2 "  1 0
0
line 100004        "Line VICTOR-SAVAGE 115.0 kV No. 3"
 line     24602     24608   "3 "  1 0
0
line 100005        "Line VICTOR-RIVERTEX 115.0 kV "
 line     24602     24624   "1 "  1 0
0
line 100006        "Line VICTOR-RIVERTEX-N. APPLE VALLEY 115.0 kV "
 line     24630     24602   "1 "  1 0
 line     24630     24624   "1 "  1 0
 line     24631     24630   "1 "  1 0
0
line 100007        "Line VICTOR-APPLE VALLEY-HESPERIA 115.0 kV "
 line     24602     24619   "1 "  1 0
 line     24619     24605   "1 "  1 0
 line     24619     24603   "1 "  1 0
0
line 100008        "Line VICTOR-AQUEDUCT-HESPERIA 115.0 kV "
 line     24602     24620   "1 "  1 0
 line     24620     24605   "1 "  1 0
 line     24620     24604   "1 "  1 0
0
line 100009        "Line VICTOR-AQUEDUCT-PHELAN 115.0 kV "
 line     24602     24621   "1 "  1 0
 line     24621     24606   "1 "  1 0
 line     24621     24604   "1 "  1 0
0
line_100010        "Line VICTOR-BLACK MOUTAIN-SOPPORT-SOUTHCAP-SOUTHDOWN 115 kV
"
 line     24602     24615   "1 "  1 0
 line     24615     24616   "1 "  1 0
 line     24615     24612   "1 "  1 0
 line     24616     24610   "1 "  1 0
 line     24616     94115   "1 "  1 0
0
line 100011        "Line APPLE VALLEY-COTTONWOOD-PLEUSS-SAVAGE 115.0 kV "
 line     24618     24603   "1 "  1 0
 line     24618     24617   "1 "  1 0
 line     24617     24611   "1 "  1 0
 line     24617     24613   "1 "  1 0
 line     24608     24618   "1 "  1 0
0
line 100012        "Line PERMANTE-COTTONWOOD 115.0 kV "
 line     24622     24613   "1 "  1 0
0
line 100013        "Line SAVAGE-COTTONWOOD 115.0 kV "
 line     24608     24613   "1 "  1 0
0
line 100014        "Line KRAMER-VICTOR   115.0 kV "
 line     24602     24702   "1 "  1 0
0
line 100015        "Line KRAMER-ROADWAY-VICTOR 115.0 kV "
 line     24614     24602   "1 "  1 0
 line     24614     24607   "1 "  1 0
 line     24614     24702   "1 "  1 0
```

```
0
line 100016        "Line KRAMER-HOLGATE 115.0 kV "
 line     24727     24702   "1 "  1 0
0
line 100017        "Line HOLGATE-MOGEN  115.0 kV "
 line     24741     24727   "1 "  1 0
0
line 100018        "Line EDWARDS-HOLGATE-SOUTHBASE 115.0 kV "
 line     24769     24727   "1 "  1 0
 line     24769     24770   "1 "  1 0
0
line 100019        "Line KRAMER-ROCKET TEST 115.0 kV "
 line     24702     24767   "1 "  1 0
0
line 100020        "Line KRAMER-SUNGEN 115.0 kV "
 line     24702     24753   "1 "  1 0
0
line 100021        "Line KRAMER-COOLWATER 115.0 kV "
 line     24702     24716   "1 "  1 0
0
line 100022        "Line KRAMER-TORTILLA 115.0 kV "
 line     24702     24759   "1 "  1 0
0
#line 100023        "Line COOLWATER-BAKER-DUNN SIDING-WHEATON 115 kV "
# line     24716     24774   "1 "  1 0
# line     24777     24774   "1 "  1 0
# line     24777     28010   "1 "  1 0
#0
#line 100024        "Line IVANPAH-MT.PASS-WHEATON 115 kV"
# line     24778     28010   "1 "  1 0
# line     28727     24778   "1 "  1 0
#0
line 100025        "Line COOLWATER-SEGS2-TORTILLA 115.0 kV "
 line     24716     24765   "1 "  1 0
 line     24759     24765   "1 "  1 0
 line     24750     24765   "1 "  1 0
0
# Normally Open Pole Switch
#line 100026        "Line WDT164TP(PS512)-GALE 115 kV "
# line     94115     24771   "1 "  1 0
#0
line 100027        "Line COLWATER-GALE 115.0 kV "
 line     24716     24771   "1 "  1 0
0
line 100028        "Line COLWATER-TIEFORT 115.0 kV "
 line     24716     24773   "1 "  1 0
0
line 100029        "Line KRAMER-(RANDSBERG) 115.0 kV "
 line     24761     24702   "1 "  1 0
0
line 100030        "Line CONTROL-INYOKERN-(HAIIWEE) 115.0 kV "
 line     24723    24731   "1 "  1 0
0
line 100031        "Line CONTROL-COSO-INYOKERN-(HAIIWEE) 115.0 kV "
 line     24723    24791   "1 "  1 0
 line     24791    24731   "1 "  1 0
 line     24790    24791   "1 "  1 0
0
line 100032        "Line CONTROL-INYO 115.0 kV "
 line     24723    24728   "1 "  1 0
0
line 100033        "Line OXBOW-CONTROL 115.0 kV "
 line     24724     24723   "1 "  1 0
0
line 100034        "Line CSA DIAB-CONTROL 115.0 kV "
 line     24725     24723   "1 "  1 0
0
```

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line 100035        "Line CSA DIAB-CONTROL-SHERWIN 115.0 kV "
 line      24764      24725    "1 "  1 0
 line      24764      24723    "1 "  1 0
 line      24764      24772    "1 "  1 0
0
line 100036        "Line CSA DIAB-RUSH CREEK 115.0 kV "
 line      24794      24725    "1 "  1 0
 line      24775      24794    "1 "  1 0
0
line 100037        "Line LEE VINE-RUSH CREEK 115.0 kV "
 line      24776      24775    "1 "  1 0
0
line 100038        "Line INYOKERN McGEN-SEARLES NO.1 115.0 kV "
 line      24731      24763    "1 "  1 0
 line      24763      24749    "1 "  1 0
 line      24739      24763    "1 "  1 0
0
line 100039        "Line INYOKERN McGEN-SEARLES NO.2 115.0 kV "
 line      24731      24763    "1 "  1 0
 line      24739      24763    "1 "  1 0
 line      24739      24762    "1 "  1 0
 line      24762      24749    "1 "  1 0
0
# 115 kV DOUBLE OUTAGES (N-2)
line 200001        "Line CONTROL-INYOKERN-(HAIIWEE) 115.0 kV, line CONTROL-
INYOKERN-(HAIIWEE)-Coso 115.0 kV "
 line      24723      24731    "1 "  1 0
 line      24723      24791    "1 "  1 0
 line      24791      24731    "1 "  1 0
 line      24790      24791    "1 "  1 0
0
line 200002        "Line KRAMER-ROADWAY-VICTOR 115.0 kV,line KRAMER - VICTOR
115.0 kV "
 line      24614      24602    "1 "  1 0
 line      24614      24607    "1 "  1 0
 line      24614      24702    "1 "  1 0
 line      24602      24702    "1 "  1 0
0
line 200004        "Line  VICTOR-RIVERTEX 115.0 kV, line VICTOR-RIVERTEX-N.
APPLE VALLEY 115.0 kV "
 line      24602      24624    "1 "  1 0
 line      24630      24602    "1 "  1 0
 line      24630      24624    "1 "  1 0
 line      24631      24630    "1 "  1 0
0
# 230/115 kV TRANSFORMER OUTAGES
# INYOKERN 230/115 kV Transformer Banks
tran 300001  "tran INYOKERN 230/ 115 kV No. 1"
 tran      24787      24731    "1 "  0
0
tran 300002  "tran INYOKERN 230/ 115 kV No. 2"
 tran      24787      24731    "2 "  0
0
# IVANPAH 230/115 Transformer Banks
tran 300003  "tran Ivanpah   230/ 115 kV No. 1"
 tran      28726      28727    "1 "  0
0
tran 300004  "tran Ivanpah   230/ 115 kV No. 2"
 tran      28726      28727    "2 "  0
0
# VICTOR 230/115 Transformer Banks
tran 300005  "tran VICTOR   230/ 115 kV No. 1"
 tran      24601      24602    "1 "  0
0
tran 300006  "tran VICTOR   230/ 115 kV No. 2"
 tran      24601      24602    "2 "  0
0
```

```
tran 300007  "tran VICTOR   230/ 115 kV No. 3"
 tran     24601     24602   "3 "  0
0
# KRAMER 230/115 kV Transformer Banks
tran 300008  "tran KRAMER   230/ 115 kV No. 1"
 tran     24701     24702   "1 "  0
0
tran 300009  "tran KRAMER   230/ 115 kV No. 2"
 tran     24701     24702   "2 "  0
0
end
# END OF CONTINGENCY LIST
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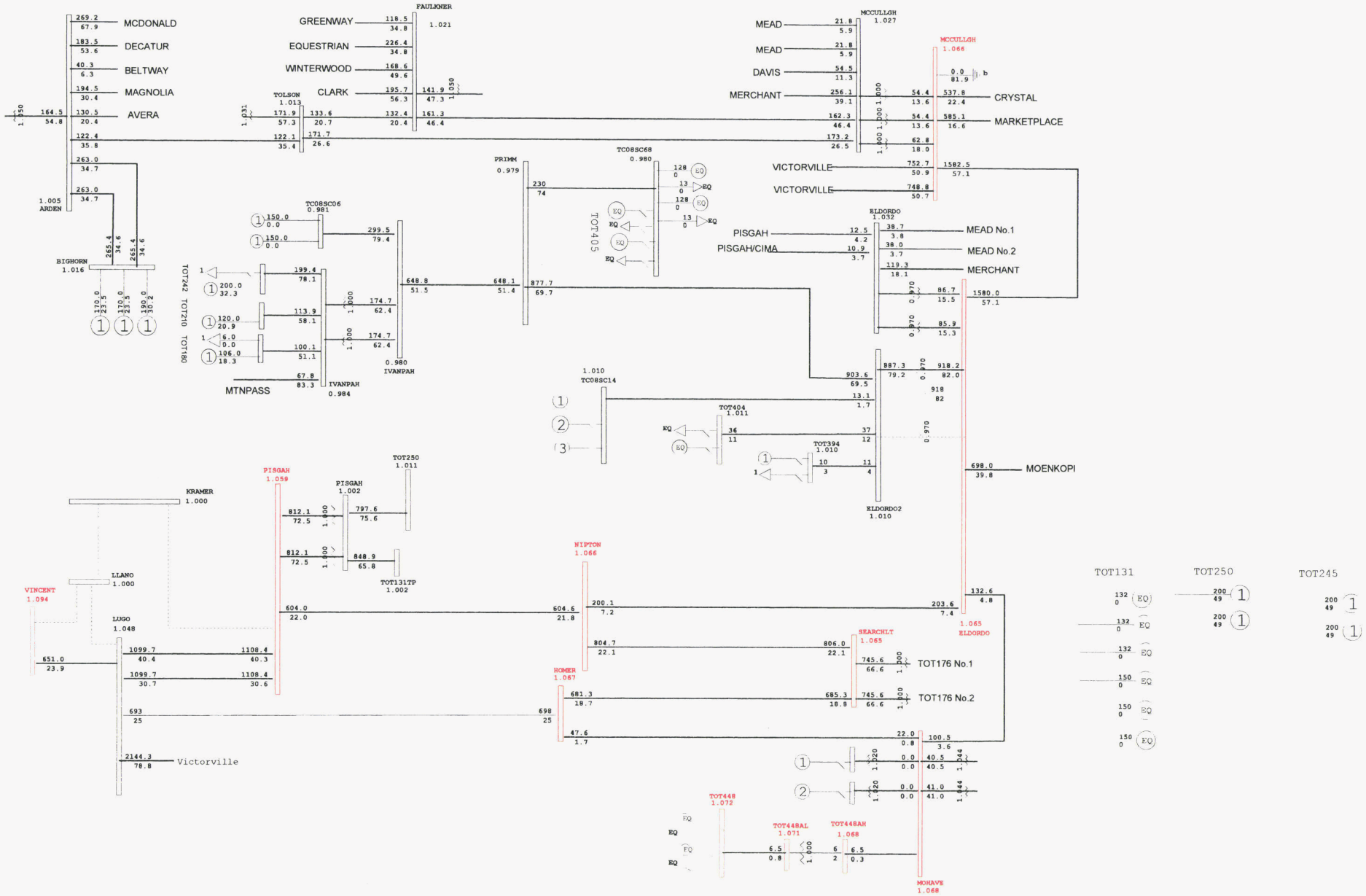

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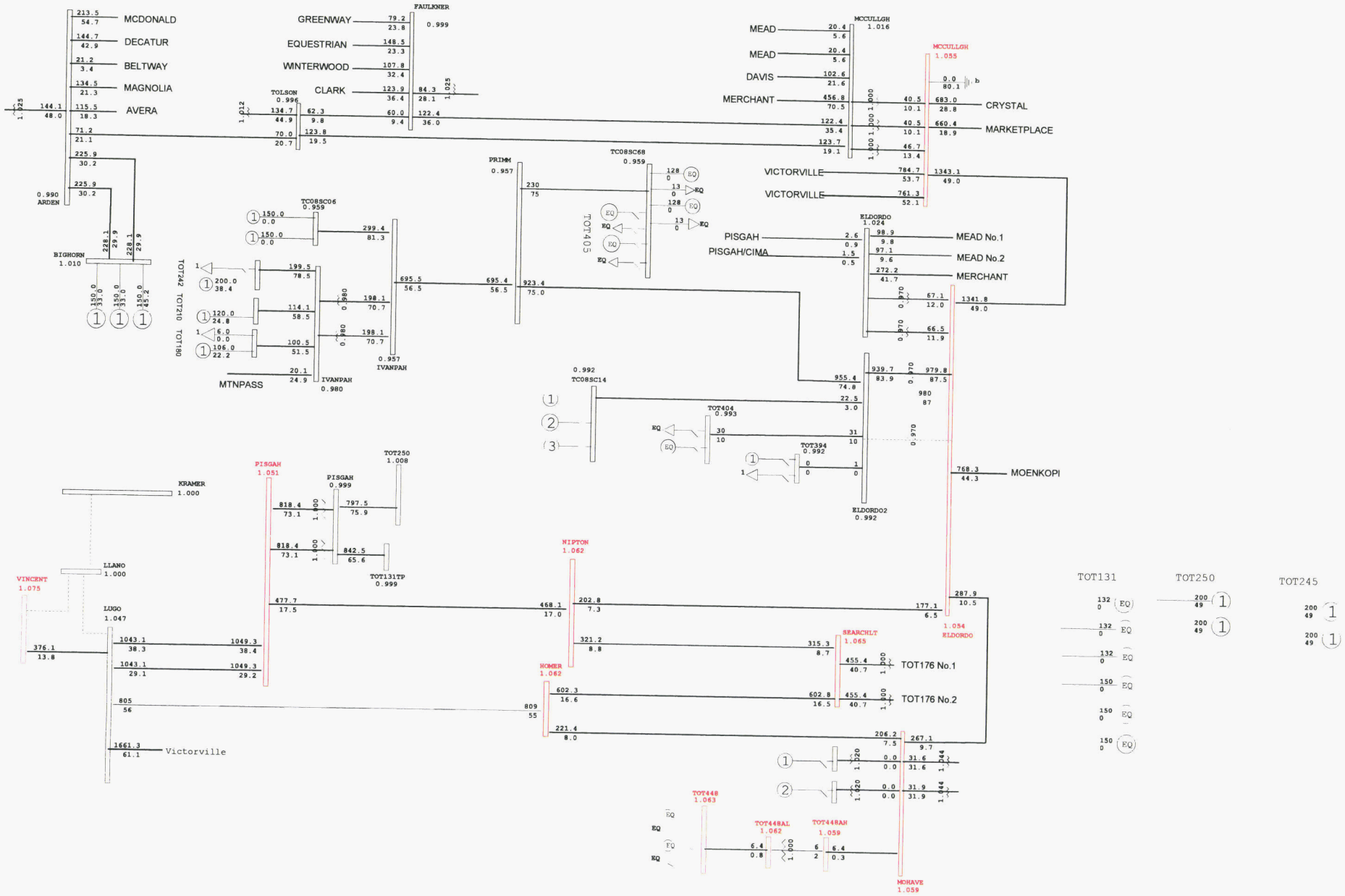
	SCE Pre Queue Cluster I&II - Heavy Summer Base Case East of Pisgah Area		MVA/%rate c1c2-rv.drw Rating = 1



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SCE Pre Queue Cluster I&II - Light Spring Base Case

East of Pisgah Area

MVA/%rate

c1c2-rv.drw

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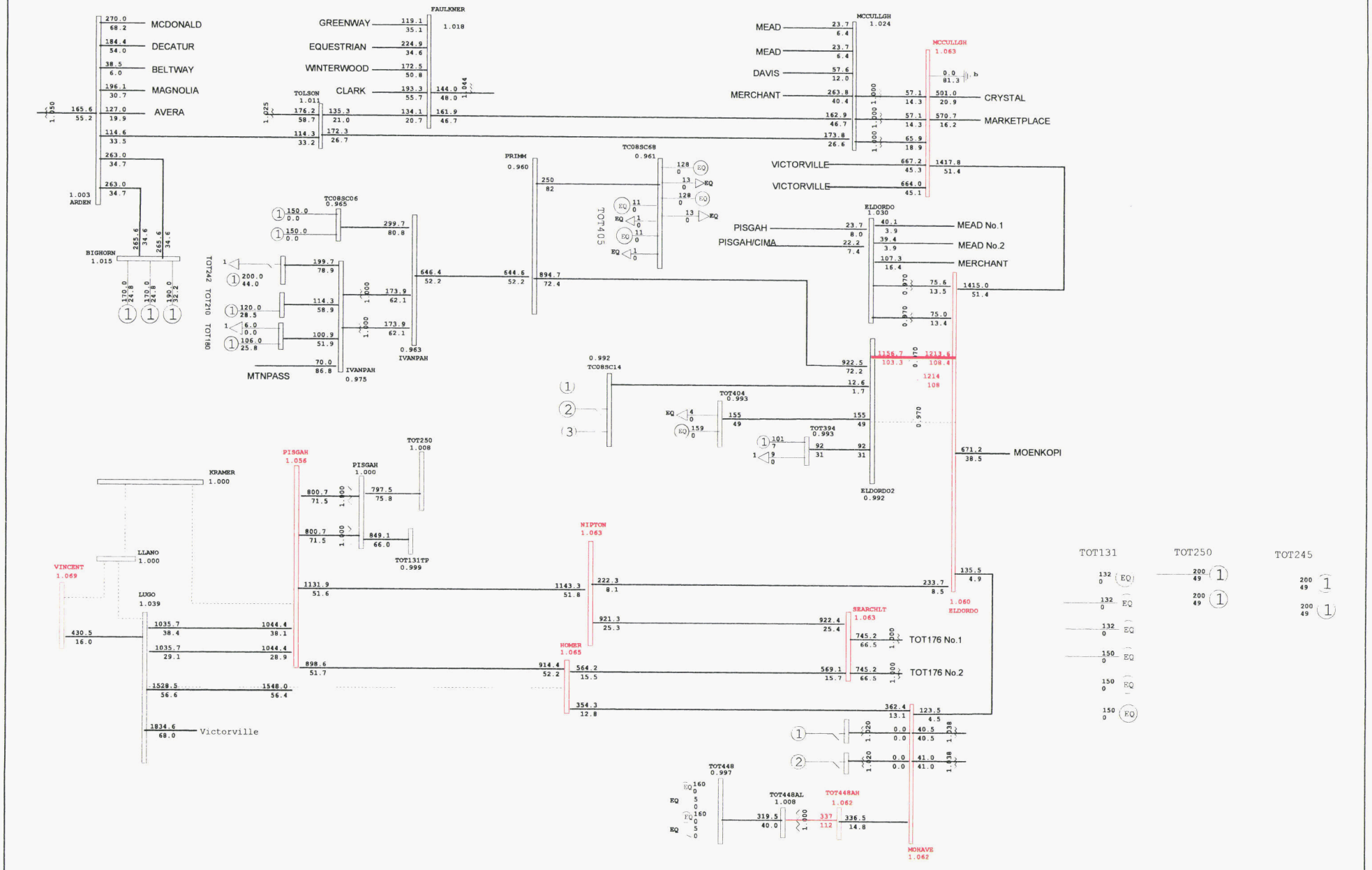

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SCE Pst Queue Cluster I&II - Heavy Summer Base Case

East of Pisgah Area

MVA/%rate

c1c2-rv.drw

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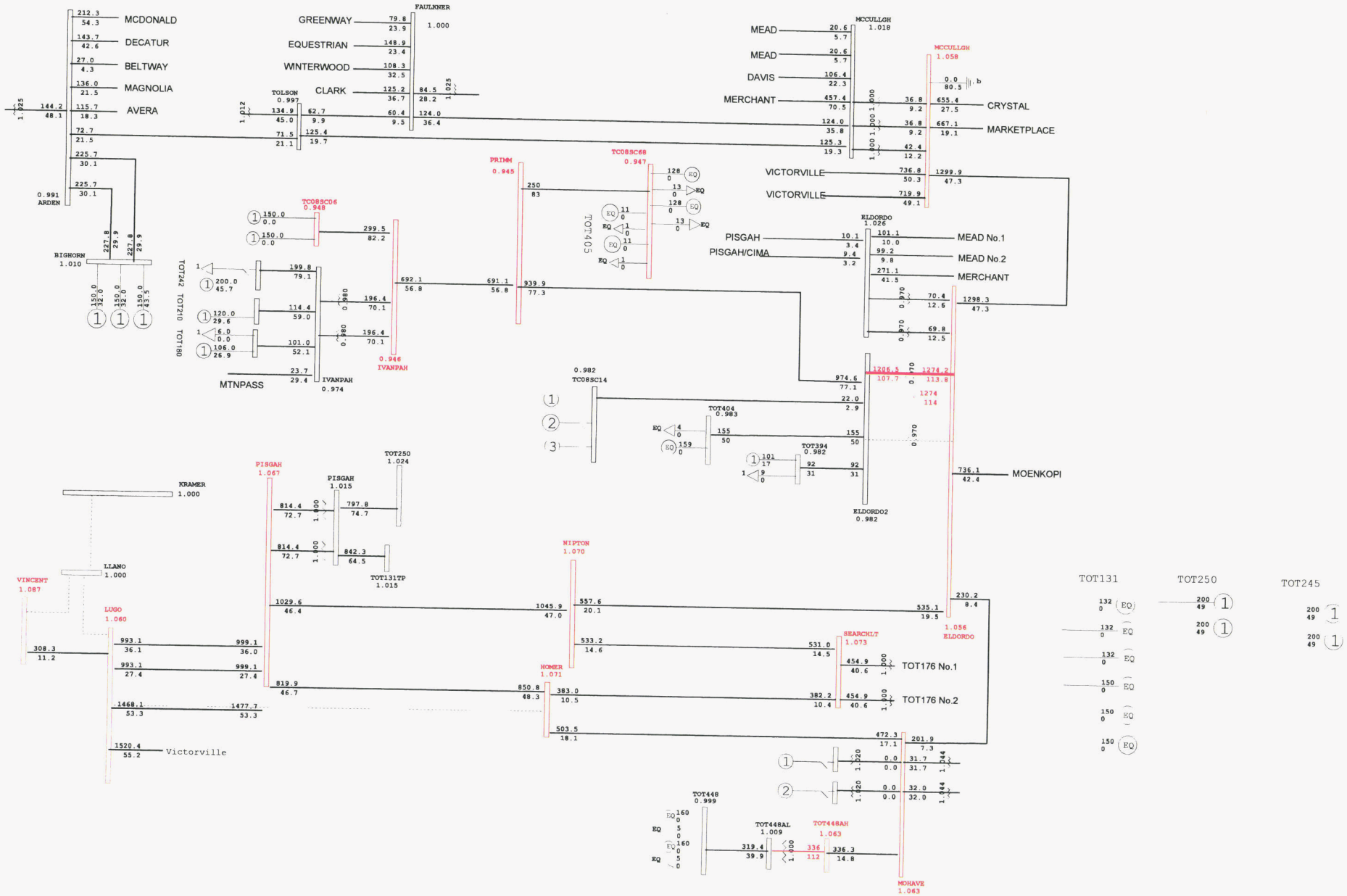

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SCE Pst Queue Cluster I&II - Light Spring Base Case

East of Pisgah Area

MVA/%rate

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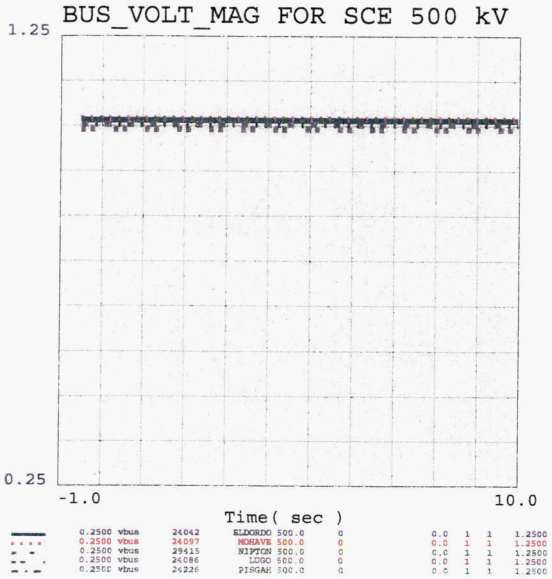
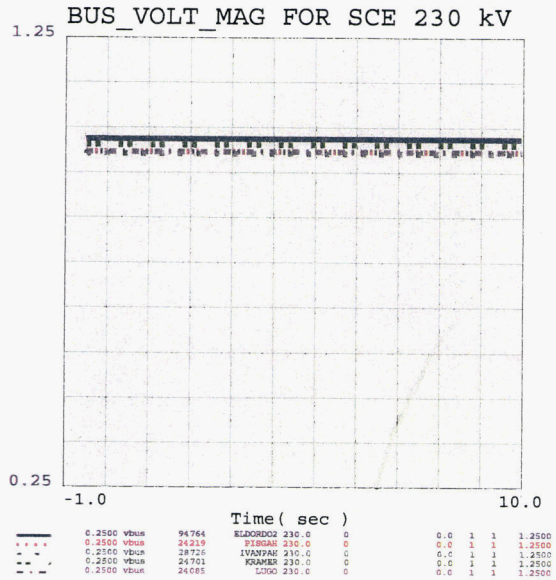
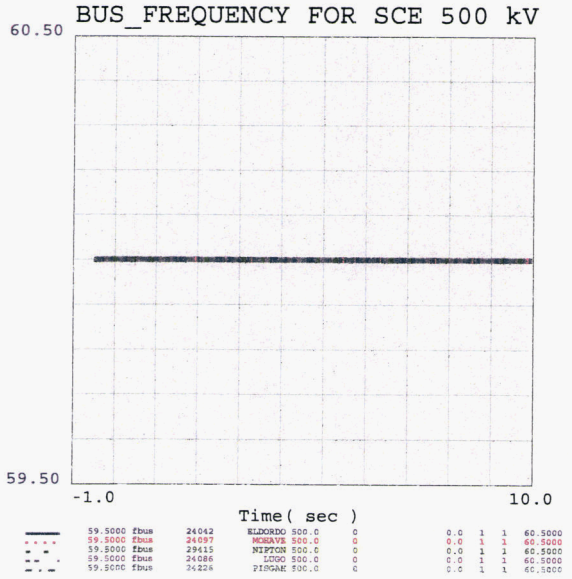
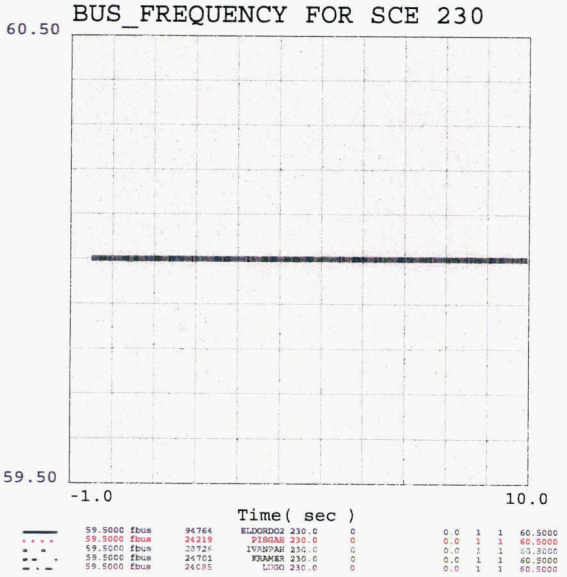
Rating = 1

Stability Plots in SCE Area







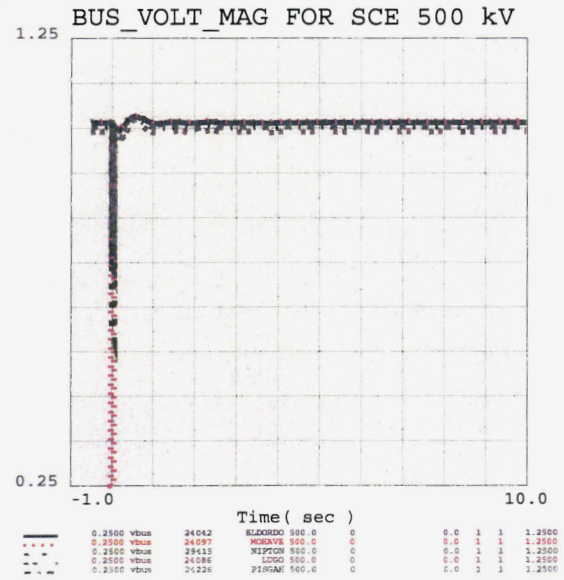


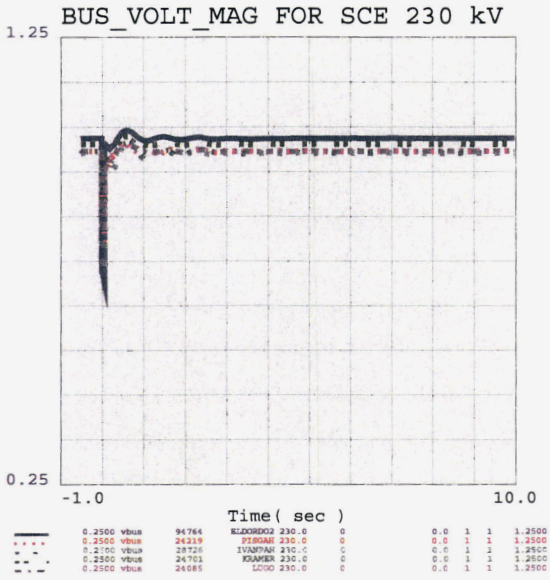
2014-hs-c1c2p2-eop-final-pre_No-fault
East of Pisgah Area

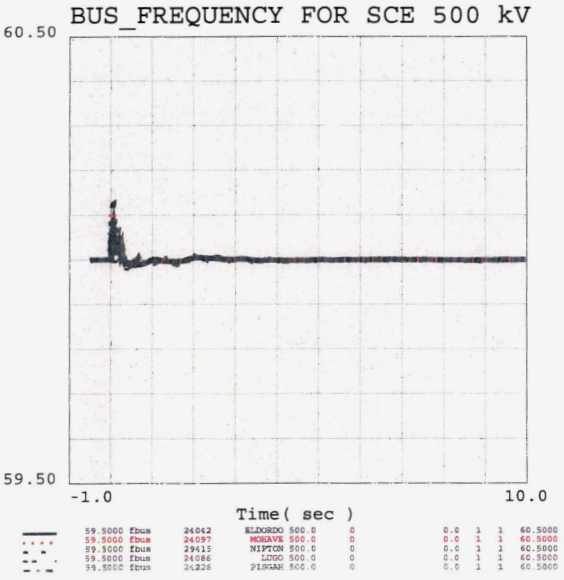
2014-hs-c1c2p2-eop-final-pre_No-fault.chf

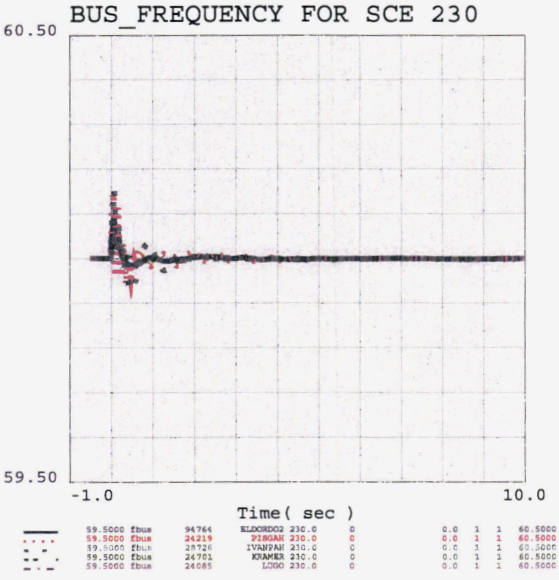
Mon Jun 06 13:48:27 2011

Stability Plots in SCE Area







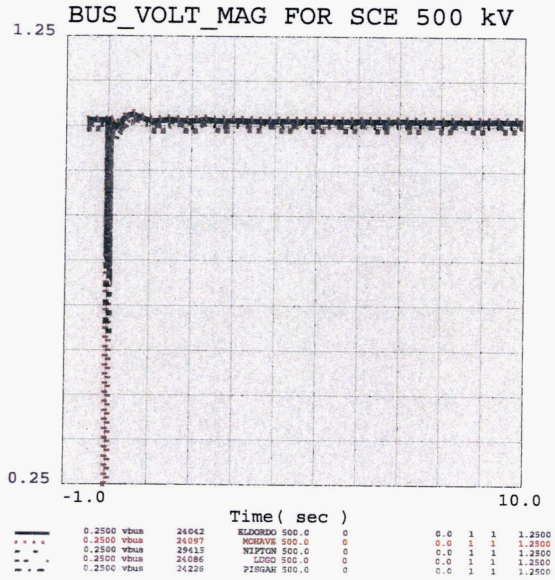


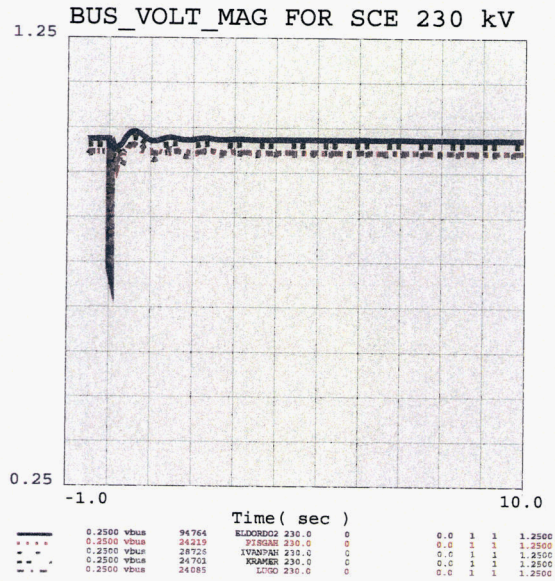
2014-hs-c1c2p2-eop-final-pre_Mohave-Lugo-slo
East of Pisgah Area

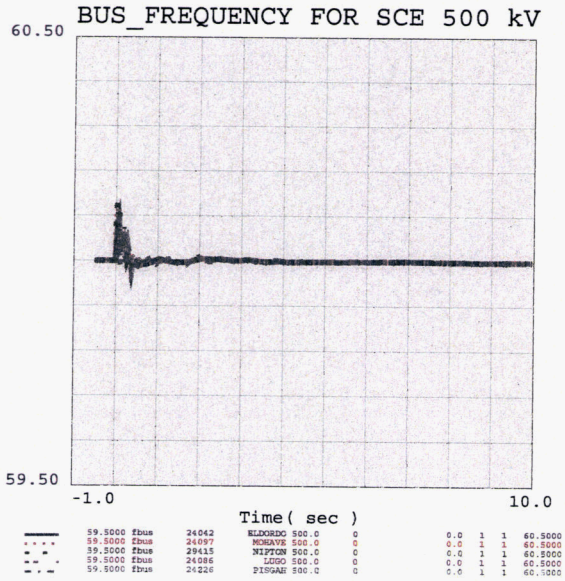
2014-hs-c1c2p2-eop-final-pre_Mohave-Lugo-slo.chf

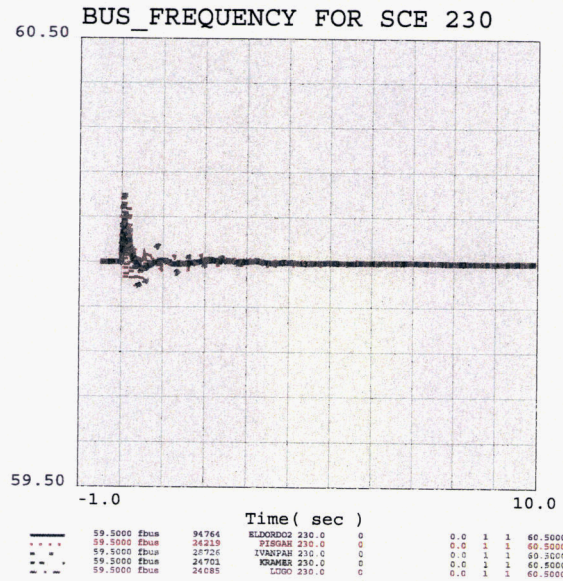
Mon Jun 06 13:48:21 2011

Stability Plots in SCE Area







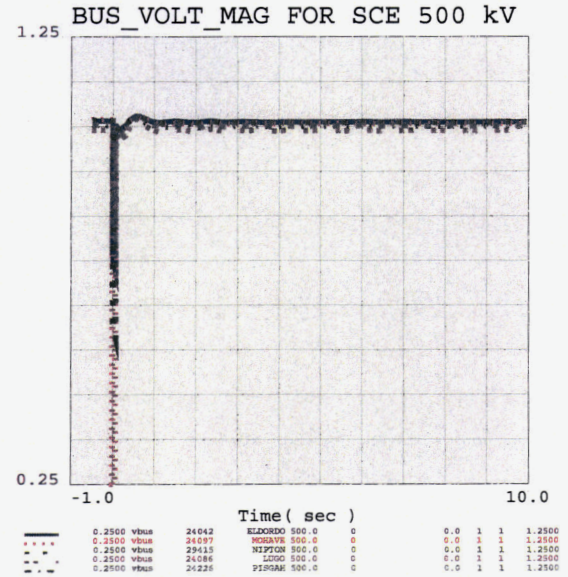


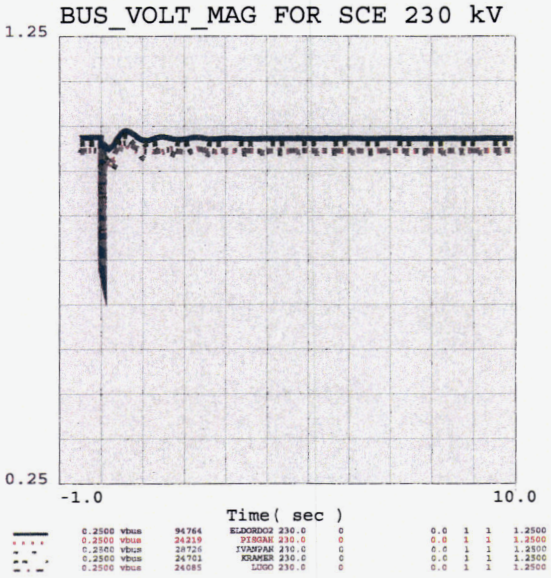
2014-hs-c1c2p2-eop-final-pre_Mohave-Homer-slo
East of Pisgah Area

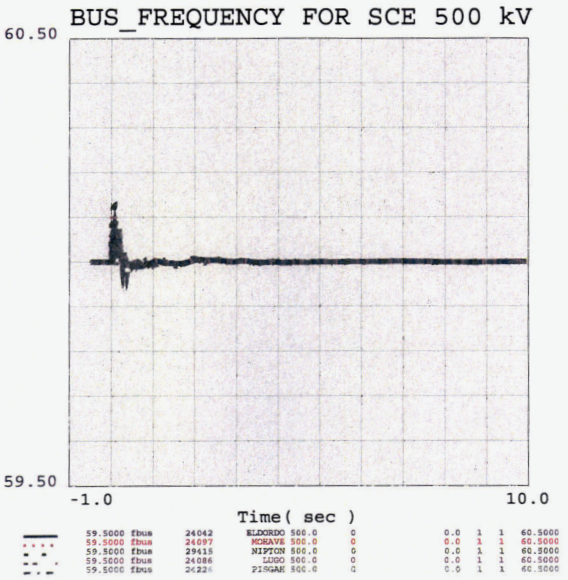
2014-hs-c1c2p2-eop-final-pre_Mohave-Homer-slo.chf

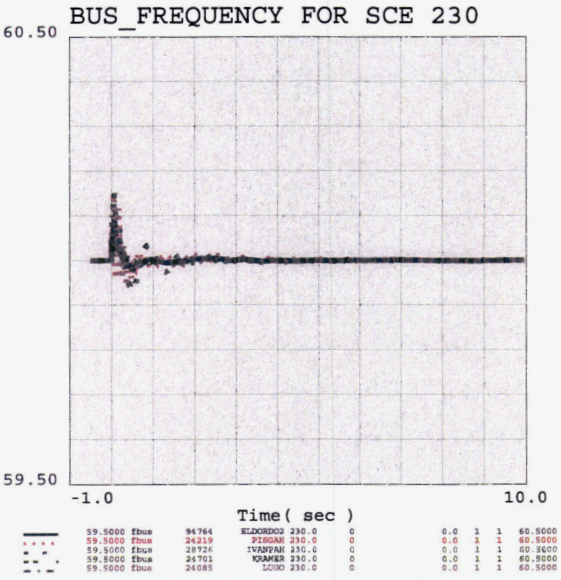
Mon Jun 06 13:48:16 2011

Stability Plots in SCE Area









2014-hs-c1c2p2-eop-final-pre_Mohave-ElDorado-slo
East of Pisgah Area

2014-hs-c1c2p2-eop-final-pre_Mohave-ElDorado-slo.chf

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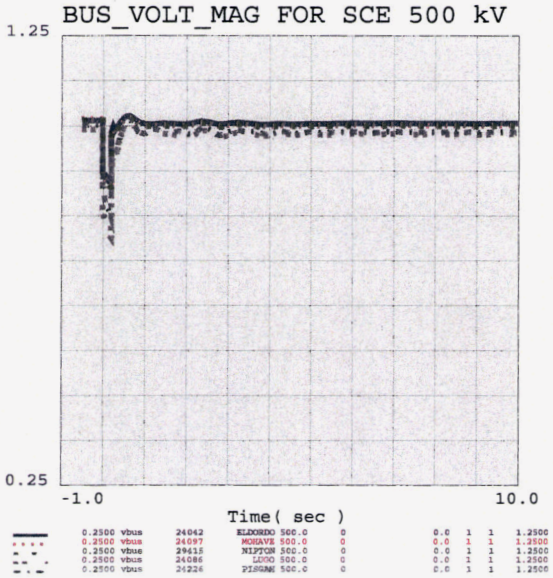
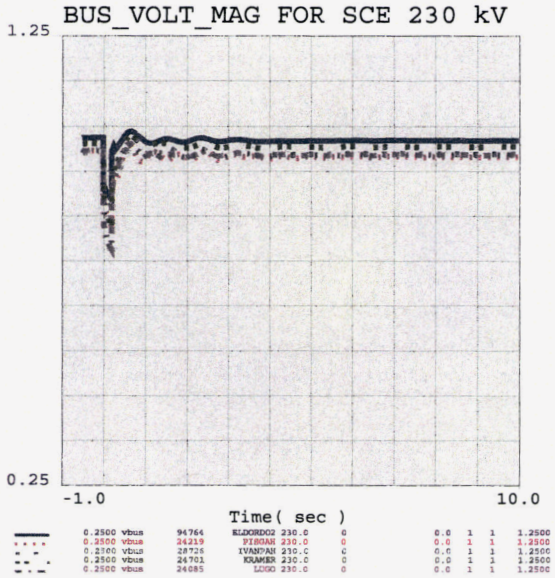
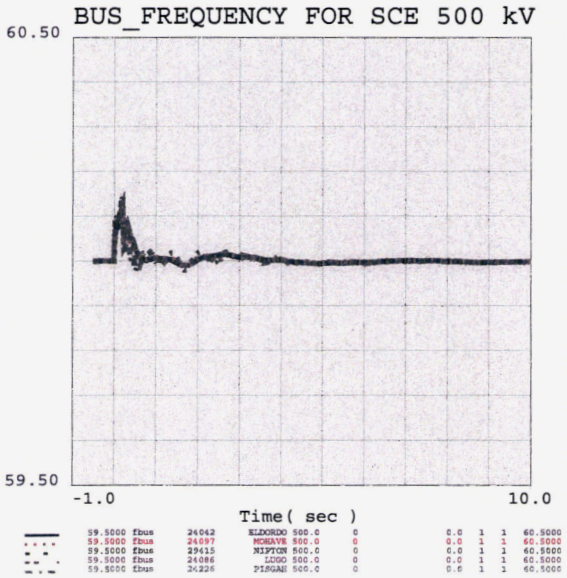
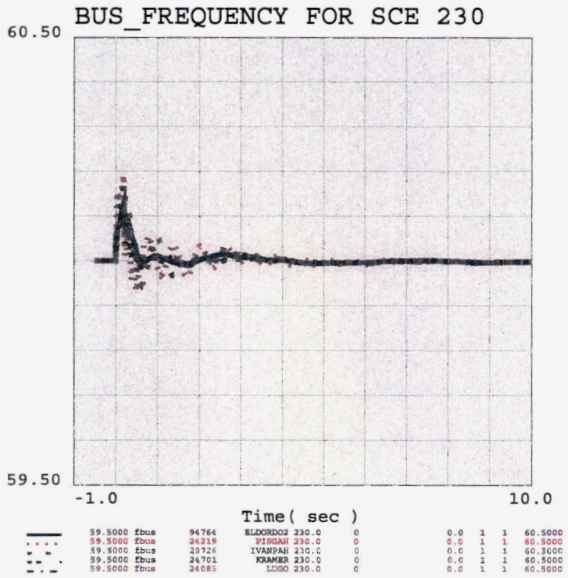
Mon Jun 06 13:48:11 2011

Stability Plots in SCE Area







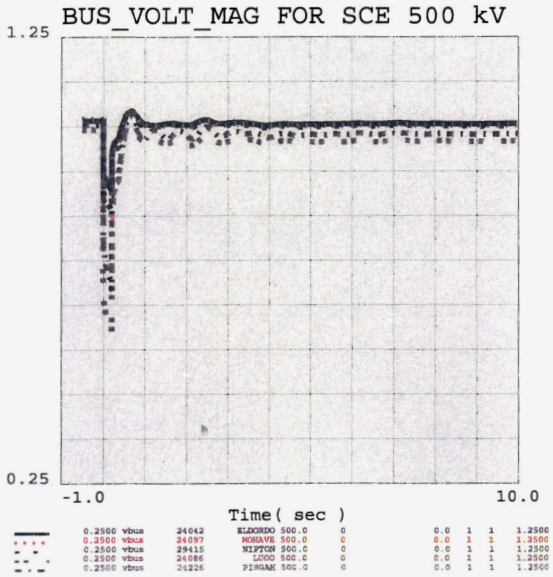


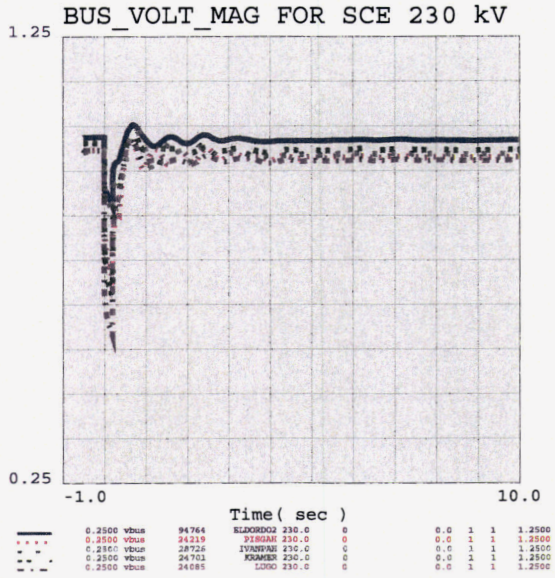
2014-hs-c1c2p2-eop-final-pre_McCullgh-Victorvl-dlo-slg
East of Pisgah Area

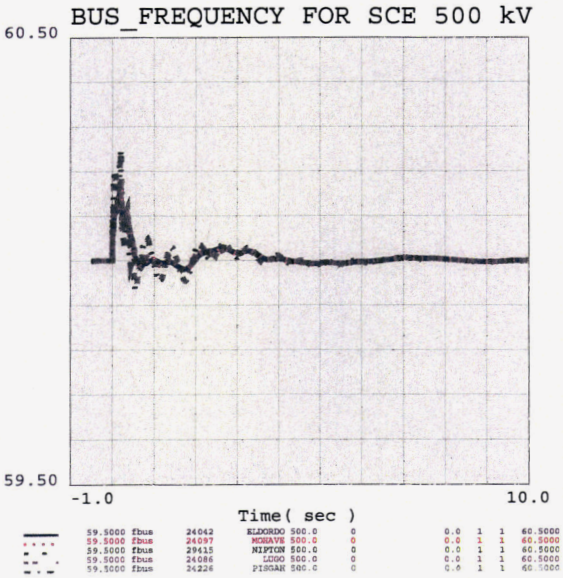
2014-hs-c1c2p2-eop-final-pre_McCullgh-Victorvl-dlo-slg.chf

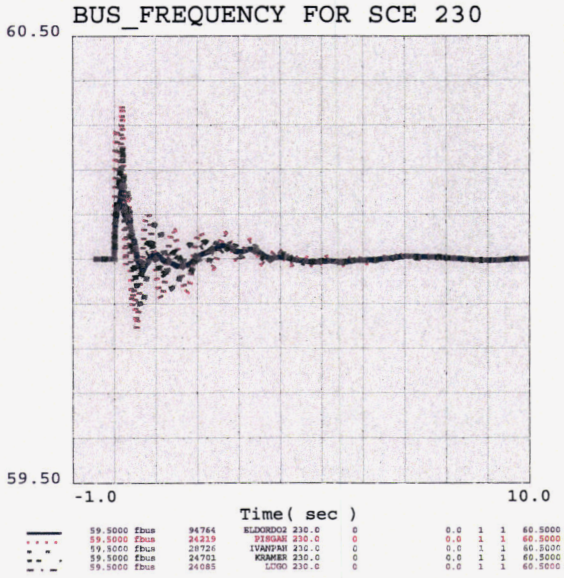
Mon Jun 06 13:48:05 2011

Stability Plots in SCE Area









2014-hs-c1c2p2-eop-final-pre_Lugo-Vincent-dlo-slg
East of Pisgah Area

2014-hs-c1c2p2-eop-final-pre_Lugo-Vincent-dlo-slg.chf

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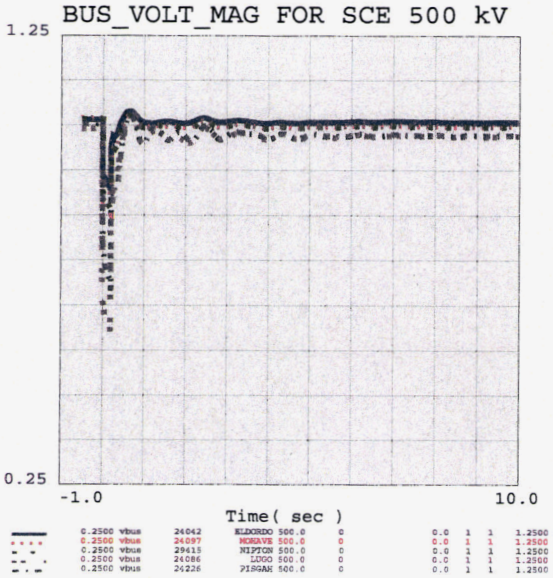
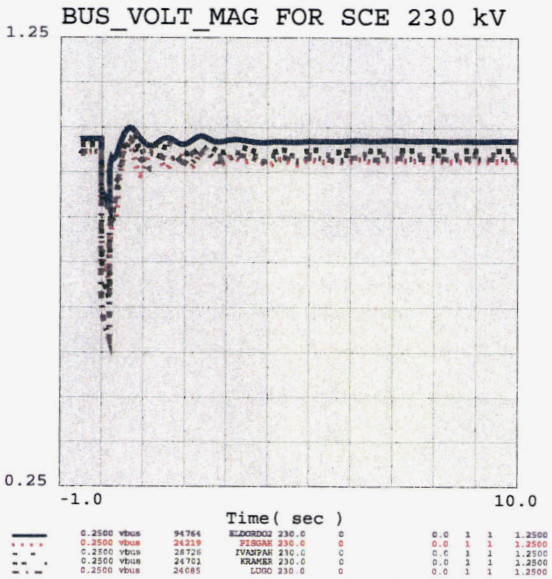
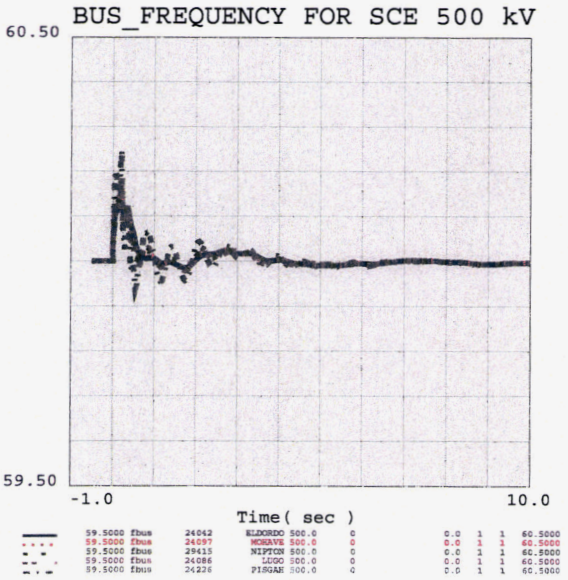
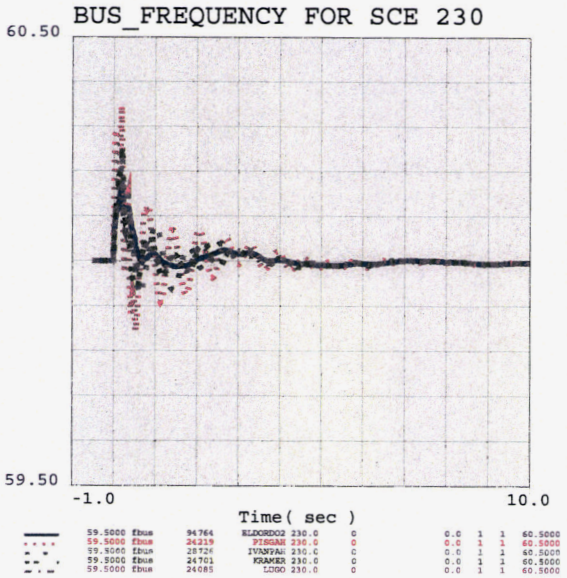
Mon Jun 06 13:47:53 2011

Stability Plots in SCE Area









2014-hs-c1c2p2-eop-final-pre_Lugo-VicVin2-dlo-slg
East of Pisgah Area

2014-hs-c1c2p2-eop-final-pre_Lugo-VicVin2-dlo-slg.chf

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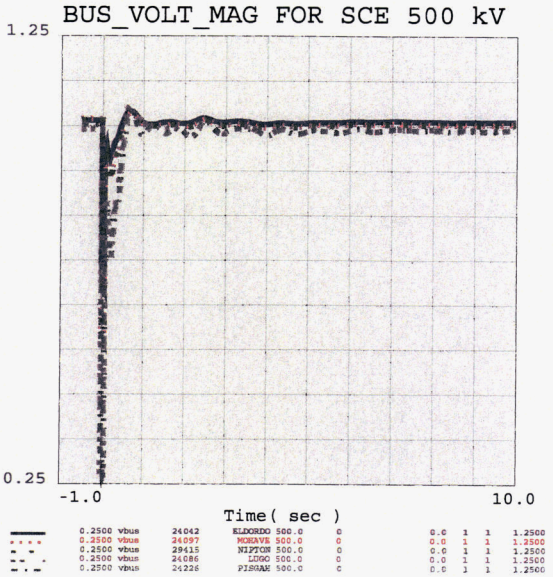
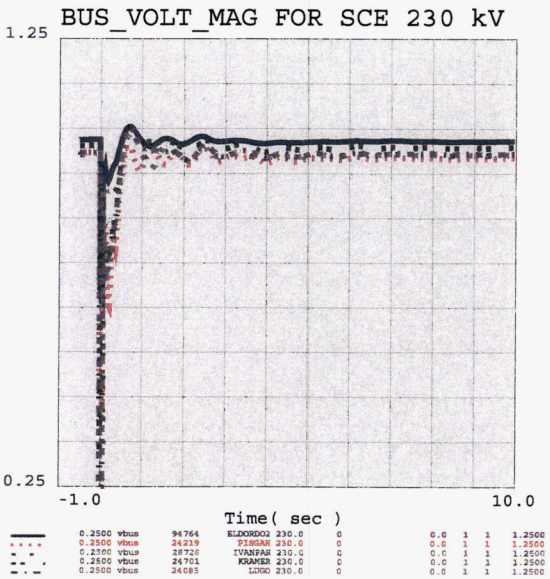
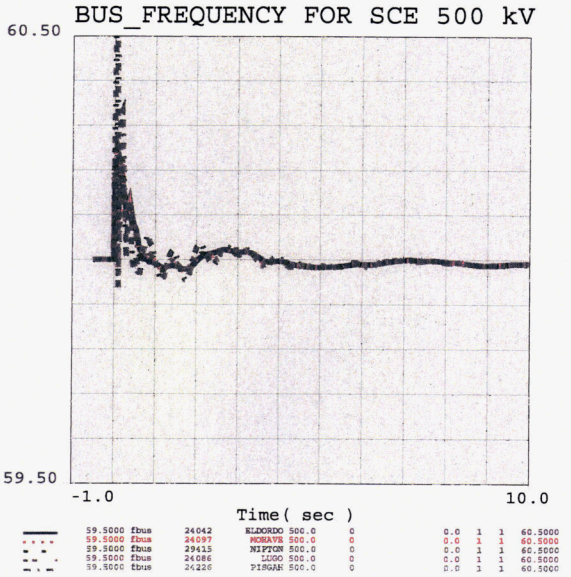
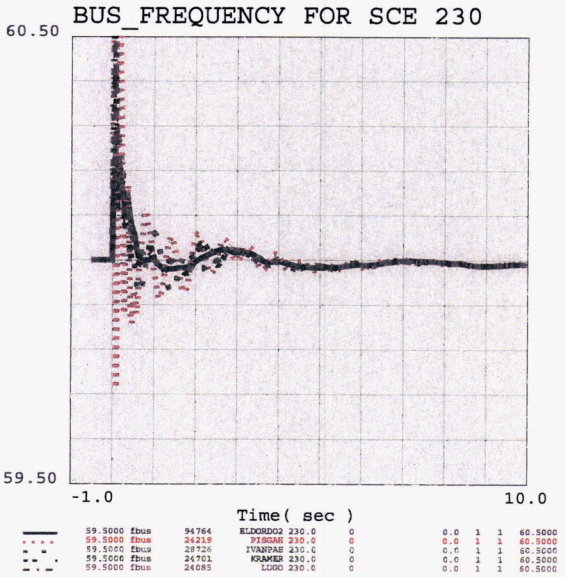
Stability Plots in SCE Area









2014-hs-c1c2p2-eop-final-pre_Lugo-Victvl-slo
East of Pisgah Area

2014-hs-c1c2p2-eop-final-pre_Lugo-Victvl-slo.chf

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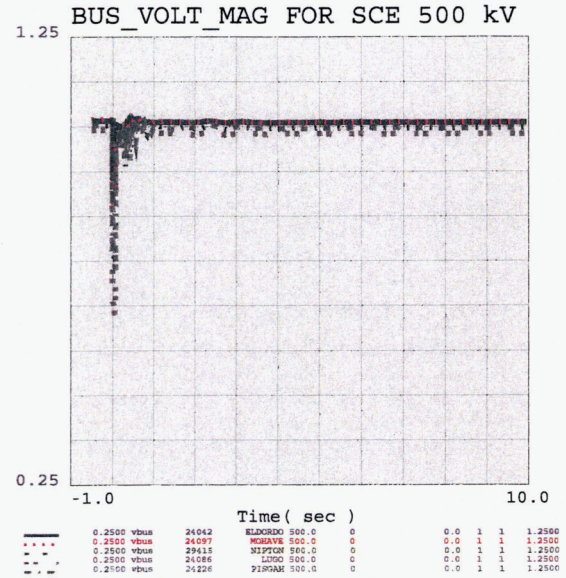
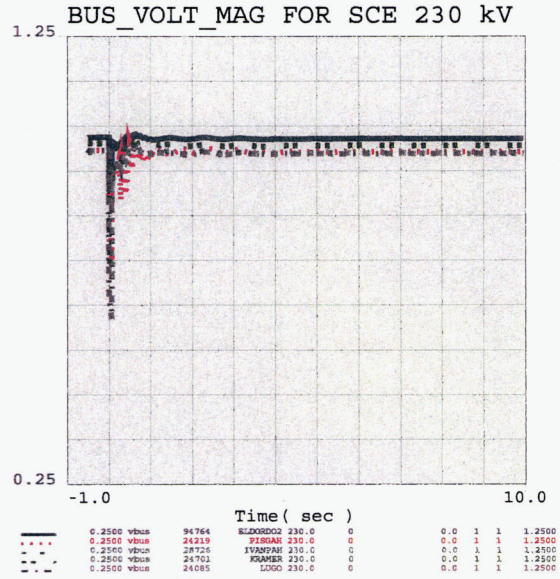
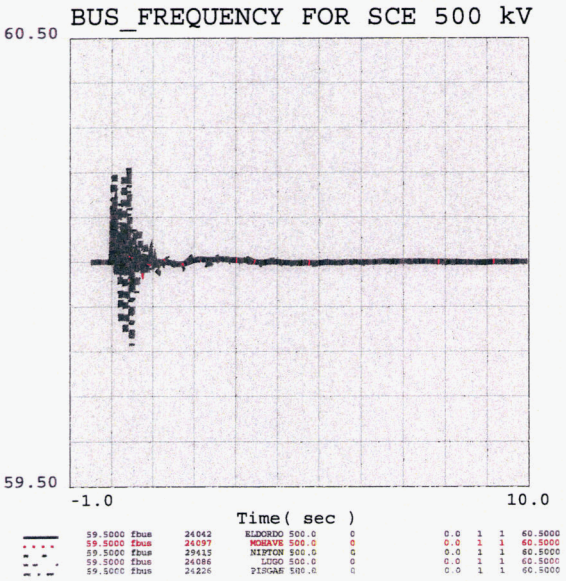
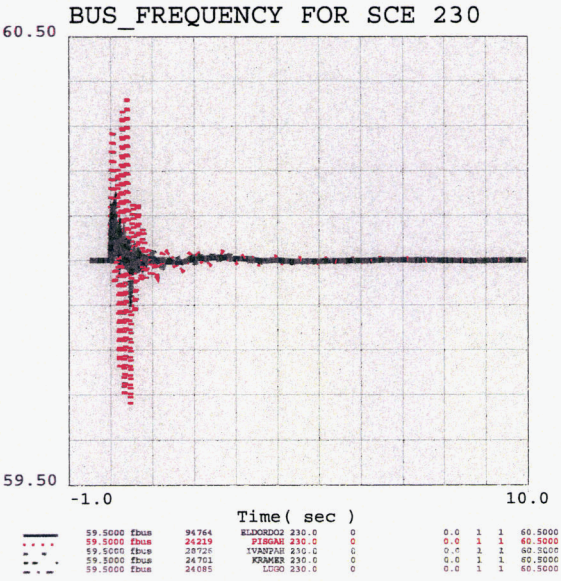
Stability Plots in SCE Area









2014-hs-c1c2p2-eop-final-pre_Lugo-PisMoh-dlo-slg
East of Pisgah Area

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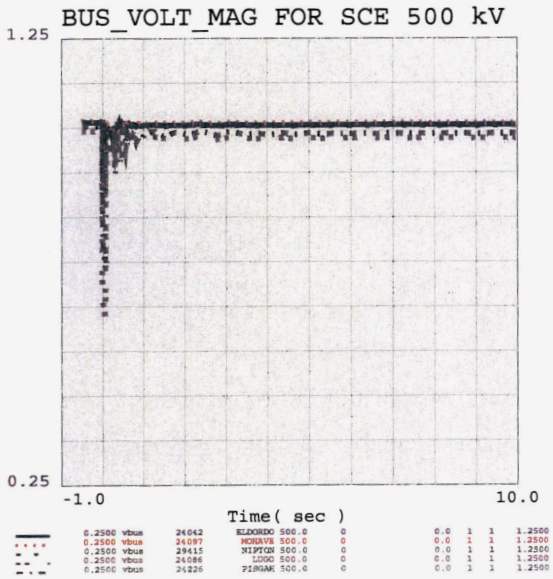
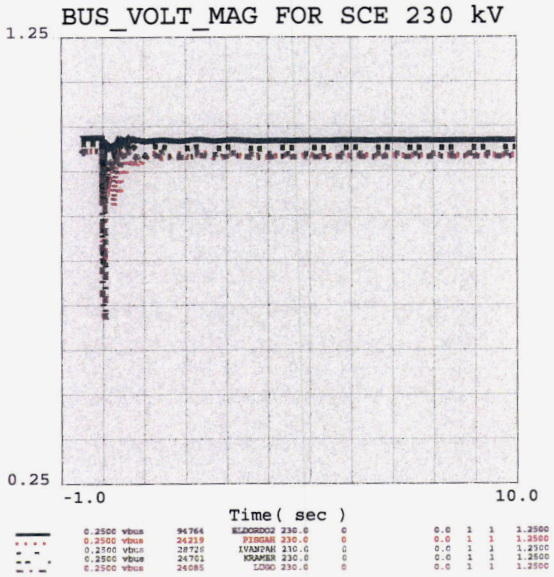
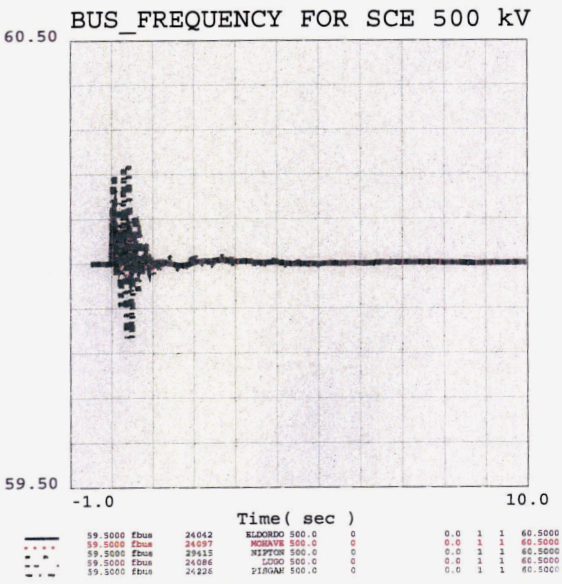
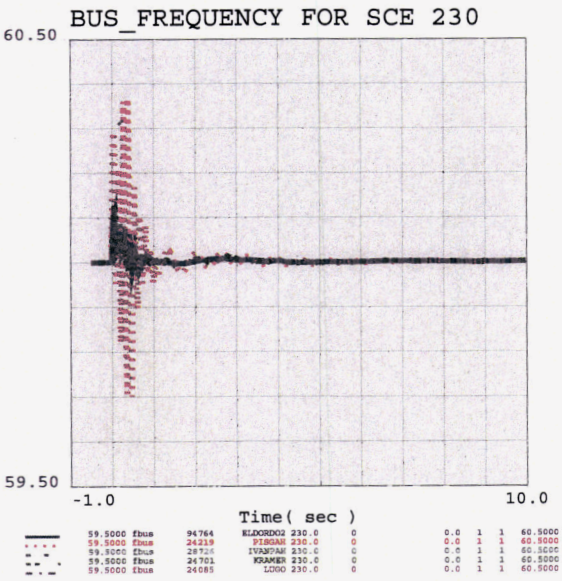
Mon Jun 06 13:47:23 2011

Stability Plots in SCE Area







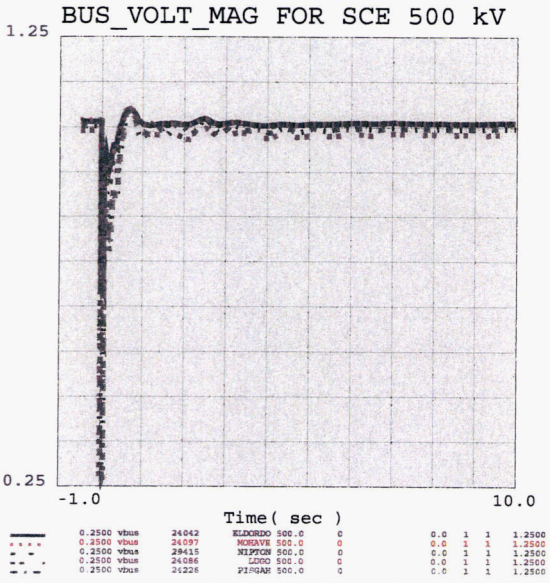


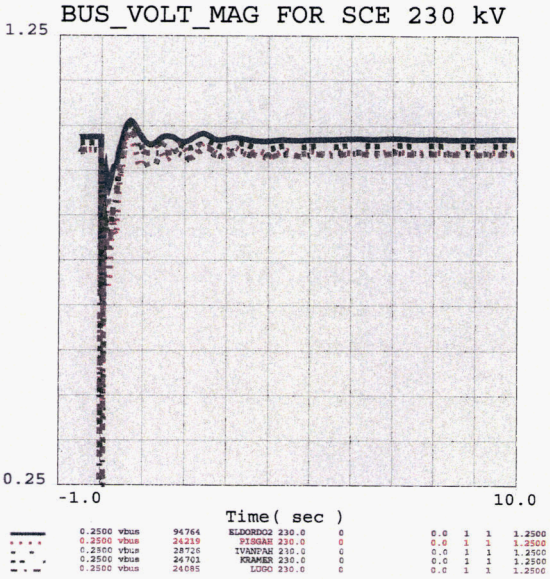
2014-hs-c1c2p2-eop-final-pre_Lugo-PisHom-dlo-slg
East of Pisgah Area

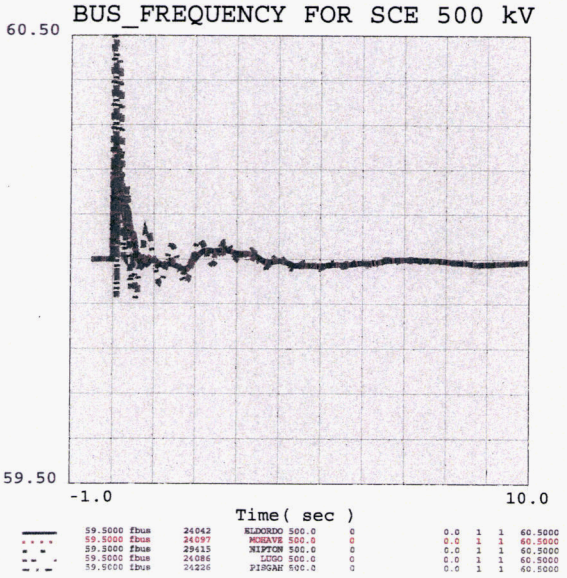
2014-hs-c1c2p2-eop-final-pre_Lugo-PisHom-dlo-slg.chf

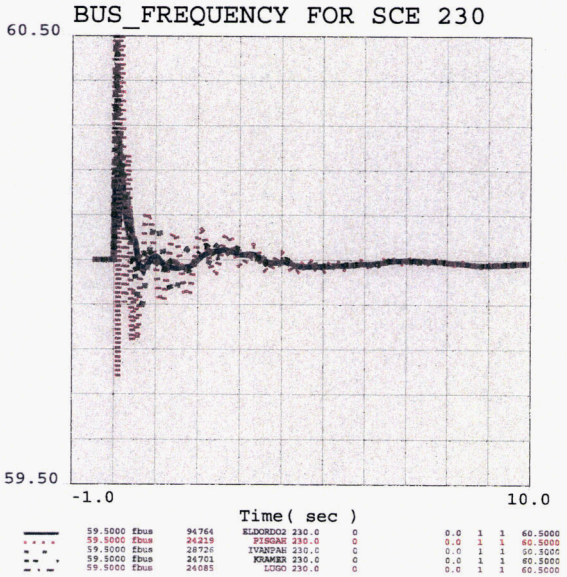
Mon Jun 06 13:47:18 2011

Stability Plots in SCE Area







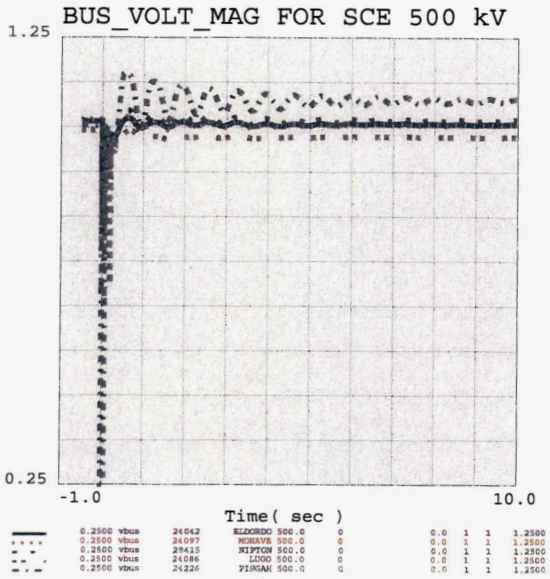


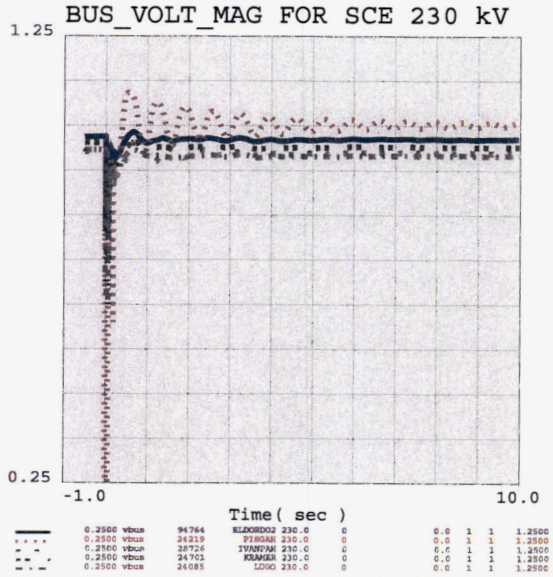
2014-hs-c1c2p2-eop-final-pre_Lugo-Pisgah500-slo
East of Pisgah Area

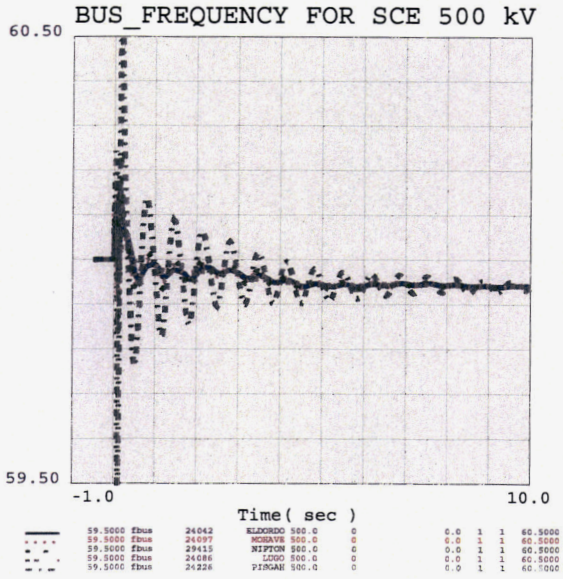
2014-hs-c1c2p2-eop-final-pre_Lugo-Pisgah500-slo.chf

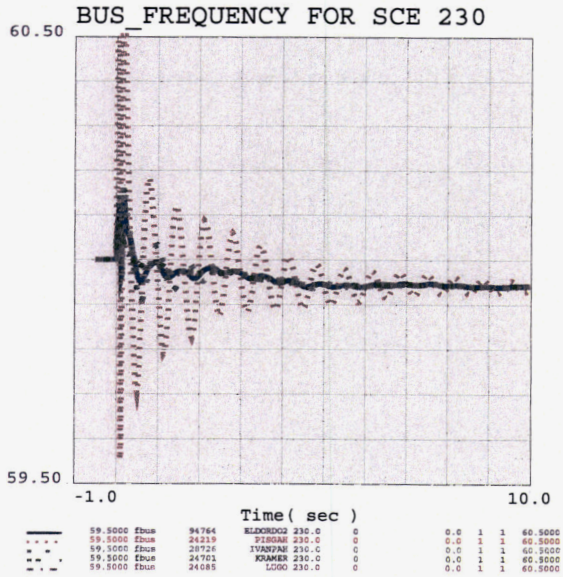
Mon Jun 06 13:47:36 2011

Stability Plots in SCE Area







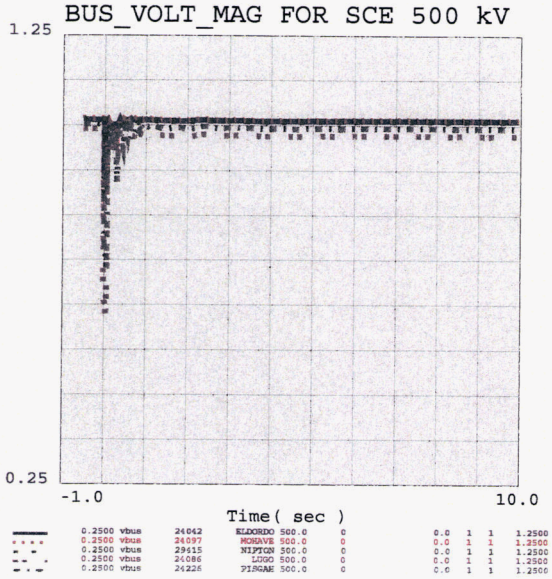


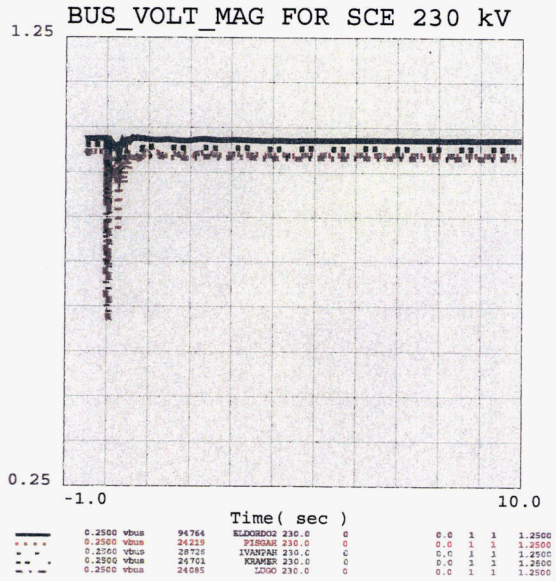
2014-hs-c1c2p2-eop-final-pre_Lugo-Pisgah500-dlo-slg-SPS
East of Pisgah Area

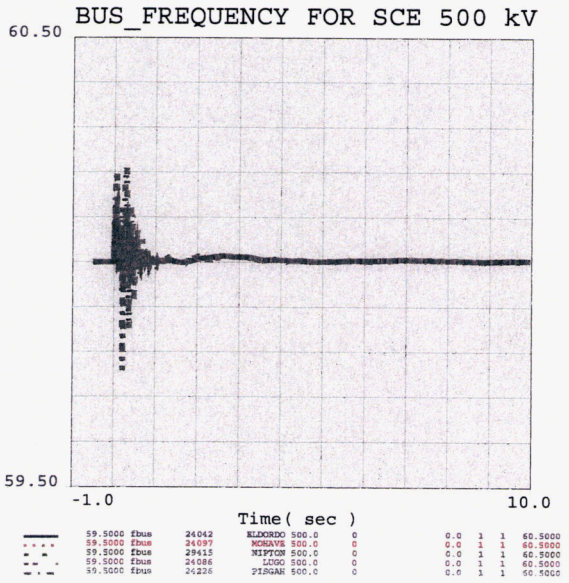
2014-hs-c1c2p2-eop-final-pre_Lugo-Pisgah500-dlo-slg-SPS.chf

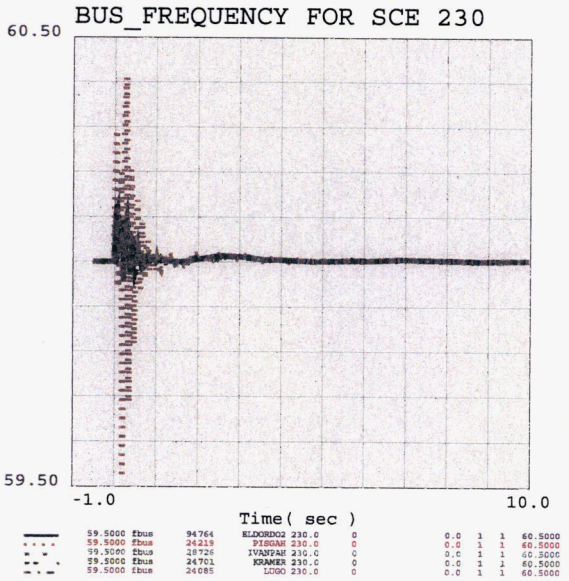
Mon Jun 06 13:47:30 2011

Stability Plots in SCE Area







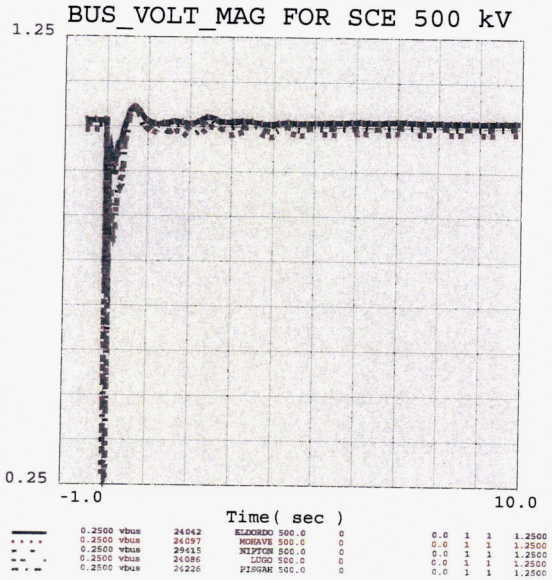


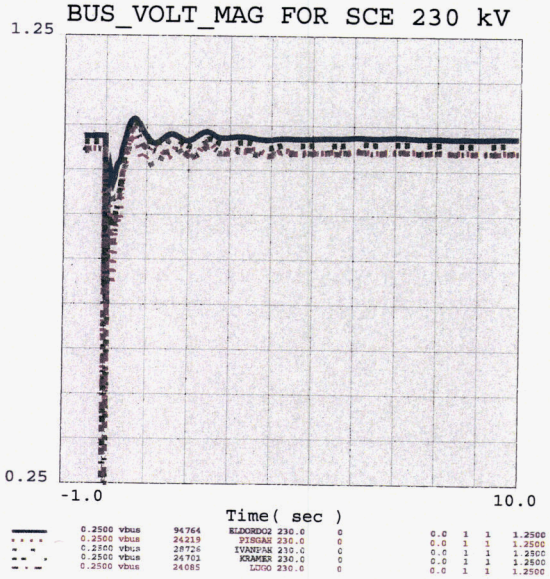
2014-hs-c1c2p2-eop-final-pre_Lugo-Miraloma23-dlo-slg
East of Pisgah Area

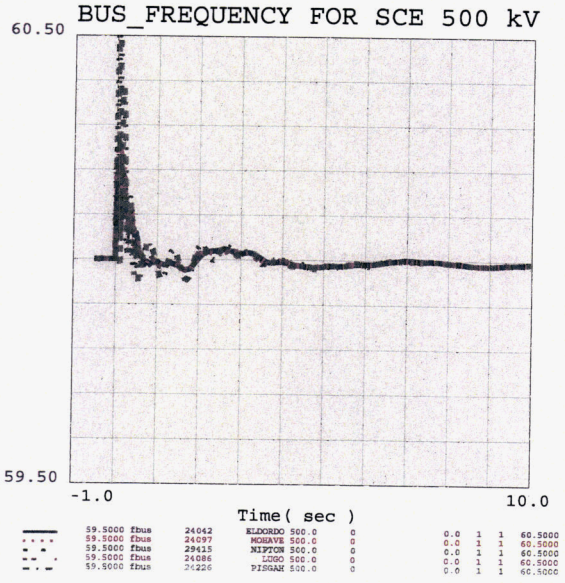
2014-hs-c1c2p2-eop-final-pre_Lugo-Miraloma23-dlo-slg.chf

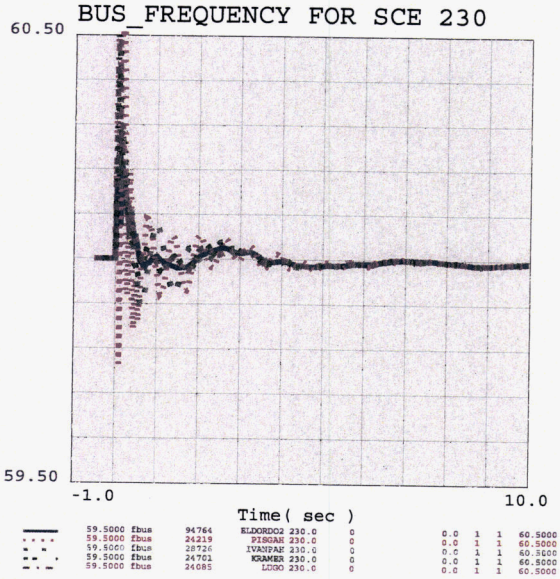
Mon Jun 06 13:47:09 2011

Stability Plots in SCE Area







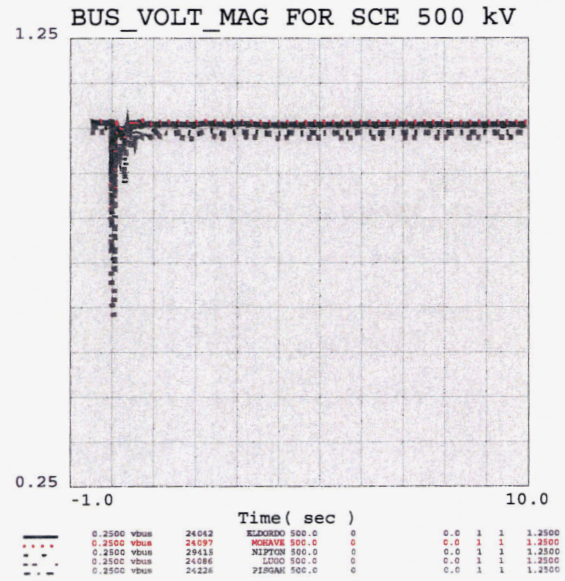


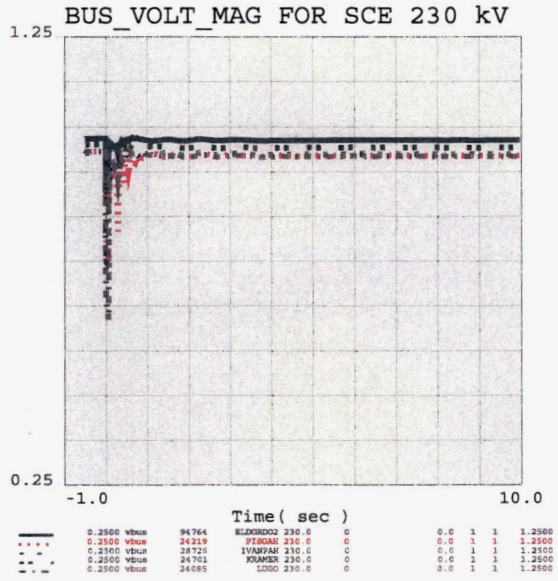
2014-hs-c1c2p2-eop-final-pre_Lugo-Miraloma2-slo
East of Pisgah Area

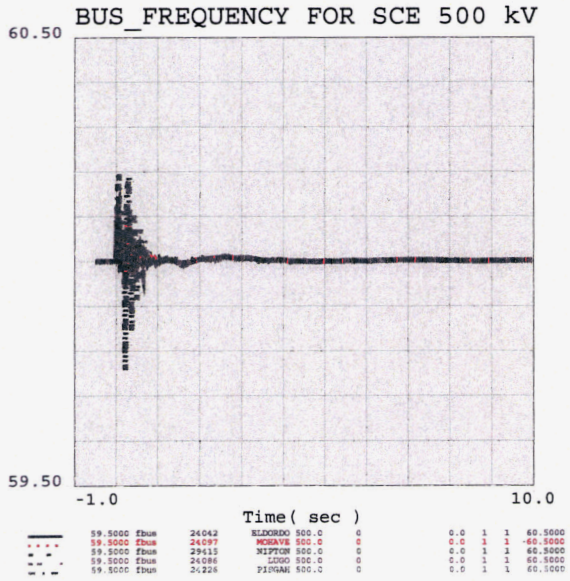
2014-hs-c1c2p2-eop-final-pre_Lugo-Miraloma2-slo.chf

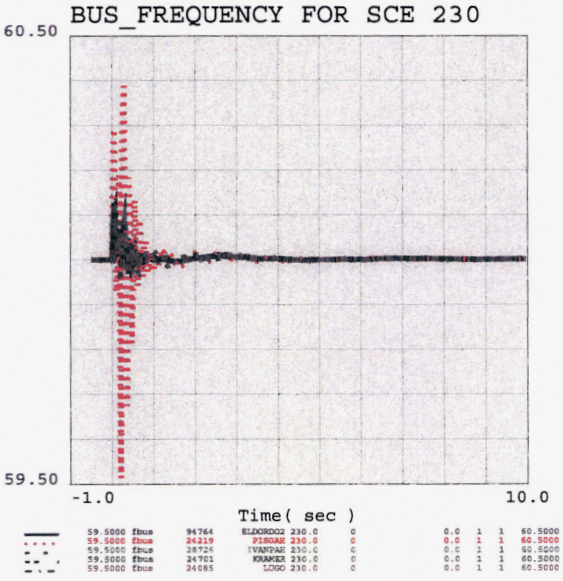
Mon Jun 06 13:47:05 2011

Stability Plots in SCE Area







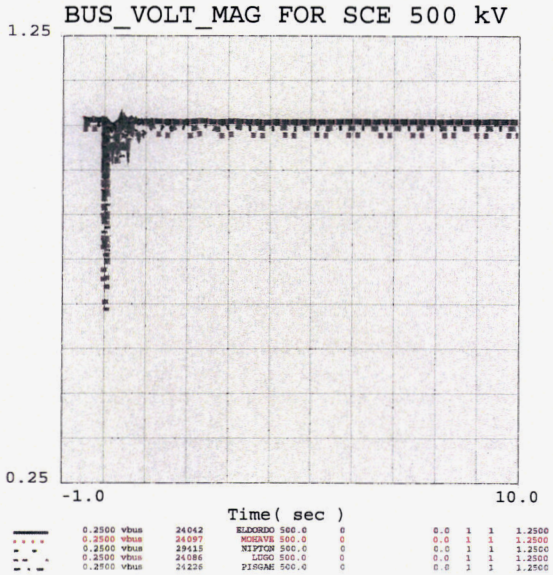


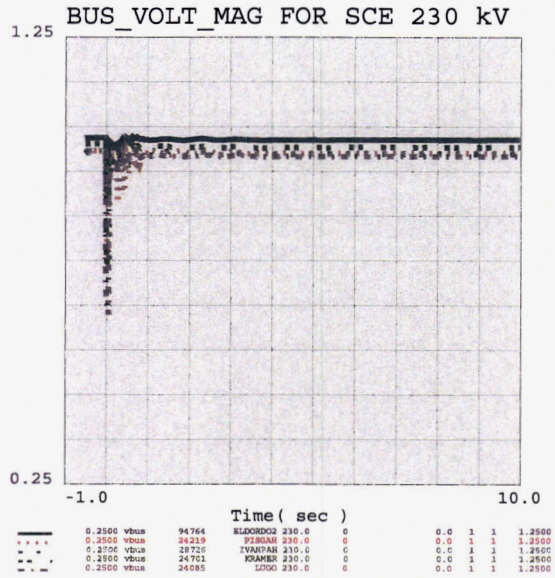
2014-hs-c1c2p2-eop-final-pre_Lugo-Mir3Hom-dlo-slg
East of Pisgah Area

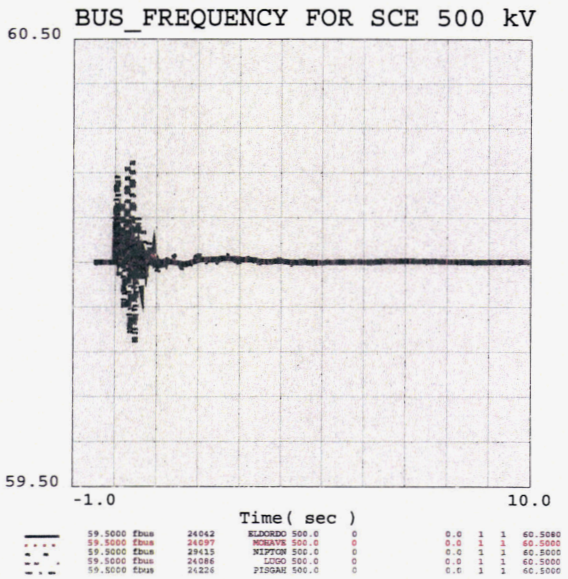
2014-hs-c1c2p2-eop-final-pre_Lugo-Mir3Hom-dlo-slg.chf

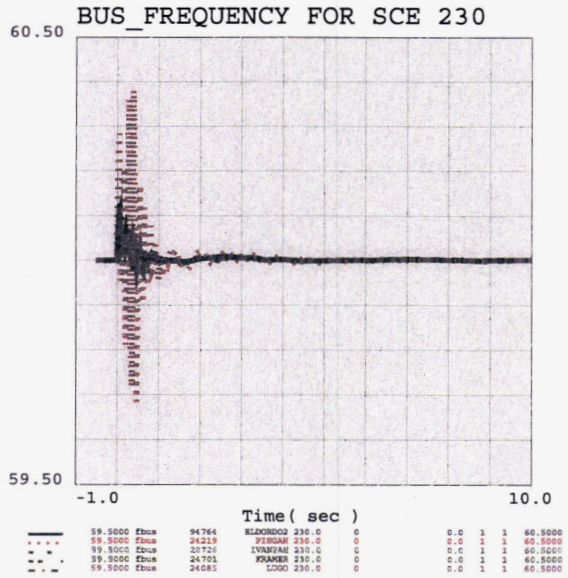
Mon Jun 06 13:47:00 2011

Stability Plots in SCE Area







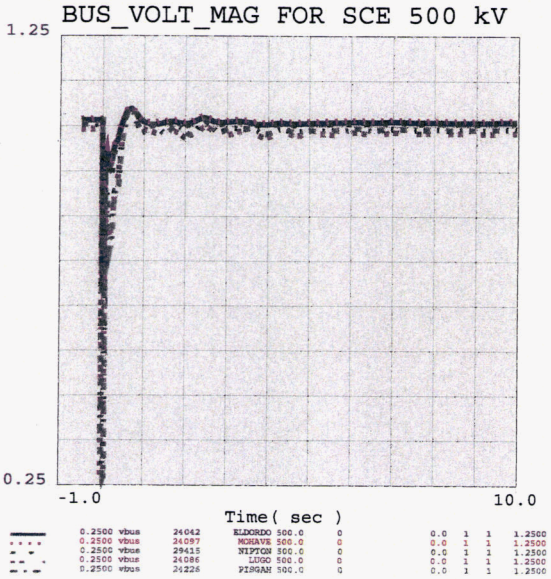


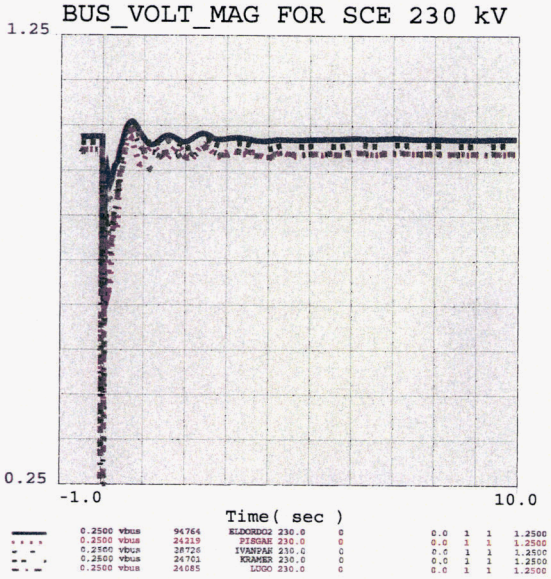
2014-hs-c1c2p2-eop-final-pre_Lugo-Mir2Pis-dlo-slg
East of Pisgah Area

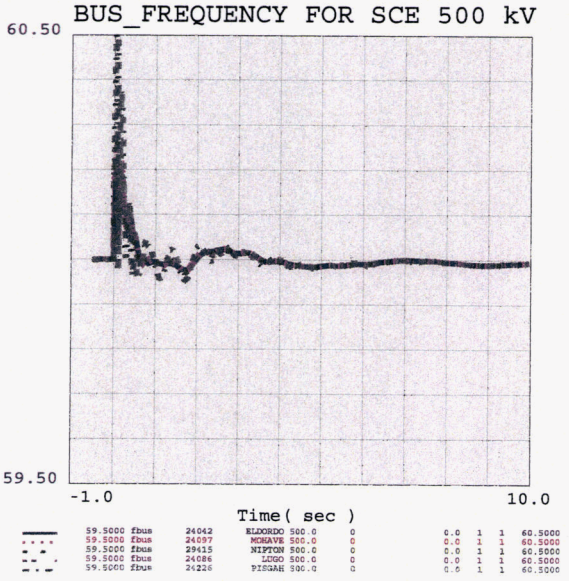
2014-hs-c1c2p2-eop-final-pre_Lugo-Mir2Pis-dlo-slg.chf

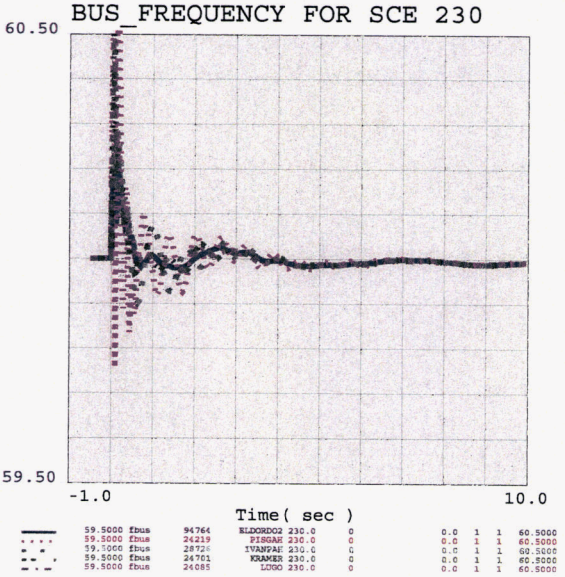
Mon Jun 06 13:46:54 2011

Stability Plots in SCE Area







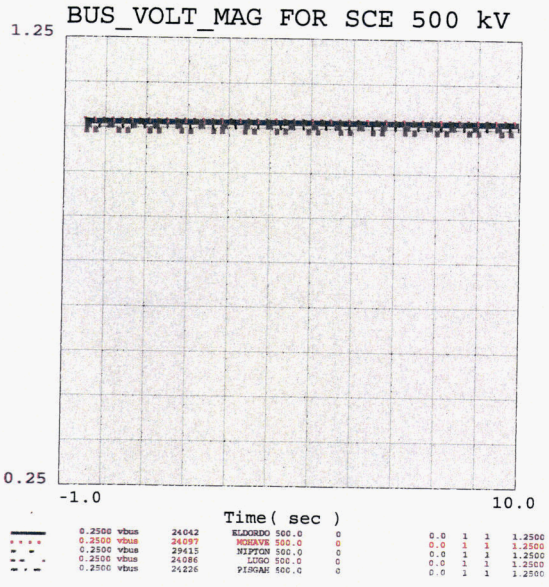


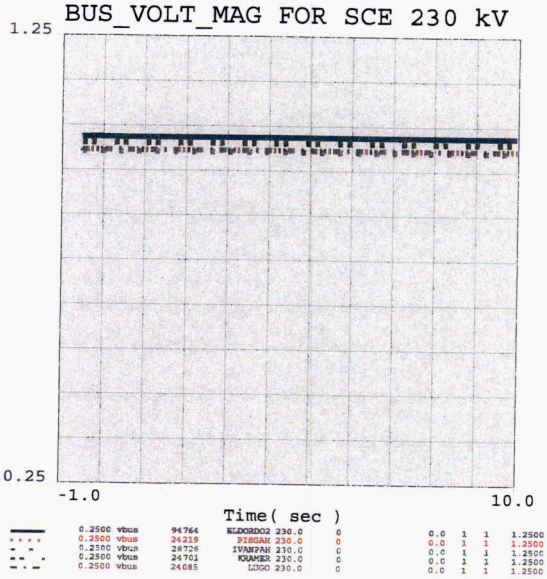
2014-hs-c1c2p2-eop-final-pre_Lugo-Homer-slo
East of Pisgah Area

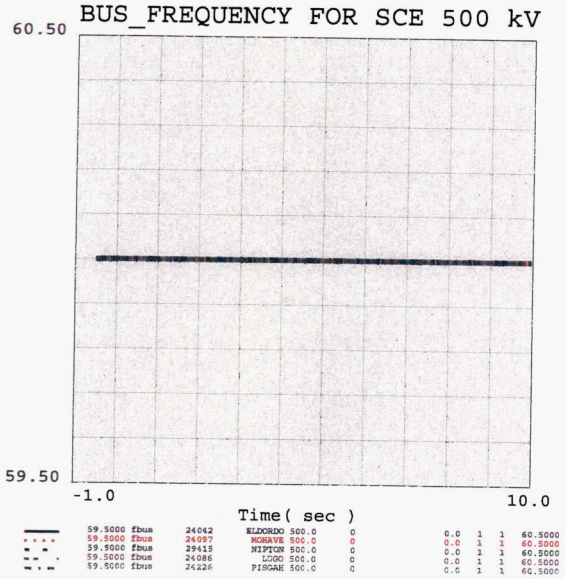
2014-hs-c1c2p2-eop-final-pre_Lugo-Homer-slo.chf

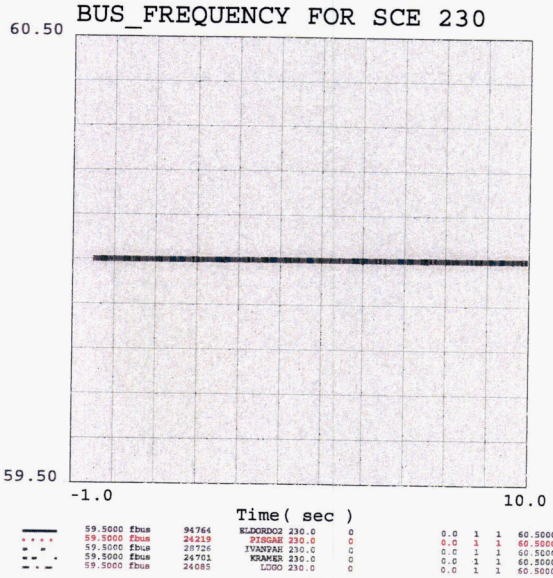
Mon Jun 06 13:46:47 2011

Stability Plots in SCE Area







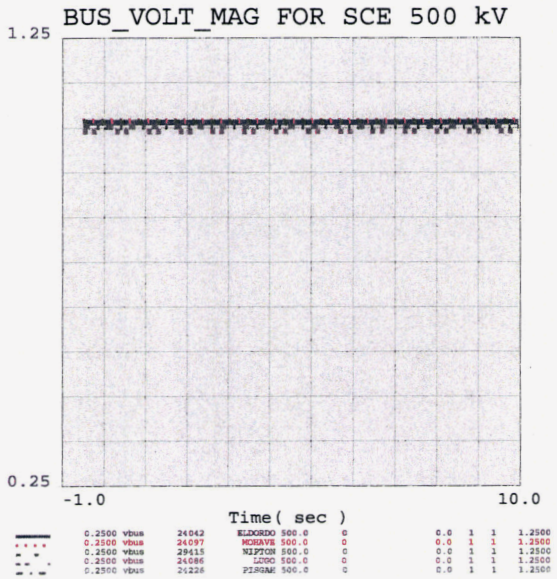


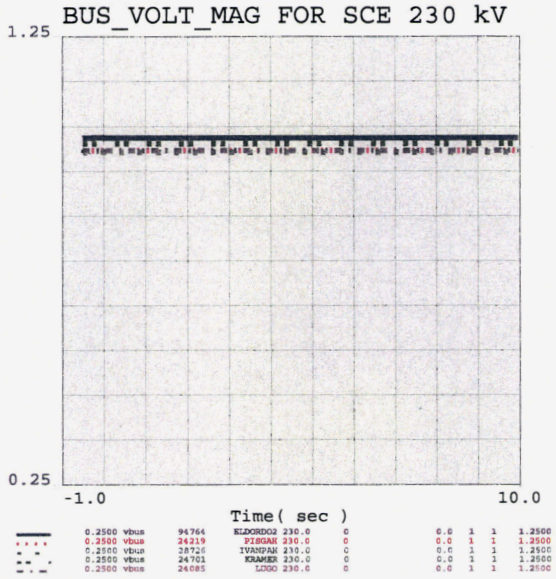
2014-hs-c1c2p2-eop-final-pre_Llano-Vincent-slo
East of Pisgah Area

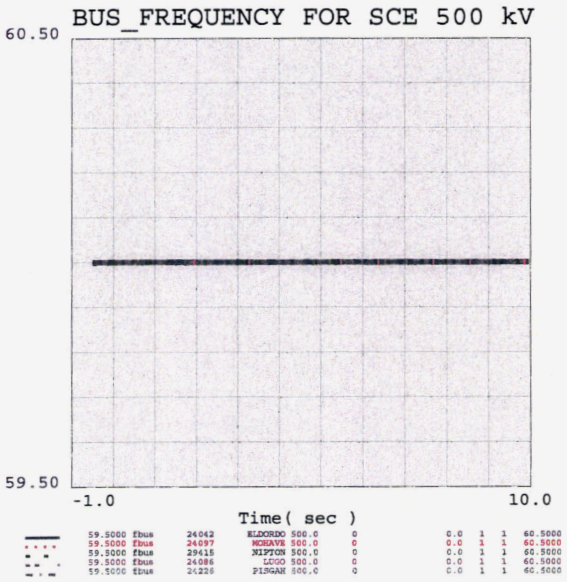
2014-hs-c1c2p2-eop-final-pre_Llano-Vincent-slo.chf

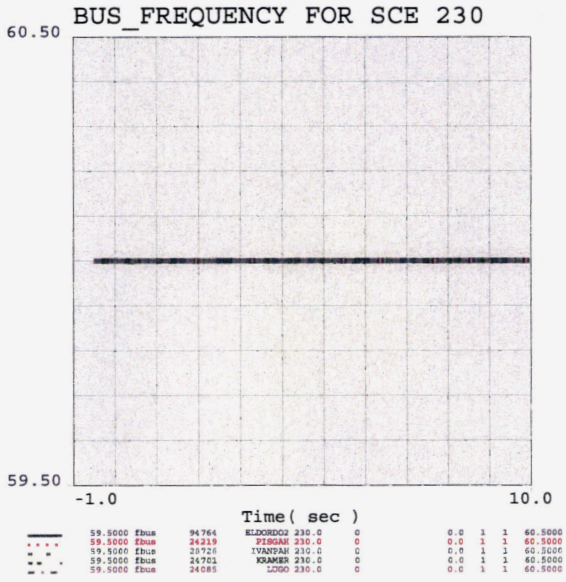
Mon Jun 06 13:46:42 2011

Stability Plots in SCE Area









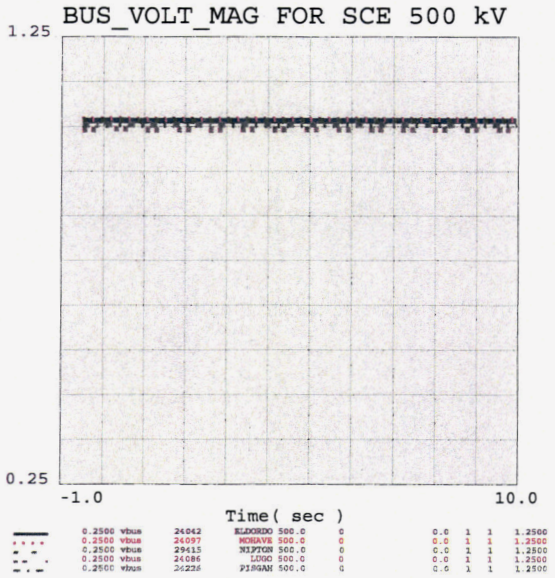
2014-hs-c1c2p2-eop-final-pre_Llano-Lugo-slo
East of Pisgah Area

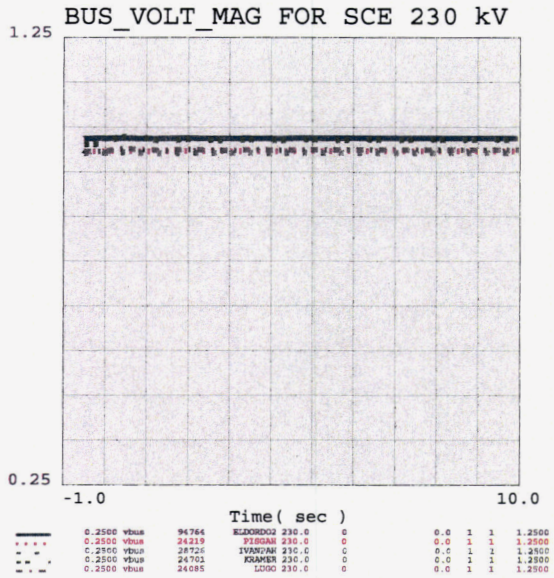
2014-hs-c1c2p2-eop-final-pre_Llano-Lugo-slo.chf

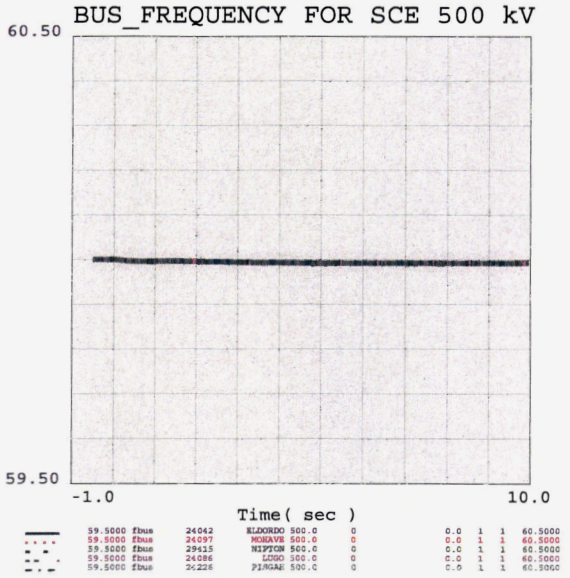
.

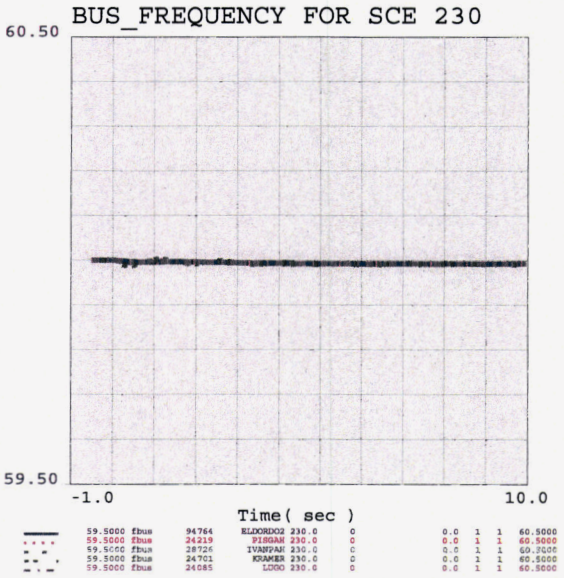
Mon Jun 06 13:46:37 2011

Stability Plots in SCE Area







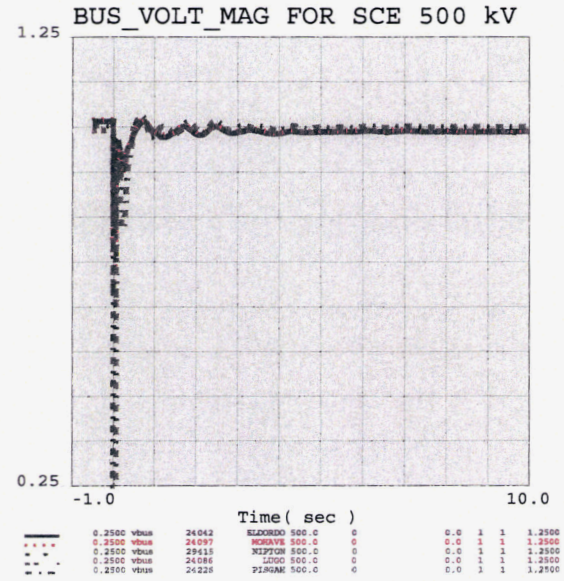


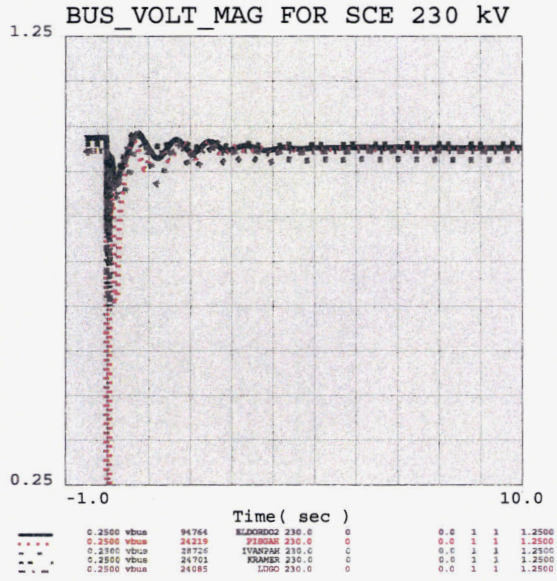
2014-hs-c1c2p2-eop-final-pre_Kramer-Llano-slo-SPS
East of Pisgah Area

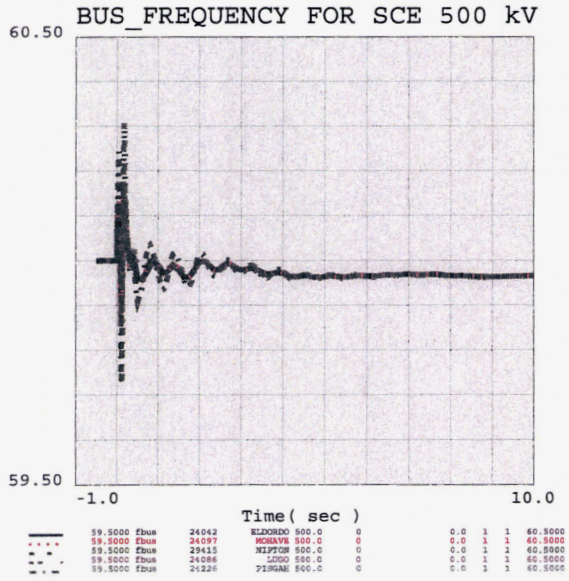
2014-hs-c1c2p2-eop-final-pre_Kramer-Llano-slo-SPS.chf

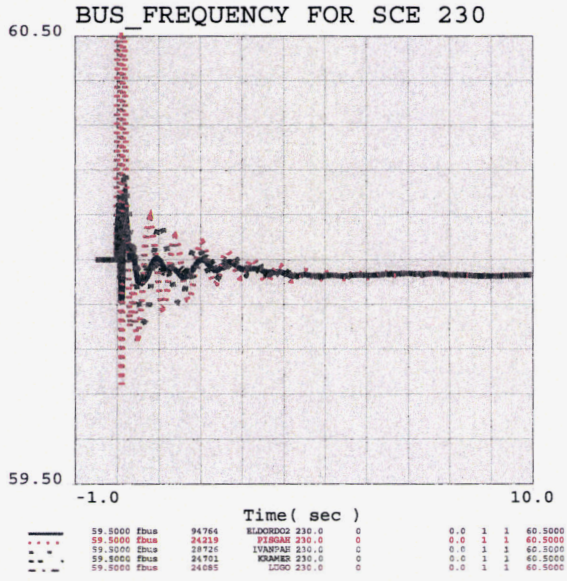
Mon Jun 06 13:46:31 2011

Stability Plots in SCE Area







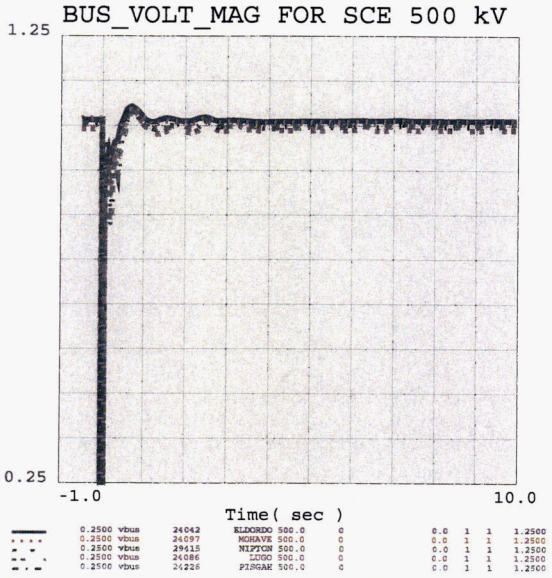


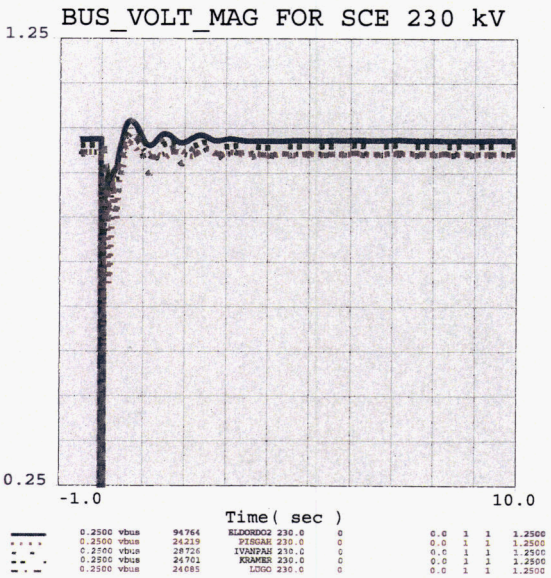
2014-hs-c1c2p2-eop-final-pre_Eldrd-McIlugh500-slo-SPS
East of Pisgah Area

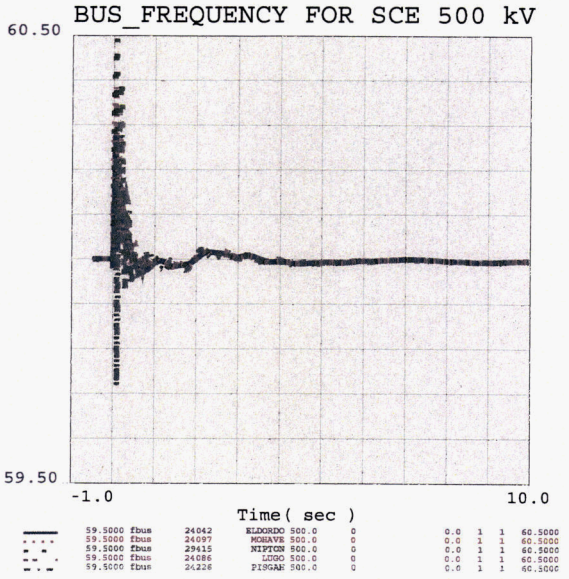
2014-hs-c1c2p2-eop-final-pre_Eldrd-McIlugh500-slo-SPS.chf

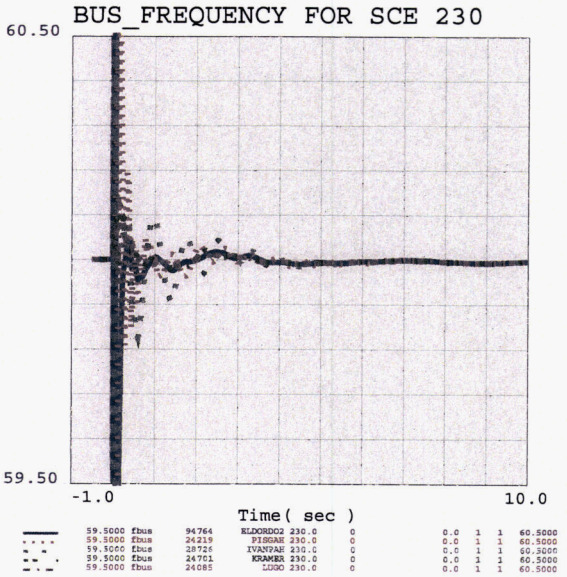
Mon Jun 06 13:46:26 2011

Stability Plots in SCE Area







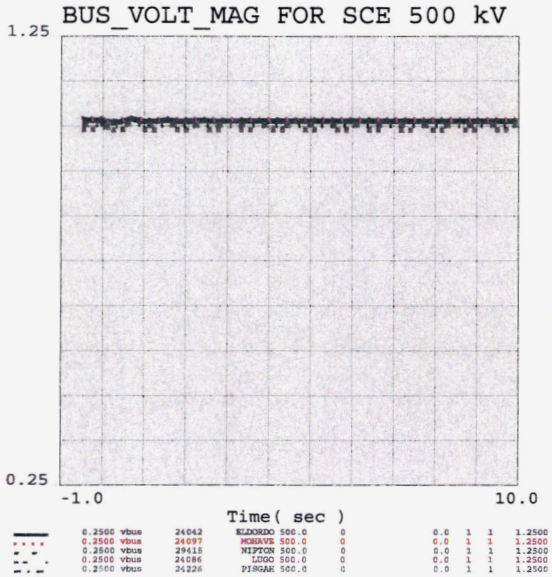


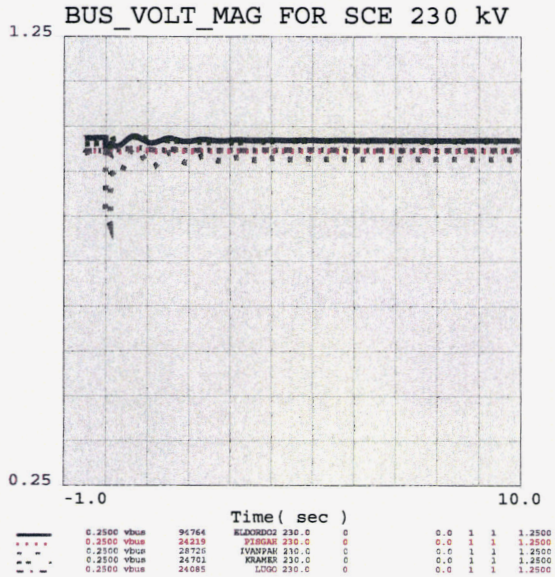
2014-hs-c1c2p2-eop-final-pre_Eldorado-Nipton-slo
East of Pisgah Area

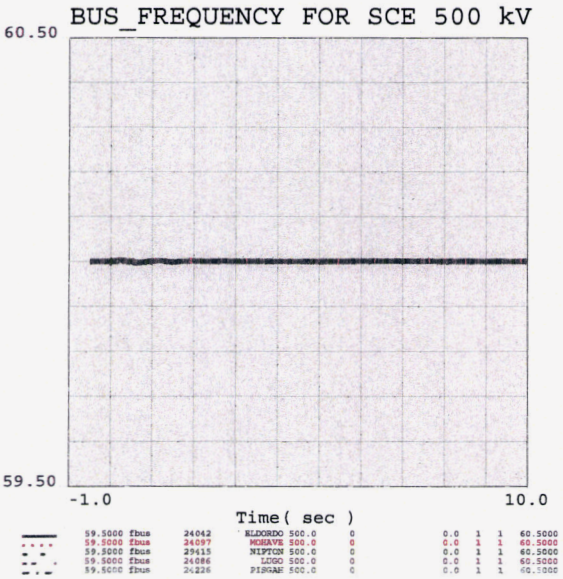
2014-hs-c1c2p2-eop-final-pre_Eldorado-Nipton-slo.chf

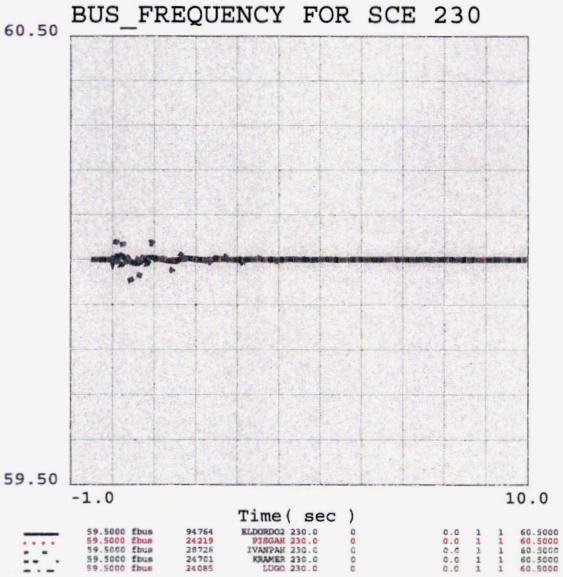
Mon Jun 06 13:46:18 2011

Stability Plots in SCE Area







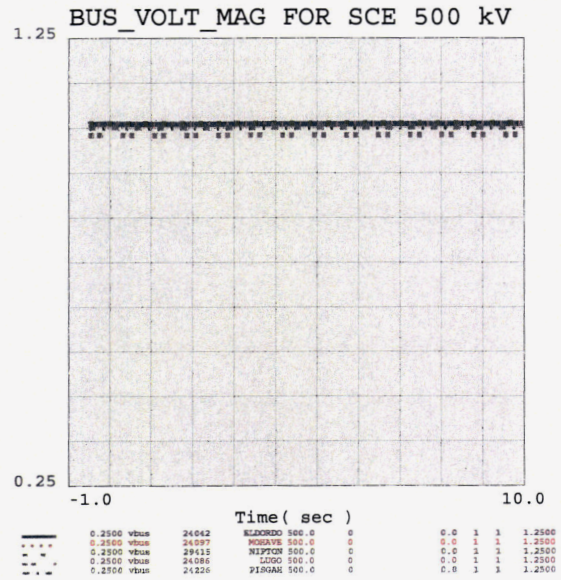


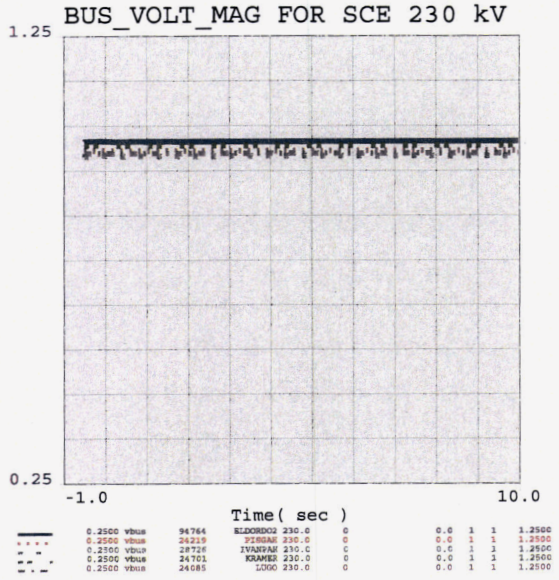
2014-hs-c1c2p2-eop-final-pre_MTPass-Ivapah115-slo
East of Pisgah Area

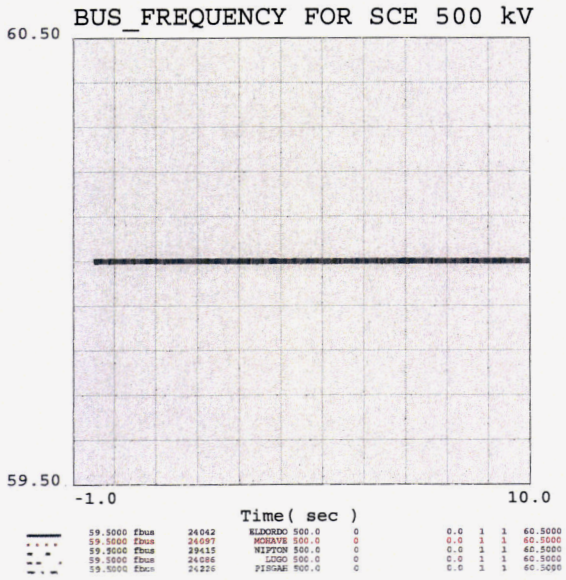
2014-hs-c1c2p2-eop-final-pre_MTPass-Ivapah115-slo.chf

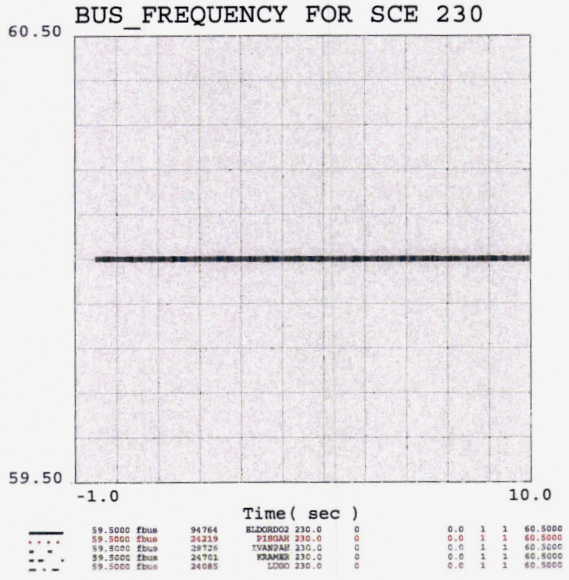
Mon Jun 06 13:48:00 2011

Stability Plots in SCE Area







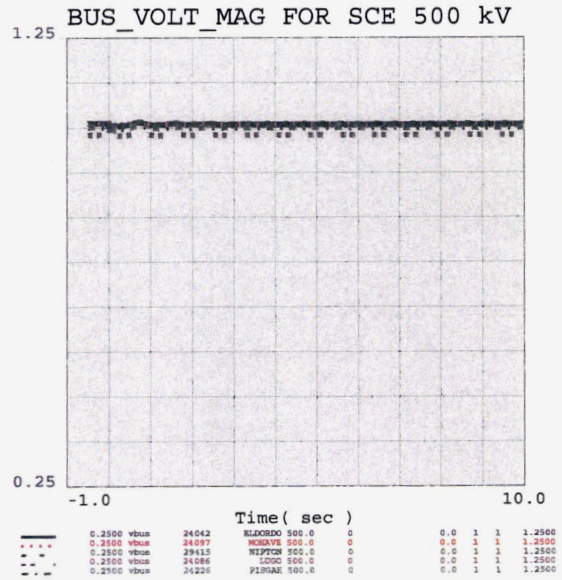


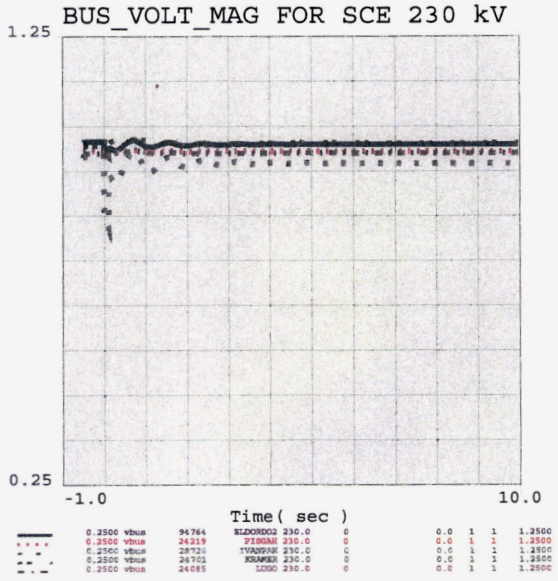
2014-hs-c1c2p2-eop-final-pst-loop1_No-fault
East of Pisgah Area

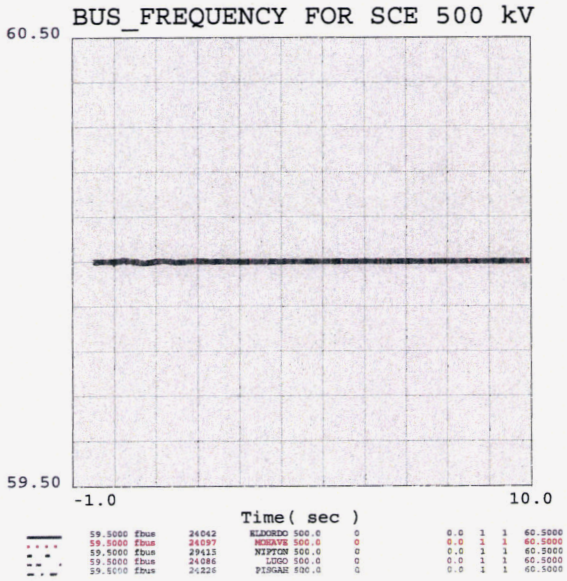
2014-hs-c1c2p2-eop-final-pst-loop1_No-fault.chf

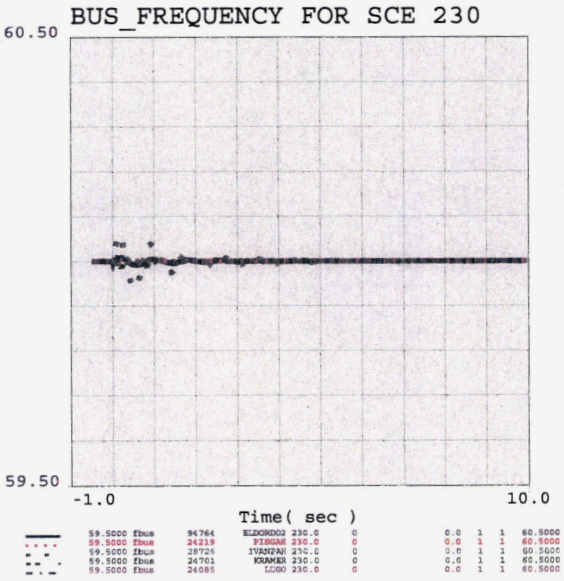
Mon Jun 06 13:50:49 2011

Stability Plots in SCE Area









2014-hs-c1c2p2-eop-final-pst-loop1_MTPass-Ivapah115-slo
East of Pisgah Area

2014-hs-c1c2p2-eop-final-pst-loop1_MTPass-Ivapah115-slo.chf

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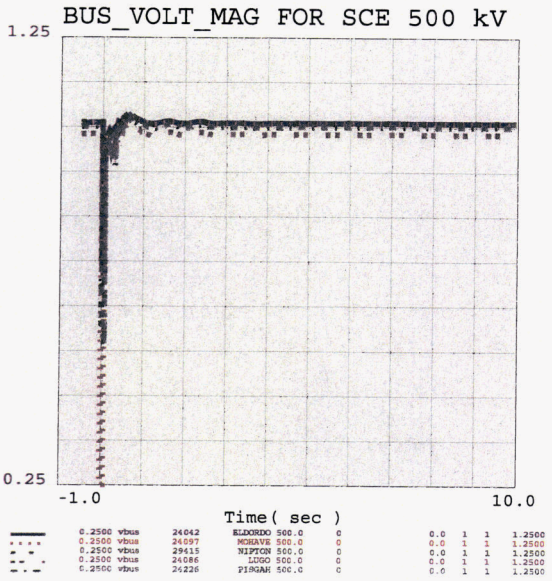
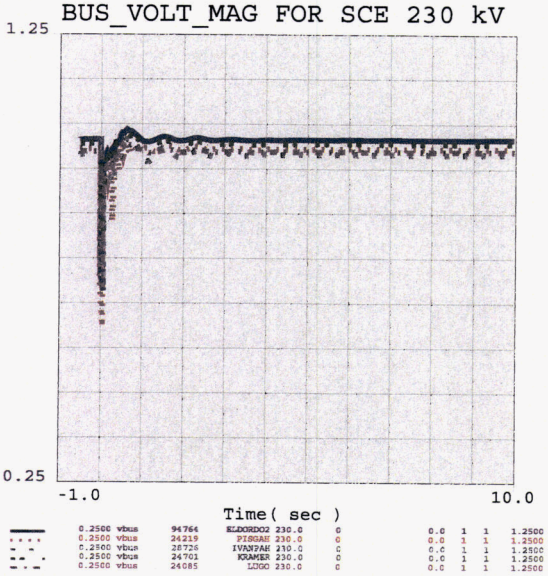
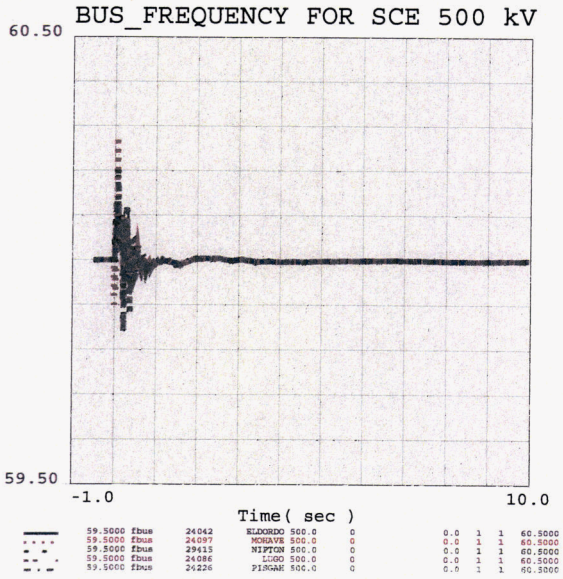
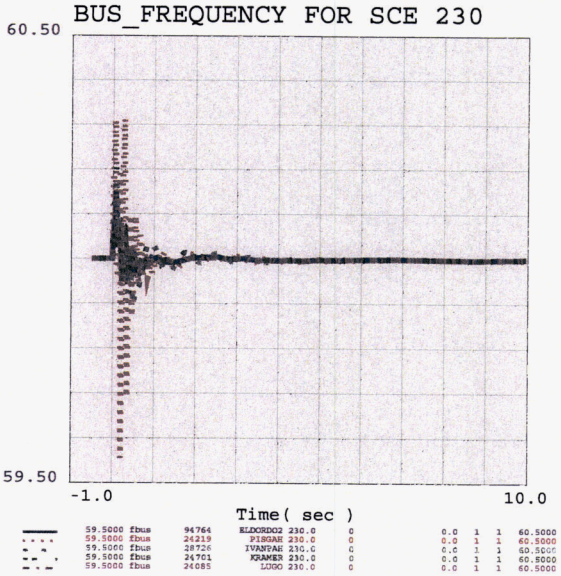
Mon Jun 06 13:50:21 2011

Stability Plots in SCE Area







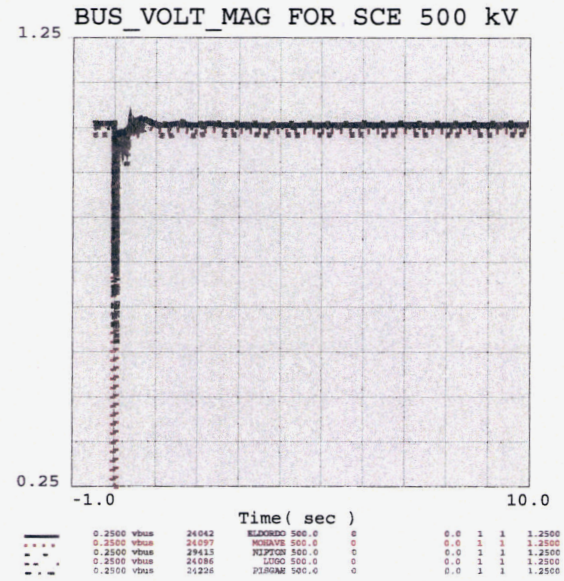


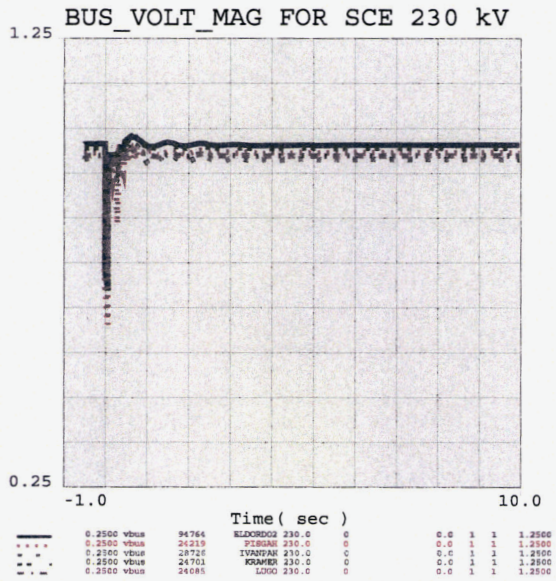
2014-hs-c1c2p2-eop-final-pst-loop1_Mohave-Lugo-slo
East of Pisgah Area

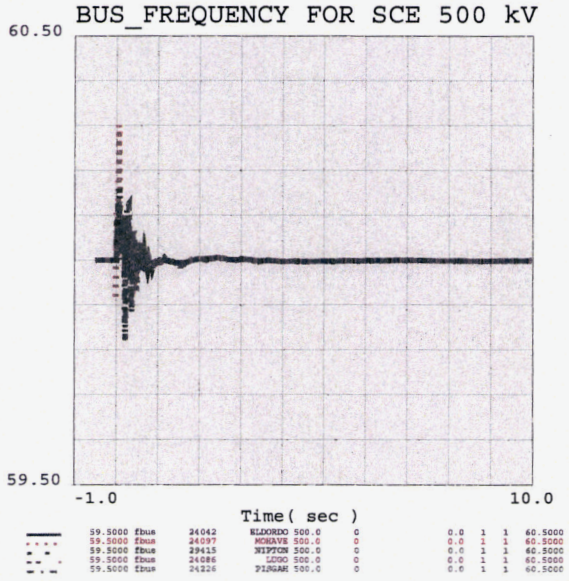
2014-hs-c1c2p2-eop-final-pst-loop1_Mohave-Lugo-slo.chf

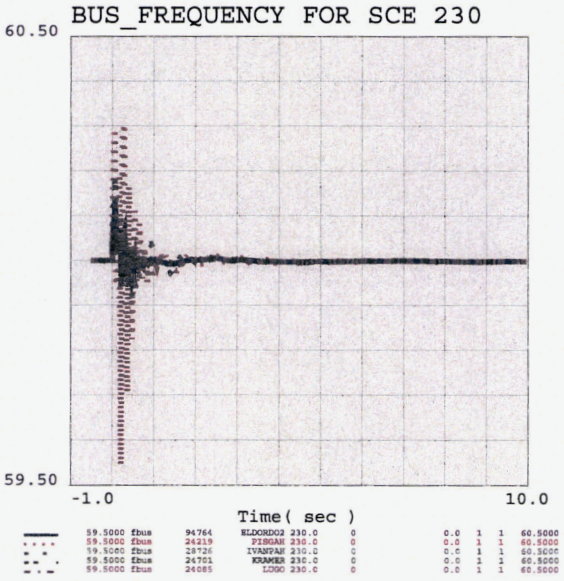
Mon Jun 06 13:50:44 2011

Stability Plots in SCE Area







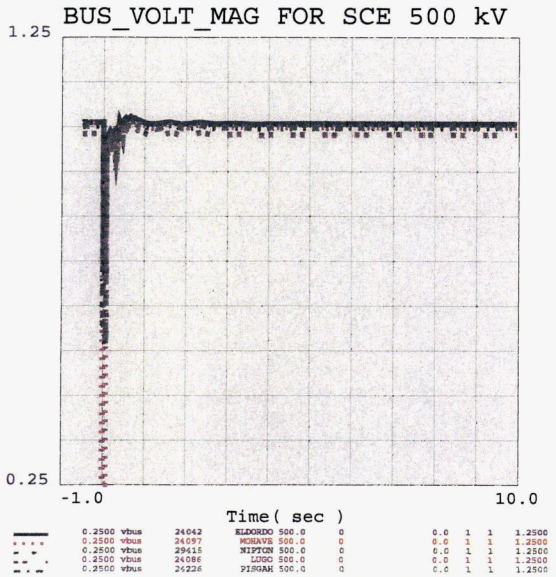


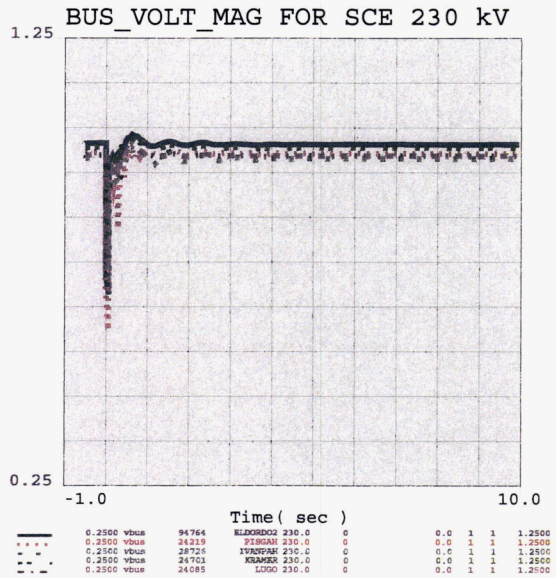
2014-hs-c1c2p2-eop-final-pst-loop1_Mohave-Homer-slo
East of Pisgah Area

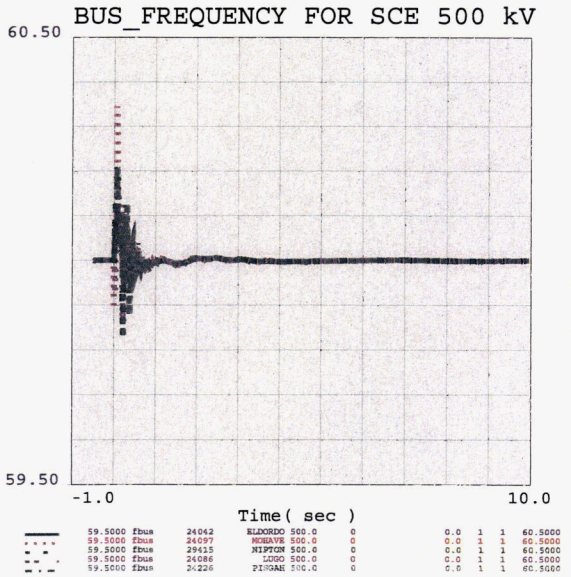
2014-hs-c1c2p2-eop-final-pst-loop1_Mohave-Homer-slo.chf

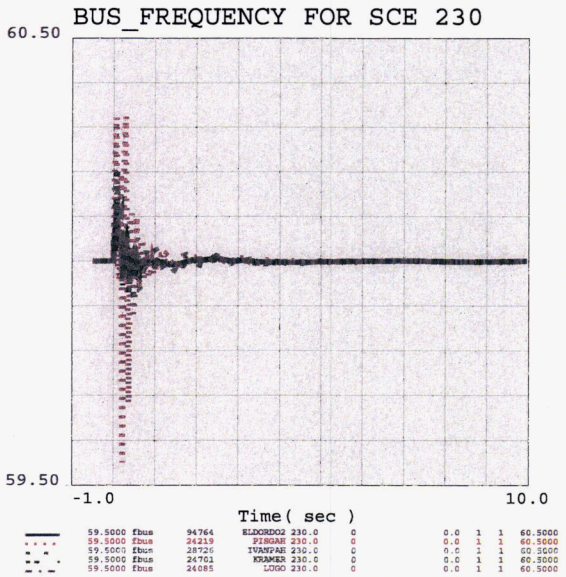
Mon Jun 06 13:50:39 2011

Stability Plots in SCE Area







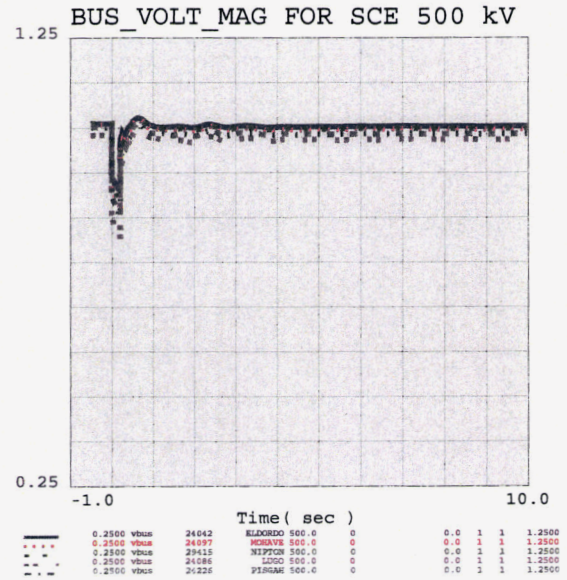


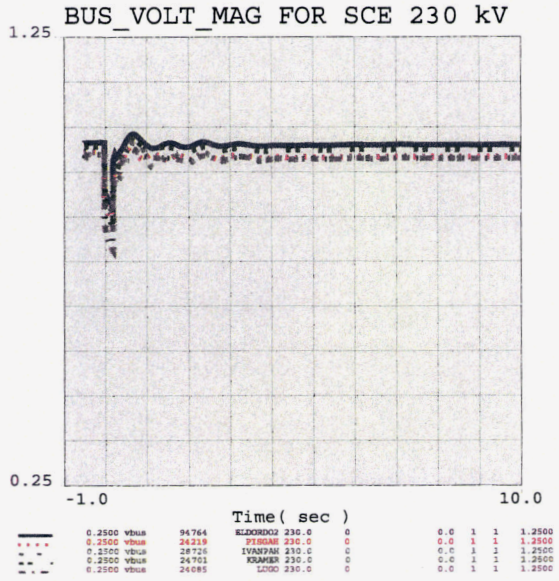
2014-hs-c1c2p2-eop-final-pst-loop1_Mohave-ElDorado-slo
East of Pisgah Area

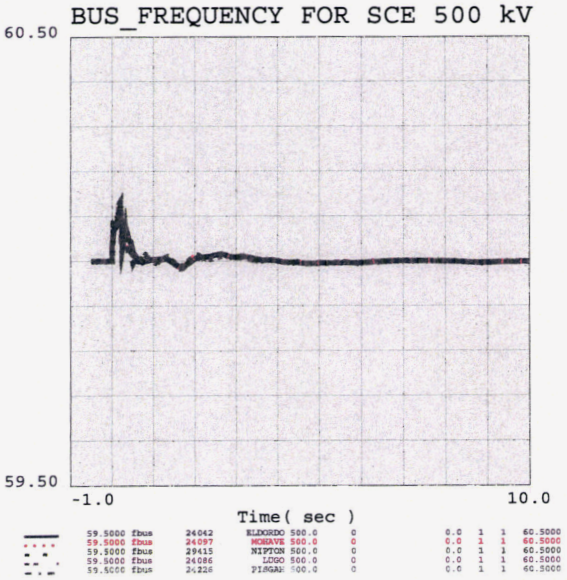
2014-hs-c1c2p2-eop-final-pst-loop1_Mohave-ElDorado-slo.chf

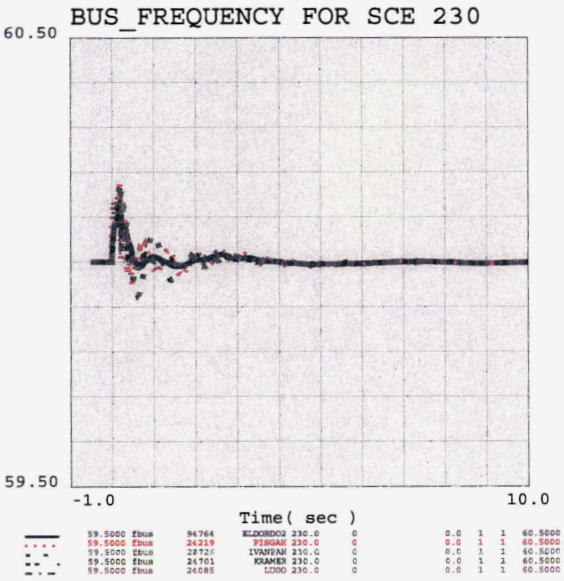
Mon Jun 06 13:50:33 2011

Stability Plots in SCE Area









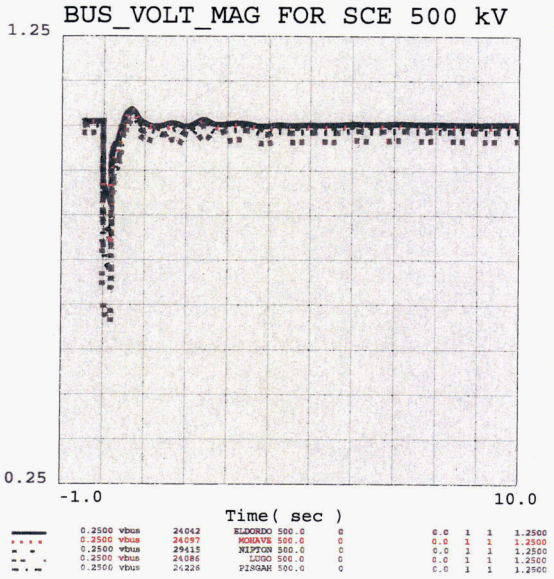
2014-hs-c1c2p2-eop-final-pst-loop1_McCullgh-Victorvl-dlo-slg
East of Pisgah Area

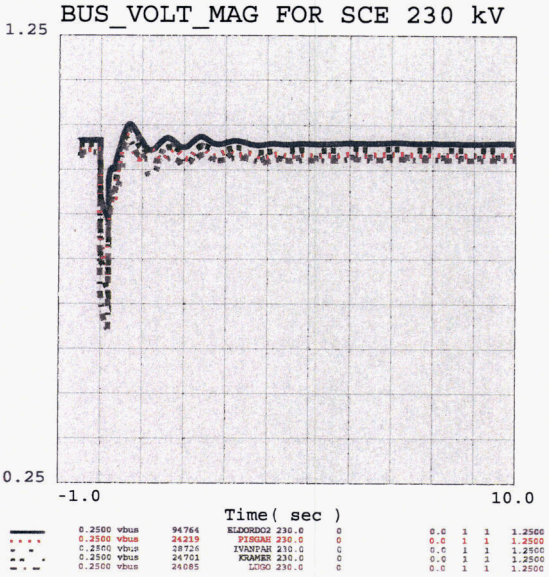
2014-hs-c1c2p2-eop-final-pst-loop1_McCullgh-Victorvl-dlo-slg.chf

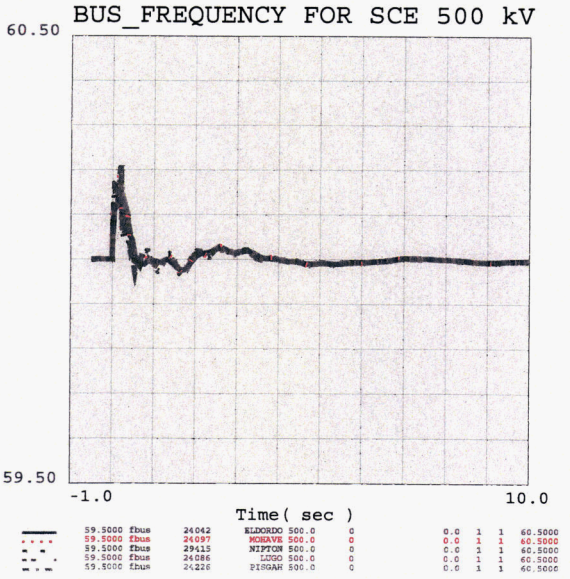
.

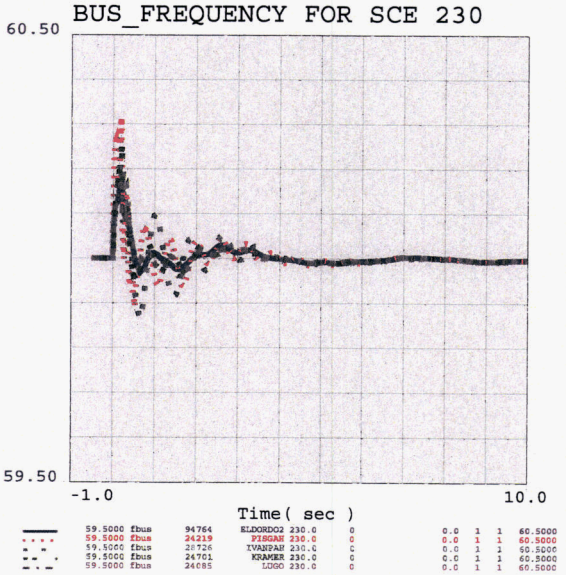
Mon Jun 06 13:50:28 2011

Stability Plots in SCE Area







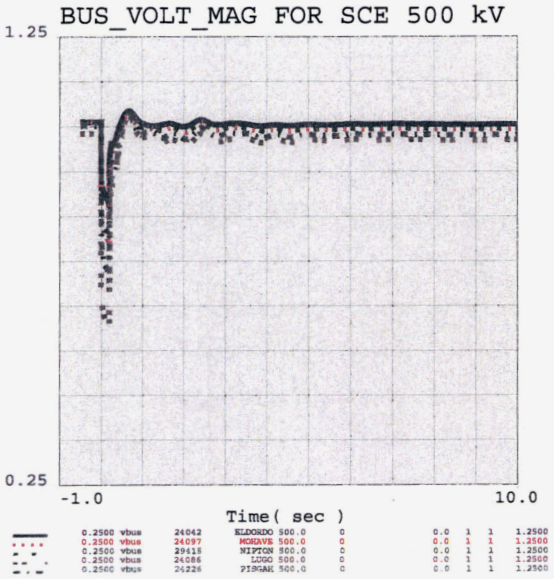


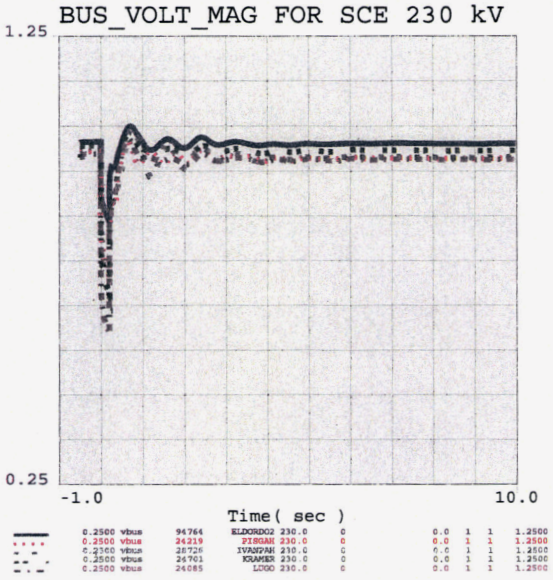
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Vincent-dlo-slg
East of Pisgah Area

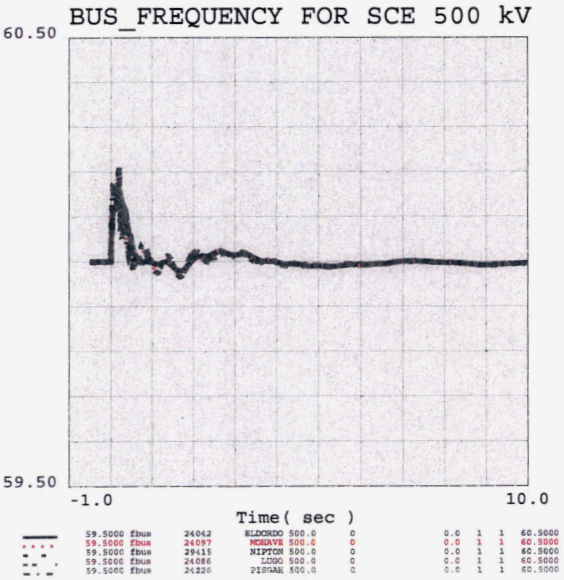
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Vincent-dlo-slg.chf

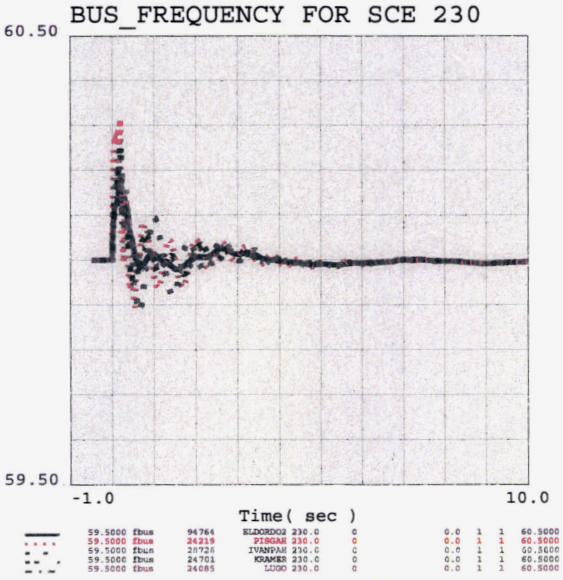
Mon Jun 06 13:50:16 2011

Stability Plots in SCE Area







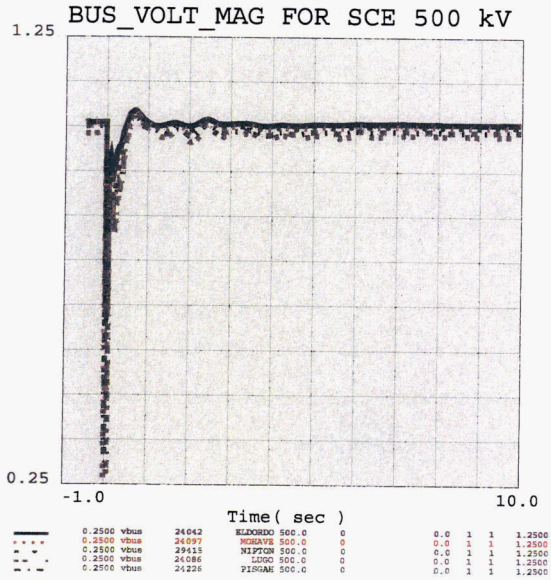


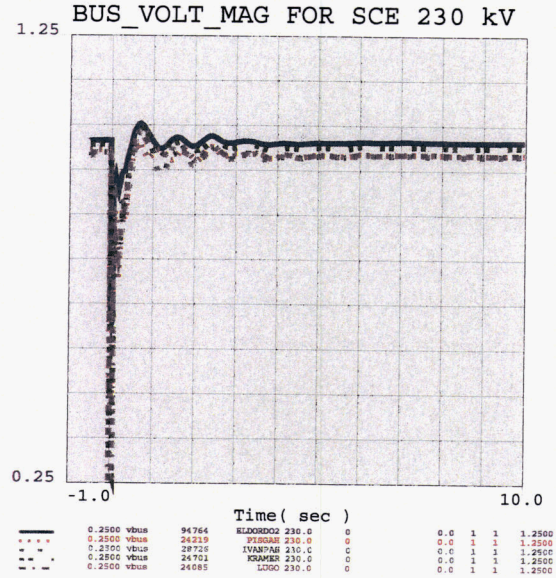
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-VicVin2-dlo-slg
East of Pisgah Area

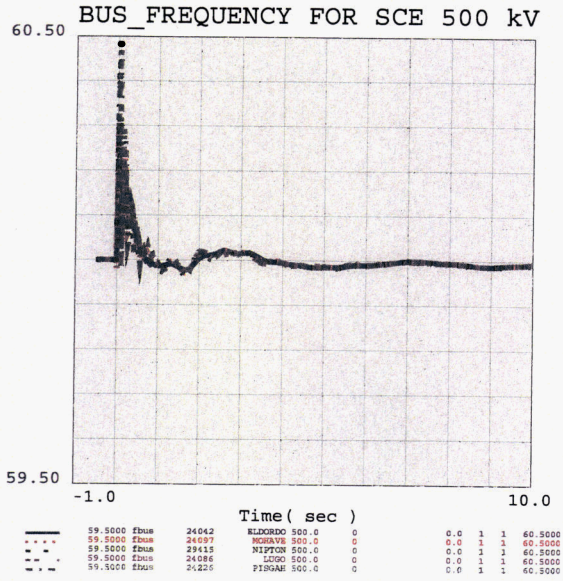
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-VicVin2-dlo-slg.chf

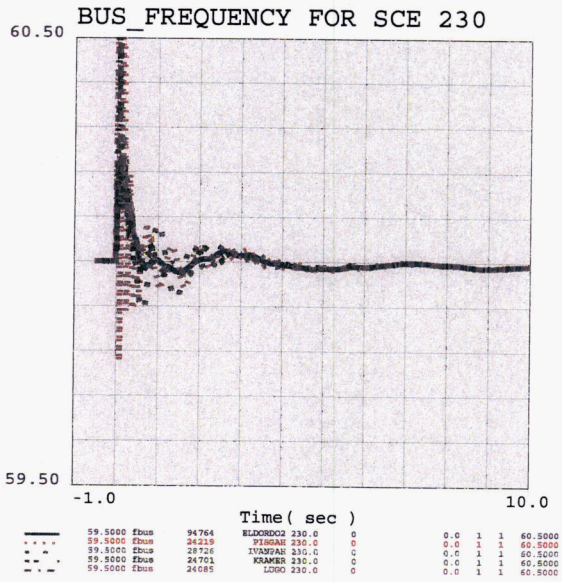
Mon Jun 06 13:50:04 2011

Stability Plots in SCE Area







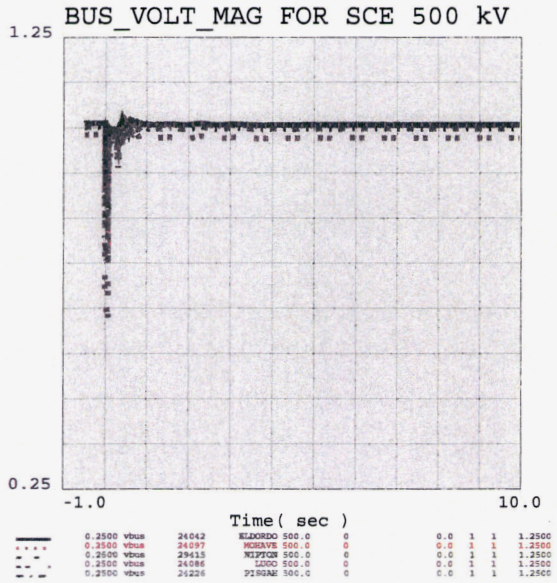


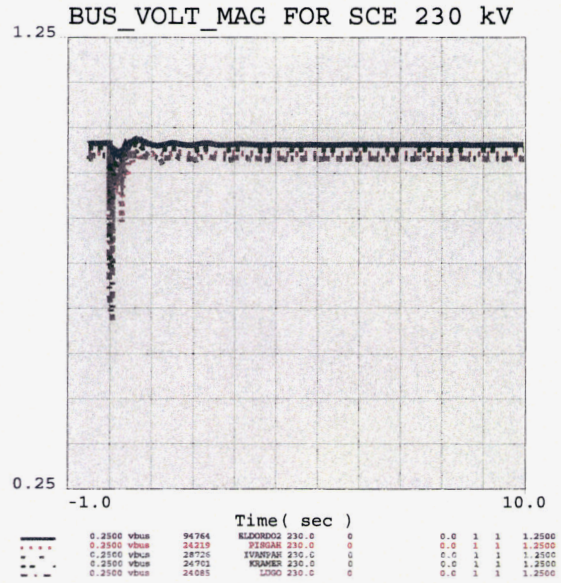
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Victvl-slo
East of Pisgah Area

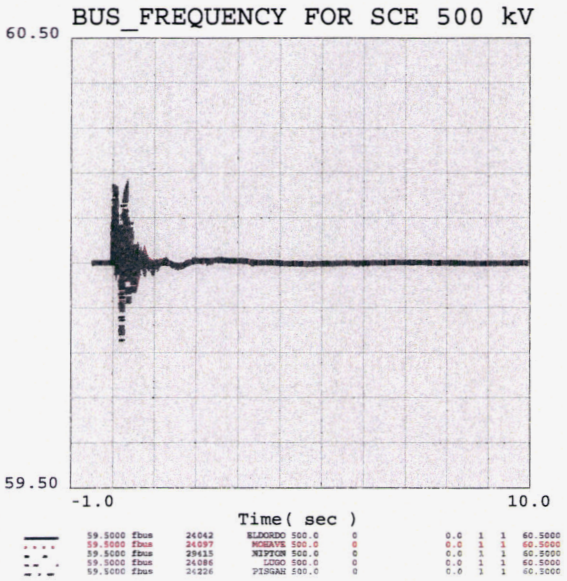
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Victvl-slo.chf

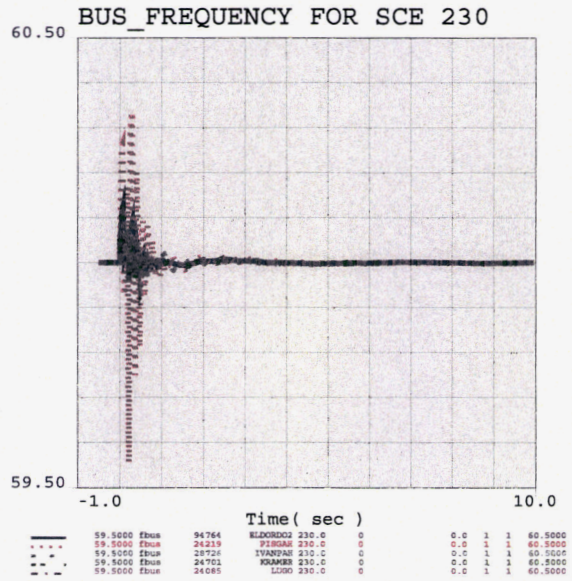
Mon Jun 06 13:50:09 2011

Stability Plots in SCE Area







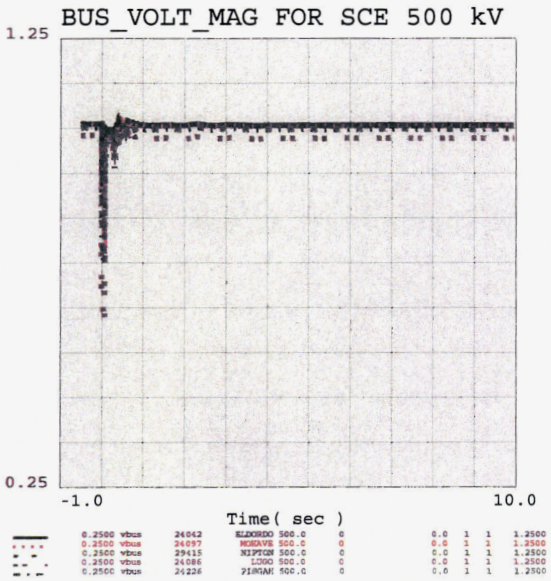


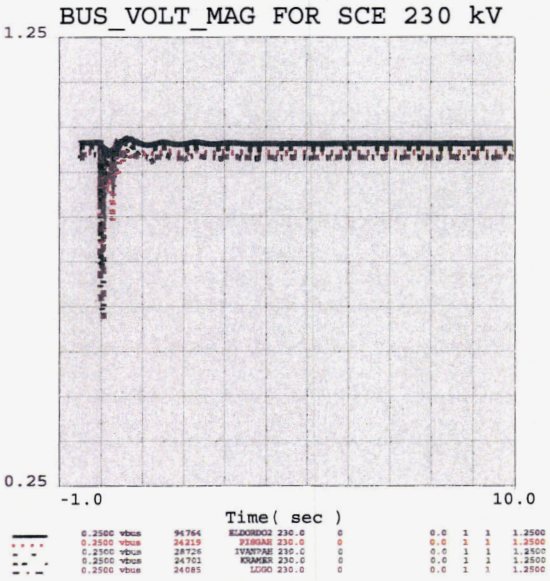
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-PisMoh-dlo-slg
East of Pisgah Area

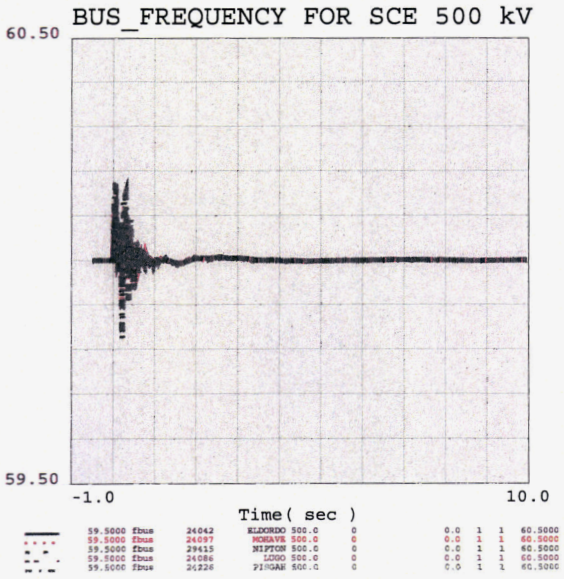
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-PisMoh-dlo-slg.chf

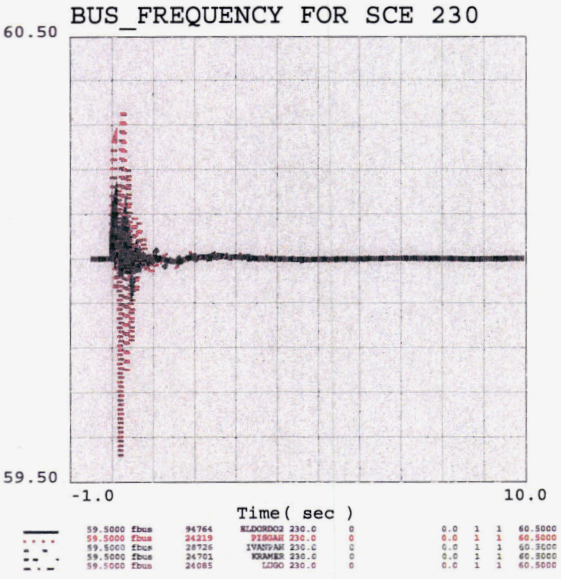
Mon Jun 06 13:49:42 2011

Stability Plots in SCE Area







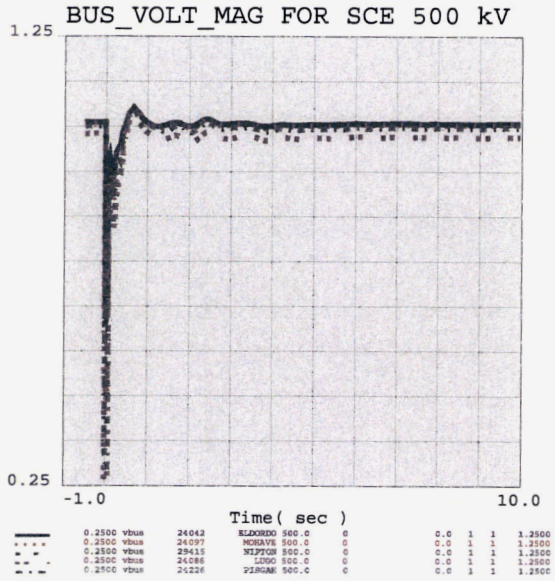


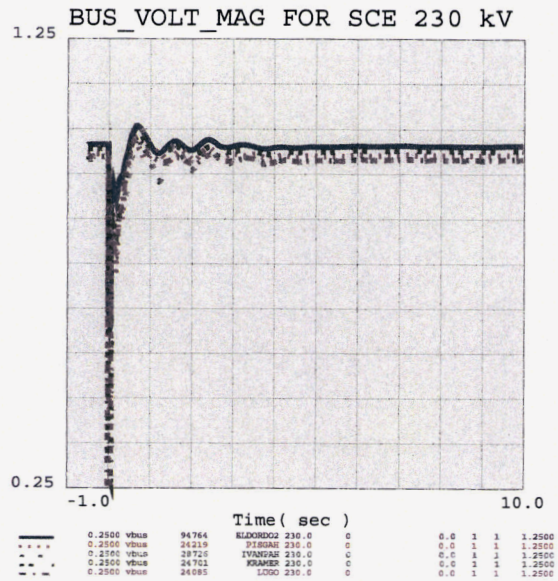
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-PisHom-dlo-slg
East of Pisgah Area

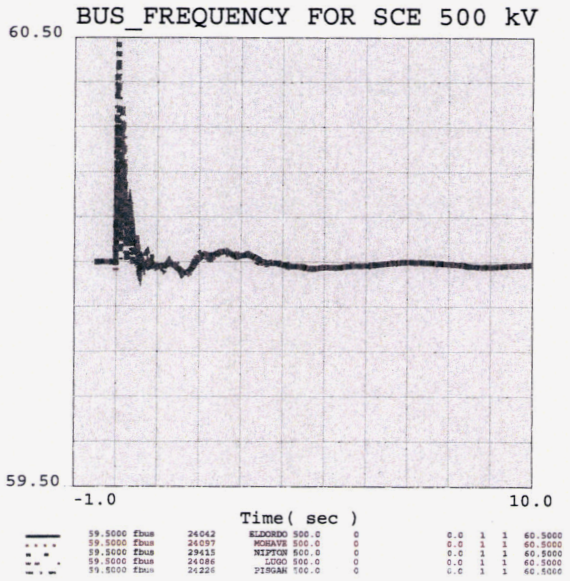
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-PisHom-dlo-slg.chf

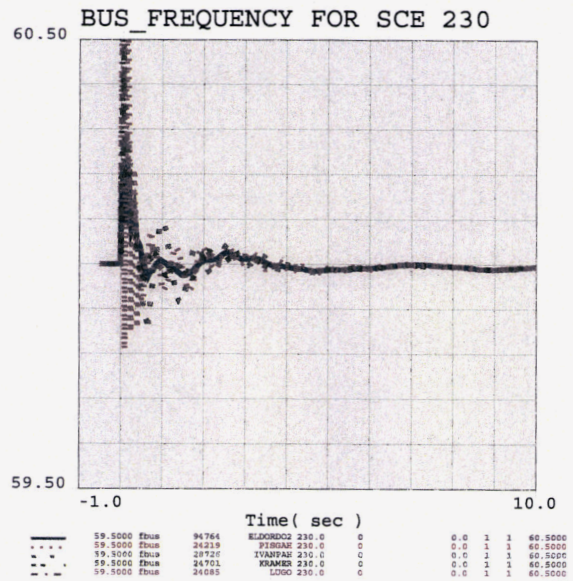
Mon Jun 06 13:49:34 2011

Stability Plots in SCE Area









2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Pisgah500-slo
East of Pisgah Area

2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Pisgah500-slo.chf

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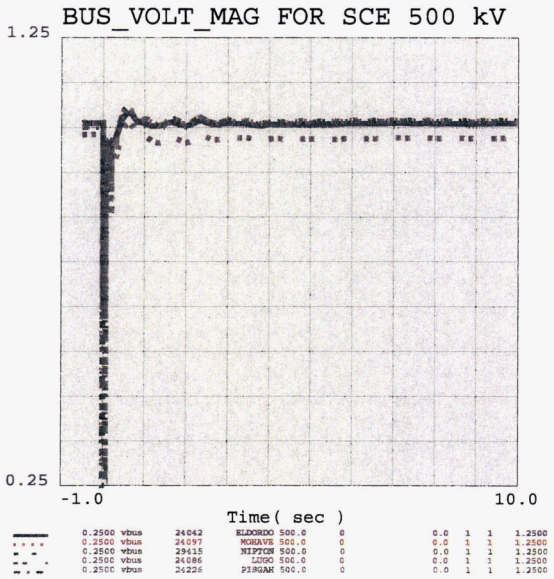
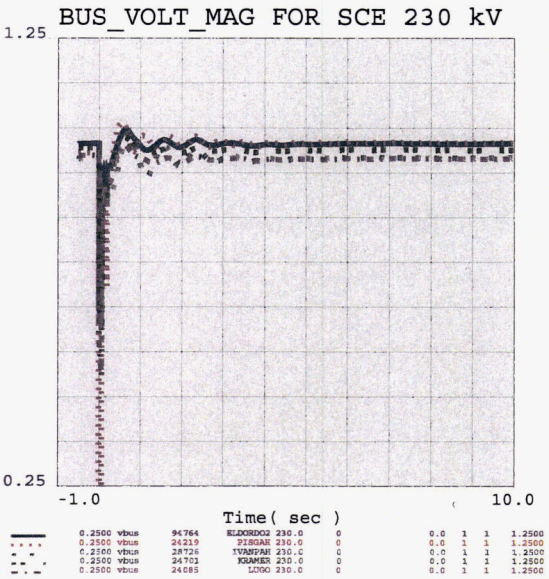
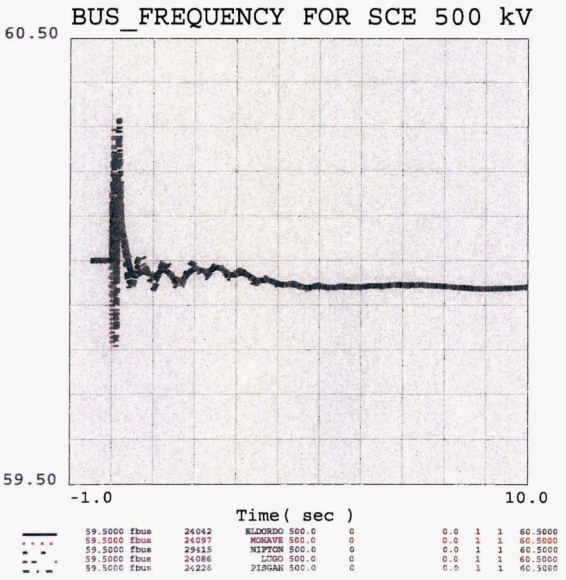
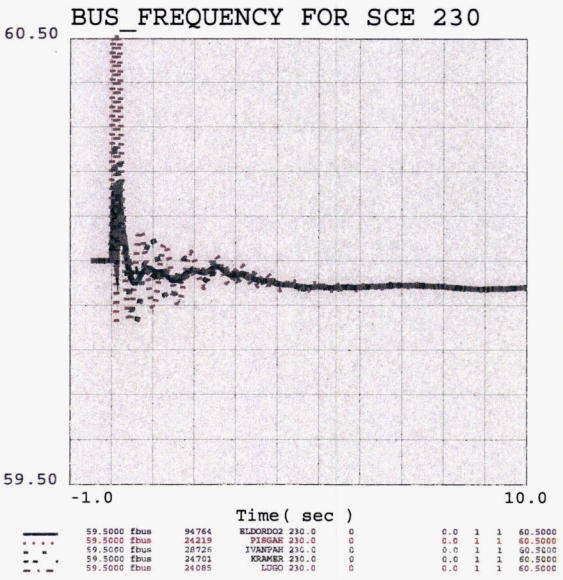
Mon Jun 06 13:49:57 2011

Stability Plots in SCE Area







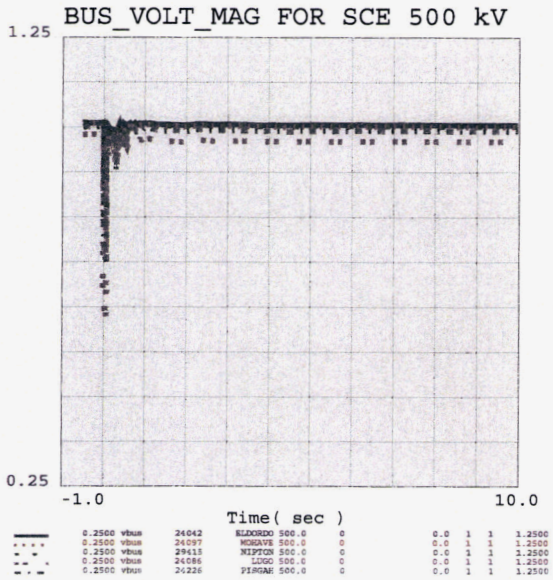


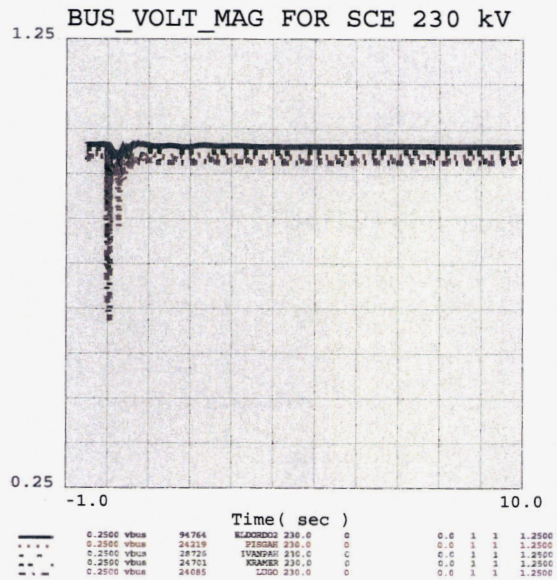
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Pisgah500-dlo-slg-SPS
East of Pisgah Area

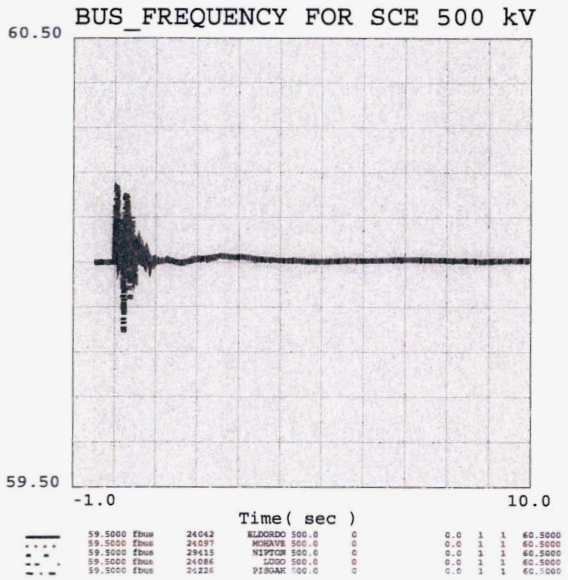
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Pisgah500-dlo-slg-SPS.chf

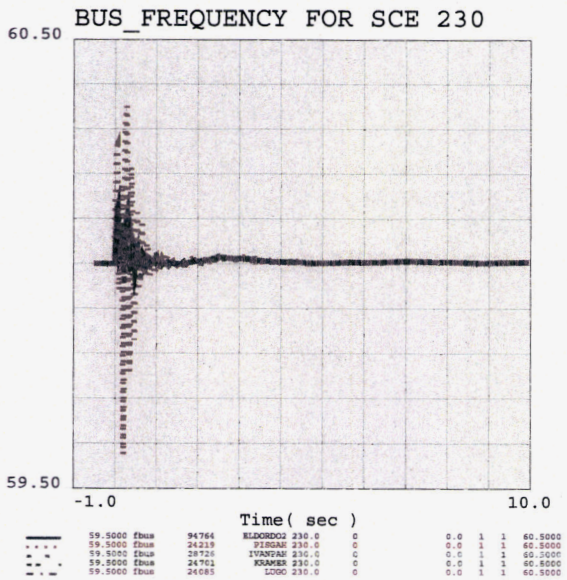
Mon Jun 06 13:49:49 2011

Stability Plots in SCE Area









2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Miraloma23-dlo-slg
East of Pisgah Area

2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Miraloma23-dlo-slg.chf

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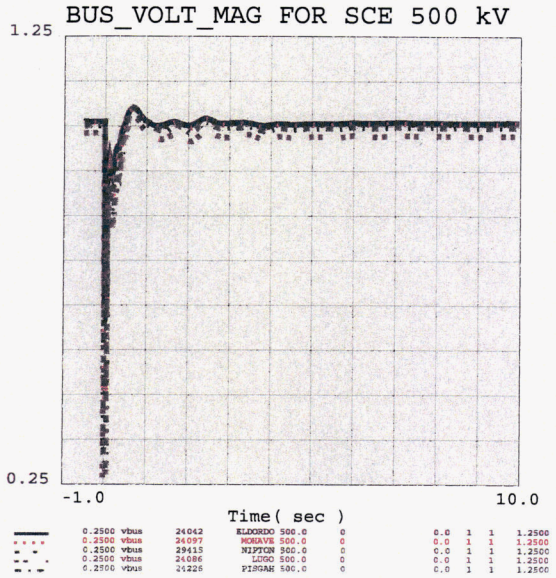
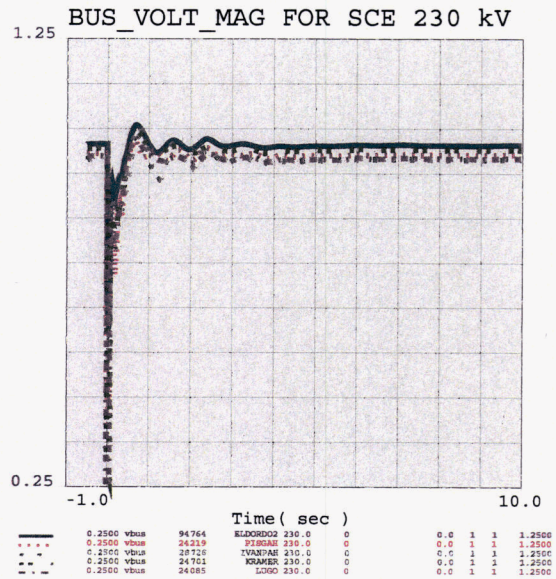
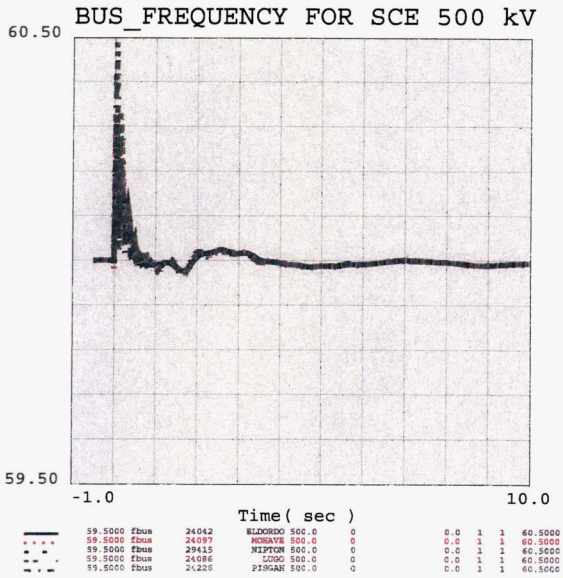
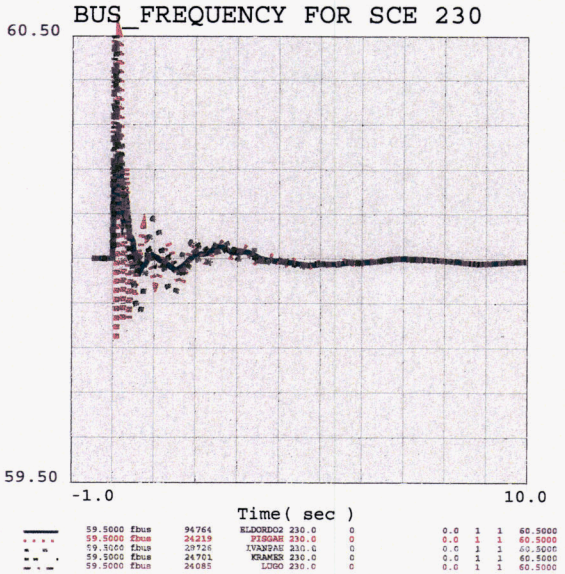
Mon Jun 06 13:49:29 2011

Stability Plots in SCE Area







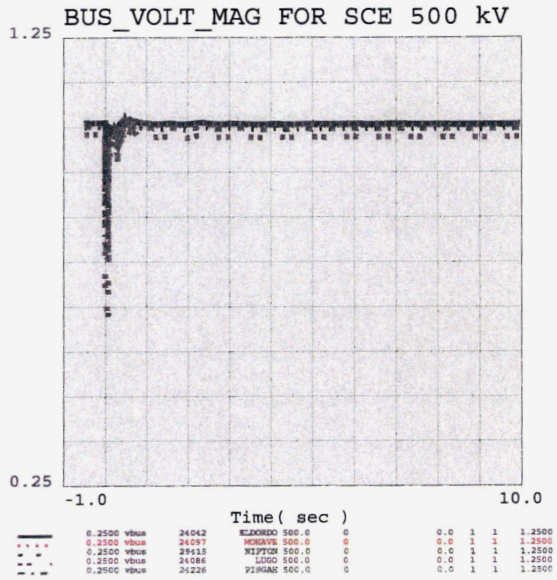


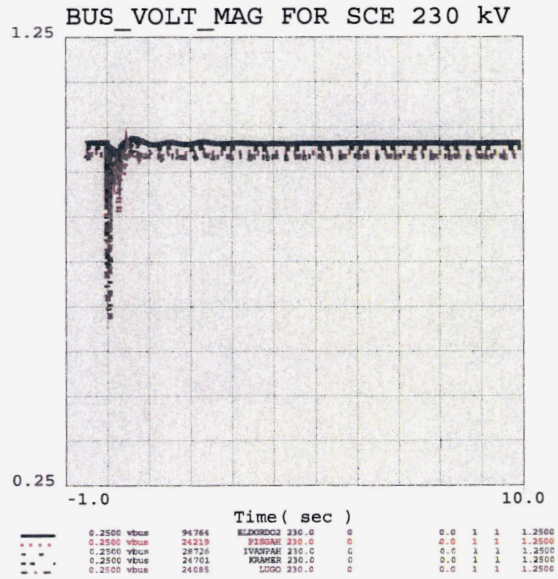
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Miraloma2-slo
East of Pisgah Area

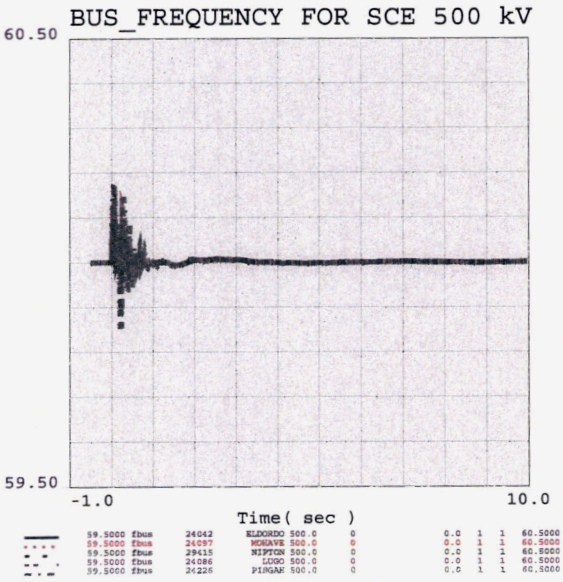
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Miraloma2-slo.chf

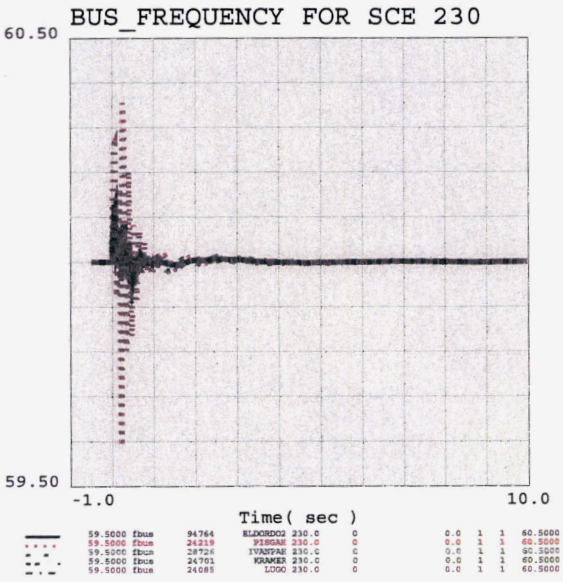
Mon Jun 06 13:49:21 2011

Stability Plots in SCE Area







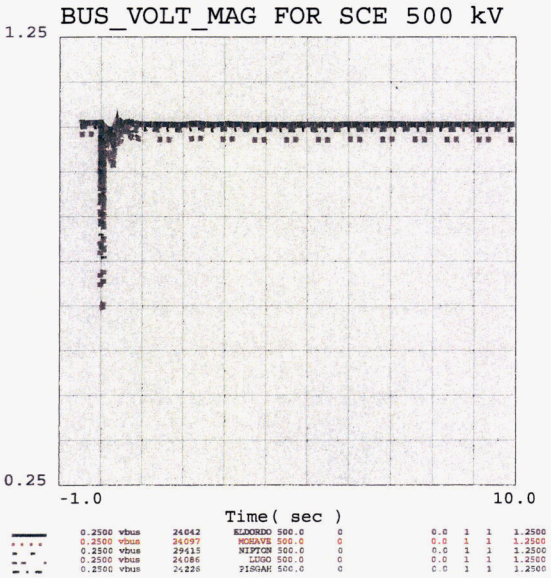


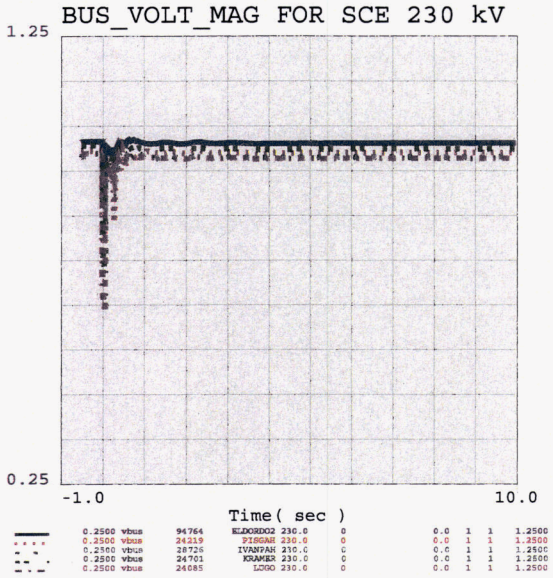
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Mir3Hom-dlo-slg
East of Pisgah Area

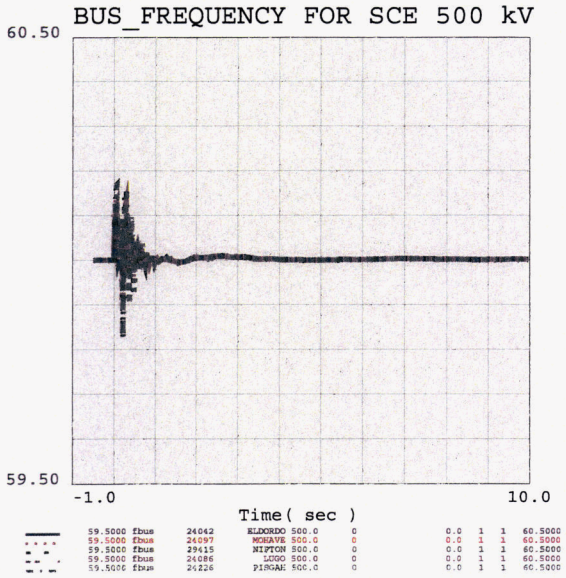
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Mir3Hom-dlo-slg.chf

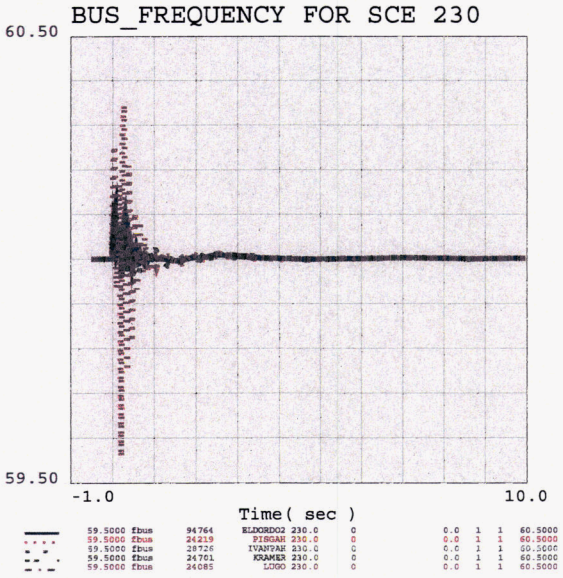
Mon Jun 06 13:49:16 2011

Stability Plots in SCE Area







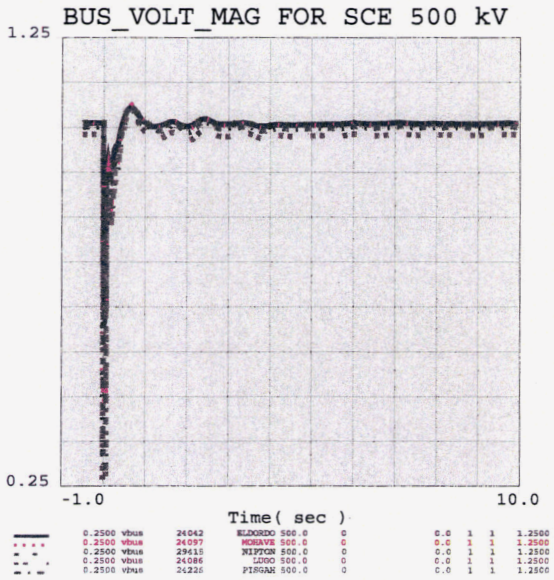


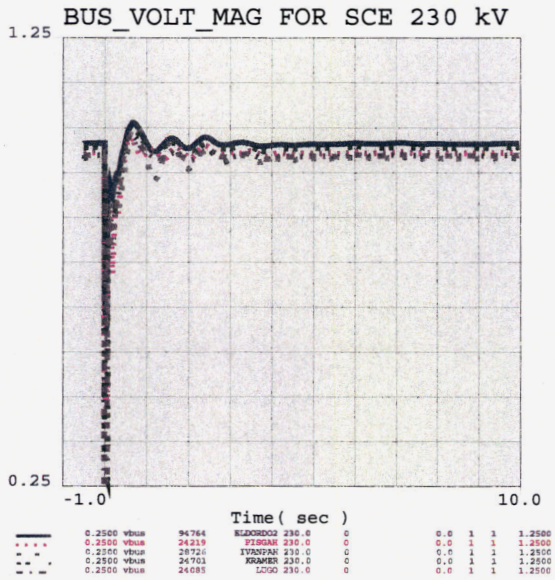
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Mir2Pis-dlo-slg
East of Pisgah Area

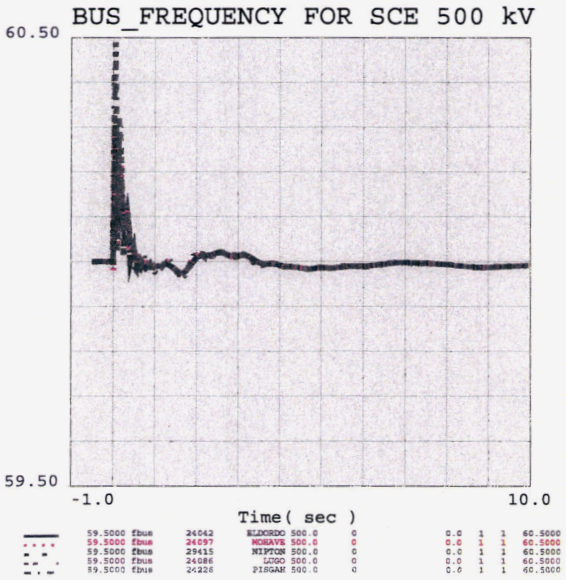
2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Mir2Pis-dlo-slg.chf

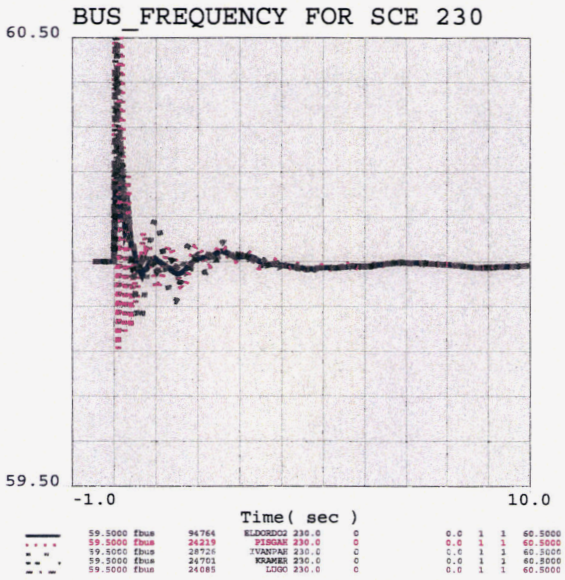
Mon Jun 06 13:49:11 2011

Stability Plots in SCE Area









2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Homer-slo
East of Pisgah Area

2014-hs-c1c2p2-eop-final-pst-loop1_Lugo-Homer-slo.chf

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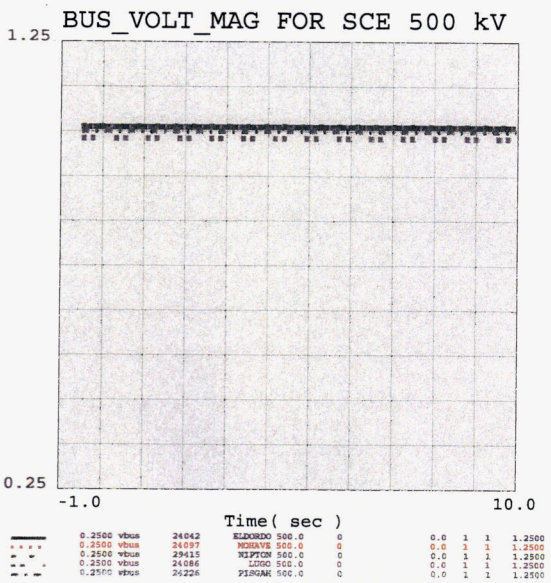
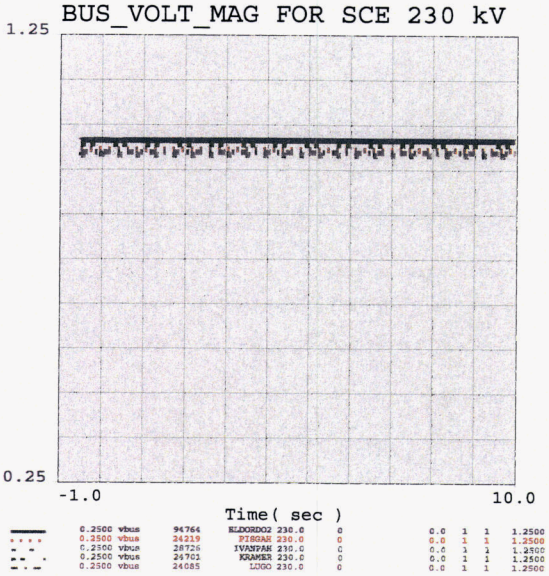
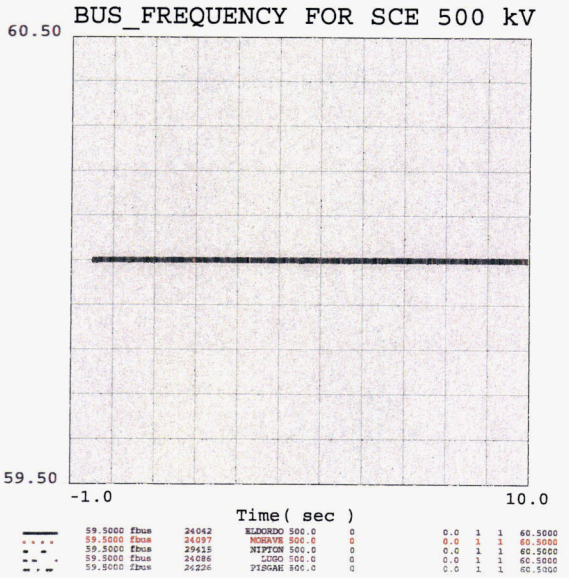
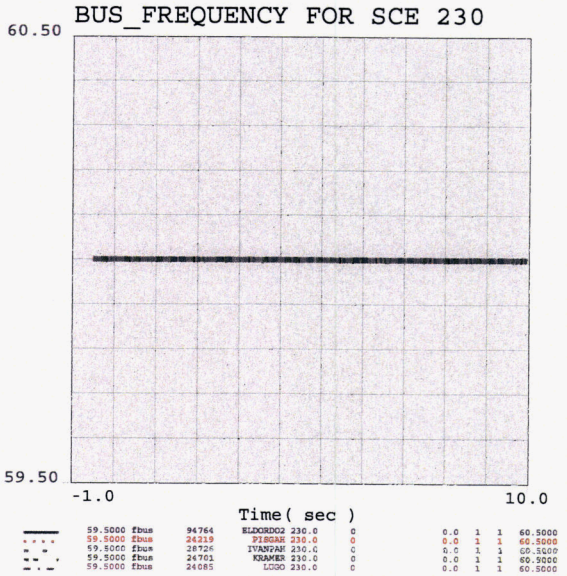
Mon Jun 06 13:49:05 2011

Stability Plots in SCE Area







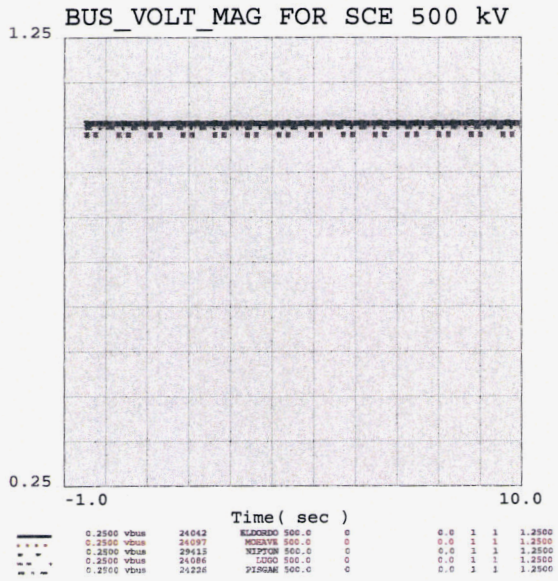


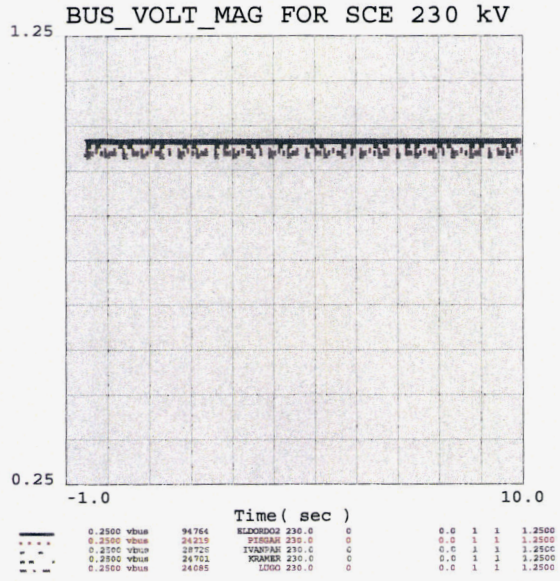
2014-hs-c1c2p2-eop-final-pst-loop1_Llano-Vincent-slo
East of Pisgah Area

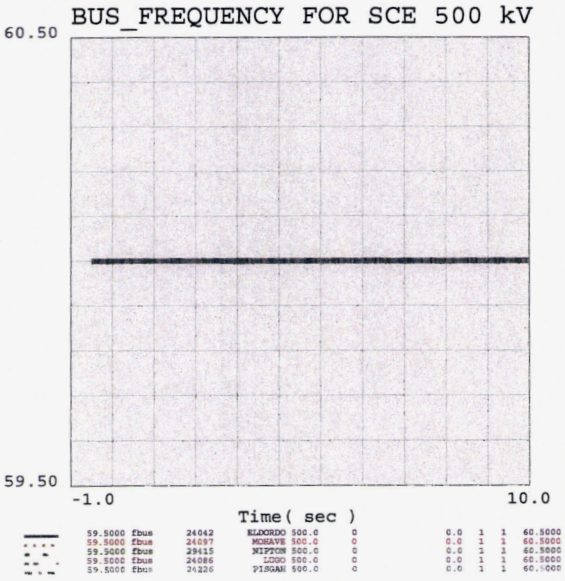
2014-hs-c1c2p2-eop-final-pst-loop1_Llano-Vincent-slo.chf

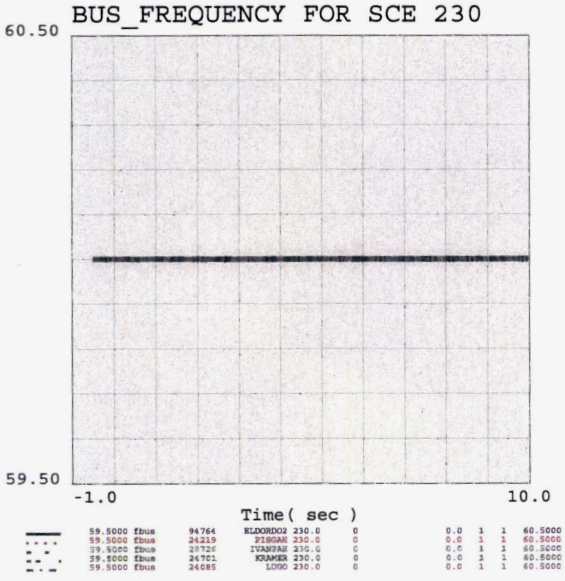
Mon Jun 06 13:48:59 2011

Stability Plots in SCE Area







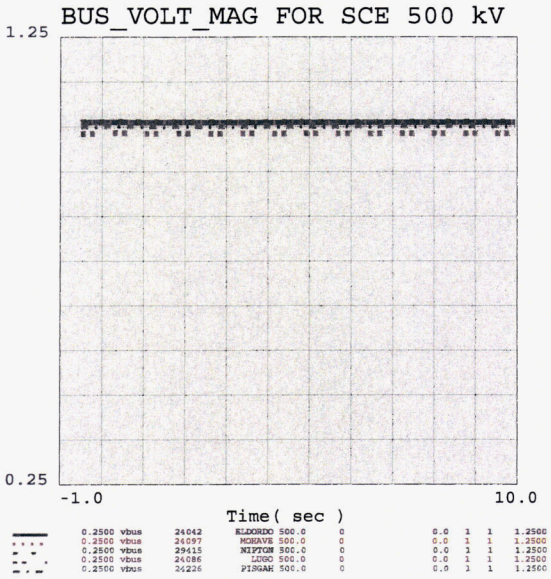


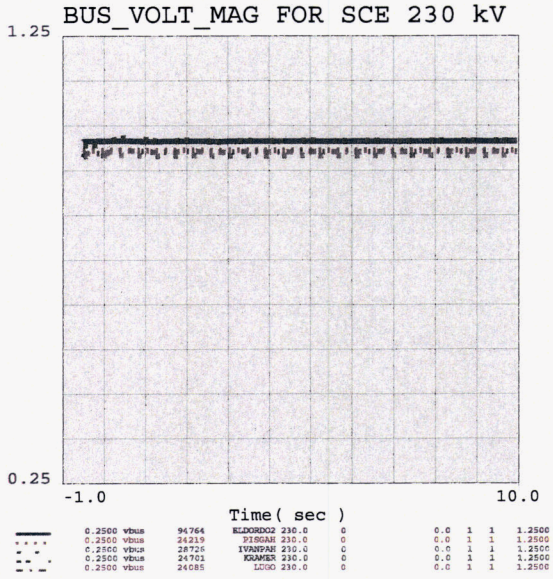
2014-hs-c1c2p2-eop-final-pst-loop1_Llano-Lugo-slo
East of Pisgah Area

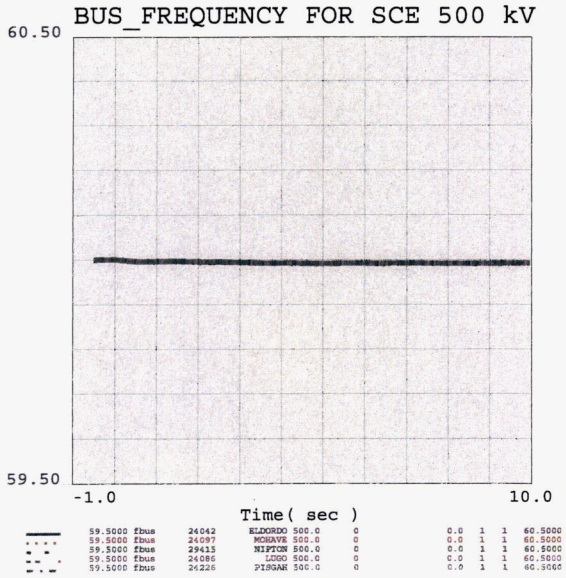
2014-hs-c1c2p2-eop-final-pst-loop1_Llano-Lugo-slo.chf

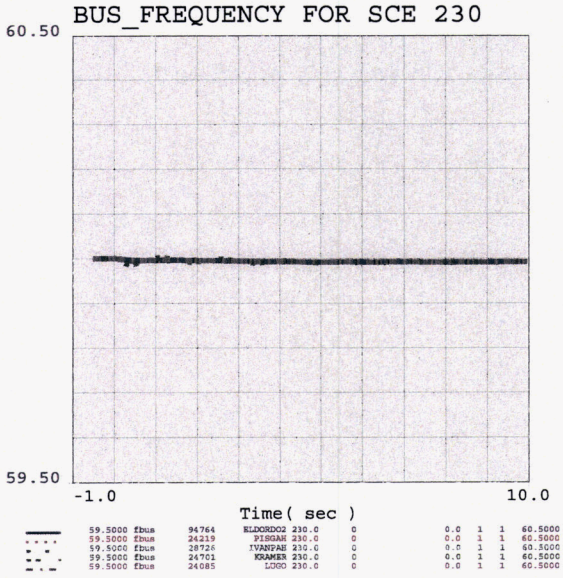
Mon Jun 06 13:48:54 2011

Stability Plots in SCE Area







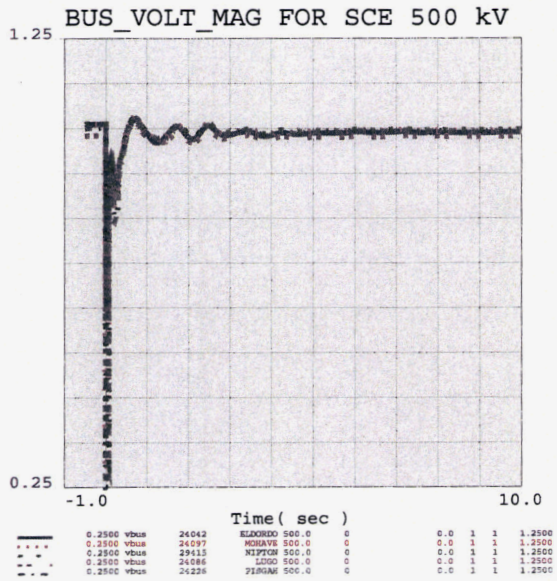


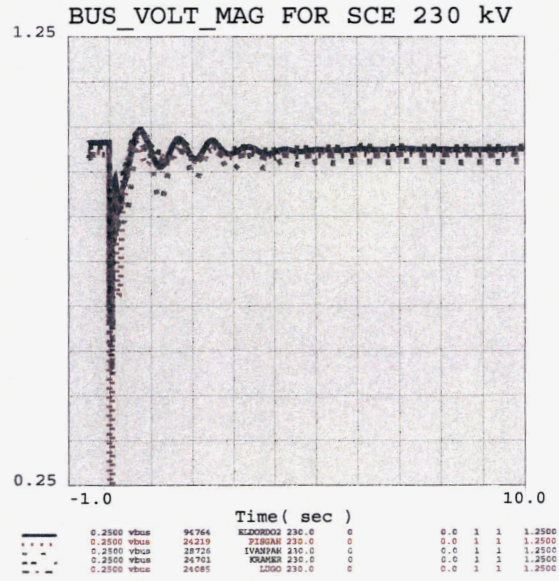
2014-hs-c1c2p2-eop-final-pst-loop1_Kramer-Llano-slo-SPS
East of Pisgah Area

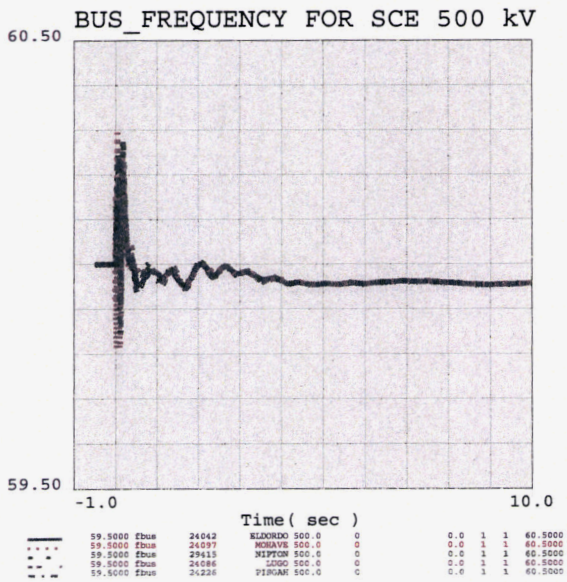
2014-hs-c1c2p2-eop-final-pst-loop1_Kramer-Llano-slo-SPS.chf

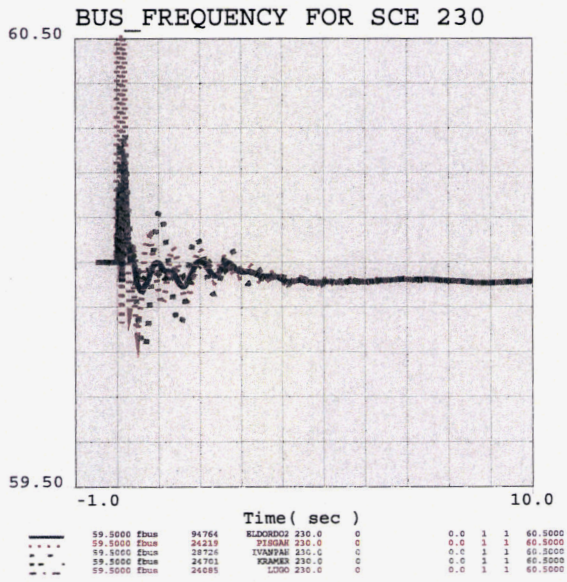
Mon Jun 06 13:48:49 2011

Stability Plots in SCE Area









2014-hs-c1c2p2-eop-final-pst-loop1_Eldrd-Mcllugh500-slo-SPS
East of Pisgah Area

2014-hs-c1c2p2-eop-final-pst-loop1_Eldrd-Mcllugh500-slo-SPS.chf

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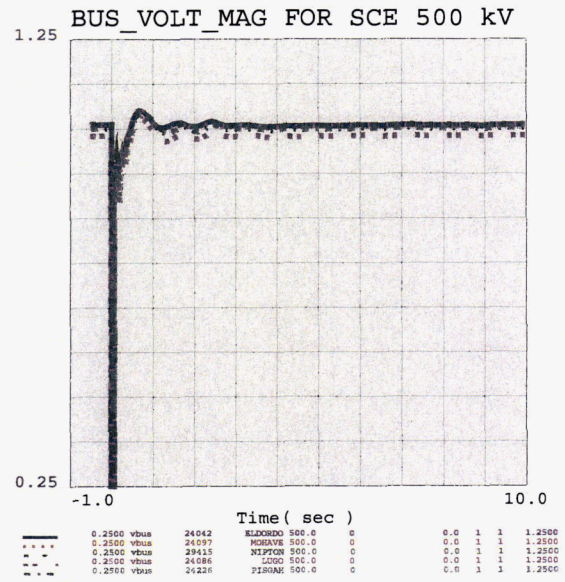
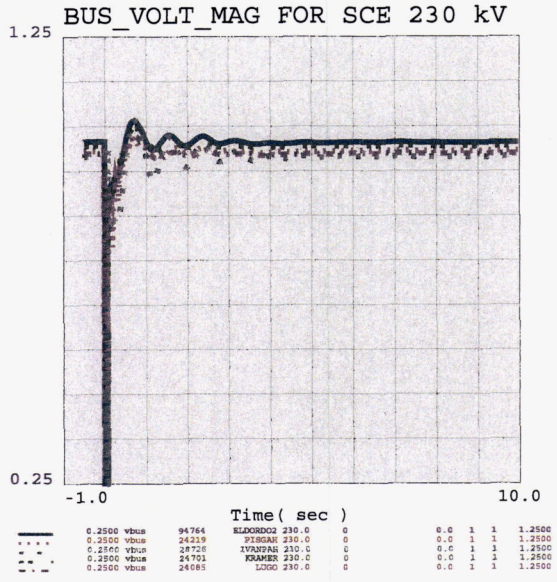
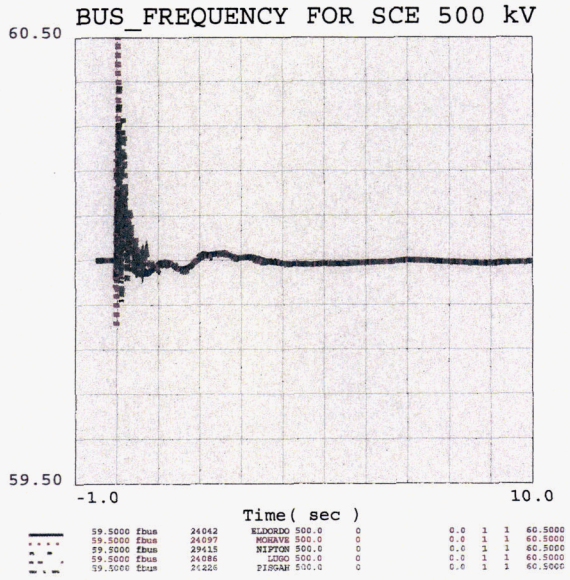
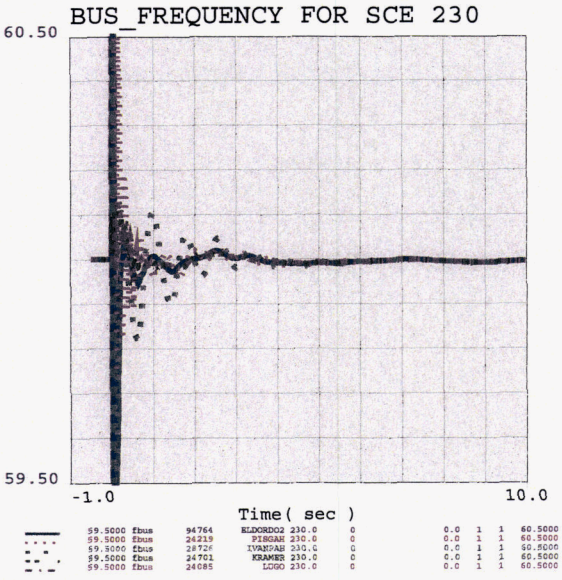
Mon Jun 06 13:48:43 2011

Stability Plots in SCE Area









2014-hs-c1c2p2-eop-final-pst-loop1_Eldorado-Nipton-slo
East of Pisgah Area

2014-hs-c1c2p2-eop-final-pst-loop1_Eldorado-Nipton-slo.chf

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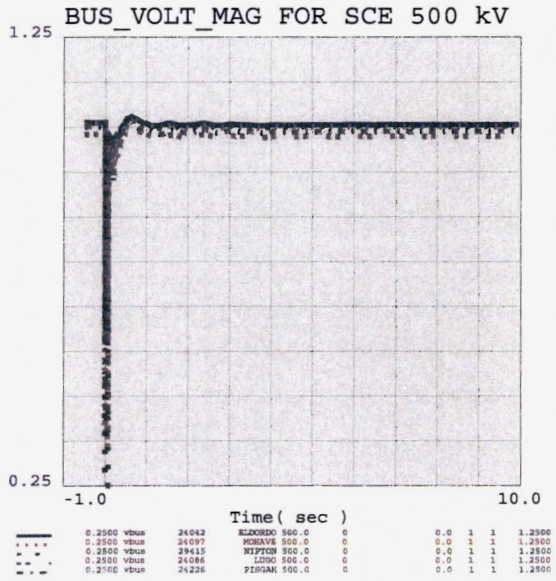
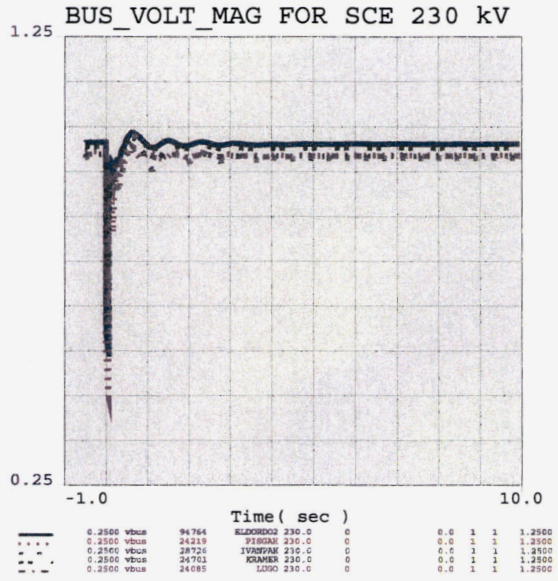
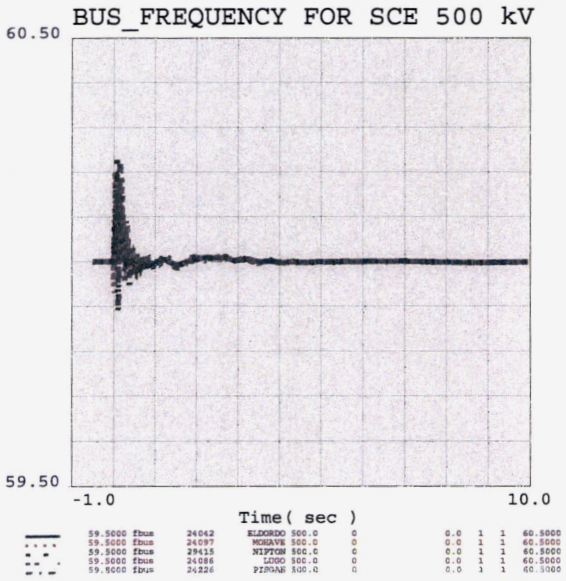
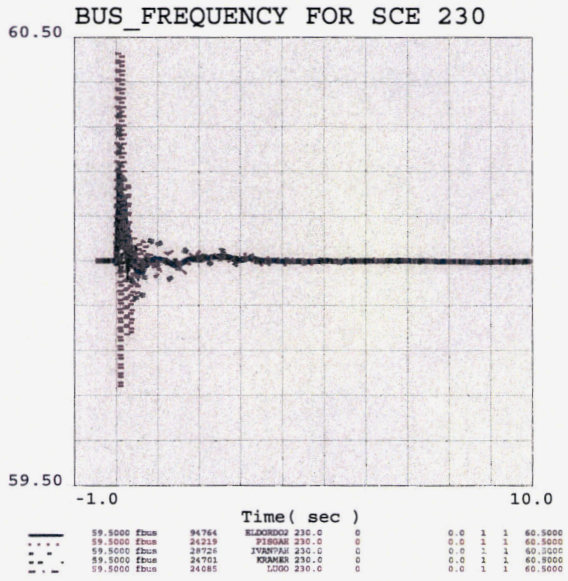
Mon Jun 06 13:48:37 2011

Stability Plots in SCE Area







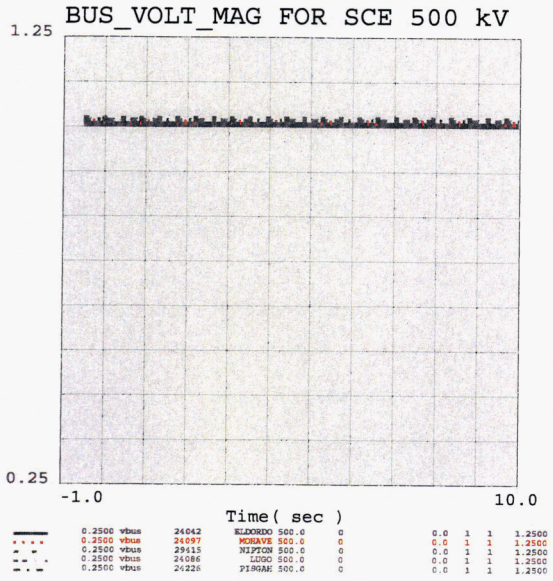


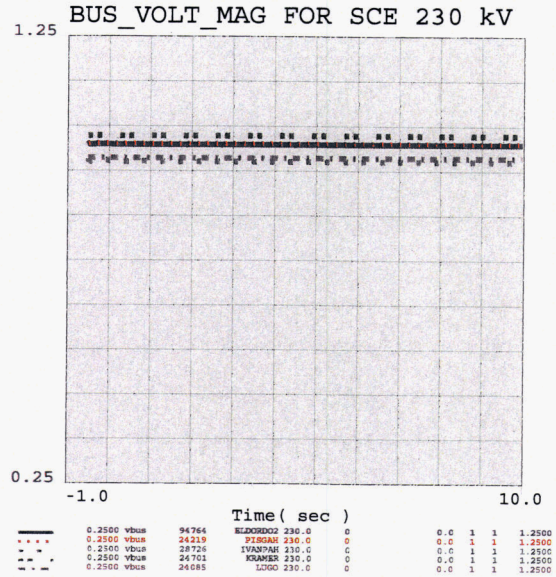
2014-hs-c1c2p2-eop-final-pst-loop1_Pisgah-Nipton-slo
East of Pisgah Area

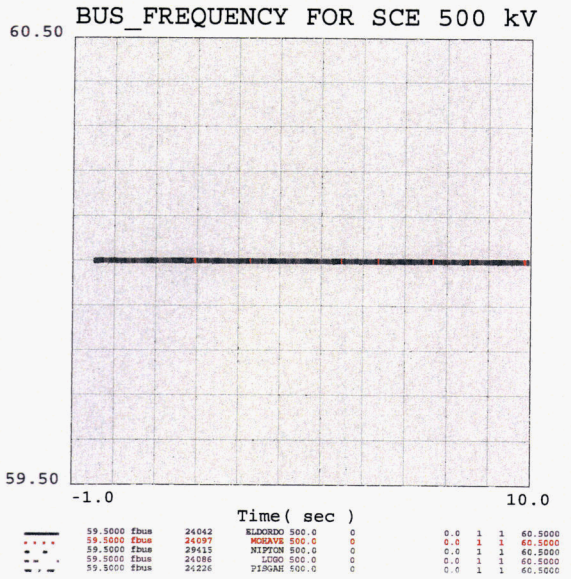
2014-hs-c1c2p2-eop-final-pst-loop1_Pisgah-Nipton-slo.chf

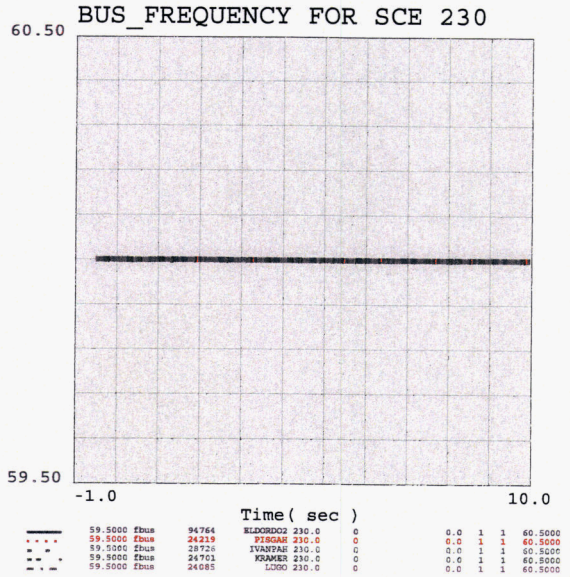
Mon Jun 06 13:50:55 2011

Stability Plots in SCE Area







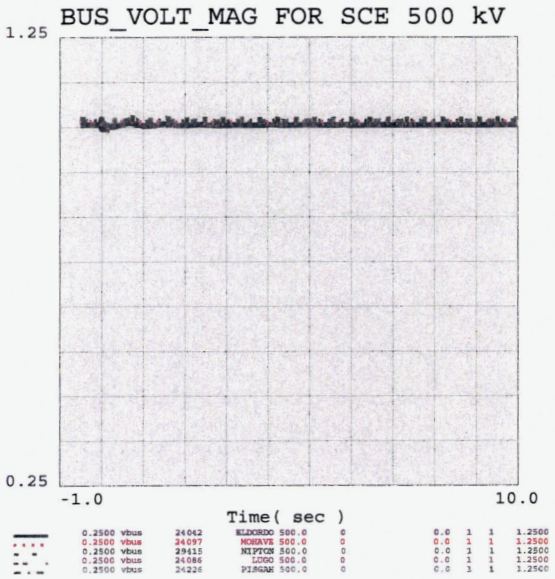


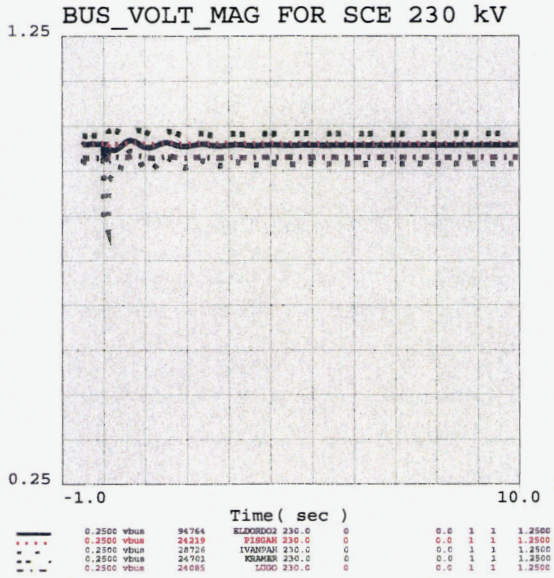
2014-ls-c1c2p2-eop-final-pst-loop1_No-fault
East of Pisgah Area

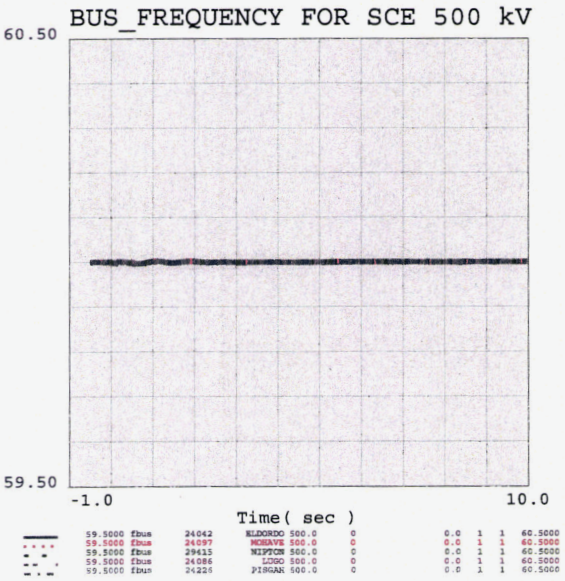
2014-ls-c1c2p2-eop-final-pst-loop1_No-fault.chf

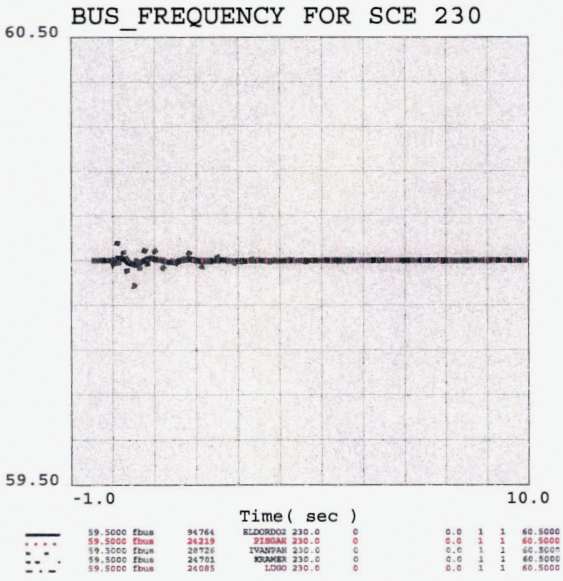
Mon Jun 06 13:55:57 2011

Stability Plots in SCE Area







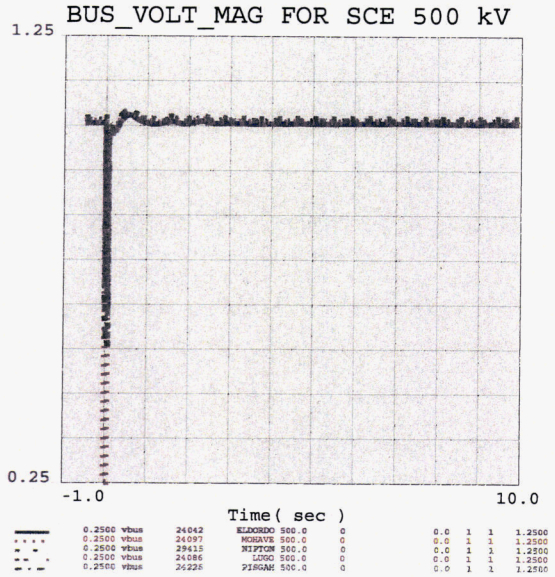


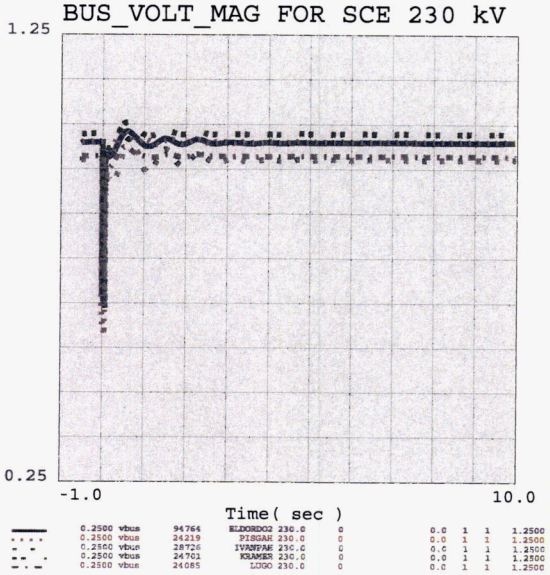
2014-ls-c1c2p2-eop-final-pst-loop1_MTPass-Ivapah115-slo
East of Pisgah Area

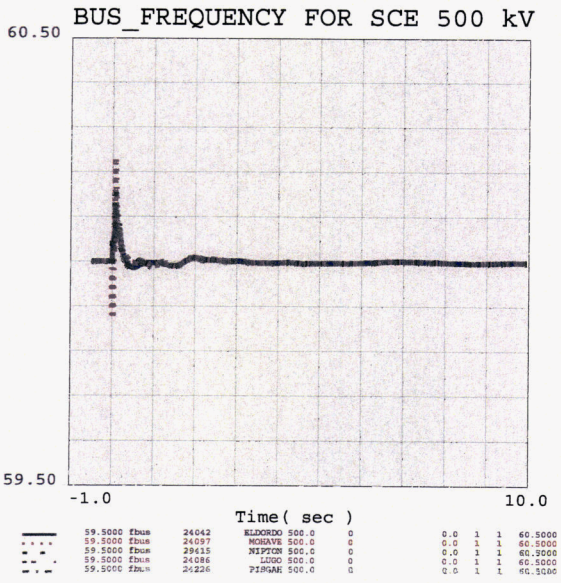
2014-ls-c1c2p2-eop-final-pst-loop1_MTPass-Ivapah115-slo.chf

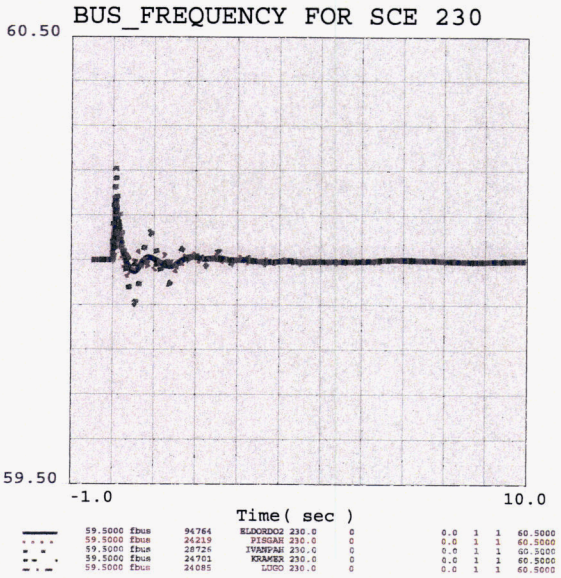
Mon Jun 06 13:55:31 2011

Stability Plots in SCE Area







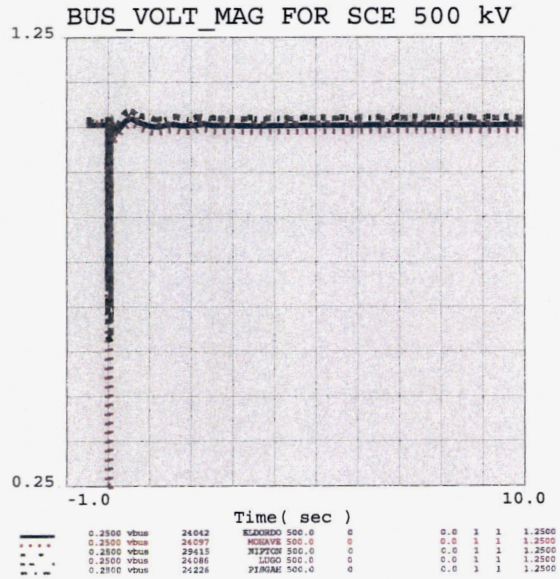


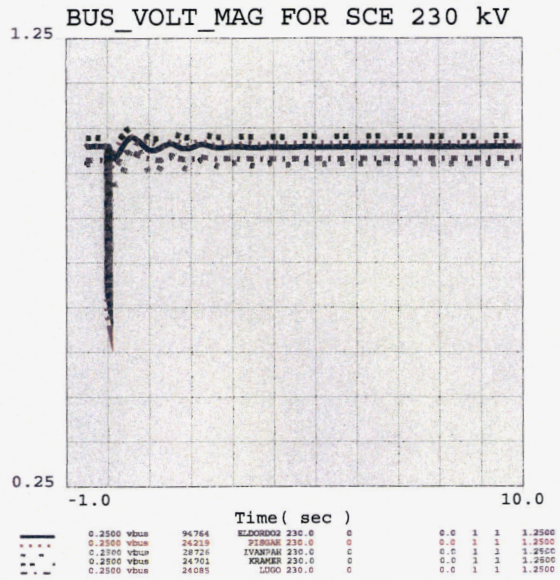
2014-ls-c1c2p2-eop-final-pst-loop1_Mohave-Lugo-slo
East of Pisgah Area

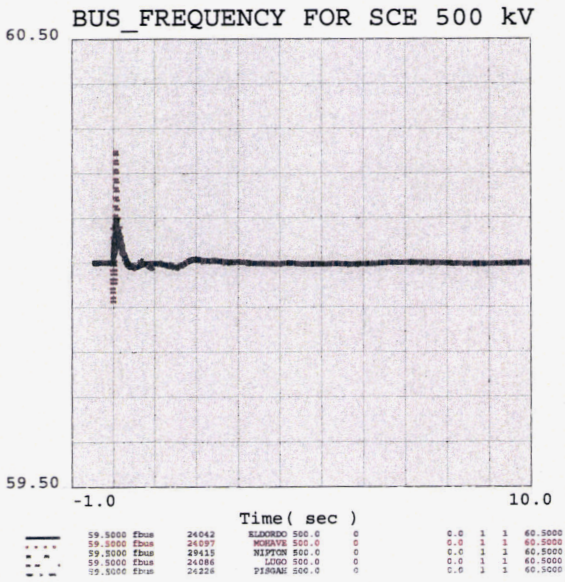
2014-ls-c1c2p2-eop-final-pst-loop1_Mohave-Lugo-slo.chf

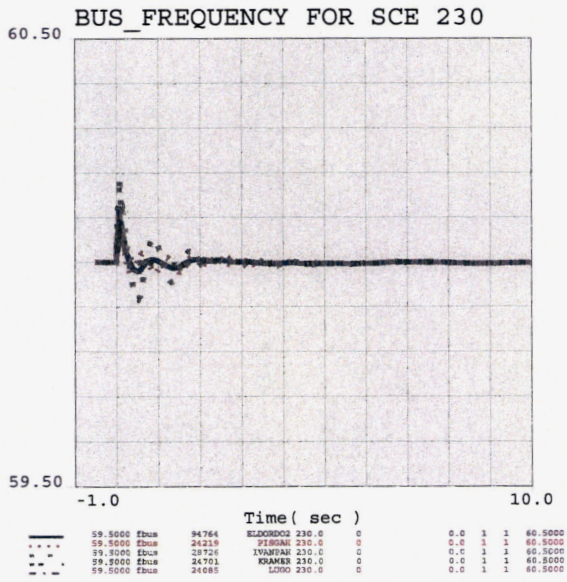
Mon Jun 06 13:55:52 2011

Stability Plots in SCE Area







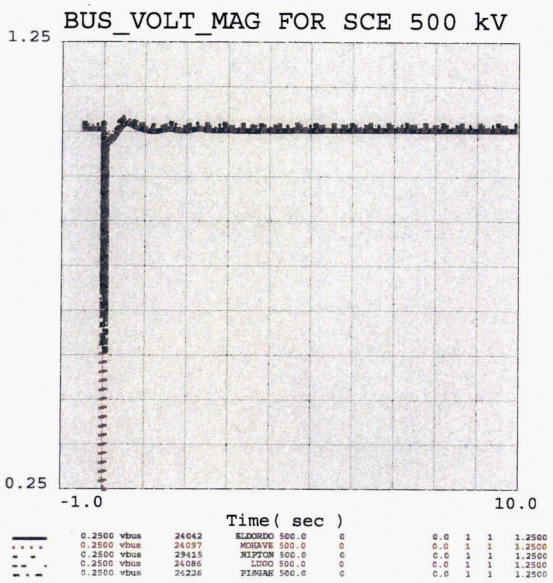


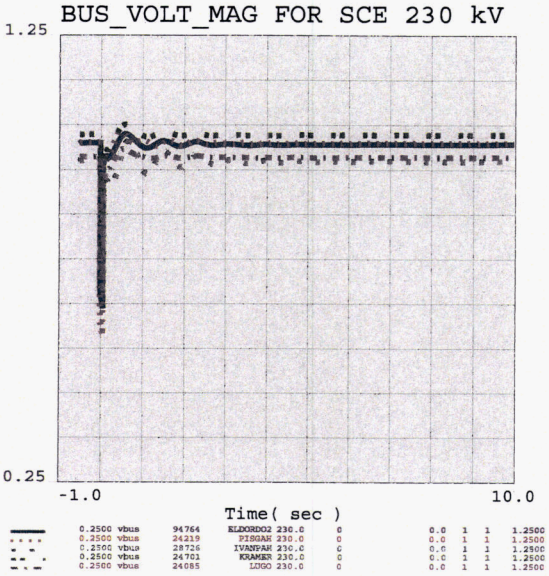
2014-ls-c1c2p2-eop-final-pst-loop1_Mohave-Homer-slo
East of Pisgah Area

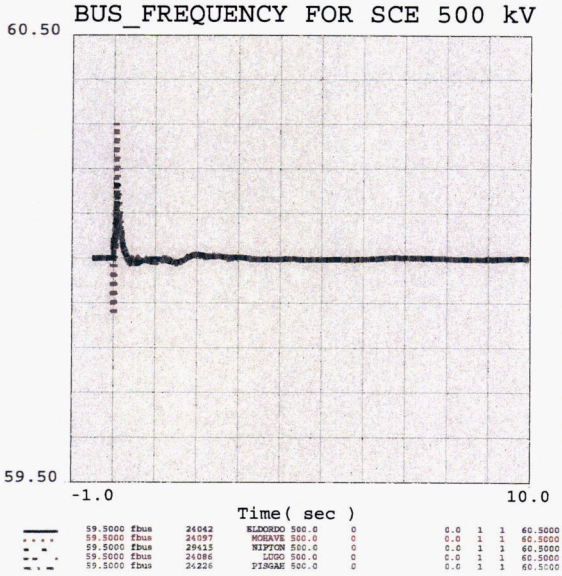
2014-ls-c1c2p2-eop-final-pst-loop1_Mohave-Homer-slo.chf

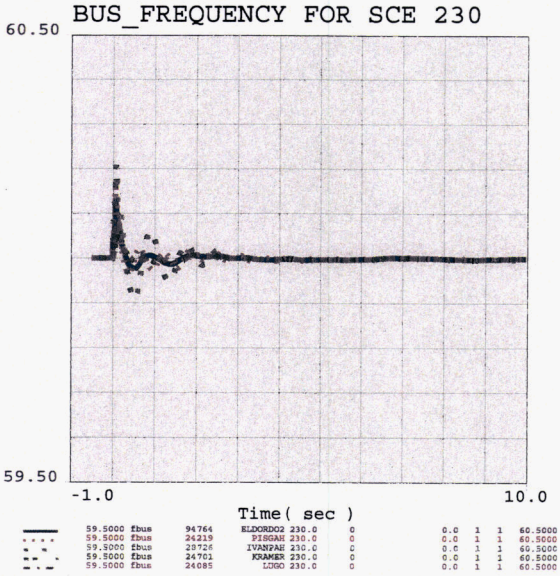
Mon Jun 06 13:55:47 2011

Stability Plots in SCE Area









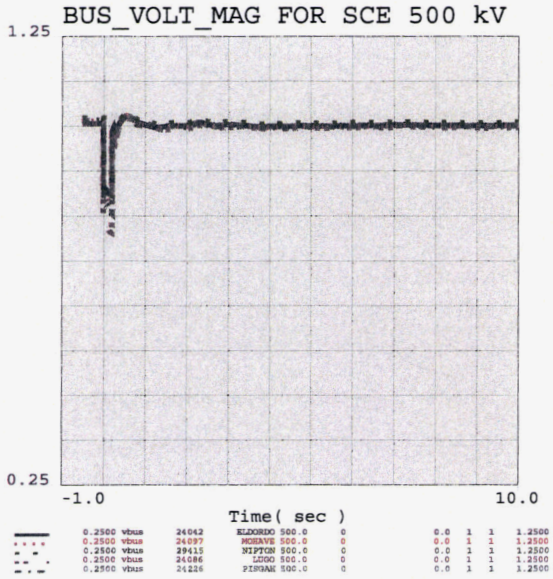
2014-ls-c1c2p2-eop-final-pst-loop1_Mohave-ElDorado-slo
East of Pisgah Area

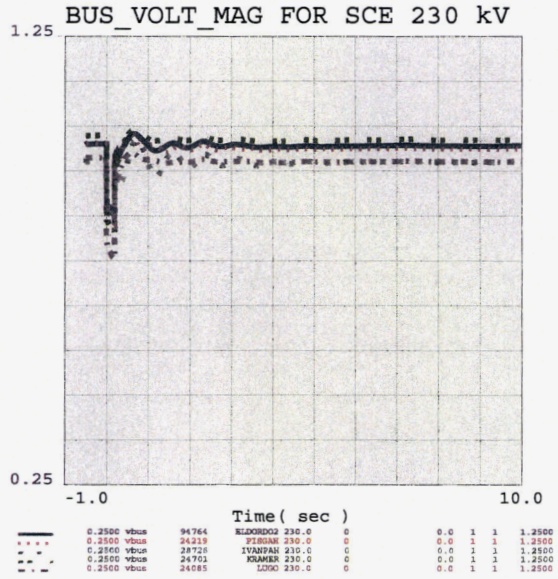
2014-ls-c1c2p2-eop-final-pst-loop1_Mohave-ElDorado-slo.chf

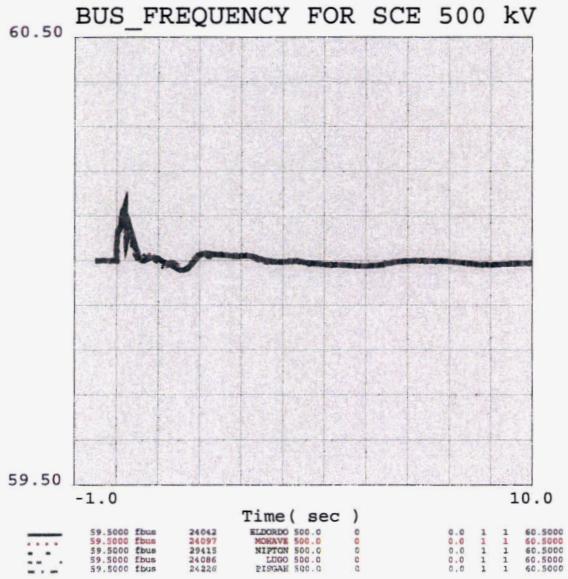
.

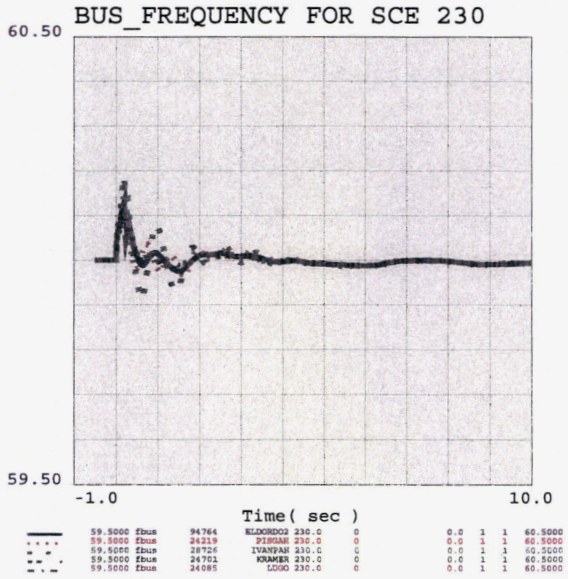
Mon Jun 06 13:55:42 2011

Stability Plots in SCE Area







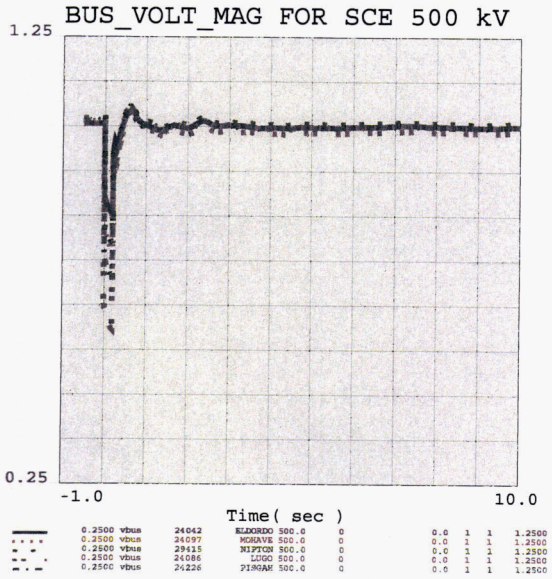


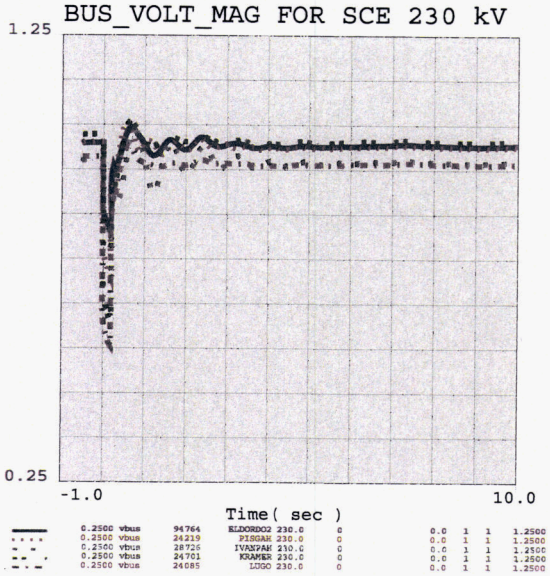
2014-ls-c1c2p2-eop-final-pst-loop1_McCullgh-Victorvl-dlo-slg
East of Pisgah Area

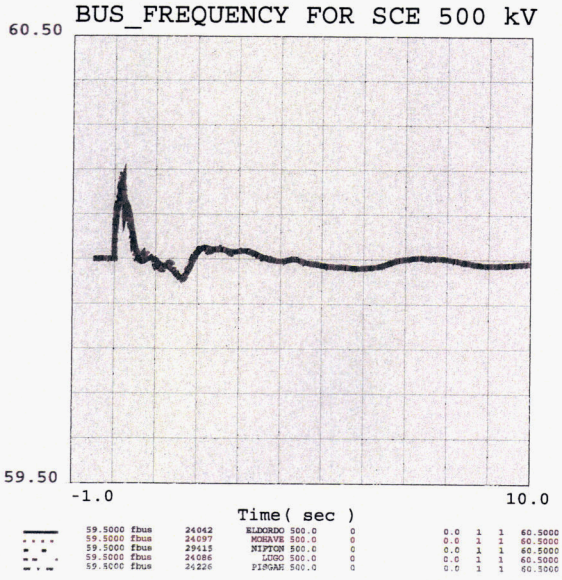
2014-ls-c1c2p2-eop-final-pst-loop1_McCullgh-Victorvl-dlo-slg.chf

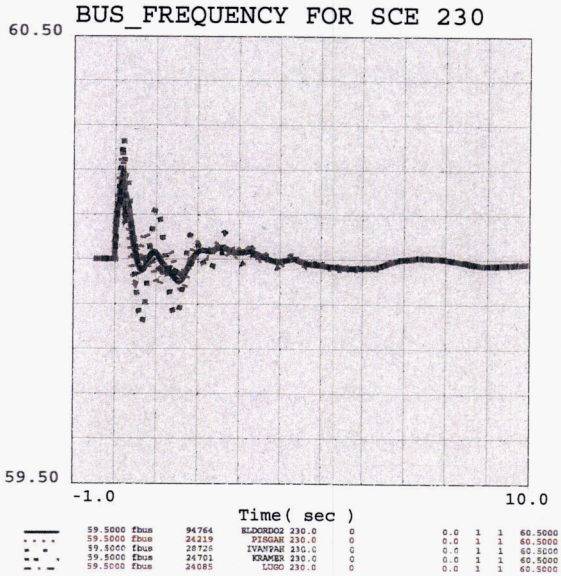
Mon Jun 06 13:55:35 2011

Stability Plots in SCE Area







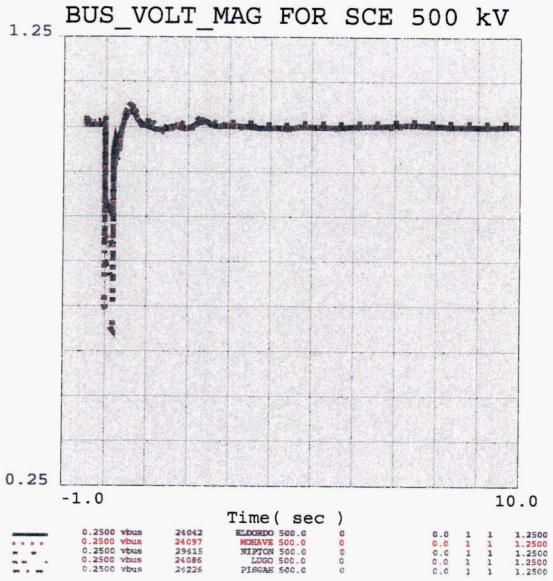


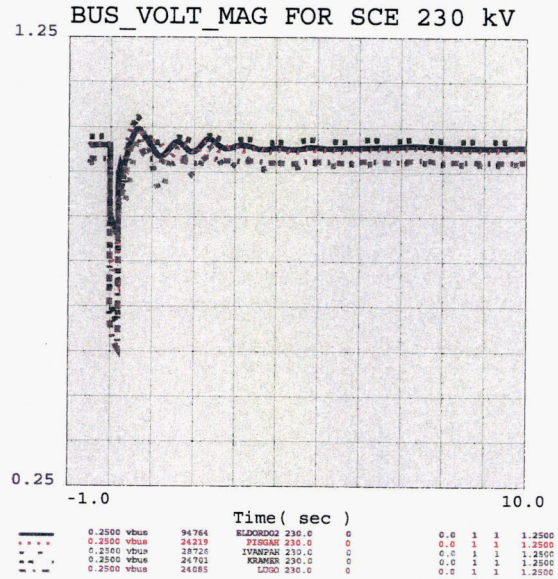
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Vincent-dlo-slg
East of Pisgah Area

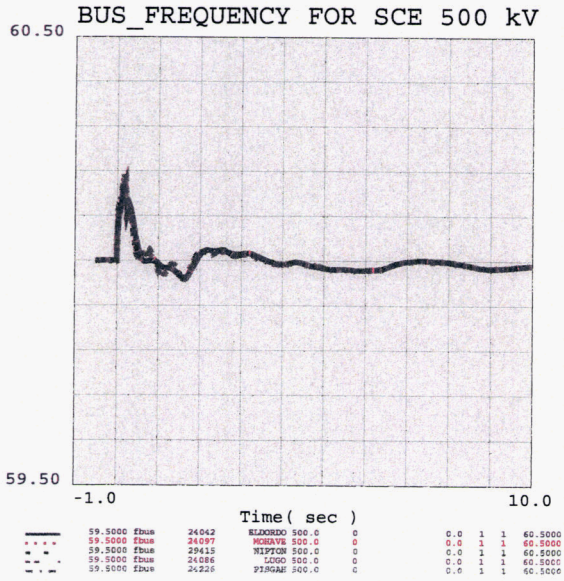
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Vincent-dlo-slg.chf

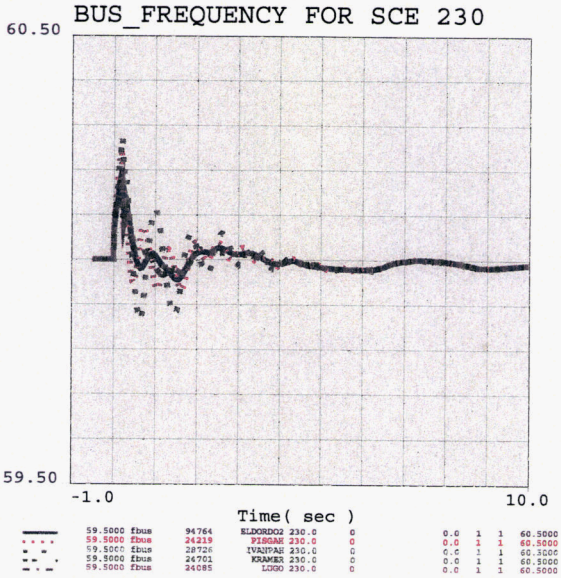
Mon Jun 06 13:55:27 2011

Stability Plots in SCE Area







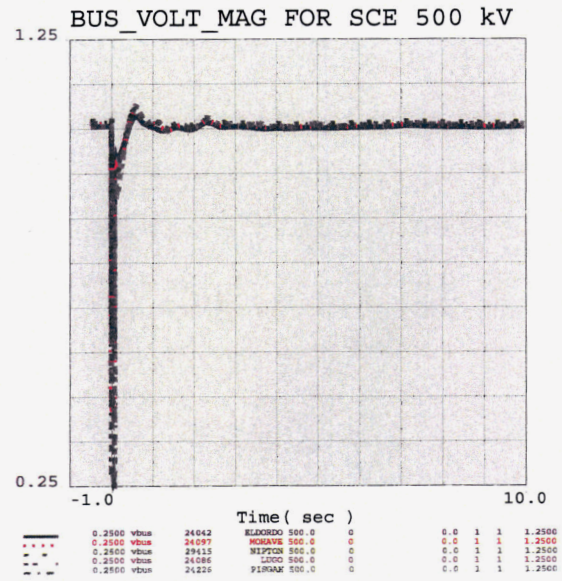


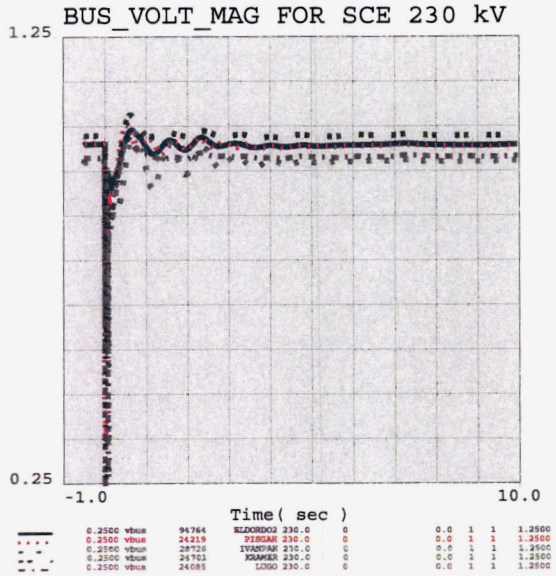
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-VicVin2-dlo-slg
East of Pisgah Area

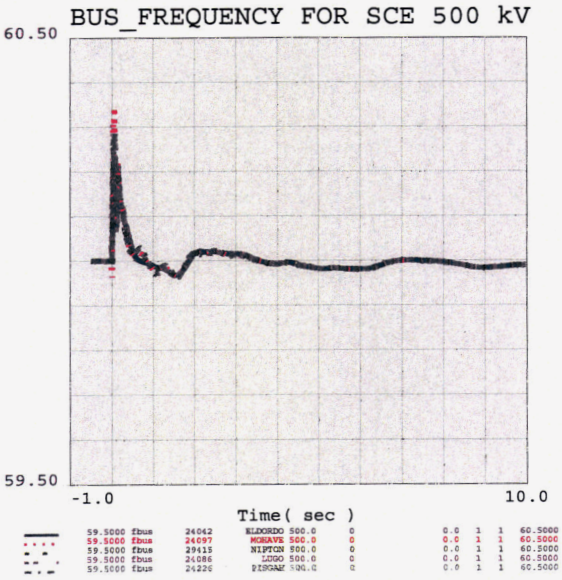
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-VicVin2-dlo-slg.chf

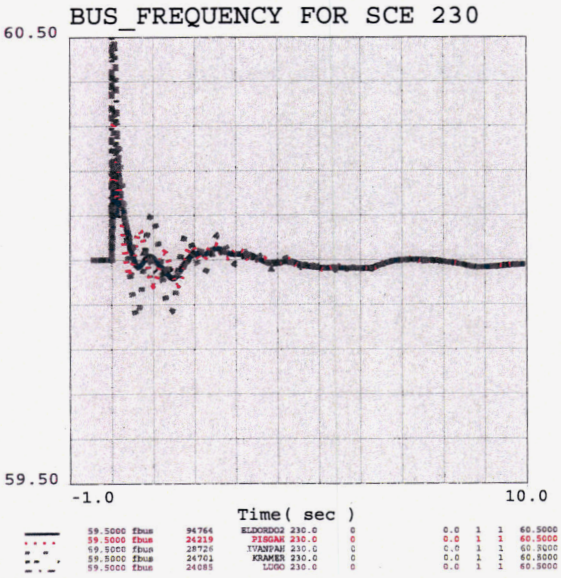
Mon Jun 06 13:55:17 2011

Stability Plots in SCE Area







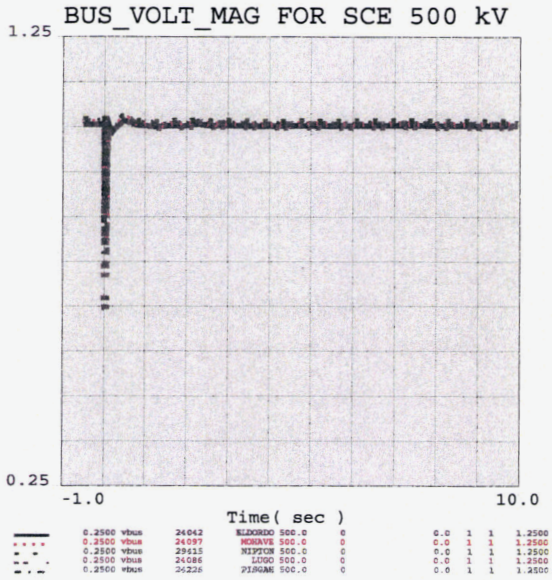


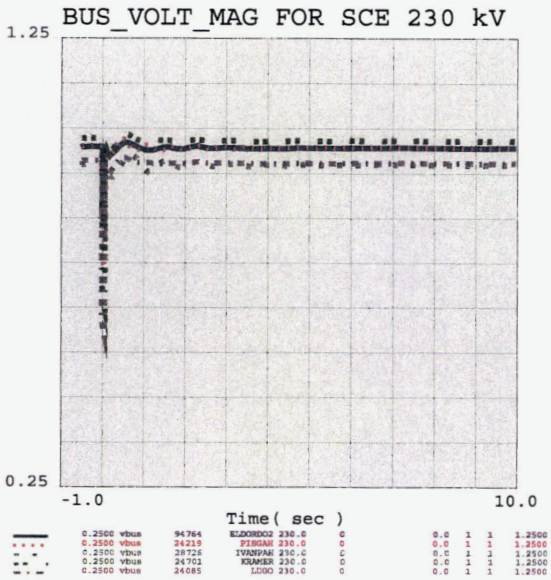
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Victvl-slo
East of Pisgah Area

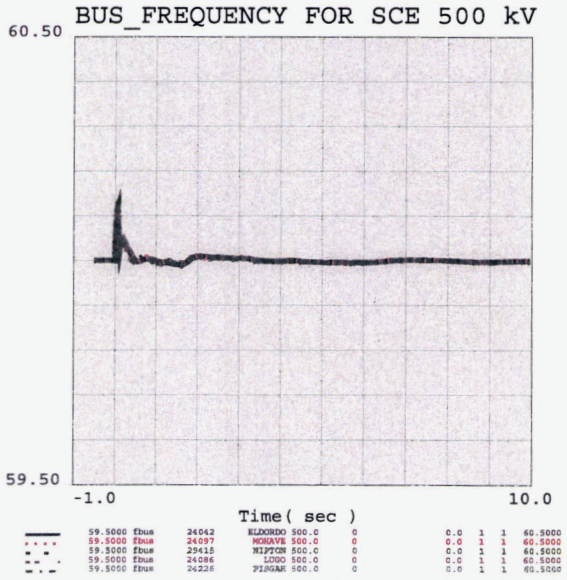
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Victvl-slo.chf

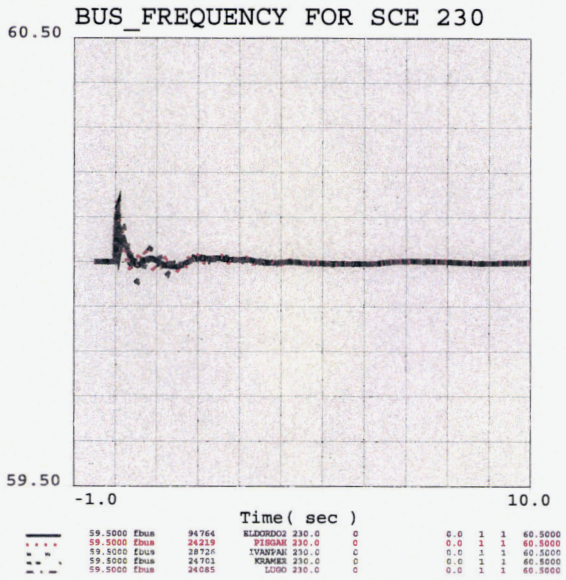
Mon Jun 06 13:55:22 2011

Stability Plots in SCE Area









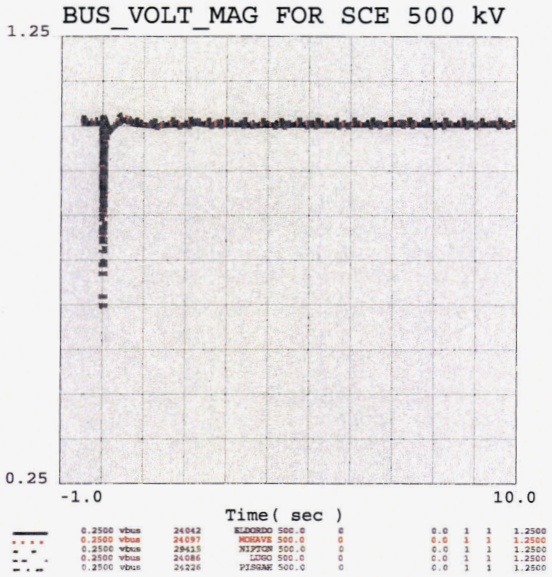
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-PisMoh-dlo-slg
East of Pisgah Area

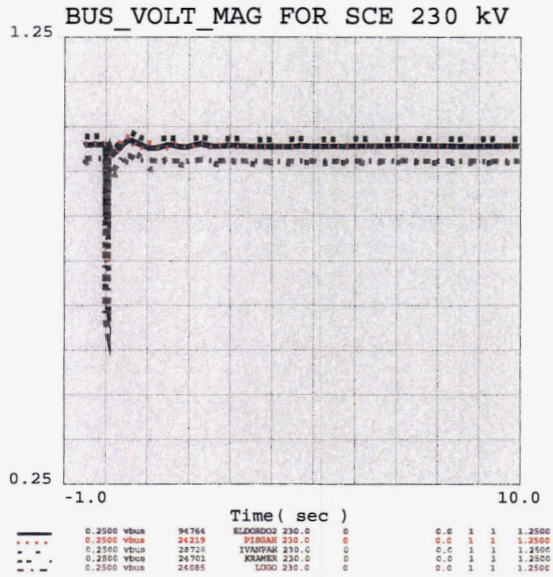
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-PisMoh-dlo-slg.chf

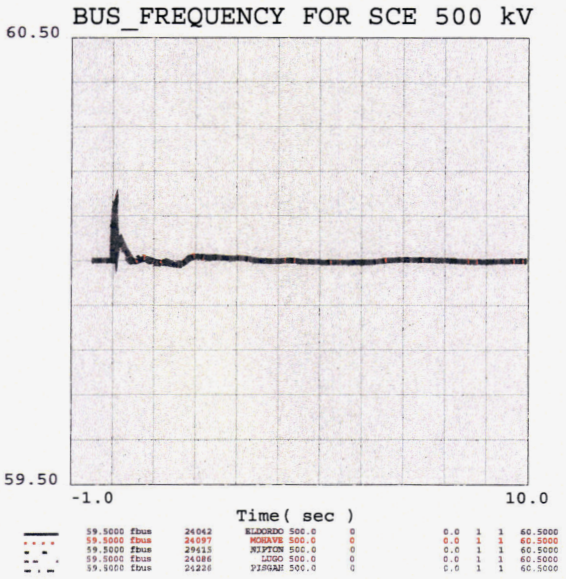
.

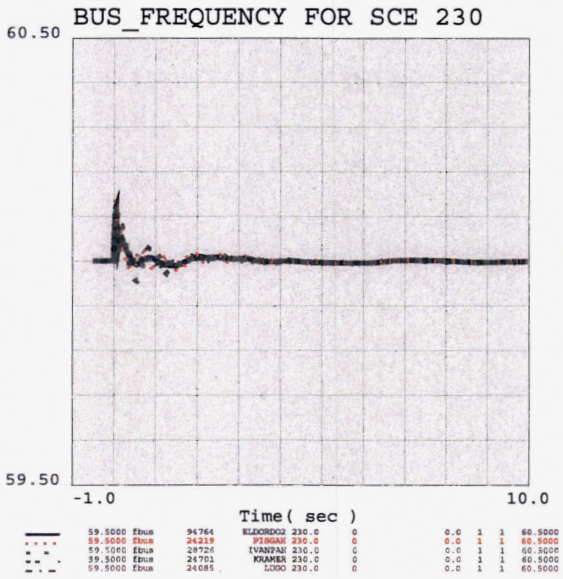
Mon Jun 06 13:55:01 2011

Stability Plots in SCE Area







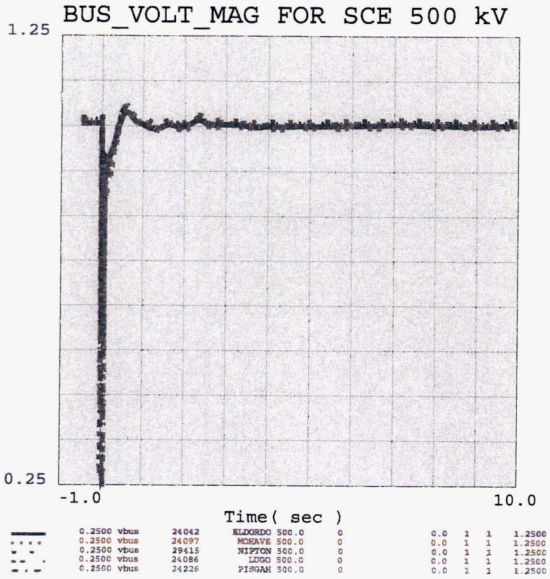


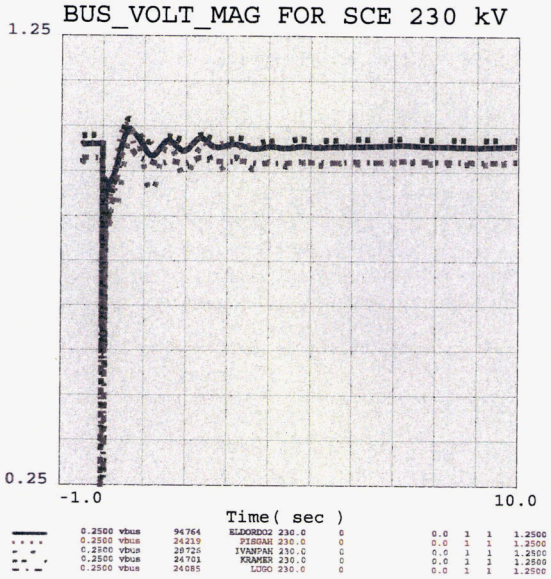
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-PisHom-dlo-slg
East of Pisgah Area

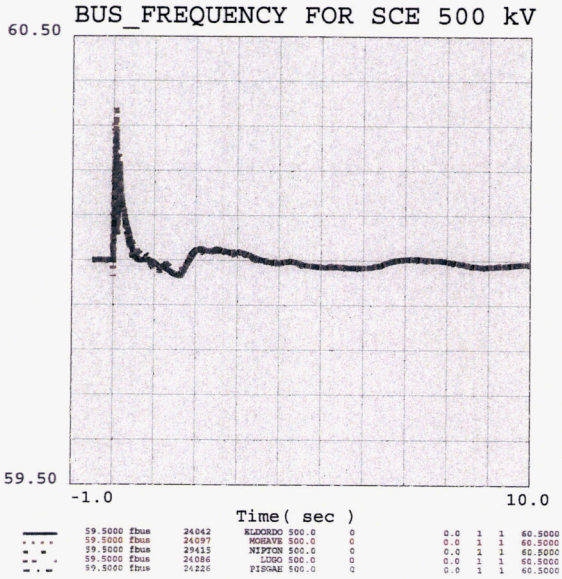
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-PisHom-dlo-slg.chf

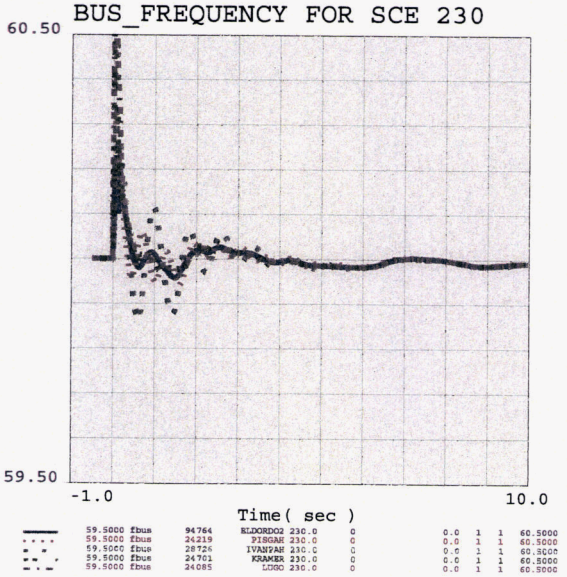
Mon Jun 06 13:54:55 2011

Stability Plots in SCE Area







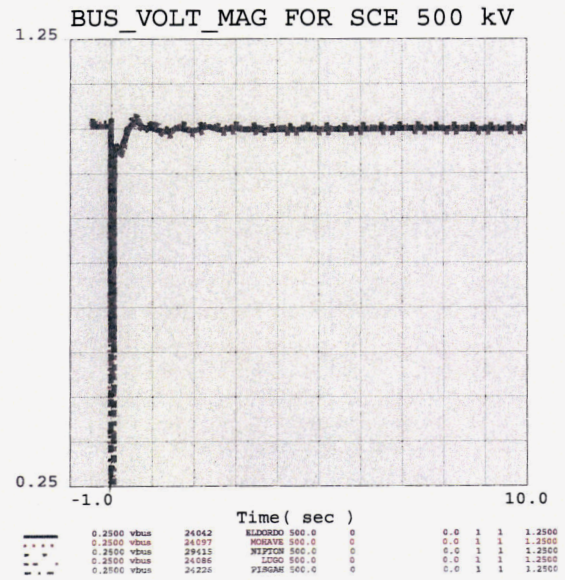


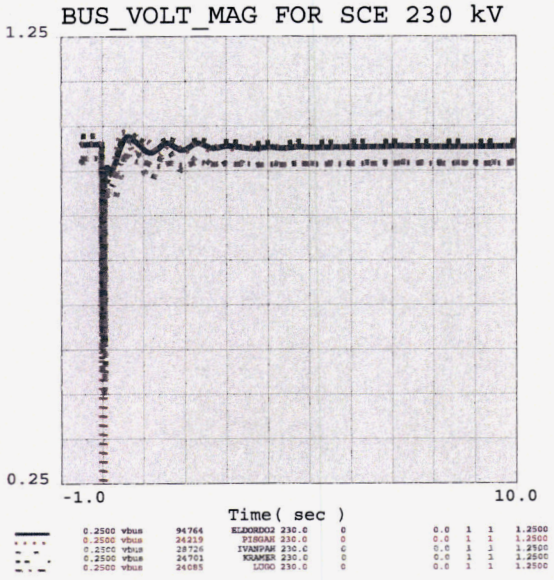
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Pisgah500-slo
East of Pisgah Area

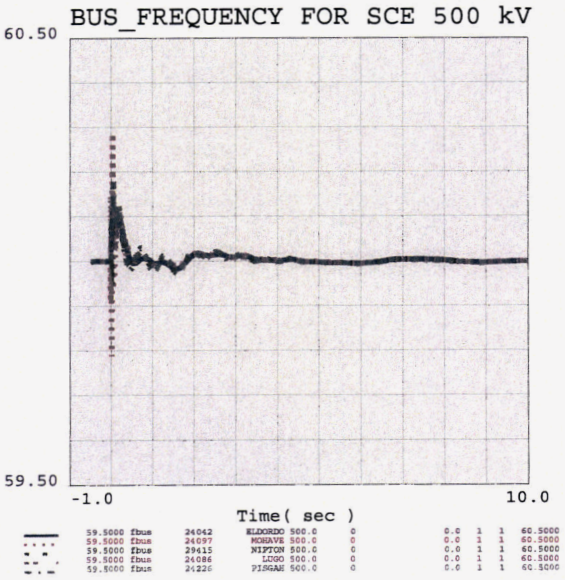
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Pisgah500-slo.chf

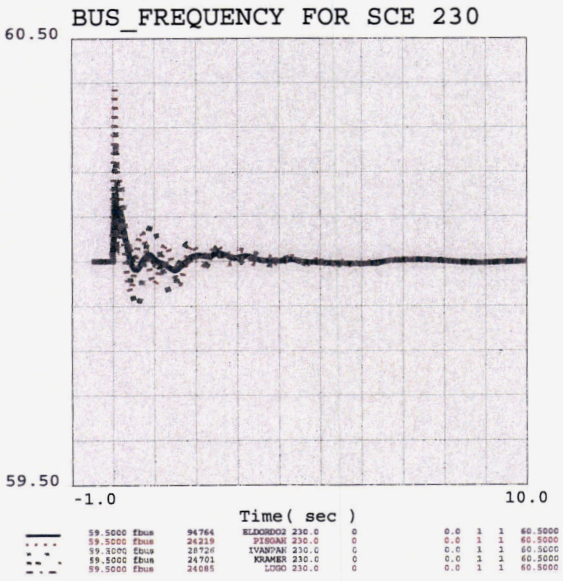
Mon Jun 06 13:55:12 2011

Stability Plots in SCE Area







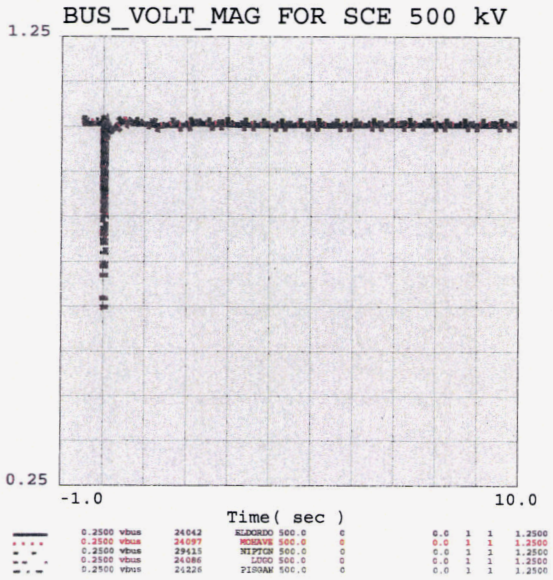


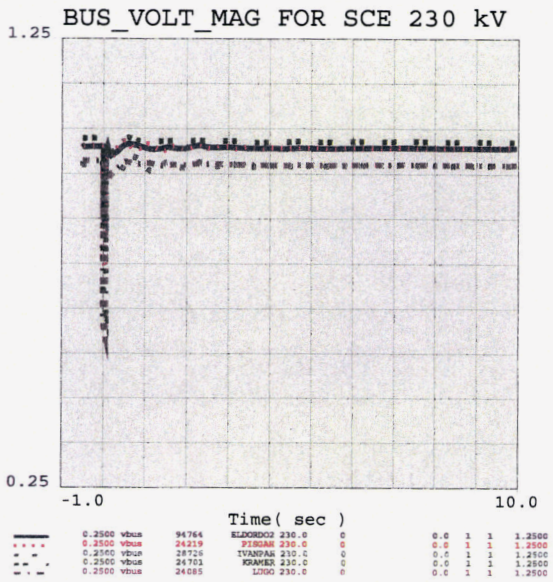
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Pisgah500-dlo-slg-SPS
East of Pisgah Area

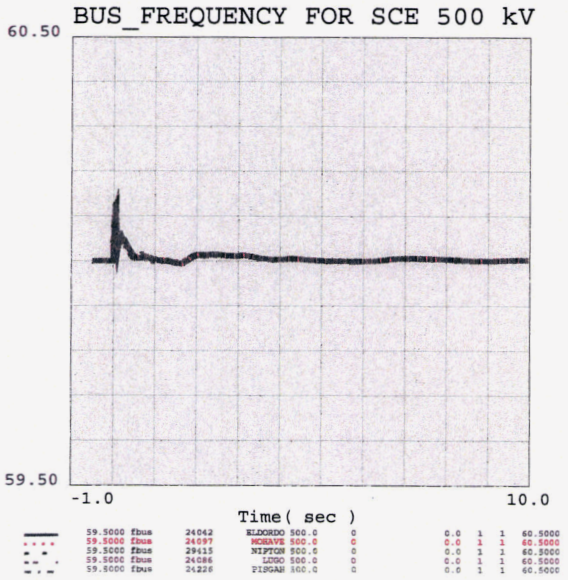
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Pisgah500-dlo-slg-SPS.chf

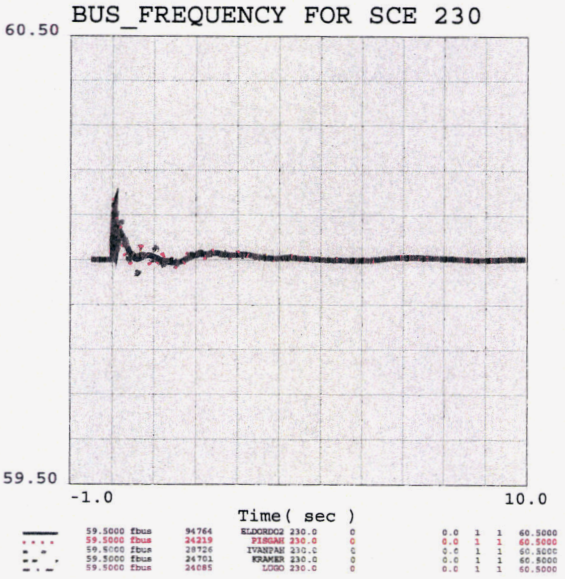
Mon Jun 06 13:55:07 2011

Stability Plots in SCE Area







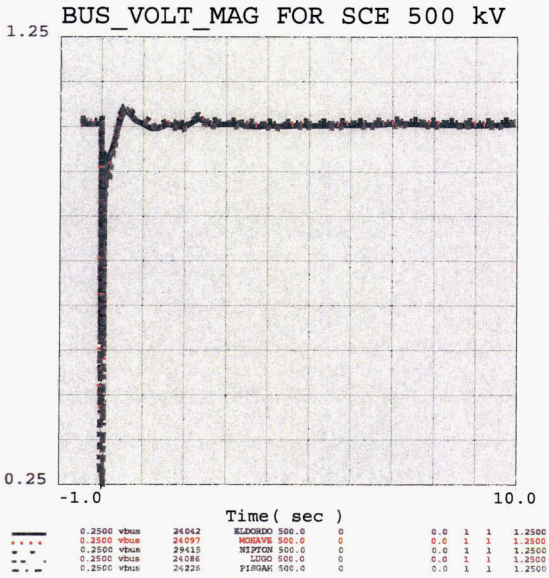


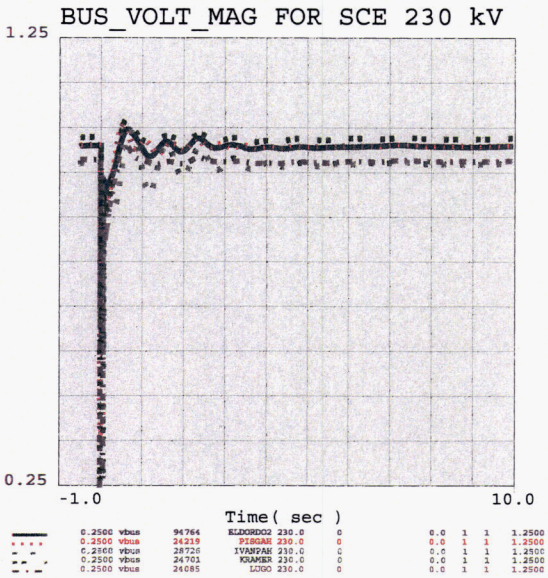
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Miraloma23-dlo-slg
East of Pisgah Area

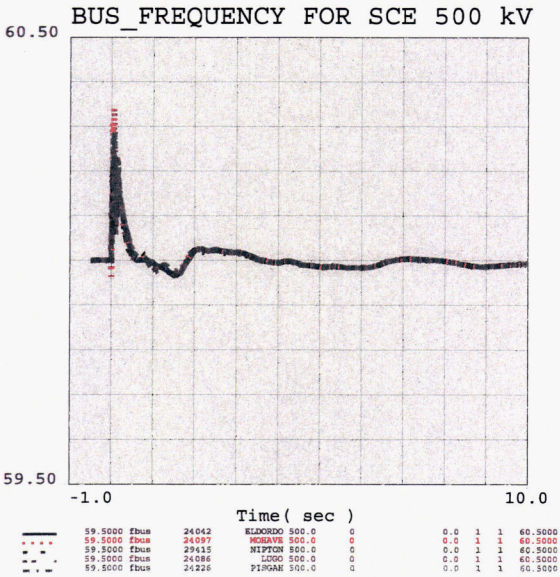
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Miraloma23-dlo-slg.chf

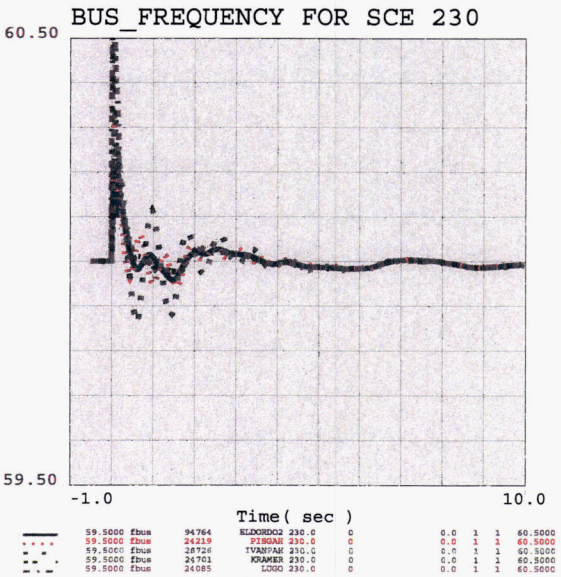
Mon Jun 06 13:54:43 2011

Stability Plots in SCE Area







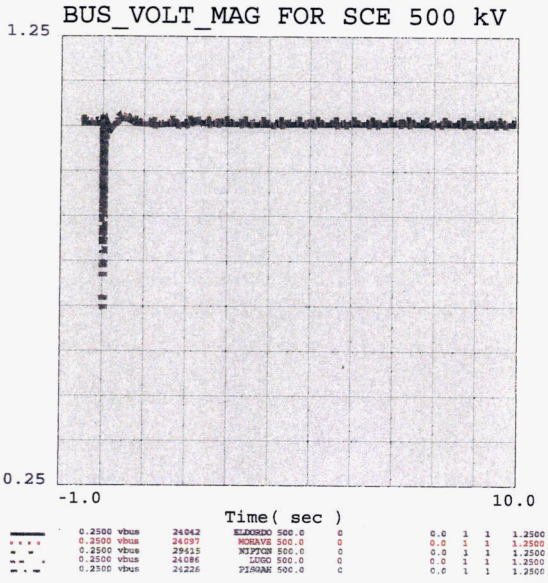


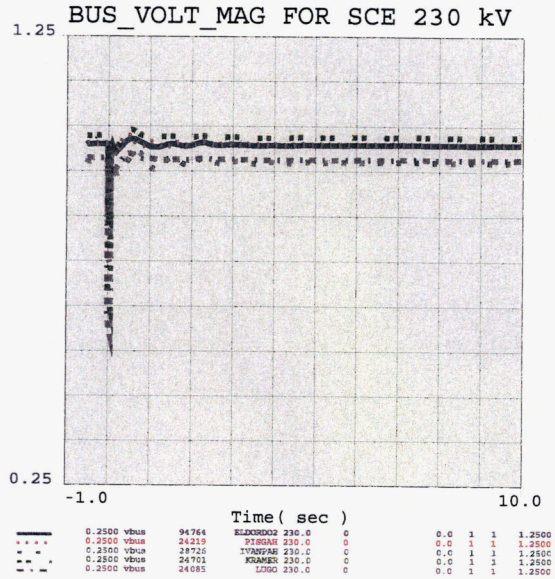
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Miraloma2-slo
East of Pisgah Area

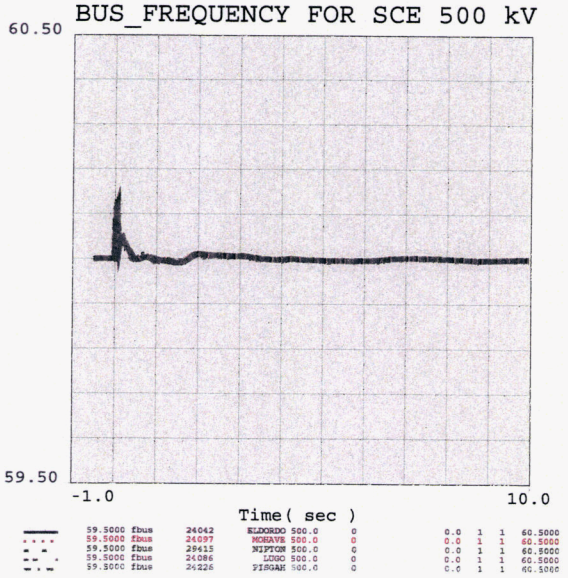
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Miraloma2-slo.chf

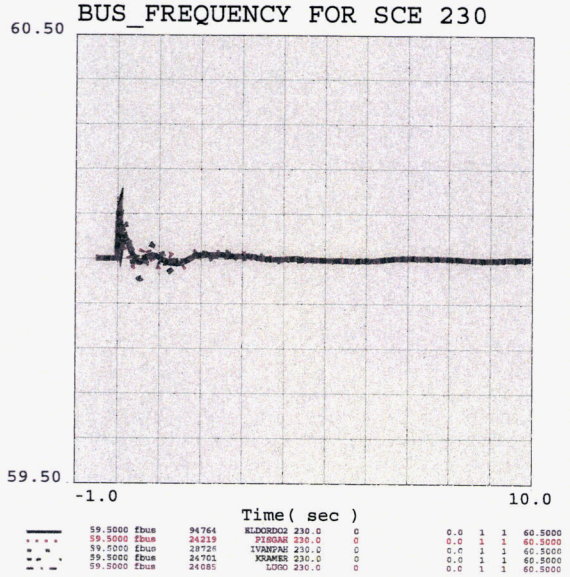
Mon Jun 06 13:54:36 2011

Stability Plots in SCE Area







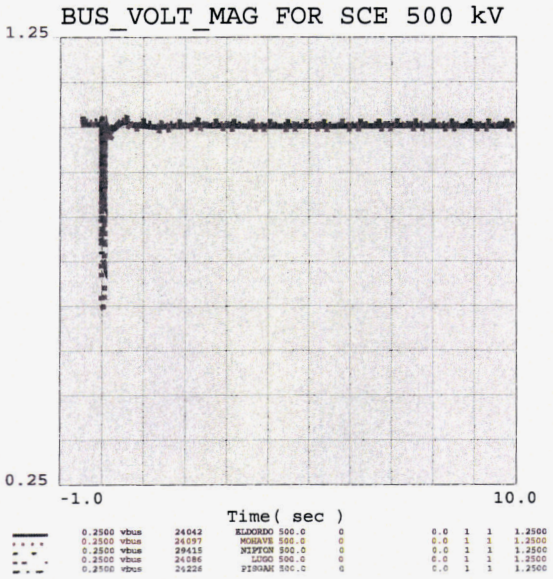


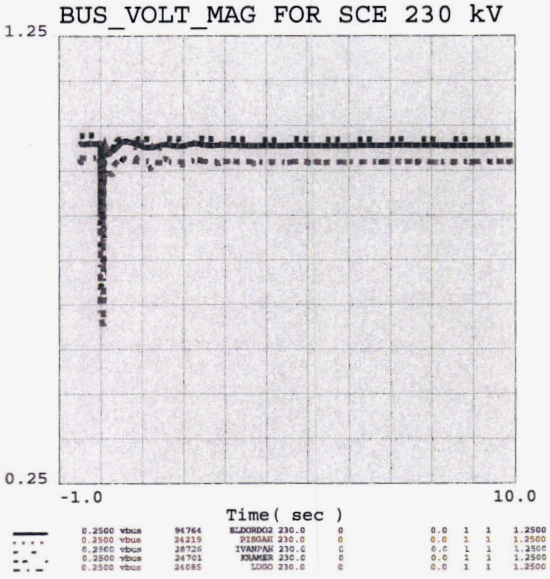
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Mir3Hom-dlo-slg
East of Pisgah Area

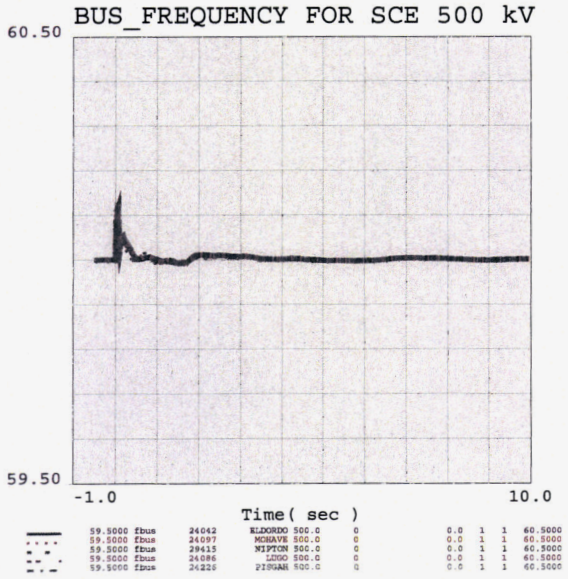
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Mir3Hom-dlo-slg.chf

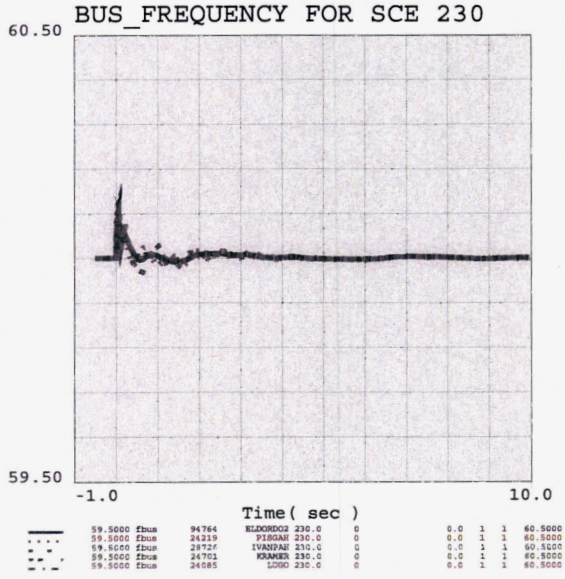
Mon Jun 06 13:54:24 2011

Stability Plots in SCE Area







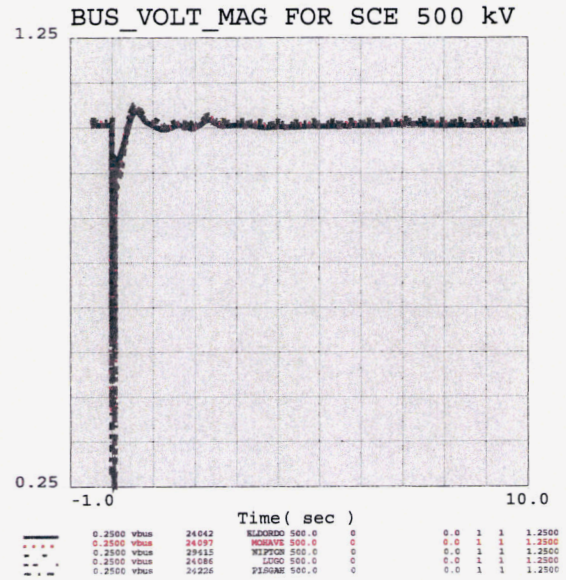


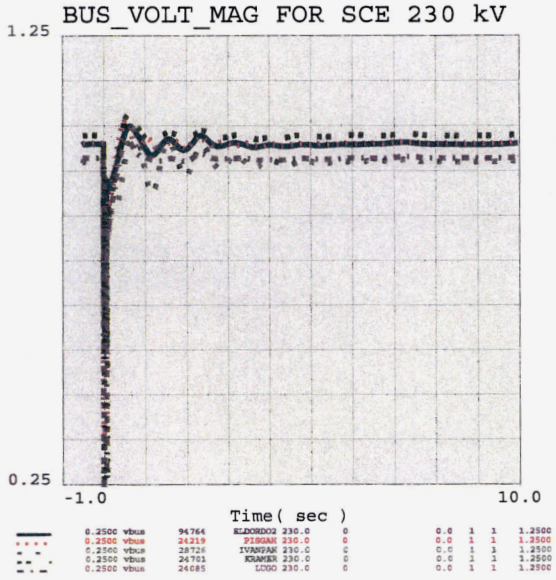
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Mir2Pis-dlo-slg
East of Pisgah Area

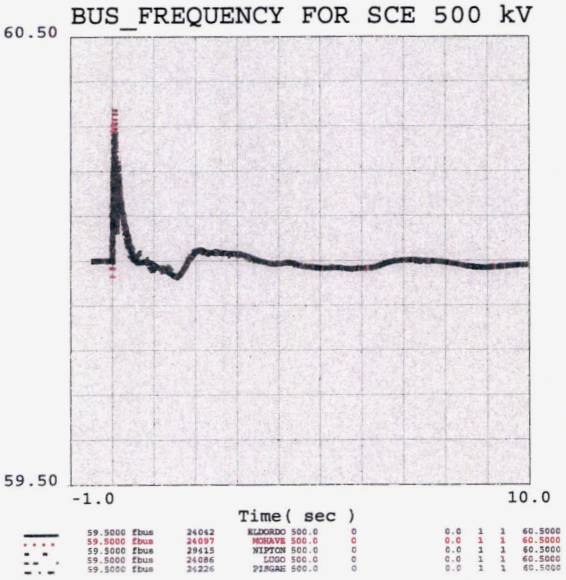
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Mir2Pis-dlo-slg.chf

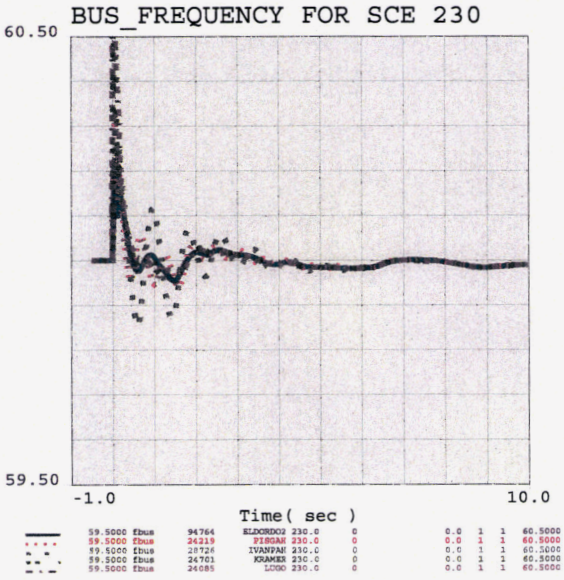
Mon Jun 06 13:54:18 2011

Stability Plots in SCE Area







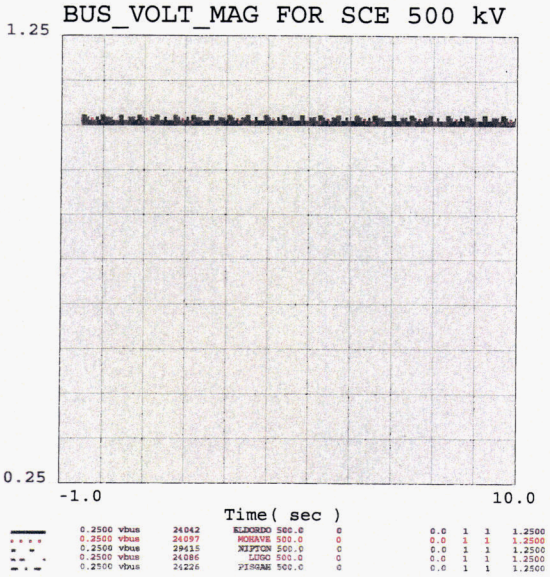


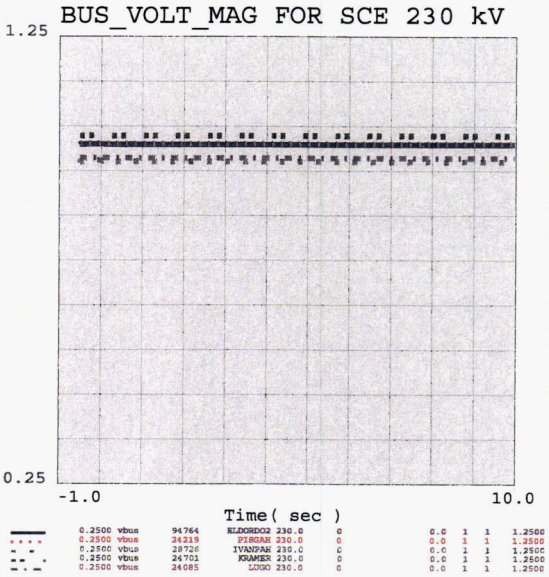
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Homer-slo
East of Pisgah Area

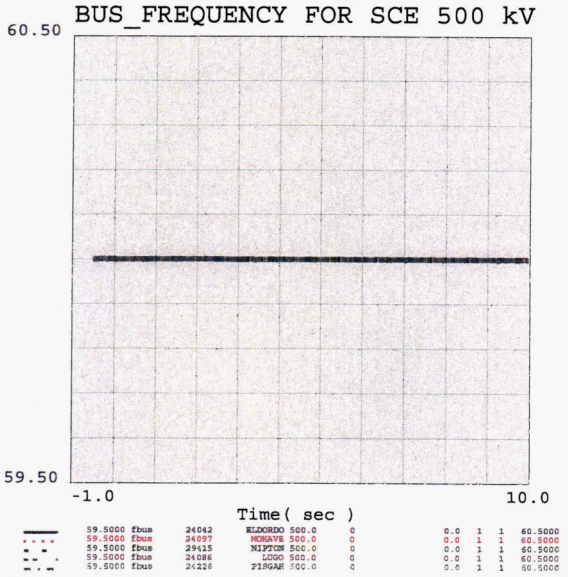
2014-ls-c1c2p2-eop-final-pst-loop1_Lugo-Homer-slo.chf

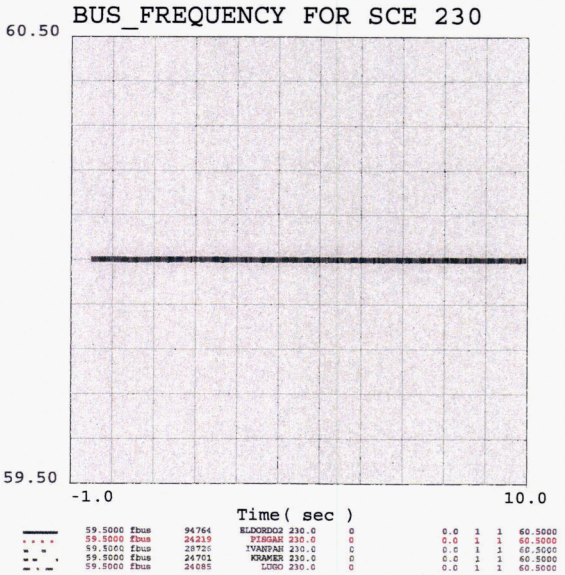
Mon Jun 06 13:54:14 2011

Stability Plots in SCE Area







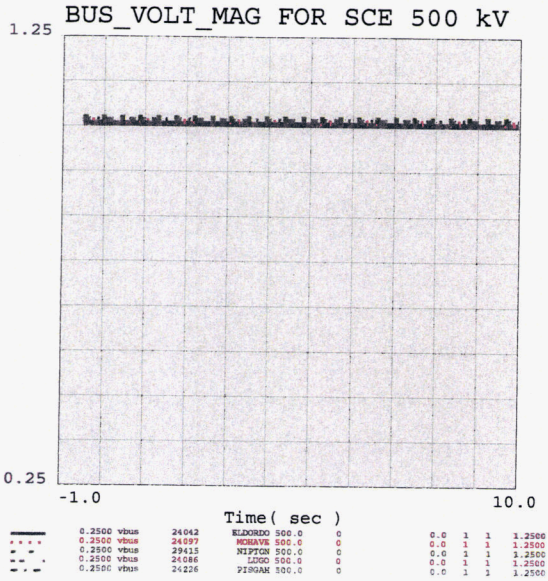


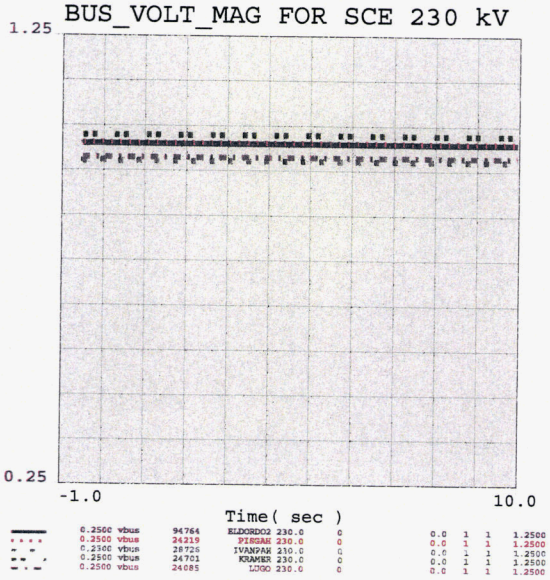
2014-ls-c1c2p2-eop-final-pst-loop1_Llano-Vincent-slo
East of Pisgah Area

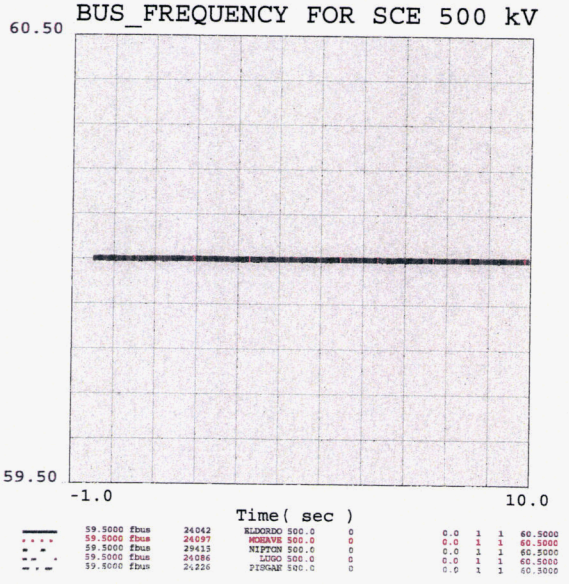
2014-ls-c1c2p2-eop-final-pst-loop1_Llano-Vincent-slo.chf

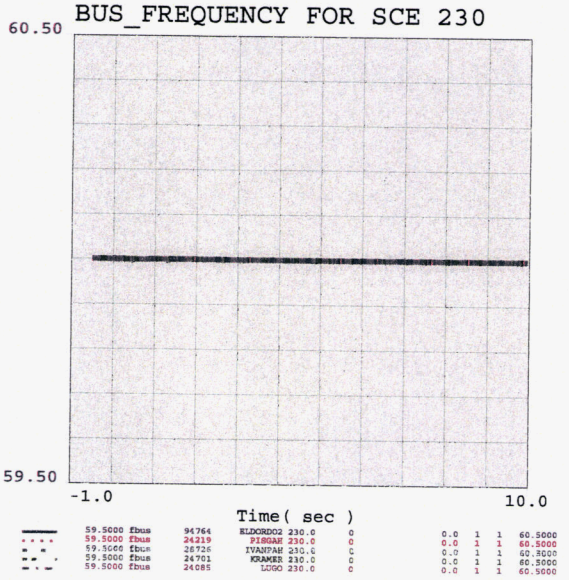
Mon Jun 06 13:54:09 2011

Stability Plots in SCE Area







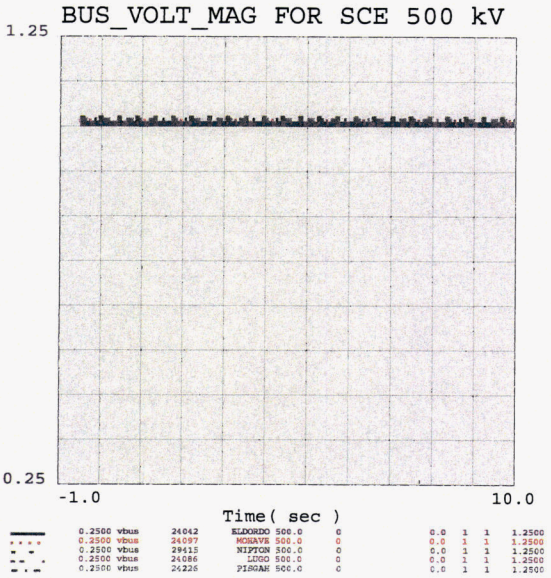


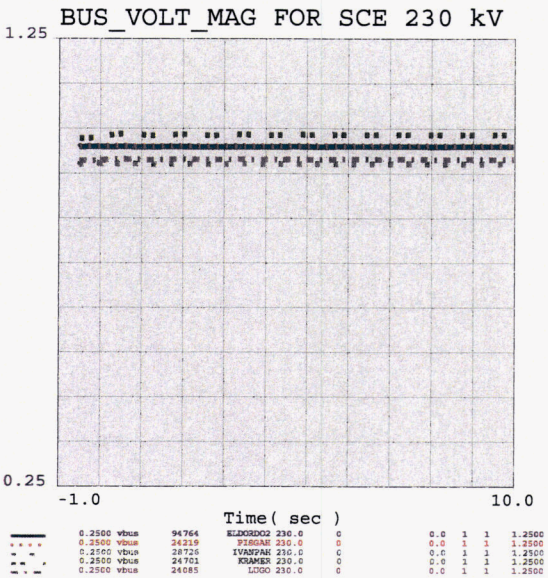
2014-ls-c1c2p2-eop-final-pst-loop1_Llano-Lugo-slo
East of Pisgah Area

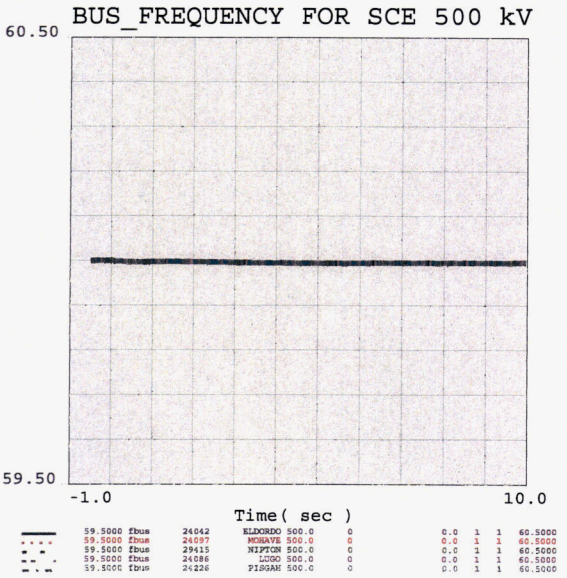
2014-ls-c1c2p2-eop-final-pst-loop1_Llano-Lugo-slo.chf

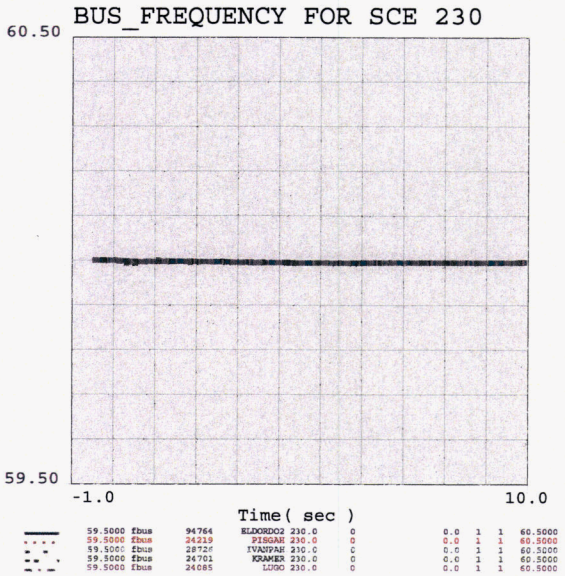
Mon Jun 06 13:54:04 2011

Stability Plots in SCE Area







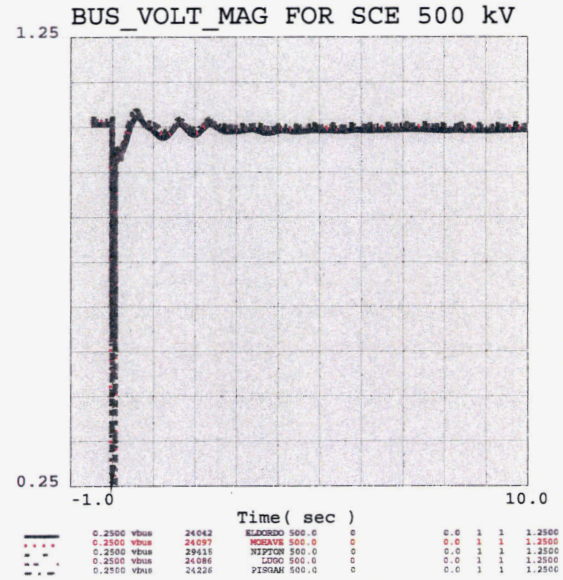


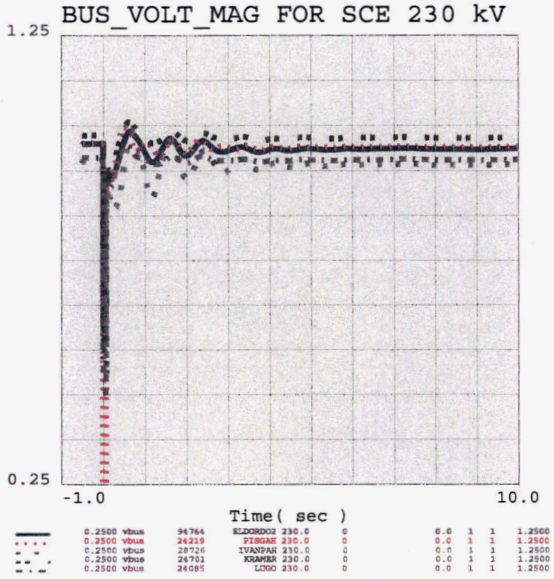
2014-ls-c1c2p2-eop-final-pst-loop1_Kramer-Llano-slo-SPS
East of Pisgah Area

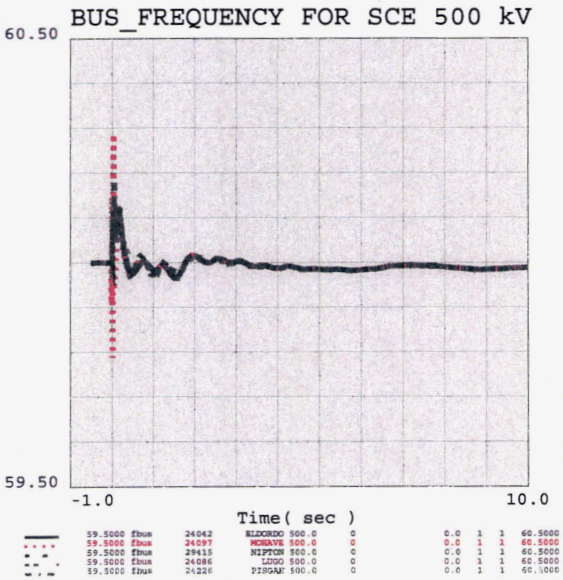
2014-ls-c1c2p2-eop-final-pst-loop1_Kramer-Llano-slo-SPS.chf

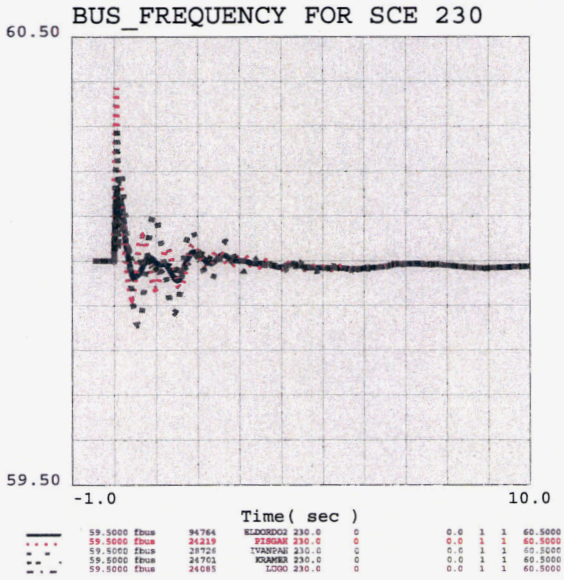
Mon Jun 06 13:54:00 2011

Stability Plots in SCE Area







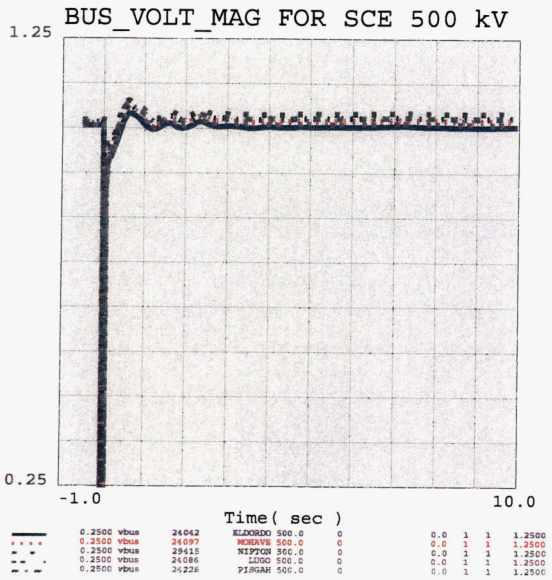


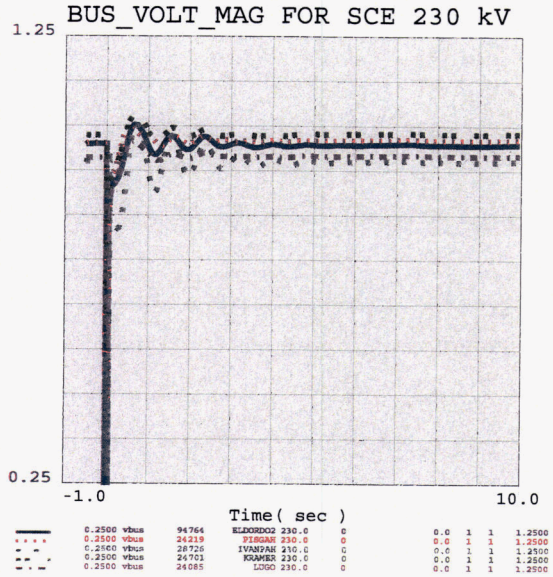
2014-ls-c1c2p2-eop-final-pst-loop1_Eldrd-Mcllugh500-slo-SPS
East of Pisgah Area

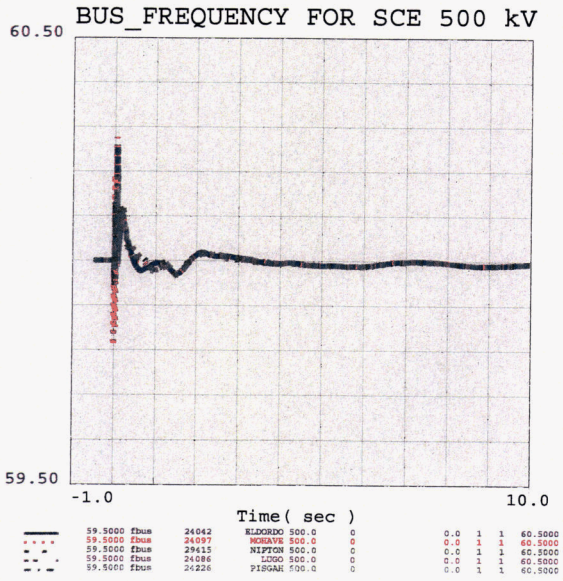
2014-ls-c1c2p2-eop-final-pst-loop1_Eldrd-Mcllugh500-slo-SPS.chf

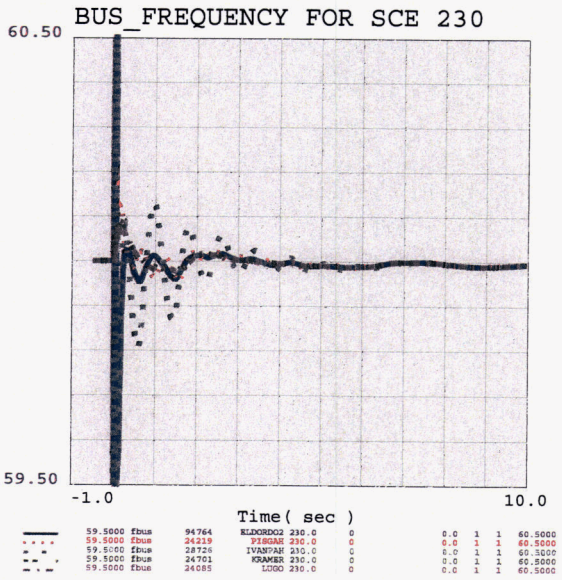
Mon Jun 06 13:53:55 2011

Stability Plots in SCE Area







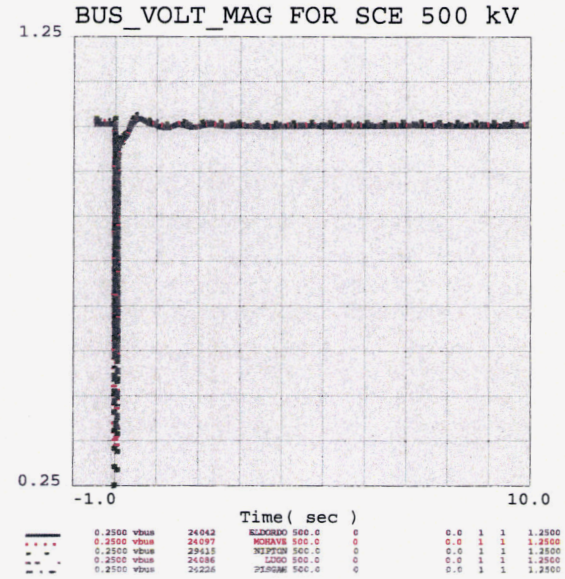


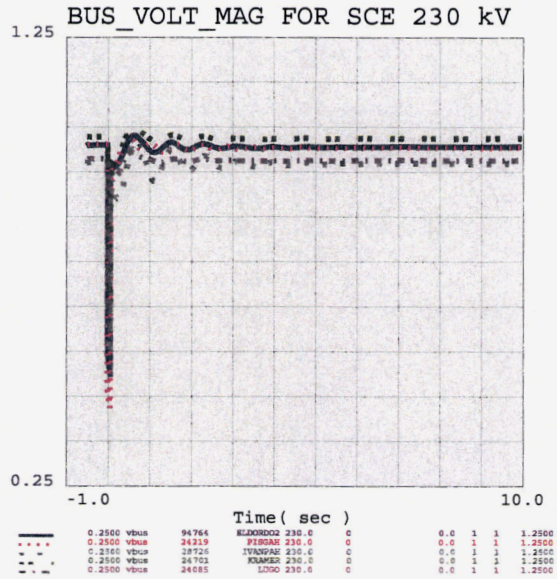
2014-ls-c1c2p2-eop-final-pst-loop1_Eldorado-Nipton-slo
East of Pisgah Area

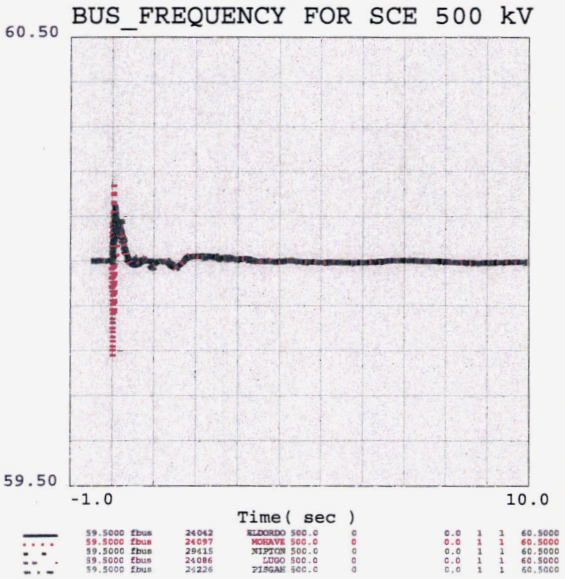
2014-ls-c1c2p2-eop-final-pst-loop1_Eldorado-Nipton-slo.chf

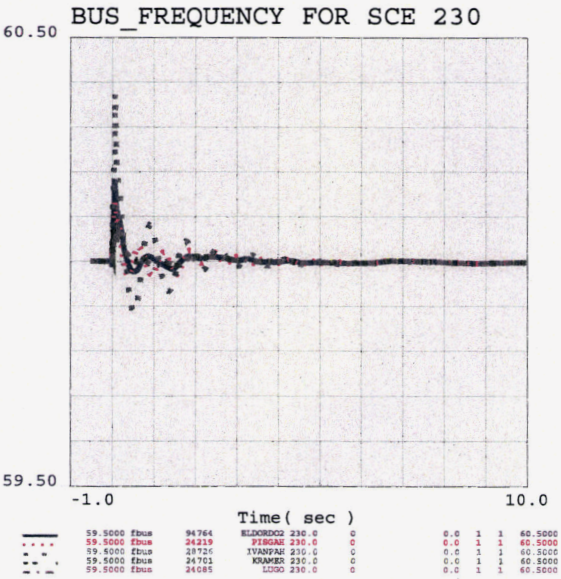
Mon Jun 06 13:53:50 2011

Stability Plots in SCE Area









2014-ls-c1c2p2-eop-final-pst-loop1_Pisgah-Nipton-slo
East of Pisgah Area

2014-ls-c1c2p2-eop-final-pst-loop1_Pisgah-Nipton-slo.chf

Mon Jun 06 13:56:03 2011

SCD Analysis Program v5
Three Phase (3PH) Short Circuit Duty Study Results

Date: 7/11/2011
Time: 2:23:17 PM

Pre File: C:\caperesults\QC1-QC2-PH2\QC12PH2-SCD-Results\PRE-QC1-2-PH2.TXT
Post File: C:\caperesults\QC1-QC2-PH2\QC12PH2-SCD-Results\PST-QC1-2-PH2.TXT
Labels: P:\Tools\Software Applications\SCD Analysis\SCE Min Breaker Ratings CAPE.csv

		PRE CASE		POST CASE		
Bus Name	Bus KV	X/R	KA	X/R	KA	DELTA KA
ALBH500	525	25	21.4	24.6	22.2	0.8
Antelope	525	23.2	37.5	23.9	38.6	1.1
Colorado Rvr	525	23.3	19.9	23.5	22.6	2.7
Eldorado	525	13.9	44.2	14	46.4	2.2
Lugo	525	23.4	47.2	22.4	49	1.8
Mira Loma	525	24.7	40	24.3	40.6	0.6
Pisgah	525	23.8	22.7	19.1	31	8.3
Red Bluff	525	21.7	20.3	22.3	23.9	3.6
Serrano	525	25.4	32	25.2	32.4	0.4
Vincent	525	21.4	48.8	21.6	50	1.2
Antelope	230	25.9	38.6	28.3	40.3	1.7
Barre	230	18.9	51	18.9	51.1	0.1
Chino	230	16.2	50.9	16.1	51.1	0.2
Colorado Rvr	230	37.5	30.2	40.1	32.8	2.6
Devers	230	26	48.8	26.1	49.5	0.7
Drycreek Wnd	230	29.9	34.9	30.2	36.3	1.4
Eldorado	230	16.9	55	17	55.4	0.4
Eldorado_2	230	36.4	31.2	37.9	32.7	1.5
Etiwanda	230	25.7	56.3	25.6	56.6	0.3
Highwind_230	230	22.1	19.7	22.2	19.9	0.2
Jasper	230	22	11.4	21.8	11.8	0.4
Kramer	230	16	19.6	15.6	20	0.4
Lewis	230	19.9	46.5	19.9	46.6	0.1
Lockhart	230	18.2	13.5	17.9	13.7	0.2
Lugo	230	33.6	41.5	33.2	50.9	9.4
Mira Loma A	230	20.2	53.8	20.1	54.1	0.3
Mira Loma B	230	23.7	65	23.6	65.4	0.4
Pardee	230	15.4	58.6	15.4	58.8	0.2
Pisgah	230	28.3	32.7	28.6	36	3.3
Rancho	230	25.6	57.1	25.5	57.4	0.3
Red Bluff	230	42.7	19.2	37.9	28.4	9.2
San Ber_dino	230	25.2	41	25.2	41.1	0.1
San Onofre	230	21.9	55.5	21.6	55.9	0.4
Serrano	230	25.1	56.7	25	57.1	0.4
Sylmar (SCE)	230	15.2	62.1	15.2	62.3	0.2
Victor	230	16.3	25	15	27.1	2.1
Villa Park	230	23	48.9	23	49.1	0.2
Vincent A	230	22.8	66.9	22.9	67.4	0.5
Vincent B	230	22.8	66.9	22.9	67.4	0.5
Vista	230	20.5	47.9	20.5	48.1	0.2
Whirlwind	230	40.1	46.3	42	48.9	2.6
ALBH115	115	61.3	19.6	61.4	19.7	0.1
Altwind	115	11	17	10.9	17.3	0.3
Devers	115	46.4	26.8	45.9	27.3	0.5
Farrell	115	9.8	13.8	9.7	14	0.2

Garnet	115	17.8	19.2	17.5	19.5	0.3
Kramer	115	12.2	26	12.2	26.6	0.6
Sanwind	115	9.5	14.2	9.4	14.6	0.4
Terawind	115	16.7	21.8	16.4	22.2	0.4
Tiffanywind	115	13.7	19.7	13.6	20.1	0.4
Venwind	115	6.3	16.3	6.3	16.5	0.2
Victor	115	18.1	24.6	18	25.5	0.9
Vista	115	28.7	20.1	29.2	20.4	0.3
ANTELOPE	66	28.4	34.8	46.8	36.6	1.8
CAL CEMENT	66	12	19.4	11.9	20	0.6
DEL SUR	66	8.6	20.5	9	21.4	0.9
GOLDTOWN	66	7.6	7.9	7.1	12.2	4.3
GREAT LAKES	66	2.9	4	2.9	4.1	0.1
OASIS	66	5.5	9.6	6	11.1	1.5
Purify	66	2.8	5.4	5	6.3	0.9
Ritter Ranch	66	7.6	12	7.9	12.3	0.3
ROSAMOND	66	3.8	9.2	4.1	9.8	0.6
Windhub66	66	50.2	34.2	49.1	35.6	1.4
Valley A	525	27.6	24.0	26.6	26.1	2.1
Valley B	525	27.6	24.0	26.6	26.1	2.1
Cool Water	230	25.0	14.9	24.5	15.1	0.2
Mesa	230	15.9	54.3	15.9	54.4	0.1
Windhub_A	230	45.8	34.6	46.9	34.9	0.3
Windhub_B	230	49.6	32.2	50.8	33.4	1.3
Valley AB	115	72.2	21.2	72.8	21.5	0.3
Valley C	115	60.8	36.3	61.2	36.6	0.4

SCD Analysis Program v5 Date: 7/11/2011
Single Line to Ground (SLG) Short Circuit Duty Study Results Time: 2:23:17 PM

Pre File: C:\caperesults\QC1-QC2-PH2\QC12PH2-SCD-Results\PRE-QC1-2-PH2.TXT
Post File: C:\caperesults\QC1-QC2-PH2\QC12PH2-SCD-Results\PST-QC1-2-PH2.TXT
Labels: P:\Tools\Software Applications\SCD Analysis\SCE Min Breaker Ratings CAPE.csv

		PRE CASE		POST CASE		
Bus Name	Bus KV	X/R	KA	X/R	KA	DELTA KA
ALBH500	525	10.8	19.6	10.5	20.1	0.5
Antelope	525	18.1	31.8	18.3	32.5	0.7
Colorado Rvr	525	19.2	18.9	19.6	22.9	4
Eldorado	525	12.7	40.1	12.7	41.6	1.5
Lugo	525	12.7	36.5	13.6	39.2	2.7
Mira Loma	525	11.5	35.6	11.5	36	0.4
Pisgah	525	19.9	19.5	16.1	24.8	5.3
Red Bluff	525	12.5	17.1	13	22.4	5.3
Serrano	525	13.1	28.6	12.9	28.9	0.3
Valley A	525	15	24.1	13.5	26.1	2
Valley B	525	15	24.1	13.5	26.1	2
Vincent	525	15.4	39.1	15.3	39.7	0.6
Antelope	230	26.8	42.2	28.3	44	1.8
Barre	230	13.9	42.1	13.9	42.2	0.1
Chino	230	12.5	40.5	12.5	40.6	0.1
Colorado Rvr	230	27.8	33.7	30.2	37.4	3.7
Cool Water	230	24.8	15.3	24.3	15.5	0.2
Devers	230	25	53.9	25	54.5	0.6
Drycreek Wnd	230	17.1	31.4	16.9	32.5	1.1
Eldorado	230	15.1	51.2	15.1	51.5	0.3
Eldorado_2	230	34	36	35.1	37.6	1.6
Etiwanda	230	17	56.3	16.9	56.5	0.2
Highwind_230	230	15.1	16	15.5	16.4	0.4
Jasper	230	11	8.1	13.6	9.5	1.4
Kramer	230	10.4	16.6	10.2	16.8	0.2
Lewis	230	15.2	43.6	15.2	43.7	0.1
Lugo	230	25.2	41.9	25.2	52.4	10.5
Mesa	230	11	44.5	11	44.6	0.1
Mira Loma A	230	11.6	54.9	11.6	55.1	0.2
Mira Loma B	230	13.2	63.2	13.2	63.6	0.4
Pardee	230	13.4	42.1	13.3	42.2	0.1
Pisgah	230	26.5	36.2	26.2	39.5	3.3
Rancho	230	16.5	57.9	16.5	58.1	0.2
Red Bluff	230	25.8	21.3	25.5	32.6	11.3
San Ber_dino	230	24.8	41.2	24.8	41.3	0.1
San Onofre	230	15.5	42.4	15.4	42.6	0.2
Serrano	230	18.1	59	18.1	59.3	0.3
Sylmar (SCE)	230	12.5	67.9	12.5	68	0.1
Villa Park	230	16.9	43.7	16.8	43.9	0.2
Vincent A	230	19.8	65.5	19.9	65.9	0.4
Vincent B	230	19.8	65.5	19.9	65.9	0.4
Vista	230	16.6	44	16.6	44.2	0.2
Whirlwind	230	30.5	53.1	31.7	56.8	3.7
Windhub_A	230	40.4	39.1	40.9	39.4	0.3
Windhub_B	230	46.7	38.3	46.4	39.8	1.5

ALBH115	115	45.4	24.3	45.3	24.5	0.2
Altwind	115	9	14	9	14.2	0.2
Devers	115	42.2	30.9	41.4	31.5	0.6
Farrell	115	9.9	12.9	9.8	13	0.1
Garnet	115	14.6	17.6	14.4	17.7	0.1
Kramer	115	11.9	25.5	11.9	25.8	0.3
Terawind	115	12.6	20.5	12.4	20.7	0.2
Tiffanywind	115	10.7	17.7	10.6	17.9	0.2
Valley AB	115	53.1	26.8	52.9	27.1	0.3
Valley C	115	47.9	44.4	47.7	44.8	0.4
Victor	115	17.4	26.9	17.3	27.6	0.7
Vista	115	26.3	22.4	26.6	22.7	0.3
ANTELOPE	66	22.5	22.8	25.3	24.4	1.6
CAL CEMENT	66	9.6	11.6	9.6	11.9	0.3
GREAT LAKES	66	4.1	2.1	4.1	2.3	0.2
Purify	66	3.9	3.1	6	3.4	0.3
Ritter Ranch	66	9	5.5	9.1	5.7	0.2
Windhub66	66	23.8	25.5	23.7	26.6	1.1
Lockhart	230	15.1	13.6	14.9	13.6	0.1
Victor	230	12.1	21.4	11.4	22.5	1.1
Sanwind	115	8.1	10.8	8.1	11.3	0.4
Venwind	115	6.5	13.3	6.4	13.4	0.1
DEL SUR	66	9.0	11.9	8.8	12.8	0.8
GOLDTOWN	66	8.9	5.2	8.2	7.6	2.4
OASIS	66	6.7	5.1	7.1	6.3	1.3
ROSAMOND	66	5.0	4.9	5.3	6.5	1.6

Appendix I: Deliverability Assessment Results

Table 1 provides a summary of the post-QC1 & QC2 contingency analysis overload results identified for the East of Pisgah study without any mitigation, including QC1 & QC2 projects within the 5% Circles that triggered each overload. These results present all post-QC1 & QC2 overload violations that need to be addressed due to addition of the QC1 & QC2 generation projects located in the East of Pisgah, Eastern Subareas and the SDG&E system, and QC1 & QC2 projects that shall be responsible to each overload.

Table 1: QC1 & QC2 Deliverability Study – East of Lugo Bulk System Contingency Analysis Summary without Delivery Network Upgrade Mitigations*

Contingency	Overloaded Facility	Project Queue	DFAX	Applicable Rating (MVA)	Overload
				MW	%
Normal Condition	SCE Eldorado 500/220 kV AA Bank	C503	98%	1120	113%
		C502	95%		
		C488	98%		
		C491	28%		
15021 PALOVRDE 500.0 kV To: 24900 ClrdoRvr 500.0 kV Ckt 1	24086 LUGO 500.00 kV to 26105 VICTORVL 500.00 kV Ckt 1	C488	27%	2598	103%
		C502	26%		
		C503	27%		
		C593	14%		
		C509	6%		
		C510	11%		
		C493	11%		
		C565	7%		
		C555	10%		
		C574	7%		
		C590	11%		
		C608	11%		
		C561	11%		
24086 LUGO 500.0 kV To: 24226 PISGAH 500.0 kV Ckt 1 24086 LUGO 500.0 kV To: 24226 PISGAH 500.0 kV Ckt 2	24086 LUGO 500.00 kV to 26105 VICTORVL 500.00 kV Ckt 1	C488	31%	2598	120%
		C502	30%		
		C503	31%		
		C576	5%		
		C593	19%		
		C509	6%		
		C510	11%		
		C493	10%		
		C565	7%		
		C555	10%		

		C574	7%		
		C590	11%		
		C608	11%		
		C561	11%		
24086 LUGO 500.0 kV To: 24226 PISGAH 500.0 kV Ckt 1 24086 LUGO 500.0 kV To: 24226 PISGAH 500.0 kV Ckt 2	24086 LUGO 500.00 kV to 29414 HOMER 500.00 kV Ckt 1	C488	22%	2221	107%
		C502	21%		
		C503	22%		
		C576	6%		
		C593	42%		
		C509	5%		
		C510	8%		
		C493	8%		
		C565	6%		
		C555	8%		
		C574	6%		
		C590	8%		
		C608	8%		
		C561	8%		
24900 ClrdoRvr 500.0 kV To: 28195 RedBluff 500.0 kV Ckt 1 24900 ClrdoRvr 500.0 kV To: 28195 RedBluff 500.0 kV Ckt 2	22536 N.GILA 500.00 kV to 22360 IMPRLVLY 500.00 kV Ckt 1	C488	12%	2572	115%
		C491	6%		
		C502	11%		
		C503	12%		
		C576	28%		
		C593	9%		
24900 ClrdoRvr 500.0 kV To: 28195 RedBluff 500.0 kV Ckt 1 24900 ClrdoRvr 500.0 kV To: 28195 RedBluff 500.0 kV Ckt 2	24086 LUGO 500.00 kV to 26105 VICTORVL 500.00 kV Ckt 1	C488	27%	2598	119%
		C502	25%		
		C503	27%		
		C576	19%		
		C593	14%		
		C509	6%		
		C510	10%		
		C493	10%		
		C565	7%		
		C555	10%		
		C574	7%		
		C590	10%		
		C608	10%		
		C561	10%		
24801 DEVERS 500.0 kV To: 28195 RedBluff 500.0 kV Ckt 1 24801 DEVERS 500.0 kV To: 28195 RedBluff 500.0 kV Ckt 2	22536 N.GILA 500.00 kV to 22360 IMPRLVLY 500.00 kV Ckt 1	C488	12%	2572	116%
		C491	6%		
		C502	11%		
		C503	12%		
		C576	28%		

		C588	28%		
		C593	9%		
24801 DEVERS 500.0 kV To: 28195 RedBluff 500.0 kV Ckt 1 24801 DEVERS 500.0 kV To: 28195 RedBluff 500.0 kV Ckt 2	24086 LUGO 500.00 kV to 26105 VICTORVL 500.00 kV Ckt 1	C488	27%	2598	124%
		C502	25%		
		C503	27%		
		C576	19%		
		C588	19%		
		C593	14%		
		C509	6%		
		C510	10%		
		C493	10%		
		C565	7%		
		C555	10%		
		C574	7%		
		C590	10%		
		C608	10%		
		C561	10%		
24801 DEVERS 500.0 kV To: 28195 RedBluff 500.0 kV Ckt 1	24801 DEVERS 500.00 kV to 28195 RedBluff 500.00 kV Ckt 2	C488	6%	2987	125%
		C502	6%		
		C503	6%		
		C576	60%		
		C588	68%		
		C510	8%		
		C493	9%		
		C565	6%		
		C555	8%		
		C574	6%		
		C590	8%		
		C608	8%		
		C561	8%		
94828 PRIMM 230 kV to 94764 ELDORADO2 230 kV Ckt 1	Load flow diverded for Single Eldorado-Primm 230 kV line outage	C502	NA	NA	NA

Table 2 provides a summary of the post-QC1 & QC2 contingency analysis overload results identified for the East of Pisgah study with all the Delivery Network Upgrades proposed for the East of Pisgah, Eastern, and SDG&E subareas. These results are used to further examine additional needs, such as Special Protections Schemes to trip generations or to bypass the series capacitors.

Contingency	Overloaded Facility	Project Queue	DFAX	Applicable Rating	Overload
				MW	%
15021 PALOVRDE 500.0 kV To: 24900 ClrdoRvr 500.0 kV Ckt 1	24086 LUGO 500.00 kV to 26105 VICTORVL 500.00 kV Ckt 1	C488	27%	2598	105%
		C503	27%		
		C502	26%		
		C593	16%		
		C510	11%		
		C493	11%		
		C590	11%		
		C608	11%		
		C561	11%		
		C555	10%		
		C565	7%		
		C574	7%		
		C509	6%		
24086 LUGO 500.0 kV To: 24226 PISGAH 500.0 kV Ckt 1 24086 LUGO 500.0 kV To: 24226 PISGAH 500.0 kV Ckt 2	24086 LUGO 500.00 kV to 26105 VICTORVL 500.00 kV Ckt 1	C503	31%	2598	110%
		C593	24%		
		C488	31%		
		C510	10%		
		C493	10%		
		C574	7%		
		C590	10%		
		C608	10%		
		C561	10%		
		C502	30%		
		C509	6%		
		C565	7%		
		C555	10%		
24226 PISGAH 500.0 kV To: 29415 NIPTON 500.0 kV Ckt 1 24041 ELDORDO 230.0 kV To: 24219 PISGAH 230.0 kV Ckt 2	24086 LUGO 500.00 kV to 26105 VICTORVL 500.00 kV Ckt 1	C488	31%	2598	101%
		C502	29%		
		C503	31%		
		C593	19%		
		C509	6%		
		C510	10%		
		C493	10%		

		C565	7%		
		C555	10%		
		C574	7%		
		C590	10%		
		C608	10%		
		C561	10%		
94828 PRIMM 230 kV to 94764 ELDORADO2 230 kV Ckt 1	Load flow diverded for Single Eldorado-Primm 230 kV line outage	C502	NA	NA	NA

Table 3A. Cost Allocation Factors of Delivery Network Upgrades

Upgrades	Type	Needed for	Phase II Project Queue	Area	Cost Allocation Factor(%)
Add SCE-owned Eldorado No.2 AA Bank	Reliability	SCE-owned Eldorado No.1 AA bank Normal Overload			27.8%
					19.6%
					5.9%
					46.8%
Homer-Lugo 500 kV line looped into Pisgah 500 kV Sub. Add series cap banks on Nipton-Pisgah and Homer-Pisgah 500 kV lines	Delivery	Lugo-Pisgah 500 kV double line outage overload Lugo-Victorville and Lugo-Homer line			6.6%
					1.4%
					11.1%
					7.9%
					34.3%
					5.4%
					5.9%
					2.3%
					1.8%
					7.1%
					4.0%
					6.7%
					5.4%
Redbluff-ValleySC line	Delivery	Devers-Redbluff 500kV double line outage overloads lugo-victorville and N.Gila-Imperial Valley line			0.9%
					0.0%
					0.2%
					1.5%
					46.0%
					20.5%
					2.0%
					4.2%
					4.4%
					1.5%
					1.3%
					4.7%
					3.2%
					5.3%
					4.2%
Redbluff-colorado river 3rd line	Delivery	Colorado river-Redbluff 500kV double line outage overloads lugo-victorville line			1.3%
					0.3%
					2.2%
					66.2%

					3.0%
					3.8%
					4.6%
					1.6%
					1.3%
					4.6%
					2.8%
					4.7%
					3.8%

Table 3B. Cost Allocation Factors of Reliability Network Upgrades Identified in Delivery Assessment

SPS Upgrade	Type	Needed for	Project queue	Area	Cost Allocation Factors
SPS #1: to trip 700 MW generation located in the EOL area	Reliability	LUGO - VICTORVL 500 kV Tie Overload for PalaVerde - Colorado River 500 kV line outage			27%
					27%
					26%
					16%
SPS #2: to trip 1400 MW generation located in the EOL area	Reliability	LUGO - VICTORVL 500 kV Tie Overload for any Pisgah - Lugo 500 kV lines N-2 outages			31%
					24%
					31%
					30%
SPS #3: to trip about 200 MW generations located in the Eldorado area	Reliability	LUGO - VICTORVL 500 kV Tie Overload for the Pisgah - Nipton 500 kV line and Eldorado-Pisgah 220 kV N-2 outages			31%
					29%
					31%
					19%
SPS-4 to trip gens at Ivanpah	Reliability	Load flow diverded for Single Eldorado-Primm 230 kV line outage			100%