Development Plan for the
Phased Expansion of

Electric Power Transmission Facilities
in the
Tehachapi Wind Resource Area

Second Report
of the
Tehachapi Collaborative Study Group

Volume 2: Appendices

California Public Utilities Commission

OII 05-09-005
OII 00-11-001

April 19, 2006

APPENDIX 1

APPENDIX 1

Continuation of Tehachapi Collaborative Study

Study Plan #2

Purpose

The purpose of this continuation of the Tehachapi Collaborative Study is to formulate a plan for the transmission of 4,000MW of wind generation at Tehachapi and 500MW in the Antelope Valley to load centers in the PG&E and SCE service areas. It is assumed that half the 4,000 MW at Tehachapi will go to PG&E and half will go to SCE. The plan resulting from this study will be sufficient to initiate the preparation of Proponent's Environmental Assessments (PEAs) which will form the basis of CPCN applications for the facilities defined in the plan. The plan covers only the facilities from Tehachapi Substation 1 to the load centers and does not include the Tehachapi collector system. It is envisioned that this transmission plan may be fine-tuned to accommodate each (or each group of) specific wind plant projects as they move through the ISO Interconnection Process and as the Tehachapi collector loop beyond Tehachapi Substation 1 becomes more precisely defined.

Background

Pursuant to CPUC Decision 04-06-010, the Tehachapi Collaborative Study Group (TCSG) was formed to develop a comprehensive transmission development plan for the phased expansion of transmission capabilities in the Tehachapi area. The CPUC Staff coordinated the collaborative study group. As directed by the decision, TCSG completed a study that assumed there would be more than 4,000 MW of wind resources at Tehachapi Wind Area[1]. To conduct the study the TCGS further assumed that 50% of the 4,000 MW would be delivered to load centers in the transmission system North of Path 26 and the remaining 50% would be delivered to load centers in the system south of Path 26[2]. The Executive Director extended the original due date for filing the report, by one week by letter dated March 4, 2005. The report entitled, "Development Plan for the Phased Expansion of Transmission in the Tehachapi Wind Resource Area" (Report), was filed by Southern California Edison (SCE) on March 16, 2005.

As stated in the Report, the development plan prepared by the TCSG is a conceptual roadmap to the eventual Tehachapi transmission system rather than a definitive plan[3].

---

[1] Decision 04-06-010, at 6
[2] Study Plan, date July 14, 2004, at 18
[3] Report, at 3

The Report recommended that further study be performed to select among the alternatives identified in the Report (and referred to herein with the same identification numbers as in the Report). These alternatives require further planning evaluation in order to formulate a single plan for implementation. To do this, additional studies (specific rather than generic) need to be performed and facility cost estimates refined. The final plan for the Tehachapi collector system requires information concerning actual wind project locations and capacities which are not available at this time, and therefore is not covered in the study. However, it is envisioned that the transmission plan may be fine-tuned in the future as each (or each group of) specific wind plant projects moves through the ISO Interconnection Process and the Tehachapi collector loop beyond Tehachapi Substation 1 becomes more precisely defined.

The CPUC Energy Division convened a study group consisting of CPUC Staff, CAISO, SCE and PG&E. The study group will be coordinated by the CPUC Staff. This new study plan will build on the earlier TCSG Study Plan, dated July 14, 2004 (Attachment A), and utilizes essentially the same study assumptions. As such, only exceptions to those earlier assumptions will be noted in this study plan.

1. Fresno 230 kV Tie: Big Creek – Fresno Interconnection

Establish a new 230 kV connection between PG&E and SCE by constructing a switching station at the crossing of PG&E-owned and SCE-owned transmission lines and installing a phase-shifting transformer to "push" power from the Big Creek corridor into the PG&E system. This study will investigate impacts on the SCE system and the PG&E system, the possible mitigation measures, and provide cost estimates for the connection and the mitigation measures associated with the amounts of power that would be "pushed" into the PG&E system. The studies will evaluate "pushing" 300 MW to 1,200 MW in successive increments. The study will consider PG&E Alternative 2, Plan A alone and in conjunction with PG&E Alternative 2, Plan B.
The cost per megawatt transferred will be evaluated to determine the optimum capacity of the connection.

1.1. Alternative 2: PG&E and SCE Fresno 230 kV Tie Plan A.

Build a switching station at the crossing of PG&E's Helms – Gregg 230 kV lines and SCE's Big Creek – Rector 230 kV lines. Establish a 230 kV tie between PG&E and SCE. A phase shifter or power flow controller may be needed to control the tie line flow.

1.2. Alternative 2: PG&E and SCE Fresno 230 kV Tie Plan B.

Build a switching station at the crossing of PG&E's Haas-McCall and Balch-McCall 230 kV lines and SCE's Big Creek – Rector 230 kV lines. Establish a 230 kV tie between PG&E and SCE. A phase shifter or power flow controller may be needed to control the tie line flow.

A. SCE Studies

Base Case Assumptions

SCE will utilize the load forecast currently under development for the upcoming CAISO Controlled SCE Transmission Expansion Plan. Studies for evaluating the two plans will be conducted assuming both heavy summer and spring load forecast in order to ensure that system performance is maintained within allowable thermal limits. Heavy summer load forecast will include a 1-in-10 year heat wave adjustment consistent with CAISO Planning Standards. Light Spring conditions will be modeled with load at 50% of summer peak consistent with study assumptions utilized in performing generation interconnection studies in the Big Creek Corridor.

Power Flow Studies

Power flow studies will be conducted by systematically increasing the power transfer from SCE to PG&E through the phase-shifted system tie. The increment step size will be 100 MW.

a. North of Magunden study

   i. Increase power transfer into the PG&E system at the Fresno 230kV tie (Plan A and Plan A in conjunction with Plan B); investigate system performance under normal (all facilities in service) conditions and under NERC/WECC Category B (N-1) contingencies and 230 kV common corridor lines in the Big Creek Corridor. (See Appendix A for a list of contingencies to be studied.) Where the system does not meet the Planning Standards, develop mitigation measures, such as the addition of a transmission upgrade.

   ii. Repeat step 1 until the power transfer reaches between 1,000 MW to 1,200 MW.

   iii. Develop cost estimates corresponding to each power transfer level

b. South of Magunden study

   i. Repeat the North of Magunden Study, for transmission system south of Magunden.

B. PG&E Studies

The study will include two different scenarios, namely, summer peak and off-peak conditions. The objectives for developing summer peak and off-peak cases are to identify transmission import and reliability concerns during both conditions. The following Table 1 describes the critical study assumption for the two scenarios proposed for this study.

Base Case Assumptions

For summer peak studies PG&E will use the summer peak base case developed for the 2005 PG&E Transmission Grid Assessment Study. This case is being developed. PG&E will send the PG&E case to the ISO for approval, but PG&E's work will not be delayed pending this approval. For the summer off peak case, the load for the Greater Fresno Area will be modeled at 50 % of the peak load from summer peak base case for the study area.

Study Scenarios

1.3. Study Scenarios	1.4. Summer peak	1.5. Summer Off peak
Starting base case	2005 PG&E Grid Expansion Study, 2010 Heavy Summer North Peak case	2005 PG&E Grid Expansion Study, 2010 Summer Off-peak case
Fresno load level	PG&E 1 in 5 year adverse weather load forecast for 500 kV system studies, and 1 in 10 year adverse weather load forecast for Greater Fresno Area for 230 kV system studies	50 % of 2010 summer peak case for the area.
Helms units	3 units generation	3 units pumping depending on the import level to find boundary conditions
Hydro dispatch	Summer peak average hydro level	Summer off-peak average hydro level
COI	4800 MW (n to s)	3650 MW (s to n)
Path 15 flow		5400 MW (s to n) or other relevant operating limit(s)
Path 26 flow	3700 MW (n to s)	<3000 MW (s to n)
Sensitive study	1. Spring hydro spill condition	Spring light load case with

	2. Path 26 4000 MW N-S	Helms PGP units Off line

Sensitivities may be run depending on the initial results.

1.6. Generation Assumptions in addition to those used in the earlier TCSG Study

Kingsburg and Sanger Qualifying Facility units will be assumed off for the summer off peak case as per the existing contracts for these units.

SCE will furnish the model to be used for the Tehachapi collector system in the absence of firm wind developer commitments. GE Wind generators will be used for the wind plant model and SVCs (at various locations) will be sized as required to provide voltage and transient stability.

1.7. Fresno 230 kV Tie Assumptions

SCE and CAISO will provide the necessary data for SCE load, network topology, generation level and pattern for the Big Creek facility. The data provided and approved by CAISO for the SCE system will be used in the base case. ISO will provide data on expected wind generation variations, such as, expected wind generation changes in MW/sec.

1.8. Technical Analyses

The technical analysis will include the following:

a. For each of the base case and study alternatives, Power Flow simulations will be carried out for the following CAISO contingency Categories in the Greater Fresno Area:

    i. ISO Category “B”: B1, B2, B3 and overlapping line and generator outage in the study area. (See Appendix B for a list of contingencies).

    ii. ISO Category “C” list for 500 KV outages, 230 kV common tower line outages in the Greater Fresno Area, and 230 kV common corridor lines in the Big Creek Corridor, also listed in Appendix B.

b. Run Post Transient and Voltage Stability simulations for critical Categories B and C contingencies to assess the reactive support requirements and potential facility overloads on the more promising alternatives.
c. Run Transient stability simulations of critical Categories B and C contingencies .

2. Further Studies on PG&E Alternatives 4 and 5

The earlier conceptual study results show that the cost estimates for PG&E Alternatives 4 and 5 are practically the same. To select the preferred alternative, more detailed studies using more specific information are needed.

A. PG&E Alternative 4

No voltage Stability study or transient stability study was conducted in the conceptual study. To form a more definitive selection of the alternatives, these studies need to be run based on selected Categories B and C contingencies in Appendix B.

B. PG&E Alternative 5

In the earlier conceptual study, Alternative 5 included a 500 kV line between Tehachapi and Gregg. This study will investigate if this Gregg – Tehachapi 500 kV line can be separated into two sections:

- Gregg – Midway 500 kV line
- Tehachapi – Midway 500 kV line

a. Run Power flow simulations for normal and single and double contingencies based on the list of ISO Categories B and C contingencies. (See Appendix B).

b. Run Post Transient and Voltage Stability simulations for critical Categories B and C contingencies to assess the reactive support requirements and potential facility overloads on the most promising alternatives..

c. Run Transient stability simulations critical Categories B and C contingencies on the most promising alternatives.

3. Further Studies on SCE Alternatives

SCE's Alternatives 1, 2, 3 and 10 will be studied as described above for PG&E Alternatives 4 and 5.

4. Production Simulation Study

The CAISO will run production simulation models to determine the production costs, congestion costs and system losses associated with the various transmission alternatives using the SSG-WI data base for study year 2008 after it is updated. The purpose of this portion of the study is to help in answering the following questions:

a. How would the Fresno 230 kV Tie be operated? How frequently would the angle change and how large would the flow be across the phase shifter?
b. How would the Helms pumped storage plant operation change with the addition of the Tehachapi generation?
c. Would the potential line additions north of Midway provide a substantial economic benefit?
d. If a line is constructed north of Midway, what is to preferred termination?
e. How would the addition of the Tehachapi generation impact the operation of the generators connected at Midway and in other areas of the system?
f. What is the optimum combination of the Fresno 230 kV Tie, PG&E's Alternatives 4 and 5 and SCE's Alternatives 1, 2, 3 and 10.
g. Would the adding a line between Tehachapi and Midway instead of from Tehachapi south help transmit Tehachapi generation to PG&E? If so, at what level of Tehachapi generation?
h. Would adding a line between Tehachapi and Midway benefit the transmission system more than adding a line from Tehachapi south? If so, identify the party or parties that benefit(s).

A. <u>Assumptions:</u>

Hydro conditions: Initially average and high hydro will be studied. Additional studies to examine high and low hydro scenarios will be conducted as necessary. For Fresno 230 kV Tie, PG&E will need to consider high hydro conditions, since this alternative would inject power into a generating system. SCE considers all hydro conditions as valid conditions that need to be explored.

Gas cost: Modeled per SSG-WI base case assumptions.

Coal cost: Modeled per SSG-WI base case assumptions.

Wind modeling: The wind generation will be modeled as non-dispatchable, fixed hourly generation quantities. Two wind generation output models will be studied. One that has been developed by NREL and others and a second that is simply a scaling up of the existing Tehachapi historical output. The production simulation runs will determine the megawatthours of wind generation used. The cost assigned to wind generation will be determined as part of this study and will be applied to the wind generation quantity determined in each run to yield the total production cost.

New resources will be included as modeled by SSG-WI, which will be consistent with each LSE's filed Long Term Plans.

Path ratings, line ratings, and nomograms: Modeled per SSG-WI base case assumptions.

Selected non-simultaneous Ratings:
COI: 4,800 MW N-S; 3,675 MW S-N
Path 15: 3,265 MW N-S; 5,400 MW S-N

Path 26: 3,700 MW N-S; 3,000 MW S-N

Additional limits to be modeled:

a. Path 26: Power flow between 3,000 MW and 3,700 MW N-S is supported by a RAS that trips Midway area generation. The Path 26 limit will be decreased by 1 MW for every 1 MW decrease in Midway generation (La Paloma, Sunrise, Elk Hills)

b. Path 15: 5,400 MW S-N is supported by RAS that trips generation connected to Midway. The Path 15 limit will be decreased by 1 MW for every 2 MW decrease in Midway generation (La Paloma, Sunrise, Elk Hills).

c. Run power flow and stability studies to see if there is a simultaneous interaction between the Fresno 230 kV Tie and Path 26. If there is, model the nomogram in the production simulation.

d. SCIT nomogram: Either from existing SCIT nomogram studies or assume no more than 60% of SCE's load would be supplied from imports into Southern California.

B. Study Scenarios

Tehachapi and Antelope Valley wind generation = 0 MW

a. Existing system after completion of SCE's Phase 1 Facilities, Segments 1, 2 and 3

b. Same as (a) but with the Fresno 230 kV Tie
Phase shifter setting to be determined.

Tehachapi and Antelope Valley wind generation = 1600 MW

c. Existing system plus SCE Phase 1 and Phase 2 facilities.
d. Same as a, but with the Fresno 230 kV Tie.

Tehachapi and Antelope Valley wind generation = 4,500 MW without Fresno 230kV tie

e. Existing System after completion of SCE's Phase 1 and Phase 2 facilities.
f. PG&E Alternative 4 with SCE Alternative 1, i.e., Tesla-Los Banos-Gates-Midway-Tehachapi, Tehachapi-Antelope, Antelope-Vincent and Antelope-Pardee. (Total of two lines between Tehachapi-Antelope)
g. PG&E Alternative 4, modified to remove Tehachapi-Midway line, and SCE Alternative 2, i.e., Tesla-Los Banos-Gates-Midway, and Tehachapi-Antelope-Vincent, Tehachapi-Vincent and Antelope-Pardee (Two lines between Tehachapi-Antelope and one Tehachapi-Vincent)
h. PG&E Alternative 5 with SCE Alternaitve 1

i. PG&E Alternative 5 modified to replace Gregg-Tehachapi with Gregg-Midway with SCE Alternative 1, i.e., Tesla-Los Banos-Gregg-Midway-Tehachapi-Antelope–Vincent and Antelope-Pardee. (Total of two lines between Tehachapi-Antelope)
j. PG&E Alternative 5, modified to replace Gregg-Tehachapi with Gregg-Midway line and SCE Alternative 2, i.e., Tesla-Los Banos-Gregg-Midway; and Tehachapi-Antelope-Vincent, Tehachapi-Vincent and Antelope-Pardee (Total of two lines between Tehachapi-Antelope).

Tehachapi and Antelope Valley wind generation = 3,300 MW

k. Same as f, above.
l. Same as h, above.
m. Tesla-Gregg, with Fresno 230kV tie, two 500kV lines Tehachapi-Antelope.
n. Tesla-Los Banos-Gates-Midway, with Fresno 230kV tie, two 500kV lines Tehachapi-Antelope

Based on the above, choose the best PG&E alternative.

o. Fresno 230 kV Tie with SCE Alternative 2

p. Best PG&E alternative with SCE Alternative 3

q. Best PG&E alternative with SCE Alternative 10

5. Cost Estimation of Facilities

All costs associated with the Fresno 230 kV Tie, PG&E Alternatives 4 and 5 and SCE Alternatives 1, 2, 3 and 10, including engineering and permitting, purchase of equipment and rights-of way, construction, interest during construction, contract administration, etc. will be estimated in 2005 dollars

6. Determination of Recommended Plan

The present value of the costs given by the production simulation runs in Section 4, above, plus the wind generation costs, over 30 years, at a discount rate to be established in the study, will be added to the costs of the facilities, determined in Section 5, above, to obtain the least cost combination of alternatives. This total present value cost will also be expressed as a series of annual costs.

This combination of alternatives will be the recommended plan.

7. Study Schedule

WORK ITEM	START	FINISH	2005 May	June	July	Aug	Sep	Oct	Nov	Dec	2006 Jan	Feb
SCE: Fresno 230 kV Tie PG&E Plan A, N of Magunden power flow	5/1/05	6/1/05										
SCE: Fresno 230 kV Tie PG&E Plan A, S of Magunden power flow	6/1/05	7/1/05										
SCE: Fresno 230 kV Tie PG&E Plan A with Plan B power flow	7/1/05	8/1/05										
PG&E: Base Case Available	6/1/05			o								
PG&E: Fresno 230 kV Tie power flow	6/1/05	7/1/05										
Meeting of Participants at PG&E	6/28/05				o							
SCE & PG&E: Fresno facilities cost estimate	6/1/05	9/1/05										
CA ISO: first results of production simulations	7/1/05	9/1/05										
All: determine optimum capacity of Fresno Tie: Plan A or A & B	9/1/05	10/1/05										
SCE & PG&E: cost of facilities for all alternatives	6/1/05	11/1/05										
CA ISO final report on results of production simulations	9/1/05	11/1/05										
CPUC: calculates ranking of combinations of alternatives	11/1/05	11/15/05										
Meeting of Participants	11/15/05								o			
CA ISO operator report on compatibility of Fresno Intertie	10/1/05	12/15/05										
CPUC: Develop Table of Contents	10/1/05	11/1/05										
ALL: draft report	11/1/05	12/15/05										
CPUC: Final Report	12/15/05	3/1/06										

ERRATA: CAISO 12/15/05 operator report topic should read “system operability with 4500MW of wind generation at Tehachapi/Antelope Valley”.

Appendix A
SCE list of on Contingencies

Table 1
Single Contingency Outage List

Outage Number	From Bus No.	To Bus No.	From Bus		To Bus		Circuit ID
			Name	Voltage	Name	Voltage	
N1-1	24301	24302	BIG CRK1	230	BIG CRK2	230	1
N1-2	24301	24320	BIG CRK1	230	EASTWOOD	230	1
N1-3	24302	24303	BIG CRK2	230	BIG CRK3	230	1
N1-4	24302	24305	BIG CRK2	230	BIG CRK8	230	1
N1-5	24304	24303	BIG CRK4	230	BIG CRK3	230	1
N1-6	24305	24303	BIG CRK8	230	BIG CRK3	230	1
N1-7	24316	24303	MAMMOTH	230	BIG CRK3	230	1
N1-8	24303	24235	BIG CRK3	230	RECTOR	230	2
N1-9	24301	25900	BIG CRK1	230	FRSNOSCE	230	1
N1-10	24303	25900	BIG CRK3	230	FRSNOSCE	230	1
N1-11	30820	39000	HELMS PP	230	FRSNOPGE	230	1
N1-12	30820	39000	HELMS PP	230	FRSNOPGE	230	2
N1-13	30810	39000	GREGG	230	FRSNOPGE	230	1
N1-14	30810	39000	GREGG	230	FRSNOPGE	230	2
N1-15	24235	25900	RECTOR	230	FRSNOSCE	230	1
N1-16	24235	25900	RECTOR	230	FRSNOSCE	230	2
N1-17	24141	24304	SPRINGVL	230	BIG CRK4	230	1
N1-18	24141	24235	SPRINGVL	230	RECTOR	230	1
N1-19	24153	24235	VESTAL	230	RECTOR	230	1
N1-20	24235	24153	RECTOR	230	VESTAL	230	2
N1-21	24235	24087	RECTOR	230	MAGUNDEN	230	1
N1-22	24087	24141	MAGUNDEN	230	SPRINGVL	230	1
N1-23	24087	24141	MAGUNDEN	230	SPRINGVL	230	2
N1-24	24087	24153	MAGUNDEN	230	VESTAL	230	1
N1-25	24087	24153	MAGUNDEN	230	VESTAL	230	2
N1-26	24142	24101	SYC CYN	230	OMAR	230	1
N1-27	24087	24101	MAGUNDEN	230	OMAR	230	1
N1-28	24087	24115	MAGUNDEN	230	PASTORIA	230	1
N1-29	24087	24115	MAGUNDEN	230	PASTORIA	230	2

N1-30	24087	24115	MAGUNDEN	230	PASTORIA	230	3
N1-31	24087	24401	MAGUNDEN	230	ANTELOPE	230	2
N1-32	24087	27020	MAGUNDEN	230	TEHACH_5	230	1
N1-33	24401	27020	ANTELOPE	230	TEHACH_5	230	1
N1-34	24401	27000	ANTELOPE	230	TEHACH_6	230	1
N1-35	24115	25613	PASTORIA	230	EDMONSTN	230	1
N1-36	24115	28050	PASTORIA	230	LEBEC	230	1
N1-37	24114	24115	PARDEE	230	PASTORIA	230	1
N1-38	24114	24217	PARDEE	230	WARNETAP	230	1
	24115	24217	PASTORIA	230	WARNETAP	230	1
	24218	24217	WARNE	230	WARNETAP	230	1
N1-39	24403	24115	BAILEY	230	PASTORIA	230	1
N1-40	24114	24403	PARDEE	230	BAILEY	230	1
N1-41	24114	24155	PARDEE	230	VINCENT	230	1
N1-42	24155	24091	VINCENT	230	MESA CAL	230	1
N1-43	24155	24126	VINCENT	230	RIOHONDO	230	1
N1-44	24155	24126	VINCENT	230	RIOHONDO	230	3
N1-45	24091	24126	MESA CAL	230	RIOHONDO	230	1
N1-46	24091	24126	MESA CAL	230	RIOHONDO	230	2
N1-47	24076	24126	LAGUBELL	230	RIOHONDO	230	1
N1-48	24114	24147	PARDEE	230	SYLMAR S	230	1
N1-49	24114	24147	PARDEE	230	SYLMAR S	230	2
N1-50	24036	24114	EAGLROCK	230	PARDEE	230	1
N1-51	24147	24089	SYLMAR S	230	GOULD	230	1
N1-52	24036	24147	EAGLROCK	230	SYLMAR S	230	1
N1-53	24086	24156	LUGO	500	VINCENT	500	1
N1-54	24086	24156	LUGO	500	VINCENT	500	2
N1-55	24156	24092	VINCENT	500	MIRALOMA	500	1
N1-56	24500	24156	ANTELOPE	500	VINCENT	500	1
N1-57	24500	24156	ANTELOPE	500	VINCENT	500	2
N1-58	24500	24510	ANTELOPE	500	PARDEE	500	1
N1-59	24520	24500	TEHACHPI	500	ANTELOPE	500	1
N1-60	24520	24500	TEHACHPI	500	ANTELOPE	500	2
N1-61	24520	30060	TEHACHPI	500	MIDWAY	500	1
N1-62	30060	24156	MIDWAY	500	VINCENT	500	1
N1-63	30060	24156	MIDWAY	500	VINCENT	500	2
N1-64	30060	24156	MIDWAY	500	VINCENT	500	3
T1-1	25900	39000	FRSNOSCE	230	FRSNOPGE	230	1
T1-2	24156	24155	VINCENT	500	VINCENT	230	1
T1-3	24092	24093	MIRALOMA	500	MIRALOMA	230	1
T1-4	24500	24401	ANTELOPE	500	ANTELOPE	230	1
T1-5	24510	24114	PARDEE	500	PARDEE	230	1

Table 2
Double Contingency Outage List

Outage Number	From Bus No.	To Bus No.	From Bus		To Bus		Circuit ID
			Name	Voltage	Name	Voltage	
N2-1	24301	25900	BIG CRK1	230	FRSNOSCE	230	1
	24303	25900	BIG CRK3	230	FRSNOSCE	230	1
N2-2	24235	25900	RECTOR	230	FRSNOSCE	230	1
	24235	25900	RECTOR	230	FRSNOSCE	230	2
N2-3	24303	24235	BIG CRK3	230	RECTOR	230	2
	24141	24304	SPRINGVL	230	BIG CRK4	230	1
N2-4	24303	24235	BIG CRK3	230	RECTOR	230	2
	24141	24235	SPRINGVL	230	RECTOR	230	1
N2-5	24141	24304	SPRINGVL	230	BIG CRK4	230	1
	24141	24235	SPRINGVL	230	RECTOR	230	1
N2-6	30820	39000	HELMS PP	230	FRSNOPGE	230	1
	30820	39000	HELMS PP	230	FRSNOPGE	230	2
N2-7	30810	39000	GREGG	230	FRSNOPGE	230	1
	30810	39000	GREGG	230	FRSNOPGE	230	2
N2-8	24153	24235	VESTAL	230	RECTOR	230	1
	24235	24153	RECTOR	230	VESTAL	230	2
N2-9	24153	24235	VESTAL	230	RECTOR	230	1
	24235	24087	RECTOR	230	MAGUNDEN	230	1
N2-10	24235	24153	RECTOR	230	VESTAL	230	2
	24235	24087	RECTOR	230	MAGUNDEN	230	1
N2-11	24087	24141	MAGUNDEN	230	SPRINGVL	230	1
	24087	24141	MAGUNDEN	230	SPRINGVL	230	2
N2-12	24087	24153	MAGUNDEN	230	VESTAL	230	1
	24087	24153	MAGUNDEN	230	VESTAL	230	2
N2-13	24087	24115	MAGUNDEN	230	PASTORIA	230	1
	24087	24115	MAGUNDEN	230	PASTORIA	230	2
N2-14	24087	24115	MAGUNDEN	230	PASTORIA	230	1
	24087	24115	MAGUNDEN	230	PASTORIA	230	3
N2-15	24087	24115	MAGUNDEN	230	PASTORIA	230	2
	24087	24115	MAGUNDEN	230	PASTORIA	230	3
N2-16	24087	24401	MAGUNDEN	230	ANTELOPE	230	2
	24087	27020	MAGUNDEN	230	TEHACH_5	230	1
N2-17	24087	24401	MAGUNDEN	230	ANTELOPE	230	2
	24401	27020	ANTELOPE	230	TEHACH_5	230	1

N2-18	24403	24115	BAILEY	230	PASTORIA	230	1
	24114	24217	PARDEE	230	WARNETAP	230	1
	24115	24217	PASTORIA	230	WARNETAP	230	1
	24218	24217	WARNE	230	WARNETAP	230	1
N2-19	24403	24115	BAILEY	230	PASTORIA	230	1
	24114	24217	PARDEE	230	WARNETAP	230	1
	24115	24217	PASTORIA	230	WARNETAP	230	1
	24218	24217	WARNE	230	WARNETAP	230	1
N2-20	24114	24115	PARDEE	230	PASTORIA	230	1
	24114	24217	PARDEE	230	WARNETAP	230	1
	24115	24217	PASTORIA	230	WARNETAP	230	1
	24218	24217	WARNE	230	WARNETAP	230	1
N2-21	24114	24403	PARDEE	230	BAILEY	230	1
	24114	24217	PARDEE	230	WARNETAP	230	1
	24115	24217	PASTORIA	230	WARNETAP	230	1
	24218	24217	WARNE	230	WARNETAP	230	1
N2-22	24114	24155	PARDEE	230	VINCENT	230	1
	24036	24114	EAGLROCK	230	PARDEE	230	1
N2-23	24114	24147	PARDEE	230	SYLMAR S	230	1
	24114	24147	PARDEE	230	SYLMAR S	230	2
N2-24	24147	24089	SYLMAR S	230	GOULD	230	1
	24036	24147	EAGLROCK	230	SYLMAR S	230	1
N2-25	24155	24126	VINCENT	230	RIOHONDO	230	1
	24155	24126	VINCENT	230	RIOHONDO	230	3
N2-26	24156	24092	VINCENT	500	MIRALOMA	500	1
	24155	24126	VINCENT	230	RIOHONDO	230	1
N2-27	24156	24092	VINCENT	500	MIRALOMA	500	1
	24155	24126	VINCENT	230	RIOHONDO	230	3
N2-28	24091	24126	MESA CAL	230	RIOHONDO	230	1
	24091	24126	MESA CAL	230	RIOHONDO	230	2
N2-29	24091	24126	MESA CAL	230	RIOHONDO	230	1
	24076	24126	LAGUBELL	230	RIOHONDO	230	1
N2-30	24091	24126	MESA CAL	230	RIOHONDO	230	2
	24076	24126	LAGUBELL	230	RIOHONDO	230	1
N2-31	24086	24156	LUGO	500	VINCENT	500	1
	24086	24156	LUGO	500	VINCENT	500	2
N2-32	24500	24156	ANTELOPE	500	VINCENT	500	1
	24500	24156	ANTELOPE	500	VINCENT	500	2
N2-33	24520	24500	TEHACHPI	500	ANTELOPE	500	1
	24520	24500	TEHACHPI	500	ANTELOPE	500	2
N2-34	30060	24156	MIDWAY	500	VINCENT	500	1
	30060	24156	MIDWAY	500	VINCENT	500	2

Appendix B
PG&E list of Contingencies

1.2.1. “B” contingencies for 500 kV system:

- Tesla – Los Banos 500 kV line outage,
- Los Banos – Gates 500 kV line outage,
- Los Banos – Midway 500 kV line outage,
- Gates – Midway 500 kV line outage,
- Tesla – Gregg 500 kV line outage (Alt. 5),
- Gregg – Midway 500 kV line outage (Alt. 5),
- PDCI Bi-pole Outage.

1.2.2. “C” contingencies for 500 kV system:

- Tesla – Los Banos and Tracy – Los Banos 500 kV double line outage (Los Banos north),
- Los Banos – Midway and Los Banos – Gates #3 500 kV double line outage (Los Banos south),
- Los Banos – Midway and Gates – Midway 500 kV double line outage (Midway north),
- Los Banos – Midway #1 and #2 (new) 500 kV double line outage (Midway north for Alt. 4),
- Tesla – Los Banos and Tesla – Gregg (new) 500 kV double line outage (Alt. 5),
- Two Palo Verde generation units outage,
- Two Diablo Canyon generation units outage.

Attachment C
July 14, 2004 Study Plan

Phased Transmission Development Plan for Interconnecting Over 4,000 MW of Wind Generation In North Los Angeles and Kern Counties Referred to as the "Tehachapi Area"

Study Plan

July 14, 2004

SOUTHERN CALIFORNIA EDISON

An *EDISON INTERNATIONAL*℠ Company

For information or questions regarding this Study Plan, please contact Jorge Chacon via phone at (626) 302-9637 or e-mail at jorge.chacon@sce.com

Summary of Revisions

A number of participants provided comments to the Tehachapi Collaborative Study Plan date June 21, 2004. The following is a summary of the revision made to the Study Plan.

A new section that discusses the purpose of the Tehachapi Conceptual Transmission Plan was added.

Objective No.2 was expanded to include the goal of a single phased conceptual transmission plan and what happens if consensus is not reached.

Objective No.7e was expanded to include determination of how much spacing between transmission lines is required to consider the lines to be on "separate" right-of-way.

Objective No.9 was added to address whether regional transmission approach should be adopted for other renewable areas in the State.

CPUC Staff responsibilities were added to the responsibility section.

The section covering currently proposed projects was expanded to include electrical characteristics and thermal ratings so that the collaborative group can effectively model these projects into any study case.

A new section was added to cover electrical characteristics and thermal ratings for each of the Alternative Tehachapi Area Conceptual Plans.

A new element was added to the power flow base case assumptions section to cover the generation displacement assumptions as provided by the CAISO

.

CONTENT

Introduction

The Tehachapi area has been categorized as the largest wind resource area in the State of California. This area, if more fully developed, could meet a significant portion of the goals for the renewable energy development in California. In order to tap this energy resource area, large-scale transmission upgrades are required as the existing transmission facilities in the area, the Antelope-Bailey 66-kV subtransmission network and the Big Creek 230-kV Corridor, are already fully utilized.

Transmission constraints into the Tehachapi area have been discussed as part of the ongoing Assembly Bill (AB) 970 Investigation 00-11-001 with Phase 6 of the proceeding devoted to Tehachapi. The outcome of AB 970 Phase 6 is an Interim Opinion on Transmission Needs in the Tehachapi Wind Resource Area which orders (CPUC Decision 04-06-010) the formation of a collaborative study group to be convened to develop a comprehensive transmission development plan for the phased expansion of transmission capabilities into the Tehachapi area.

The CPUC Staff will coordinate the collaborative study group with assistance by the California Independent System Operator (CAISO) as needed. The collaborative study group will include participation by Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), wind developers, and any other interested parties including the California Energy Resources Conservation and Development Commission (CEC), Department of Defense, the counties of Kern and Los Angeles, the Los Angeles Department of Water and Power (LADWP), and the owners of the independently owned Sagebrush line. It is envisioned that the collaborative study group will function in a manner similar to the Southwest Transmission Expansion Plan (STEP) process.

This Study Plan provides a proposed guideline for the Tehachapi Comprehensive Transmission Development Assessment. The study plan is divided into fourteen sections: (1) Introduction, (2) Background, (3) Purpose of Tehachapi Conceptual Transmission Plan, (4) Objectives, (5) Responsibilities, (6) Currently Proposed Projects in Area, (7) Alternative Tehachapi Area Conceptual Plans, (8) Electrical Characteristics and Thermal Ratings of Alternate Conceptual Plans, (9) Assessment Process Outline, (10) Study Areas and Study Conditions, (11) Power Flow Base Case Assumptions, (12) Power Flow Screening Level Preliminary Assessment, (13) Final Report, and (14) Schedule of Major Milestones. The study plan will be followed by the Collaborative Study Group in completing the order set forth which requires Edison, acting on behalf of the study group, to file a report in the AB 970 proceeding containing the study group's findings and recommendations within nine months of the effective date of CPUC Decision 04-06-010 which is March 9, 2005.

Background

Southern California Edison has performed a number of conceptual studies for interconnecting renewable wind generation in the Tehachapi area. These conceptual studies were performed for the purpose of identifying conceptual transmission facilities necessary to meet future delivery needs for wind generation in the Tehachapi area. The initial conceptual study was done with participation of ten wind developers who collectively identified, on a conceptual basis, a total of 2,500 MW of potential wind development in the Tehachapi area.

A subsequent conceptual study (Phase 2) was performed with participation of eight wind developers. The purpose for this subsequent conceptual study was to perform preliminary substation site selection studies in the Cal Cement, Monolith, and Jawbone areas as well as identify potential line routes for new transmission into the Tehachapi area. Total wind generation considered was unchanged at the 2,500 MW level. Testimony was filed by SCE in the AB 970 Phase VI proceeding based on the study results of this conceptual study. The CAISO interjected testimony suggesting a different project alternative to interconnect Tehachapi area wind generation.

A third conceptual study (Phase 3) was performed to evaluate an additional 770 MW of wind generation development increasing the total Tehachapi wind generation potential from 2,500 MW to 3,270 MW. This conceptual study resulted in two conceptual transmission alternatives (230-kV and 500-kV conceptual alternative) for integrating Tehachapi area wind generation. The 500-kV transmission alternative plan was further refined to accommodate increased Tehachapi area wind generation potential as identified by the CEC in their Electric Transmission Plan for Renewable Resources in California Report to the Legislature dated December 1, 2003. The new Tehachapi area wind generation potential as identified by the CEC is now in excess of 4,000 MW. The CPUC adopted the 500-kV transmission alternative in their report to the Legislature for interconnecting over 4,000 MW of wind generation.

This increased MW potential and the identification of a 500-kV transmission alternative has resulted in the presentation of yet another transmission alternative to the SCE Conceptual Study Plan. The alternative, as presented by Oak Creek Energy Systems and CalWea, includes the development of a fourth Midway-Vincent (via Tehachapi) 500-kV transmission line.

These project alternatives resulted in a number of outstanding issues that need to be addressed by the Tehachapi Collaborative Study Group. The outstanding issues include the determination if the CAISO proposed PG&E-SCE interconnection alternative provides statewide benefits and allow wind generation development to proceed, identification of expected demarcation between gen-ties and network transmission facilities, and consideration of regional benefits when developing revised Tehachapi Phased Conceptual Transmission plan.

<u>Purpose of Tehachapi Conceptual Plan</u>

Conceptual studies are no substitute for System Impact or Facilities Studies, which will be required prior to interconnecting any new wind generation in the area. The results of the conceptual studies are to be used as a roadmap in developing transmission facilities into the Tehachapi area. The roadmap will serve as a means to avoid the piecemeal transmission additions associated with construction of facilities to interconnect only each year's winning RPS bidders or to interconnect only the projects which request interconnection (incremental requests). The actual timing of construction of transmission facilities will be driven by actual interconnection requests. However, instead of sizing the facility to accommodate the requested interconnection amount, the facilities will be developed in a way that is consistent with the conceptual transmission plan.

It should be noted that conceptual transmission plans should not be viewed as a permanent plan. Modifications to the conceptual transmission plan may be necessary as a result of actual need. In other words, the plan needs to be flexible so that future changes can be made if actual generation locations turn out to be different than what is assumed in developing this conceptual transmission plan.

<u>Objectives</u>

Edison, PG&E and the collaborative study group, in coordination with the CPUC Staff and the CAISO, will:

a. assess the amount of resources available in the Tehachapi Area that can be accommodated using existing transmission system capacity

b. develop a comprehensive Tehachapi transmission development plan in order for upgrades in the Tehachapi area to be most cost effective, least environmentally disruptive, orderly, and logical based on the magnitude of the wind resource identified by the CEC

    i. The study group should cooperatively work on developing a single phased conceptual transmission plan, at least for the initial portions of the phased upgrades

    ii. If consensus among the participants is not reached, the study group should explain clearly factors that would influence a choice among any alternative proposals

c. incorporate the transmission facilities for the Tehachapi Upgrades necessary to interconnect the PPM Project into the conceptual plan

    i. the PPM Project has completed the System Impact and Facilities Studies, has priority over conceptual projects, is ready to pursue as a Market Participant, and should not be held-up by the Collaborative Study Group

    ii. approval of System Impact and Facilities Studies should follow the FERC Interconnection Process

d. identify viable transmission alternatives, taking a statewide approach, for systematically phasing transmission into the Tehachapi area to ultimately interconnect the full Tehachapi wind resource potential identified by the CEC (over 4,000 MW)

e. assess the extent to which each transmission alternative configuration would assist in the transport of power to companies other than Edison in order to meet their corresponding RPS goals

f. develop phasing and priority of each transmission alternative

    i. develop a list of short lead time transmission upgrades can be pursued on a fast-track schedule

    ii. identify phase development of each transmission alternative in an orderly, rational and cost effective manner

    iii. determine the amount of wind generation that can be accommodated with each phase of each transmission alternative

    iv. determine if any additional transmission elements should be included into a subsequent CPCN filing

    v. identify all new conceptual transmission facilities (e.g. lines, substations, and upgrades to existing lines and substations) required to transmit the power from Tehachapi to the various load centers (PG&E, Edison, and SDG&E)

    vi. identify the expected demarcation between gen-ties and network transmission facilities to the extent feasible

    vii. develop recommendations regarding the procedures whereby each phase of the upgrades would be trigger after the first phase

g. perform preliminary feasibility analysis for the transmission facilities identified

    i. perform preliminary "screening-level" power flow analysis

    ii. perform preliminary engineering review to identify transmission elements that may be problematic

    iii. perform preliminary environmental review of transmission facilities based on available information contained in currently available environmental data bases in order to identify potential significant environmental constraints

iv. develop a preliminary list of licensing and environmental requirements for the transmission line right-of-way and potential substation sites

v. resolve with the Department of Defense any critical issues surrounding transmission line routes and heights and minimum distance between lines to consider lines as different corridor

vi. address how long it would take for the anticipated transmission owner to prepare and file each of the needed certificate applications based on the study group recommendations

vii. identify the maximum reasonably foreseeable build-out for the utility-owned assets in order to comply with CEQA requirements

h. identify estimates of the transmission costs, including substation costs and land acquisition costs, based on standard, off-the-shelf, general unit cost basis

i. determine if the regional transmission planning approach should be adopted for other renewable areas in the State

<u>Responsibilities</u>

The following are assignments for the supply of information to the Study Group to facilitate the development of a Collaborative Transmission Development Plan

a. The CPUC Staff will coordinate the collaborative study group with assistance by the California Independent System Operator (CAISO) as needed.

b. Edison is responsible for completing the aforementioned objectives for identifying

   a. conceptual facilities required within SCE's service territory to interconnect additional Tehachapi wind generation into SCE's existing network

   b. potential transmission upgrades needed to deliver energy to SCE's load center or to the first interconnection point with PG&E and/or SDG&E,

   c. potential impacts to SCE's network as a result of new facilities that are proposed to interconnect the SCE system with the PG&E system,

   d. potential impacts to SCE's existing network as a result of implementing third party transmission expansion.

c. PG&E is responsible for completing the aforementioned objectives for

a. Identifying new facilities within PG&E's service territory required to deliver Tehachapi wind generation from SCE's first interconnection point to PG&E's load center in the Bay area,

b. evaluating new facilities that are proposed to directly interconnect additional Tehachapi wind generation into PG&E's existing network

c. evaluating potential impact to PG&E's network as a result of new facilities that are proposed to interconnect the SCE system with the PG&E system

d. potential impacts to SCE's existing network as a result of implementing third party transmission expansion

d. The CAISO is responsible for conducting cost analysis for

a. quantifying any new RMR exposure identified in either SCE's or PG&E's system as a result of the proposed alternatives,

b. quantifying any additional congestion exposure on Path 26, Path 15, and other parts of the ISO Grid as a result of either connecting the SCE system with the PG&E system, delivering Tehachapi area wind generation to SDG&E, or delivering Tehachapi area wind generation to PG&E

e. Third Parties who may wish to participate (such as LADWP and the Sagebrush Owners) in the study process are responsible for

a. identifying whether they are interested in participating in conceptual studies to support Tehachapi,

b. providing the specifics on how any facilities currently owned by those entities or new proposed facilities to be owned by those entities can be used to integrate additional Tehachapi area wind generation

If active participation of these third parties does not evolve or is of limited input, the study group should dispense in evaluating how these non-CAISO controlled assets could be utilized since they are outside the jurisdiction of the CAISO and CPUC and therefore should not be rolled into the final plan.

<u>Currently Proposed Projects in the Area</u>

The following are transmission projects that have been identified in a different forum and should be included into the starting base cases. The Collaborative Tehachapi Study Group should base transmission development plans with these projects included into the starting cases.

1. Transmission requirements to interconnect the 201 MW PPM project (Antelope-Pardee)

I. transmission requirements to interconnect the PPM project includes a new transmission line from the SCE Antelope substation to the SCE Pardee substation and substation expansions at Pardee and Antelope to accommodate the new line

II. the CAISO has reviewed the System Impact and Facilities studies for this project and will present to their governing board on July 29 for approval

III. electrical characteristics (per-unit) for this transmission line are as follows:

a.	100 MVA / 230-kV base	R=0.00124	X=0.02812	B=2.0699
b.	100 MVA / 500-kV base	R=0.00026	X=0.00595	B=0.4380

IV. transmission ratings are as follows:

a. Normal Rating = 3950 amps
b. Long-Term Emergency Rating = 4540 amps
c. Short-Term Emergency Rating = 5330 amps

2. Pastoria-Pardee Transmission Line Reconductor

This project is an infrastructure replacement project which was identified in the 2004-2008, 2013 CAISO Controlled SCE Transmission Expansion plan. The scope of the project is to replace the existing 605 ACSR conductor on the Pastoria-Bailey, Pastoria-Pardee, and Bailey-Pardee 230-kV transmission lines with 666.6 ACSS/TW. This conductor type is the largest conductor that can be utilized on the existing transmission towers without requiring tear-down and rebuild. The project is not driven by Tehachapi wind generation needs.

The CAISO has reviewed the studies for this project and provided conditional concurrence pending receiving any input from the Collaborative Study Group.

SCE has presented this project to the Collaborative Study Group for informational purposes only and did not receive any opposition

V. electrical characteristics (per-unit) for this upgrade provided on 100 MVA / 230-kV base are as follows:

a.	Pastoria-Pardee	R=0.0109	X=0.0587	B=0.1085
b.	Pastoria-Bailey	R=0.0035	X=0.0187	B=0.0346
c.	Pardee-Bailey	R=0.0073	X=0.0398	B=0.0737

VI. ratings for the Pastoria-Bailey and Pardee-Bailey lines are as follows:

a. Normal Rating = 1240 amps
b. Long-Term Emergency Rating = 1426 amps
c. Short-Term Emergency Rating = 1500 amps

VII. ratings for the Pastoria- Pardee line is 1500 amps under all conditions

3. San Joaquin Valley Rector Loop and SVC

This project is a reliability driven project first identified in the 2002-2006, 2011 CAISO Controlled SCE Transmission Expansion plan and validated over the last two expansion plans. The project consists of constructing a new 15-20 mile double-circuit 230-kV transmission line so that the existing Big Creek3-Springville 230-kV line can be looped in and out of the Rector 230-kV substation and adding a 175 MVAR static VAR compensator (SVC) at Rector. This project has been approved by the CAISO governing board on June 24, 2004.

electrical characteristics (per-unit) for this upgrade provided on 100 MVA / 230-kV base are as follows:

a.	New Big Creek3-Rector	R=0.0106	X=0.0889	B=0.1711
b.	New Rector-Springville	R=0.0079	X=0.0660	B=0.1277

ratings for the New Big Creek3-Rector line will be as follows:

c. Normal Rating = 1200 amps (wave trap)
d. Long-Term Emergency Rating = 1200 amps (wave trap)
e. Short-Term Emergency Rating = 1284 amps (wave trap)

ratings for the New Rector-Springville line will be as follows:

f. Normal Rating = 1200 amps (wave trap)
g. Long-Term Emergency Rating = 1200 amps (wave trap)
h. Short-Term Emergency Rating = 1284 amps (wave trap)

<u>Alternative Tehachapi Area Conceptual Plans</u>

The following is a discussion of the currently proposed Tehachapi Area Conceptual Transmission Alternatives:

Revised SCE Conceptual Transmission Plan

New 500-kV Transmission line from Pardee to the Tehachapi area via Antelope. The line section between Antelope and Pardee (25 miles) should be included into the starting cases (initially energized at 230-kV) for reasons identified above. This line section will replace an existing 66-kV transmission line between Antelope and Pardee requiring expansion of existing right-of-way (ROW). New ROW will be required between Tehachapi and Antelope (30 miles).

New 500-kV Transmission line from Vincent to the Tehachapi area via Antelope. The line section between Vincent and Antelope will replace existing 230-kV transmission line(s). New ROW will be required between Tehachapi and Antelope that is distinct from the ROW required above (30 miles).

Second new 500-kV Transmission line from Vincent to the Tehachapi area via different route due to right-of-way restrictions. This line will require new ROW between Vincent and Tehachapi.

Additional capacity between Vincent and the Los Angeles Basin in order to deliver output from the Tehachapi area wind generation to the SCE or SDG&E load centers.

New 500/230-kV substation(s) located near the Tehachapi Pass with several (up to four) 230/66-kV substations located in the various wind regimes.

220-kV transmission lines from the new 500/230-kV substation(s) to the 230/66-kV substations.

66-kV transmission lines from the new 230/66-kV substation(s) to the windfarms to collect the wind generation from the various sites.

Substation Expansion at Pardee and Vincent.

SCE-PG&E Phase-shifted System-Tie (CAISO Suggestions)

New phase-shifted system-tie in the Fresno Area

New phase-shifted system-tie in the Bakersfield Area

New 500-kV or 230-kV transmission line from the Tehachapi area to existing transmission facilities (to be determined). New ROW will be required between Tehachapi and the existing transmission facilities.

New 500/230-kV substation(s) located near the Tehachapi Pass with several (up to four) 230/66-kV substations located in the various wind regimes.

220-kV transmission lines from the new 500/230-kV substation(s) to the 230/66-kV substations.

66-kV transmission lines from the new 230/66-kV substation(s) to the windfarms to collect the wind generation from the various sites.

Midway-Vincent No.4 via Tehachapi

New 500-kV Transmission line from Midway to the Tehachapi area. Some new ROW may be required.

New 500-kV Transmission line from Vincent to the Tehachapi area via Antelope. This line will replace existing 230-kV transmission line(s) between Vincent and Antelope. New ROW will be required between Tehachapi and Antelope.

New 500/230-kV substation(s) located near the Tehachapi Pass with several (up to four) 230/66-kV substations located in the various wind regimes.

220-kV transmission lines from the new 500/230-kV substation(s) to the 230/66-kV substations.

66-kV transmission lines from the new 230/66-kV substation(s) to the windfarms to collect the wind generation from the various sites.

Substation Expansion at Midway and Vincent.

Electrical Characteristics and Thermal Ratings of Alternative Conceptual Plans

The following are the corresponding electrical characteristics and corresponding thermal ratings for each Tehachapi Area Conceptual Transmission Alternative. The transmission line parameters are provided in percent per mile and the transformer parameters are provided in percent.

Revised SCE Conceptual Transmission Plan

New 500-kV Transmission lines based on 100 MVA / 230-kV Base
Bundled 2156 ACSR R=0.00496 X=0.11250 B=8.2798

New 500-kV Transmission lines based on 100 MVA / 500-kV Base
Bundled 2156 ACSR R=0.00105 X=0.02380 B=1.7520

New 230-kV Transmission lines based on 100 MVA / 230-kV Base
Bundled 1590 ACSR R=0.00627 X=0.10330 B=0.4060

New 66-kV Transmission lines based on 100 MVA / 66-kV Base
954 SAC R=0.28 X=1.49 B=0.0280

Transmission Line Ratings (amps)
500-kV: Normal-3,950 Long-Term Emergency-4,540 Short-Term Emergency-5,330
230-kV: Normal-3,230 Long-Term Emergency-3,710 Short-Term Emergency-4,360
66-kV: Normal-1,090 Long-Term Emergency-1,470 Short-Term Emergency-1,470

Transformer Parameters
500/230-kV : 15.0 percent based on 1120 MVA with V_{from} of 525 and V_{to} of 230
230/66-kV : 19.7 percent based on 280 MVA with V_{from} of 230 and V_{to} of 70.5
230/34.5-kV : 11.5 percent based on 100 MVA with V_{from} of 230 and V_{to} of 34.5
34.5/0.545kV : 5.75 percent based on 1.5 MVA with V_{from} of 34.5 and V_{to} of 0.545
Transformer Ratings
500/230-kV : 1120 MVA
230/66-kV : 280 MVA
230/34.5-kV : 100 MVA
34.5/0.545kV : 1.5 MVA

SCE-PG&E Phase-shifted System-Tie (CAISO Suggestions)

New switching station north of Rector at the crossing of Helms/Big Creek lines

Loop existing Big Creek-Rector lines into new switching station (FresnoTie)

i.	Big Creek1-FresnoTie	R=0.0079	X=0.0403	B=0.0760
j.	Big Creek3-FresnoTie	R=0.0049	X=0.0250	B=0.0470
k.	Rector-FresnoTie No.1	R=0.0139	X=0.0707	B=0.1330
l.	Rector-FresnoTie No.2	R=0.0139	X=0.0707	B=0.1330
m.	Normal Rating = 885 amps	Emergency Rating = 936 amps on all lines		

Loop existing Gregg-Helms lines into new switching station (FresnoTie)

n.	Helms-FresnoTie No.1	R=0.0025	X=0.0313	B=0.1110
o.	Helms-FresnoTie No.2	R=0.0025	X=0.0313	B=0.1110
p.	Gregg-FresnoTie No.1	R=0.0025	X=0.0313	B=0.1110
q.	Gregg-FresnoTie No.2	R=0.0025	X=0.0313	B=0.1110
r.	Normal Rating = 1,910 amps	Emergency Rating = 2,264 amps on all lines		

Assume SCE 230-kV transmission line characteristics provided above for new line from Bakersfield (PG&E) to Magunden (SCE)

Assume same electrical parameters as the Crystal 230-kV phase-shifter shown in WECC Base Case for new phase shifters at Bakersfield and new switching station

Midway-Vincent No.4 via Tehachapi

SCE 500-kV transmission lines are discussed above in Item 1b

PG&E 500-kV transmission lines (100 MVA / 500-kV Base)
Bundled 2300 AAL R=0.00102 X=0.02470 B=1.7440

Transmission Line Ratings (amps)
Summer Normal-2,478 Summer Emergency-2,964

Assume parameters discussed above in item for Tehachapi localized 230-kV and 66-kV Facilities

Assessment Process Outline

The following is the process outline for developing the phased Tehachapi Transmission Plan.

Develop Tehachapi conceptual transmission plans for the various alternatives in order to interconnect the magnitude of the wind resource identified by the CEC.

From each conceptual transmission plan, identify the short-lead time project elements that can be pursued on a fast-track schedule

Determine if any of the short-lead time project elements should be included into a Phase 1b CPCN filing so that SCE can amend CPCN filing as needed

Perform necessary conceptual studies in order to identify phase development of each transmission alternative in an orderly, rational and cost effective manner

determine the amount of wind generation that can be accommodated with each phase of each transmission alternative on a conceptual basis

identify all new conceptual transmission facilities (e.g. lines, substations, and upgrades to existing lines and substations) required to transmit the power from Tehachapi to the various load centers (PG&E, Edison, and SDG&E)

validate potential impacts associated with (a) and (b) above by performing screening level power flow studies and determine if project element(s) should be further evaluated

Perform preliminary feasibility analysis for the transmission facilities identified in the various alternatives that pass the screening level study

i. perform preliminary engineering review to identify transmission elements that may be problematic

ii. perform preliminary environmental review of transmission facilities based on available information contained in currently available environmental data bases in order to identify potential significant environmental constraints

iii. resolve with the Department of Defense any critical issues surrounding transmission line routes and heights

Determine how long it would take for the anticipated transmission owner to prepare and file each of the certificate applications based on the outcome of the preferred alternative develop a preliminary list of licensing and environmental requirements for the transmission line right-of-way and potential substation sites

identify the maximum reasonably foreseeable buildout for the utility-owned assets in order to comply with CEQA requirements

Develop appropriate transmission cost estimates, including substation costs and land acquisition costs, based on standard, off-the-shelf, general unit cost basis

Study Areas and Study Conditions

Edison proposes the following study areas and study conditions in developing the transmission facilities necessary to interconnect the full potential of renewable resources in the Tehachapi area as identified by the CEC:

CAISO Controlled SCE Transmission System Areas

Edison will utilize the latest heavy summer and light spring power flow cases developed for the 2004-2008, 2013 Annual CAISO Assessment recently completed. The cases will be adjusted as necessary to accommodate the additional wind generation modeled in the Tehachapi area in order to reflect maximum anticipated stress conditions on SCE transmission facilities consistent with the ISO Grid Planning Criteria assuming delivery of wind generation to either PG&E or SCE/SDG&E. The adjustment will be made by displacing either import generation into SCE from the north to capture delivery of wind generation to PG&E via Path 26 or displacing SCE and/or SDG&E internal generation to capture delivery into SCE and/or SDG&E. The displacement will be made as identified in Section XI Item 6. The cases will include transmission projects identified and approved by the CAISO as part of the annual expansion plan.

4. Main 500-kV and 230-kV System – Heavy Summer Load Conditions

Summer peak load conditions requiring high internal SCE generation dispatch and high imports result in maximum stress on the system. Although historical data indicates that under peak load conditions the Tehachapi area wind generation levels are relatively low, the study will be performed assuming maximum wind generation dispatch to cover those instances when wind generation actually produces at a high generation levels during high system load conditions.

Studies will be performed to cover fifty percent delivery to the north and remaining fifty percent delivered to the south. These studies will address the conditions where power from wind generation resources are partially delivered to the north with remaining output delivered to the south. Sensitivity studies may be performed to evaluate full deliveries to the south and full deliveries to the north. Actual deliveries resulting from actual RPS contracts may be different and therefore additional transmission facilities not identified by this study may be required to deliver to the load centers.

5. Main 500-kV and 230-kV System – Spring Peak Load Conditions

Spring peak load conditions, with high import levels, high Big Creek corridor generation and reduced main system generation (sufficient generation on-line to maintain adequate voltages in the Los Angeles Basin) will be examined. Studies will be performed to cover fifty percent delivery to the north and remaining fifty percent delivered to the south. These studies will address the conditions where power from wind generation resources are partially delivered to the north with remaining output delivered to the south. Sensitivity studies may be performed to evaluate full deliveries to the south and full deliveries to the north. Actual deliveries resulting from actual RPS contracts may be different and therefore additional transmission facilities not identified by this study may be required to deliver to the load centers.

6. Big Creek and San Joaquin Valley 230-kV System – Under heavy summer load with maximum generation, light spring load with maximum generation, and off-peak load summer with maximum hydro pumping conditions

This portion of the system, which is served practically radial from the Main Transmission system, has been identified to be transmission deficient under both maximum load with maximum generation and minimum load with maximum generation. The system includes two Special Protection Schemes (Big Creek and Pastoria Energy Facility) that could be affected by additional wind generation. Studies will be performed to evaluate corridor under both heavy summer load and light spring load conditions.

CAISO Controlled PG&E Transmission System Areas

PG&E will utilize the latest heavy summer and light autumn power flow cases developed for the 2004-2008, 2013 Annual CAISO Assessment recently completed. The cases will be adjusted as necessary to accommodate the additional wind generation modeled in the Tehachapi area in order to reflect maximum anticipated stress conditions on the PG&E transmission facilities consistent with the ISO Grid Planning Criteria assuming delivery of wind generation at the existing Midway substation or the proposed new 230 kV tie at Big Creek and Magunden. Old and less efficient generation units in the NP15 will be displaced to accommodate the import of wind generation into the PG&E system. The cases will include transmission projects identified and approved by the CAISO as part of the annual expansion plan

Heavy Summer Load Conditions

Summer peak load conditions with maximum North to South flow on Path 26 will be evaluated to assess impact of delivering Tehachapi area wind generation to the Bay area via Path 26 and Path 15

Autumn or Winter Off-Peak Load Conditions

Autumn or Winter Off-peak load conditions, with maximum South to North flow on Path 15 will be evaluated to assess impact of delivering Tehachapi area wind generation to the Bay area via Path 26 and Path 15.

Fresno and Bakersfield Area Studies

Studies will be performed to evaluate the impact of the proposed Big Creek-Helms Interconnection on the Fresno area transmission system. The studies will be based on the Fresno area summer peak base cases modeling three Helms units generating and Fresno area summer off-peak base cases modeling two Helms units pumping.

Studies will also be performed to evaluate the impact of the proposed Magunden Interconnection on the Kern area transmission system. The studies will be based on the summer peak base cases modeling 3400 MW of north-to-south flow on Path 26 and the autumn off-peak base cases modeling 5400 MW of south-to-north flow on Path 15.

Power Flow Base Case Assumptions

Edison proposes the following key assumptions in developing the conceptual transmission facilities necessary to interconnect the full potential of renewable resources in the Tehachapi area as identified by the CEC:

Load Related Assumptions

Loads will be modeled in load flow studies as follows:

Peak summer load conditions for SCE or PG&E will represent maximum anticipated loads based on a coincident load forecast, which will include consideration of a one-in-ten-year heat wave. Three cases will be used to represent coincident Control Area Peak, Northern California Peak and Southern California Peak.

Peak summer load conditions for RMR analysis within SCE and PG&E will represent maximum anticipated loads based on a localized coincident load forecast, which will include consideration of a one-in-five-year heat wave.

Spring Peak representing typical daily Spring Season load will be assumed for the main SCE 500-kV and 230-kV system. This load assumption represents approximately 65% of the summer normal peak loads through the main SCE network and approximately 50% of the summer normal peak for the Big Creek Corridor.

Autumn or Winter Off-Peak load will be assumed for the main SCE 500-kV and 230-kV system. This load assumption represents approximately 50% of the summer normal peak loads through the main SCE network and approximately 40% of the summer normal peak for the Big Creek Corridor. For PG&E, this load assumption represents approximately 45% of the summer normal peak. Both systems experience maximum pumping under this load condition.

Loads located within the service area of a Non-Participating Transmission Owner that is directly interconnected to a transmission or distribution facility owned by SCE or PG&E will be modeled based on the most recent forecast that the Non-Participating TO has provided.

Reactive load WATT/VAR ratios for the transmission substation loads represented in the base cases will reflect reasonable values for the operating conditions being studied.

Generation Related Assumptions

a. Edison and PG&E will incorporate the generation resources required to meet the WECC Minimum Operating Reliability Criteria (MORC): 1% for regulation plus 7% or the largest generation unit. The required generation will include all existing generation: 2004 Reliability Must Run (RMR), regulatory must-take resources (QF), Hydro, and Nuclear and all existing market generation resources.

b. Future market generation proposed through the FERC Interconnection Process for which has an active request will be incorporated into the completed phased development plan if those projects can impact the study results since these projects have priority over conceptual resources.

c. Hydro generation located within the Edison and PG&E CAISO Controlled Grid will be modeled at an output level that provides the maximum anticipated stress conditions on the corresponding transmission systems.

d. Nuclear generation will be assumed at the maximum capability consistent with the ISO Grid Planning Criteria.

e. All QF generation will be modeled in the base case consistent with the ISO Grid Planning Criteria and study practices for transient stability analysis, provided data is available to simulate actual machine characteristics.

f. All QF generation explicitly represented in the power flow base cases will have their reactive capabilities modeled according to contractual requirements, otherwise historical operating data will be used. Actual reactive power capabilities (i.e. manufacturer data or field test data) will be modeled for dynamic stability analysis as available.

g. All generation connected to Edison's or PG&E's distribution system (at 12, 16, or 33-kV) will be netted with the transmission substation loads on the low side of the transformers. Other generation connected to the subtransmission systems will be represented with equivalent generators at the low side of the transmission substation transformers, when these systems are not CAISO controlled.

Imports into SCE

The generation import for SCE will be scheduled at the present 2004 maximum Southern California Import Transfer limit (SCIT), 14,300 MW for the summer and 13,600 MW for the spring, with Path 26 (Midway-Vincent) north-to-south flows modeled at maximum (3,400 MW) in order to stress the SCE 500-kV system and the 500/230-kV transformer banks

Edison will perform studies for delivering wind generation output to either SCE and/or SDG&E by assuming maximum north-to-south flow on Path 26 (Midway-Vincent). Edison will perform studies for delivering wind generation output to PG&E by reducing exchanges between Edison and PG&E, which will result in lowering north-to-south flow on Path 26 (Midway-Vincent).

Imports into PG&E

The generation import for PG&E in the Autumn/Winter off-peak cases will be scheduled at the maximum allowable south-to-north flow on Path 26 (Midway-Vincent). Path 15 will be stressed to the south-to-north rating of 5400 MW.

PG&E will perform studies for receiving wind generation output at Midway by increasing exchanges between Edison and PG&E and displacing older and less efficient generation units in the NP15, which will result in increasing south-to-north flow on Path 26 (Midway-Vincent) and Path 15.

Generation Displacement

In order to assess the impacts on the bulk system when performing the power flow simulations it is important to schedule the 4,000+ MW to "reasonable" locations. To perform the necessary conceptual studies which would identify the facilities necessary to interconnect and deliver renewable resources to the load centers, 50% of the Tehachapi area wind generation will be assumed to be delivered to the system north of Path 26 and the remaining 50% delivered to the system south of Path 26. This will be accomplished by reducing generation as follows:

COI by 7.5 % (import north of Path 26)
NP-15 by 42.5% (north of Path 26)
SCE by 17.5% (south of Path 26)
SDG&E by 17.5% (south of Path 26)
CFE by 2.5% (south of Path 26)
West-of-River by 12.5% (import south of Path 26)

These estimates are subject to change based on feedback from the study group. The feedback should be provided no later than the second meeting (August 18th) since last minute changes to the assumptions will result in failure to meet the scheduled milestones.

Other Assumptions

The Tehachapi Comprehensive Transmission Development Assessment will comply with the CAISO Grid Planning Standards which incorporate the NERC/WECC Planning Standards.

Existing or proposed special protection schemes in the Big Creek Corridor will be operational.

Comply with the CAISO guidelines on the use of Special Protection Schemes to integrated Tehachapi area generation. In particular, limit the tripping of generation to 1,150 MW for the loss of one transmission line and 1,400 MW for the loss of two transmission lines.

Major Path Flows will be modeled at reasonable and expected patterns.

For the long-term, include the generation projects identified by the CEC.

The existing Path 15 RAS and Path 26 RAS will be modeled in the studies.

Power Flow Screening Level Preliminary Assessment

To assess the performance of the CAISO Controlled Grid owned by Edison and PG&E, screening-level preliminary power flow analysis will be performed under base case and contingency conditions for both summer and spring/autumn/winter load assumptions. Contingency analysis will follow the requirements of the ISO Grid Planning Criteria.

Contingency evaluation will include selective single contingencies (e.g. loss of a transmission line, generating unit, or transformer bank) and selective multiple-contingencies (e.g. overlapping outage of two transmission lines), consistent with the ISO Grid Planning Criteria.

If the loading of a transmission component of the CAISO Controlled Grid owned by Edison is determined to exceed its thermal rating during normal or contingency conditions, Edison will identify the corrective action(s) necessary to address the reliability concern (e.g. facility addition, special protection scheme, etc.) and will provide one project alternative. There may be other alternative solutions that may not be identified in these conceptual studies which would be evaluated in the future system impact studies.

If the loading of a transmission component of the CAISO Controlled Grid owned by PG&E is determined to exceed its thermal rating during normal or contingency conditions, PG&E will identify the corrective action(s) necessary to address the reliability concern (e.g. facility addition, special protection scheme, etc.) and will provide one project alternative. There may be other alternative solutions that may not be identified in these conceptual studies which would be evaluated in the future system impact studies.

Final Report

The final report, to be filed by SCE with the CPUC, will contain all criteria, assumptions, methodologies, simulation results, conclusion, and recommendations for "master plan", and any other pertinent information necessary to comply with CPUC Order #04-06-010. A draft report will be made available for comments to the Collaborative Study Group four weeks prior to filing with the CPUC. The results and recommendations will be presented to all interested parties for discussion three weeks prior to filing with the CPUC. Final comments are due one week prior to filing with the CPUC.

Schedule of Major Milestones

The schedule of the Major Milestones of the Tehachapi Comprehensive Transmission Development Assessment is as follows:

Ref. #	Milestone	Target Date
1.	**Milestone Meeting #1** at CPUC for presentation and discussion of the Tehachapi Comprehensive Transmission Development Assessment Study Plan	06/23/2004
2.	Written comments on Tehachapi Comprehensive Transmission Assessment Study Plan including identification of additional project alternatives are due to Edison via e-mail (jorge.chacon@sce.com)	07/06/2004
3.	Edison posts revised Study Plan	07/12/2004
4.	Development of preliminary conceptual transmission plans for the various transmission alternatives and identification of additional fast-track project elements using the top-down approach	07/21/2004 to 08/11/2004
5.	**Milestone Meeting #2** at CPUC to discuss fast-track project elements, additional project alternatives (if any), and progress of the phased assessment and solicit input	08/18/2004
6.	Written comments on project alternatives and requests for sensitivity studies due to Edison via e-mail (jorge.chacon@sce.com)	08/25/2004
7.	Commence development of transmission phasing prioritization for each conceptual transmission plan (Edison, PG&E, CAISO, and other project alternatives)	08/26/2004
8.	**Milestone Meeting #3** at CPUC to discuss progress of the phased assessment	10/27/2004
9.	Written comments on progress of the phased assessment and requests for last sensitivity studies due to Edison via e-mail (jorge.chacon@sce.com)	11/03/2004
10.	Finalize development of transmission phasing prioritization for each conceptual transmission plan (Edison, PG&E, CAISO, and other project alternatives)	11/05/2004
11.	Commence preliminary feasibility analysis for the conceptual transmission facilities identified in finalized transmission alternative	11/08/2005
	NOTE: Edison Files CPCN for Phase 1	12/09/2004
	VACATION ANYONE?	12/18/2004 to 01/02/2004
12.	**Milestone Meeting #4** at CPUC to discuss progress of the preliminary feasibility analysis for the conceptual transmission facilities identified in finalized transmission alternative	01/05/2004
13.	Written comments on preliminary feasibility analysis due to Edison via e-mail (jorge.chacon@sce.com)	01/11/2005
14.	Finalize preliminary feasibility analysis	01/25/2004
15.	Commence draft report of complete Tehachapi Transmission Phased Development Plan	01/26/2005
16.	Edison makes draft report of complete Tehachapi Transmission Phased Development available	02/09/2005
17.	**Milestone Meeting #5** at CPUC for study group to present final study report of complete transmission phased development	02/16/2005
18.	Final comments due to Edison via e-mail (jorge.chacon@sce.com)	02/23/2005
19.	Edison files final draft report of complete Tehachapi Transmission Phase Development Plan with Commission	03/09/2005

APPENDIX 2

Appendix 2

Preliminary Power Flow Study Report
PG&E Area Conceptual Transmission Plan
Continuation of Tehachapi Collaborative Study

1.9.

1.10.

1.11.

1.12. Purpose

The purpose of this continuation of the Tehachapi Collaborative Study is to formulate a plan for the transmission of 4,000MW of wind generation at Tehachapi and 500MW in the Antelope Valley to load centers in the PG&E and SCE service areas. It is assumed that half the 4,000 MW at Tehachapi will go to PG&E and half will go to SCE. The plan resulting from this study will be sufficient to initiate the preparation of Proponent's Environmental Assessments (PEAs) which would form the basis of CPCN applications for the facilities defined in the plan. The plan covers only the facilities from Tehachapi Substation 1 to the load centers and does not include the Tehachapi collector system. It is envisioned that this transmission plan will be updated in the future as each (or each group of) specific wind plant project moves through the ISO Interconnection Process and the Tehachapi collector loop beyond Tehachapi Substation 1 becomes more definitive.

1.13. Background

Pursuant to CPUC Decision 04-06-010, the Tehachapi Collaborative Study Group (TCSG) was formed to develop a comprehensive transmission development plan for the phased expansion of transmission capabilities in the Tehachapi area. The CPUC Staff coordinated the collaborative study group. As directed by the decision, TCSG completed a study that assumed there would be more than 4,000 MW of wind resources at Tehachapi Wind Area[4]. To conduct the study the TCGS further assumed that 50% of the 4,000 MW would be delivered to load centers in the transmission system North of Path 26 and the remaining 50% would be delivered to load centers in the system south of Path 26[5]. The Executive Director extended the original due date for filing the report by one week in a letter dated March 4, 2005. A report entitled, "Development Plan for the Phased Expansion of Transmission in the Tehachapi Wind Resource Area" (Report), was filed by Southern California Edison (SCE) on March 16, 2005.

As stated in that Report, the development plan prepared by the TCSG is a conceptual roadmap to the eventual Tehachapi transmission system rather than a definitive plan[6]. The Report recommended that further study be performed to select among the alternatives identified in the Report (and referred to herein with the same identification numbers as in the Report). These alternatives require further planning evaluation in order to formulate a single plan for implementation. To do this, additional studies (specific rather than generic) need to be performed and facility cost estimates refined. The final plan for the Tehachapi collector system requires information concerning actual wind project locations, capacities and characteristics which are not available at this time, and therefore is not covered in the study. However, since the Tehachapi collector system and actual wind projects would impact the utilities' transmission plan, it is envisioned that the

[4] Decision 04-06-010, at 6
[5] Study Plan, date July 14, 2004, at 18
[6] Tehachapi Collaborative Study Report, at 3

utilities' transmission systems would be updated in the future as each (or each group of) specific wind plant project moves through the ISO Interconnection Process and the Tehachapi collector loop beyond Tehachapi Substation 1 becomes more definitive. This flexible approach will allow the study to move forward at this time.

PG&E had investigated three alternatives in addition to the status quo (Alternative 1) to mitigate the impacts of scheduling and delivering 2,000 MW of Tehachapi generation (Alternatives 4 and 5) and two alternatives to mitigate the impact of scheduling and delivering 300 MW of Tehachapi area renewable generation (Alternatives 2 and 3) to PG&E. Alternative 3 to deliver 300 MW to PG&E was subsequently dropped because it could not provide the intended 300 MW of transfer capability. In this study PG&E performed further investigation on Alternatives 1, 2, 4 and 5. In addition, Alternative 2 was expanded to investigate the impact of scheduling and delivering 300 MW, 600 MW and 1,200 MW of Tehachapi area renewable generation.

1.14. Study Objective

The objective of this study is to evaluate the impact of importing 2000 MW (half of potential 4,000 MW, which is assumed to be technically available) of Tehachapi wind generation on the bulk transmission system in Northern California. This study evaluated the summer peak conditions with north-to-south transfer over Path 26 and the summer off-peak conditions with south-to-north transfer over Path 15 and Path 26.

1.15. Study Conclusion

The study conclusion is summarized in the following Tables 2-1 through 2-5. This study confirms the findings of the earlier study that determined: 1) the additional 2,000 MW of import at Midway, under system peak conditions with the Path 26 flow in the North to South direction, is not expected to require upgrades in the PG&E system (see Table 2-1); and 2) there is no spare transmission capacity for additional power import at Midway under system off-peak conditions with the Path 26 flow in the South to North direction (see Tables 2-2 and 2-3).

Table 2-1
2010 Summer Peak Base Case

Descriptions	**Existing Transfer**	**Import 2,000 MW at Midway w/o Upgrade**
Path 66 Flow (north to south)	4,793	4,503
Path 15 Flow (north to south)	-29	-1,958
Path 26 Flow (north to south)	3,394	1,397
PDCI Flow (north to south)	3,104	3,104
PG&E Area Load plus Losses	28,358	28,390
PG&E Area Generation	26,910	25,239
Fresno/Yosemite Division Loads	2,923	2,923
Helms PSP Generation	1,218	1,218
Imports from Tehachapi Generation	0	2,000
Generation Reduction in the Bay Area	0	1,700

Table 2-2
2010 Summer Off-Peak Base Case

Descriptions	Existing Transfer	Import 2,000 MW at Midway w/o Upgrade
Path 66 Flow (south to north)	3,666	3,614
Path 15 Flow (south to north)	4,999	7,005
Path 26 Flow (south to north)	1,624	3,752
PDCI Flow (south to north)	1,845	1,845
PG&E Area Load plus Losses	13,430	13,620
PG&E Area Generation	15,478	13,487
Fresno/Yosemite Division Loads	1,409	1,409
Helms PSP Generation*	-600	-600
Imports from Tehachapi Generation	0	2,000
Gen Reduction in Bay Area	0	2,000

* Note: Positive values denote operation in the generating mode. Negative values denote operations in the pumping mode

Table 2-3
2010 Summer Off-peak Base Case without Contingency

Transmission Facilities	SN Rating	Existing Transfer		Import 2,000 MW at Midway w/o Upgrade	
	(Amps)	(Amps)	(%)	(Amps)	(%)
Gates - Midway #1 500 kV line	2230	2088	93.6	3299	***147.9***
Los Banos - Midway 500 kV line	2230	1805	80.9	2814	***126.2***
Los Banos - Gates #1 500kV line	2230	1605	72	2466	***110.6***
Los Banos - Gates #3 500kV line	4332	800	18.5	1216	28.1
Gates - Panoche #1 230kV line	742	491	66.1	765	***103.1***
Gates - Panoche #2 230kV line	742	491	66.1	765	***103.1***
McCall - Henrietta tap2 230kV line	825	781	94.6	941	***114.1***
Gates - Henrietta tap1 230kV line	1600	1376	86	1642	***102.6***
Gates - Midway 230kV line	742	617	83.2	826	***111.3***
Los Banos - Westley 230 kV line	1484	783	52.7	1296	87.3

Note: Potential problems in the 115 kV and 69 kV systems are not included.

Since Path 15 does not have spare capacity for transporting additional generation from Midway to the Bay Area under certain off-peak conditions, this study evaluated several alternatives and explored potential phasing development for importing 2,000 MW of Tehachapi wind generation into PG&E. The results are summarized in Tables 2-4 and 2-5 below:

Table 2-4
Study Conclusions for PG&E Alternative 2 (Figure A2.1)

Import Level	Plan "A" (100% at Switching Station #1)	Plan "B" (50% at Switching Station #1 and 50% at Switching Station #2)
300 MW	Build Switching Station #1 with a 300 MVA phase shifter **Other Reinforcement in PG&E Area:** • Upgrade Borden-Gregg 230kV line (peak).	N/A
600 MW	Same as 300MW import level, except, with one 600MVA phase shifter and building a new 230kV line between Switching Station #1 and Gregg. **Other Reinforcement in PG&E Area:** • Upgrade Borden-Gregg 230 kV line (peak) • Upgrade Storey 1 – Gregg 230kV line (peak)	Build Switching Station #1 and #2 with a 300 MVA phase shifter at each station. **Other Reinforcement in PG&E Area:** • Upgrade Hass-McCall and Balch-McCall 230 kV lines (peak & off-peak) • Upgrade Borden-Gregg 230kV line (peak)
1200MW (Peak)	Not feasible (Due to the maximum phase angle range of +/-45 degree)	Not feasible (Due to the maximum phase angle range of +/-45 degree)
1200MW (Off-peak)	Same as 600 MW import level, except, with two 600MVA phase shifters. **Other Reinforcement in PG&E Area:** • Install 450 MVAR of voltage support. • Restrict the import level to Helms operation at 600 MW or more of pumping.	Same as 600 MW import level, except, with a 600 MVA phase shifter at each station. **Other Reinforcement in PG&E Area:** • Upgrade Hass-McCall and Balch-McCall 230 kV lines. • Restrict the import level to Helms operation at 600 MW or more of pumping.

Table 2-5
Study Conclusion for PG&E Alternatives 1, 4 and 5

Import Level	PG&E Alternative 1	PG&E Alternative 4 (Figure A2.2)	PG&E Alternative 5 (Figure A2.3)
500MW	Network upgrade not determined (see discussion above)	**Phase 4A**: Build a new Los Banos-Midway 500kV line operated at 230kV. **Other Reinforcements in PG&E Area:** None	**Phase 5A:** Build a new Gregg-Midway 500kV line operated at 230kV. **Other Reinforcements in PG&E Area:** None
1100MW	**Network upgrade not determined** (see discussion above)	**Phase 4B:** Same as 4A, except, re-connecting the new line to 500kV and installing 65% series compensation. **Other Reinforcements in PG&E Area:** Upgrade Los Banos – Westley 230 kV line and Los Banos 500/230 kV bank	**Phase 5B:** Same as 5A, except, building Gregg 500kV Substation with a 500/230kV, 1122/1350 MVA bank and re-connecting the new line. **Other Reinforcements in PG&E Area:** None
2000MW	**Network upgrade not determined** (see discussion above)	**Phase 4C:** Same as 4B, except, also building Tesla – Los Banos 500 kV line. This Phase would increase the OTC from 5000 MW to 7000 MW. However, it may ***not*** be feasible to increase Path 15 Rating to 7,400 MW from the existing Rating of 5,400 MW[7] **Other Reinforcements in PG&E Area:** Install additional RAS	**Phase 5C:** Same as 5C, except, installing series comp on Gregg -Midway line (31%), and Tesla-Gregg line (62%). **Other Reinforcements in PG&E Area:** None

[7] The Path 15 south-to-north flow was modeled at the Operating Transfer Capability (OTC) limit of 5000 MW in the pre project base case. This alternative would be able to import additional 2000 MW of generation at Midway by tripping 4319 MW of generation/pumps/load using the Remedial Action Scheme (RAS) for the simultaneous loss of Los Banos-Midway 500 kV and the new Los Banos-Midway 500 kV line in Phases 4A and 4B). The additional import would result in the Path 15 south-to-north flow at 7000 MW. However, unlike the findings in the previous study, this alternative would not be able to increase the Path 15 south-to-north Path Rating from 5400 MW to 7400 MW without increases in load shedding via RAS. Such increases may not be acceptable.

1.16. PG&E Area Transmission Alternatives

This study evaluated the following four transmission alternatives:

(1) PG&E Alternative 1 (Status Quo):

This Alternative investigates the possibility of installing no or minimum transmission upgrade and instead accommodating 2,000 MW of Tehachapi wind generation through curtailment of generation under normal conditions. Power flow study to date shows overloads, ranging from 3% to 48% over the ratings (or allowable limit) of eight transmission facilities under normal (all facilities in service) operating conditions (see Table 2-3). As a result, this alternative would expand the times and conditions under which curtailment of generation would be required. It could also require installation of Remedial Action Schemes (RAS) to trip additional generation immediately after a disturbance and/or reduction in existing Path 15 transfer capability.

If existing generation in areas around Midway Substation is curtailed to allow transfer of Tehachapi power, Path 15 south to north transfer capability will have to be reduced. This is because the existing Path 15 south-to-north transfer capability under normal conditions can only be supported with operation of the Remedial Action Scheme (RAS) immediately following identified outages. If Midway area generation that is connected to the existing RAS were dispatched off-line or kept at minimum generating levels (assuming that the FERC open access rules were somehow satisfied), there would be no effective way of reducing power flow on Path 15 immediately following a double line outage and before the operator can intervene. As a result, Path 15 would have to be operated under normal conditions at a reduced level. Study shows that curtailing all Midway area generation that can be curtailed (about 2,600 MW) would reduce Path 15 south to north transfer capability from 5,000 MW to about 3,600 MW. This would enable Path 26 to load to about 2,700 MW.

Connecting Tehachapi generation to the RAS to support Path 15 is neither effective nor is it practical even assuming installation of a new type of RAS controller and other equipment so it can predict the amount of wind generation available to trip if the outage occurs. For wind turbines to be part of generation RAS to replace the Midway generation RAS, the new RAS controller would need to also arm those generators that are on-line to provide regulation for the Tehachapi wind generation to the extent they are connected to systems south of Midway. It is also less effective because of the system configuration, a larger amount of generation from Tehachapi generators and these “regulating” generators will need to be tripped to provide the same relief on Path 15. This will in turn require tripping a higher amount of load commensurate with the increased amount of generation tripped to keep the net amount of net generation to be tripped within the allowable limit. Such a RAS would also increase by many folds the complexity of the existing Path 15 RAS and increase the probability of RAS misoperation.

In addition, Compliance with FERC Open Access rules, and agreement from the CAISO, approval from WECC, among other requirements would also be needed.

(2) PG&E Alternative 2 (Figure A2.1):

PG&E Alternative 2 is to establish a new 230 kV connection between PG&E and SCE by constructing a switching station at the crossing of PG&E-owned and SCE-owned transmission lines and installing a phase-shifting transformer to "push" power from SCE's Big Creek corridor into the PG&E system. This study investigated impacts on the PG&E system, and the possible mitigation measures for the connection. This study evaluated "pushing" 300 MW, 600 MW, and 1,200 MW by the following two Plans:

Plan A (PG&E_Alt-2A):

Establish one 230 kV tie between PG&E and SCE. Build Switching Station #1 at the crossing of PG&E's Helms – Gregg 230 kV lines and SCE's Big Creek – Rector 230 kV lines. Install one phase shifter or power flow controller to control the tie line flow.

Plan B (PG&E_Alt-2B):

Same as Plan "A", except, also building Switching Station #2 at the crossing of PG&E's Haas-McCall and Balch-McCall 230 kV lines and SCE's Big Creek – Rector 230 kV lines. Install a phase shifter or power flow controller at both switching stations to control the tie line flow.

(3) PG&E Alternative 4 (Figure A2.2):

PG&E Alternative 4 is to build a new Tesla – Los Banos 500 kV line and a new Los Banos – Midway 500 kV line. This alternative could be implemented in the following three phases:

Phase A (PG&E_Alt-4A):

Build a new Los Banos – Midway 500kV line operated at 230 kV.

Phase B (PG&E_Alt-4B):

Same as 4A, except, re-connecting the new Los Banos – Midway line to 500kV bus and installing 65% series compensation.

Phase C (PG&E_Alt-4C):

Same as 4B, except, also building a new Tesla - Los Banos 500kV line without series compensation.

(4) PG&E Alternative 5 (Figure A2.3):

PG&E Alternative 5 is to build a new Tesla – Gregg 500 kV line and a new Gregg – Midway 500 kV line. This alternative could be implemented in the following three phases:

Phase A (PG&E_Alt-5A):

Build a new Gregg - Midway 500kV line operated at 230 kV.

Phase B (PG&E_Alt-5B):

Same as 5A, except, also building a Gregg 500 kV Substation with a 500/230 kV transformer bank and re-connecting the new Gregg - Midway 500kV line.

Phase C (PG&E_Alt-5C):

Same as 5B, except, also building a new Tesla - Gregg 500kV line with 62% series compensation and installing 31% series compensation on the Gregg – Midway 500 kV line.

1.17. Power Flow Base Case Assumptions

Post-transient power flow studies for 500 kV system were based on the 2010 summer peak and 2010 summer off-peak WECC full loop system base cases developed for PG&E's 2005 Electric Transmission Grid Expansion Plan Study (a05sum2010.sav and a05sumopk2010.sav). The summer peak system base cases model 1-in-5 year load forecasts for the Northern California Area.

Contingency power flow studies for 230, 115 and 70 kV system were based on the 2010 summer peak and 2010 summer off-peak area base cases (a05sum2010_pge_a6.sav, and a05sumopk2010_pge.sav). The summer peak area base cases model 1-in-10 year load forecasts for Area 6 that includes the Yosemite, Fresno and Kern Divisions.

Since this study is to evaluate the impact of importing 2000 MW (half of potential 4,000 MW) of Tehachapi wind generation on the bulk transmission system in Northern California, only the PG&E portion of the Tehachapi wind generation (up to 2000 MW) was modeled on line and scheduled to PG&E at Midway and SCE portion of the Tehachapi wind generation was modeled off line in the study base cases. This would not impact the results of studies on system performance north of Midway since SCE's portion, which, if on line, would be scheduled to SCE would therefore not flow to PG&E.

These study base cases were reviewed and approved by CAISO and other stakeholders. Table 2-6 summarized the PG&E area loads, generation, and the major path flow assumptions modeled in the 2010 summer peak and 2010 summer off-peak system base cases. The study assumptions used for this study differs somewhat from that used in PG&E's 2005 Electric Transmission Grid Expansion Plan studies because the assumptions developed in the Grid Expansion Plan studies are meant to be starting cases, from which modifications would be made to simulate case-specific system conditions. These system conditions are indicated in Table 2-6 below.

Table 2-6
Area Loads/Generation and Major Path Flow

	Descriptions	Summer Peak System Base Case	Summer Off-peak System Base Case
1	Path 66 Flow (north_to_south)	4800	-3670
2	Path 15 flow (north_to_south)	<500	-5000
3	Path 26flow (north_to_south)	3400	-1625
4	PDCI flow (north_to_south)	3100	-1848
5	PG&E Area Loads plus Losses	28441	13402
6	PG&E Area Generation	26294	14453
7	Fresno/Yosemite Division Loads	2923	1409
8	Helms Generation	1200[8]	-900[9]

* Note: Positive values denote operation in the generating mode. Negative values denote operations in the pumping mode

1.18. Power Flow Studies for Pre-Transmission Project Conditions

Power flow studies were conducted to evaluate the potential thermal violations before the transmission alternatives for importing Tehachapi wind generation. The power flow studies were based on the 2010 summer peak area base case modeling the three Helms units on line at 1200 MW of generation, and the 2010 summer off-peak area base case modeling the three Helms units off-line. It is important to note that PG&E's 2005 Electric Transmission Grid Expansion Plan studies only model 930 MW of Helms generation in the 2010 summer peak area base case. Therefore, this study shows additional thermal overloaded facilities that were not identified in the Expansion Plan studies. The study results were summarized in Table A3-3 of Attachment 3 for summer peak conditions and in Table A4-2 of Attachment 4 for summer off-peak conditions. The study results show emergency overloads on the following facilities:

---

[8] The Helms generation may be outside the current Fresno Area Generation Nomogram. See CAISO Operating Procedure T-129. Helms generation was modeled at 930 MW in PG&E's 2005 Electric Transmission Grid Expansion Plan studies base case for Fresno area.

[9] In order to simulate a reasonably stressed summer off-peak conditions, Helms units were modeled off line for PG&E_Alt-2 analyses, on-line at -600MW of pumping for PG&E_Alt-4 analyses, and on-line at -900MW of pumping for PG&E_Alt-5 analyses.

(1) 2010 Summer Peak Conditions[10]

- Herndon 230/115kV Bank-1 and Bank-2.
- Atwater Jct-Cressey Jct 115kV line
- Herndon - Woodward 115kV line
- Merced-Atwater Jct 115kV line
- Wilson A-Merced 115kV line
- Wilson B-Merced 115kV line

1.2.1. 2010 Summer Off-peak Conditions

- Helm-McCall 230kV line
- Henrietta-GWF_HEP 115kV line
- Henrietta-McCall 230kV line

1.19. Power Flow Studies Results for PG&E Alternative 2

Power flow studies for PG&E Alternative 2 were based on the 2010 summer peak base case modeling three Helms units on-line with a total of 1200 MW generation and the 2010 summer off-peak base case modeling three Helms units off-line.

(1) 2010 Summer Peak Conditions with Helms at 1200 MW of Generation

The power flow study results for 2010 summer peak conditions were summarized in Attachment 3.

(1.1) Import 300 MW with Plan "A"

This alternative would build the Switching Station #1 and import 300 MW of generation. The study results show that the Borden – Gregg 230 kV line could load up to 108.8% of summer normal rating of 675 amperes under the summer peak conditions studied. (See Table A3-1, Attachment 3.) The import would not cause emergency overload for "B" or "C" contingencies studied. The following transmission facilities would need upgrading:

- Borden – Gregg 230 kV line

(1.2) Import 600 MW with Plan "A"

This alternative would build the Switching Station #1 and import 600 MW of generation. The existing Helms – Gregg #1 and #2 230 kV lines do not have spare capacity for importing additional 600 MW under summer peak conditions with three Helms units on

[10] Most of the emergency overloads were due to Helms generation operated outside Fresno Area Generation Nomogram.

line at 1200 MW of generation. This study assumes that this alternative would also build an additional 230 kV line between the proposed Switching Station #1 and Gregg Substation.

The study results show that the Borden – Gregg 230 kV line could load up to 127.7% of summer normal rating of 675 amperes. (See Table A3-1, Attachment 3.) In addition, the import could also cause emergency overload on the Storey 1 – Gregg 230 kV line for loss of the Wilson – Storey 2 – Borden 230 kV line with Melones #1 offline (Category "B" contingency; G-1/L-1). (See Case F-B213, Table A3-3, Attachment 3.) The following transmission facilities would need upgrading:

- Borden – Gregg 230 kV line, and
- Storey 1 – Gregg 230 kV line.

The following transmission facilities would be needed:

- A new 230 kV line between Switching Station #1 and Gregg,

(1.3) Import 600 MW with Plan "B"

This alternative would build both Switching Station #1 and #2, and import 300 MW of generation at each stations (total 600 MW). The study results show that the import could cause normal overload on the Borden – Gregg 230 kV line. In addition, the import could also cause normal overloads on the Haas – McCall and Balch – McCall 230 kV lines between the proposed Switching Station #2 and Mc Call Substation while the hydro power houses on Kings River were dispatched at the maximum generation of 520 MW. (See Table A3-1 and 2, Attachment 3.) The following transmission facilities would need upgrading:

- Borden – Gregg 230 kV line, and
- Haas – McCall and Balch – McCall 230 kV lines between Switching Station #2 and McCall Substation.

.

(1.4) Import 1200 MW with Plan "A" or "B"

The power transfer capability of a phase shifter is determined by the MVA rating and the maximum phase angle range. This study assumes the maximum phase angle range of +/- 45 degree, which is the same as most phase-shifters in the WECC system. The study results show that, due to the phase angle limitation, this Alternative would only be able to transfer 600 MW from SCE's Big Creek system to PG&E's Fresno area under the summer peak conditions with all three Helms units dispatched online at 1200 MW of generation.

1.2.1. Summer Off-peak Conditions with Helms off line

The power flow study results for 2010 summer off-peak conditions were summarized in Attachment 4.

(2.1) Import 600 MW with Plan "A" or "B"

The study results show that the existing transmission system has adequate capacity for importing 600 MW of generation with either Plan "A" or "B" under 2010 summer off-peak conditions studied. The import would not cause normal or emergency overloads. (See Attachment 4.)

(2.2) Import 1200 MW with Plan "A"

This alternative would build the Switching Station #1 and import 1200 MW of generation. The power flow studies results show that the voltage at Switching Station #1 230 kV bus could be as low as 217.8 kV (0.947 pu) under the 2010 summer off-peak conditions with all facilities in service. The study results also show that the Big Creek/Fresno area could experience voltage collapse following a Midway north 500 kV double-line outage[11]. This alternative would need a 150 MVAR of shunt capacitor bank at Switching Station #1 to improve steady state bus voltage and another 300 MVAR of switchable shunt capacitors to avoid voltage collapse following a Midway north 500 kV double-line outage.

The study results show that the import could cause normal overload on the Cottle B – Warnerville 230 kV line under summer off-peak conditions studied. (See Table A4-1, Attachment 4.) The import could also cause emergency overloads on the following lines (see Table A4-2, Attachment 4):

- Borden – Gregg 230kV line,
- Storey 2 – Borden 230 kV line,
- Storey 1 – Gregg 230 kV line, and
- Wilson – Storey 1 230 kV line. .

The study results also show that the Gates – Midway 500 kV line could load up to 3598 amperes (101.2% of 30-minute emergency rating of 3556A) following the Los Banos – Midway 500 kV single line outage. (See Case OPK-B3, Table A4-3, Attachment 4.) The Los Banos – Westley 230 kV line could also load up to 2276 amperes (113.8% of emergency rating of 2000A) for the Los Banos north 500 kV double-line outage[12]. (See Case OPK-C1, Table A4-4, Attachment 4.)

---

[11] Simultaneous loss of Midway – Gates 500 kV line and Midway – Los Banos 500 kV line
[12] Simultaneous loss of Tesla – Los Banos 500 kV line and Tracy – Los Banos 500 kV line

There is an operational solution for the above described normal and emergency overloads. The study results show that the import of 1200 MW would not cause normal or emergency overloads if two of the three Helms units were dispatched on line with 600 MW of pumping during summer off-peak conditions studied. The study results show the following facilities would still be needed for voltage support:

- 450 MVAR of 230 kV shunt capacitor banks.

(2.3) Import 1200 MW with Plan "B"

This alternative would build both Switching Station #1 and #2, and import 600 MW of generation at each stations (total 1200 MW). The study results show that the import could cause normal overload on the Haas – McCall and Balch – McCall 230 kV lines between the Switching Station #2 and McCall Substation under summer off-peak conditions. (See Table A4-1, Attachment 4.)

The study results also show emergency overload on the Cattle B – Warnerville 230 kV line for the Pacific DC Intertie bipolar outage (Category "B" contingency). (See Case OPK-B5, Table A4-3, Attachment 4.) The Los Banos – Westley 230 kV lines could also experience emergency overload for the Los Banos north 500 kV double-line outage with 3360 MW of RAS (Category "C" contingency). (See Case OPK-C1, Table A4-4, Attachment 4.)

The study results also show that the import would not cause the emergency overloads if two of the three Helms units were dispatched on line with 600 MW of pumping during summer off-peak conditions studied. The following transmission facilities would still need upgrading:

- Haas – McCall and Balch – McCall 230 kV lines between Switching Station #2 and McCall Substation.

1.20. Power Flow Studies Results for PG&E Alternative 4

The power flow studies were based on the 2010 summer off-peak base case modeling two Helms units on line with a total of 600 MW pumping. The preliminary power flow study results for PG&E Alternative 4 are summarized in Attachment 5. The study results show that this alternative would have adverse impact on Helms pumping operation. This alternative would increase loading on the Gates – Gregg and Gates – McCall 230 kV lines that would results in emergency overloads following a PDCI bipolar outage (Category "B" contingency). See Case B7, Table A5-2, Attachment 5.

(1) Phase A (PG&E_Alt-4A): Import 500 MW

Phase A is to build a new Los Banos – Midway 500 kV line operated at 230 kV. This alternative would increase the existing Path 15 south-to-north transfer capability by about 500 MW. The most limiting facility is the Gates – Midway 500 kV line for the Los

Banos – Midway 500 kV single line outage (Category "B" contingency). (See Case B3, Table A5-2, Attachment 5.)

1.2.1. Phase B (PG&E_Alt-4B): Import 1100 MW

Phase B is same as Phase A, except, re-connecting the new Los Banos – Midway line to the 500 kV buses and operate at 500 kV and installing 65% of series compensation on the new 500 kV line. This alternative would increase the existing Path 15 south-to-north transfer capability by about 1100 MW.

The study results show that the Los Banos – Westley 230 kV line could load up to 105.3% of its short-term emergency rating of 2000 amperes and the Los Banos 500/230 kV transformer bank could also load up to 102.2% of its 1-hour emergency rating of 1050 MVA after loss of Tesla – Los Banos and Tracy – Los Banos 500 kV lines with 3369 MW of RAS under the 2010 summer off-peak conditions studied. (See Case C1, Table A5-3, Attachment 5.)

The Gates – Henrietta section of the Gates – Gregg 230 kV line could also load up to 101.5% of its emergency rating of 1600 amperes after the PDCI bipolar outage. Helms pumping operation could be decreased to relieve the emergency overload. (See Case B7 in Table A5-2, Attachment 5.) The following transmission facilities would need upgrading:

- Los Banos – Westley 230 kV line
- Los Banos 500/230 kV transformer bank

1.2.2. Phase C (PG&E_Alt-4C): Import 2000 MW

Phase C is same as Phase B, except, also building a new Tesla – Los Banos 500 kV line without series compensation. This alternative would increase the existing Path 15 south-to-north transfer capability by 2000 MW up to about 7000 MW. The study results show that the Gates – Midway 500 kV line could load up to 98.7% of its short-term emergency rating of 3556 amperes after loss of the existing Los Banos – Midway #1 500 kV line and the new Los Banos – Midway #2 500 kV line (Category "C" contingency) with 4319 MW of load and resources tripped through Remedial Action Scheme (RAS) under the 2010 summer off-peak conditions studied. The RAS includes 2578 MW of generation at Midway, 691 MW of pumps and 1050 MW of loads. (See Case C3 in Table A5-3, Attachment 5.) The following reinforcements would be needed:

- Install additional RAS.

The Gates – Henrietta section of the Gates – Gregg 230 kV line could also load up to 102.2% of its emergency rating of 1600 amperes after the PDCI bipolar outage (Category "B" contingency). Helms pumping operation could be decreased to relieve the emergency overload. (See Case B7 in Table A5-2, Attachment 5.)

1.21. Power Flow Studies Results for PG&E Alternative 5

The power flow studies were based on the 2010 summer off-peak base case modeling three Helms units on line with a total of 900 MW pumping. Attachment 6 summarizes the study results. This alternative would increase the Fresno area import capability and improve Helms pumping operation.

(1) Phase A (PG&E_Alt-5A): Import 500 MW

Phase A is to build a new Gregg – Midway 500 kV line operated at 230 kV. This alternative would increase the existing Path 15 south-to-north transfer capability by about 500 MW. The most limiting facility is the Gates – Midway 500 kV line for the Los Banos – Midway 500 kV single line contingency (Category "B" contingency). (See Case B3, Table A6-2, Attachment 6.)

1.2.1. Phase B (PG&E_Alt-5B): Import 1100 MW

Phase B is same as Phase A, except, also building a new Gregg 500 kV Substation with a 500/230 kV 1122 MVA transformer bank and re-connecting the new Gregg - Midway 500kV line to the 500 kV buses to operate at 500 kV. This alternative would increase the existing Path 15 south-to-north transfer capability by about 1100 MW. The most limiting facility is the Gregg 500/230 kV transformer bank that could load up to 99.2% of its normal rating of 1122 MVA. (See Table A6-1, Attachment 6.) Gregg 500/230 kV transformer bank would also load up to 102.5% of its emergency rating of 1260 MVA for the Gates – Midway 500 kV single line outage (Category "B" contingency). The Gregg 500/230 kV transformer bank would need the normal and emergency ratings of at least 1122 and 1350 MVA, respectively.

In addition, the Panoche – Kearney, Warnerville – Wilson, and Gates – Gregg 230 kV lines would also load above their respective emergency ratings for loss of the new Gregg – Midway 500 kV line (Category "B" contingency). (See Cases B6 at Table A6-2, Attachment 6.) Helms pumping operation could be decreased to relieve the emergency overload.

1.2.2. Phase C (PG&E_Alt-5C): Import 2000 MW

Phase C is same as Phase B, except, also building a new Tesla - Gregg 500kV line with 62% series compensation and installing 31% series compensation on the Gregg – Midway 500 kV line. This alternative would increase the existing Path 15 south-to-north transfer capability by about 2000 MW. The most limiting facility is the Gregg 500/230 kV transformer bank that could load up to 106.4% of its emergency rating of 1260 MVA for the Tesla – Gregg 500 kV single line outage (Category "B" contingency). (See Case B5, Table A6-2, Attachment 6.) The Gregg 500/230 kV transformer bank would need to have a normal rating of 1122 MVA and a summer emergency rating of at least 1350 MVA.

1.22. Future Studies

Additional sensitivity studies of Helms units off line need to be conducted for PG&E Alternative 4 and 5. The sensitivity studies may discover additional restrictions on the import capability for each phase of the Alternative 4 and 5.

Transient stability studies and post-transient voltage studies also need to be conducted for PG&E alternatives 1, 2, 4 and 5.

1.23. Attachment list

1. Contingency List
2. One-line Diagrams
3. 2010 Summer Peak Power Flow Study Results for PG&E Alternative 2
4. 2010 Summer Off-peak Power Flow Study Results for PG&E Alternative 2
5. Preliminary Power Flow Study Results for PG&E Alternative 4
6. Preliminary Power Flow Study Results for PG&E Alternative 5

Attachment 1
Contingency List

1.24. 500 kV Contingencies

The following "B" contingencies for 500kV lines were studied:

- Tesla – Los Banos 500 kV line outage,
- Los Banos – Midway 500 kV line outage,
- Los Banos – Gates #3 500 kV line outage,
- Gates – Midway 500 kV line outage,
- PDCI Bi-pole Outage.

The following "C" contingencies for 500 kV lines were studied:

- Tesla – Los Banos and Tracy – Los Banos 500 kV double line outage (Los Banos north),
- Los Banos – Midway and Los Banos – Gates #3 500 kV double line outage (Los Banos south),
- Los Banos – Midway and Gates – Midway 500 kV double line outage (Midway north),
- Two Palo Verde generation units outage,
- Two Diablo Canyon generation units outage.

1.25. 230, 115 and 70 kV Contingencies:

Additional "B" and "C" contingencies for 230, 115 and 70 kV system in the Fresno/Yosemite area were also run. Attachment 3 lists the contingencies.

Attachment 2

Figure A2.1 - PG&E Alternative 2: Fresno 230 kV Tie

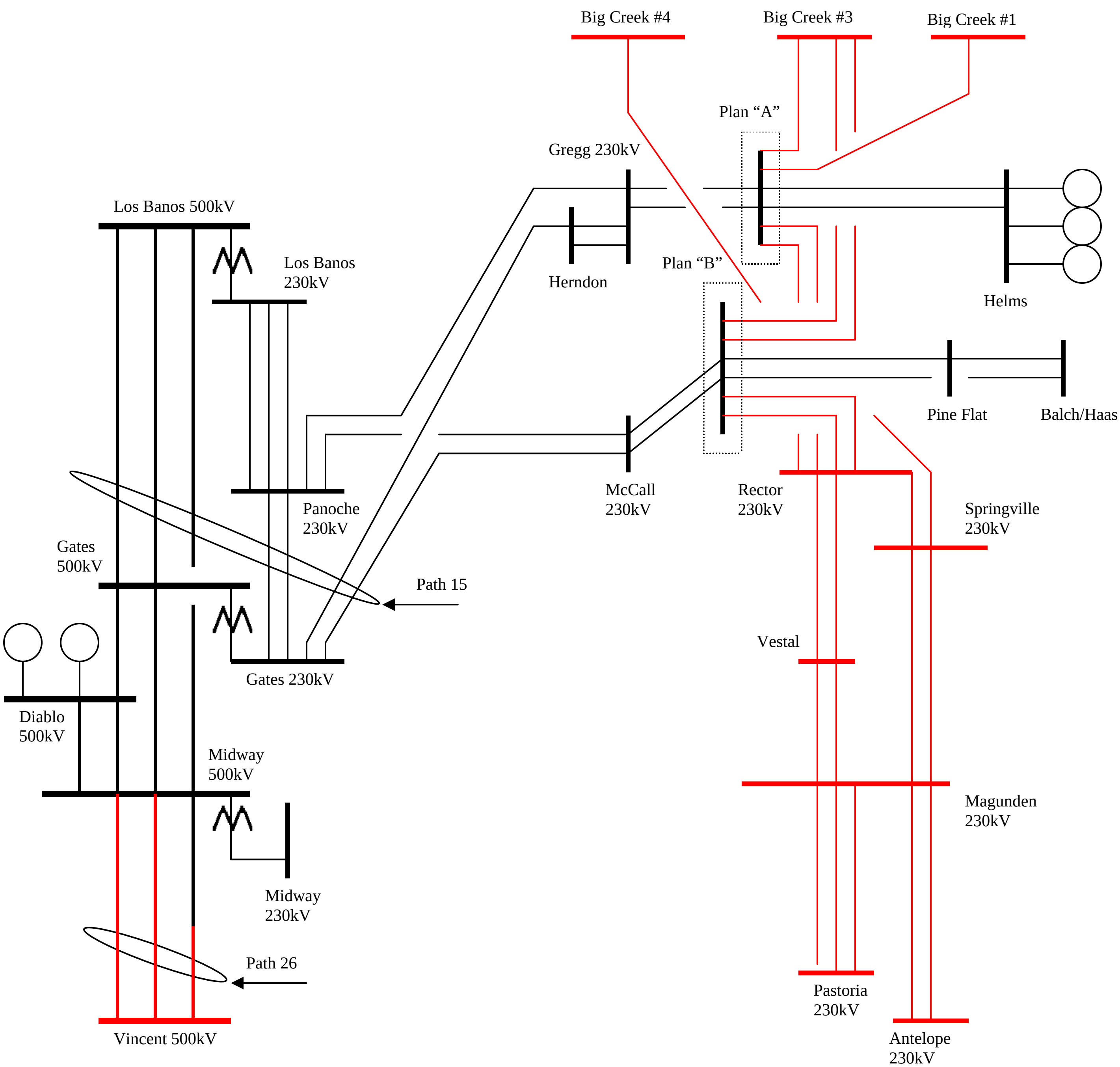


Figure A2.2 - PG&E Alternative 4: Tesla – Los Banos – Midway 500 kV line

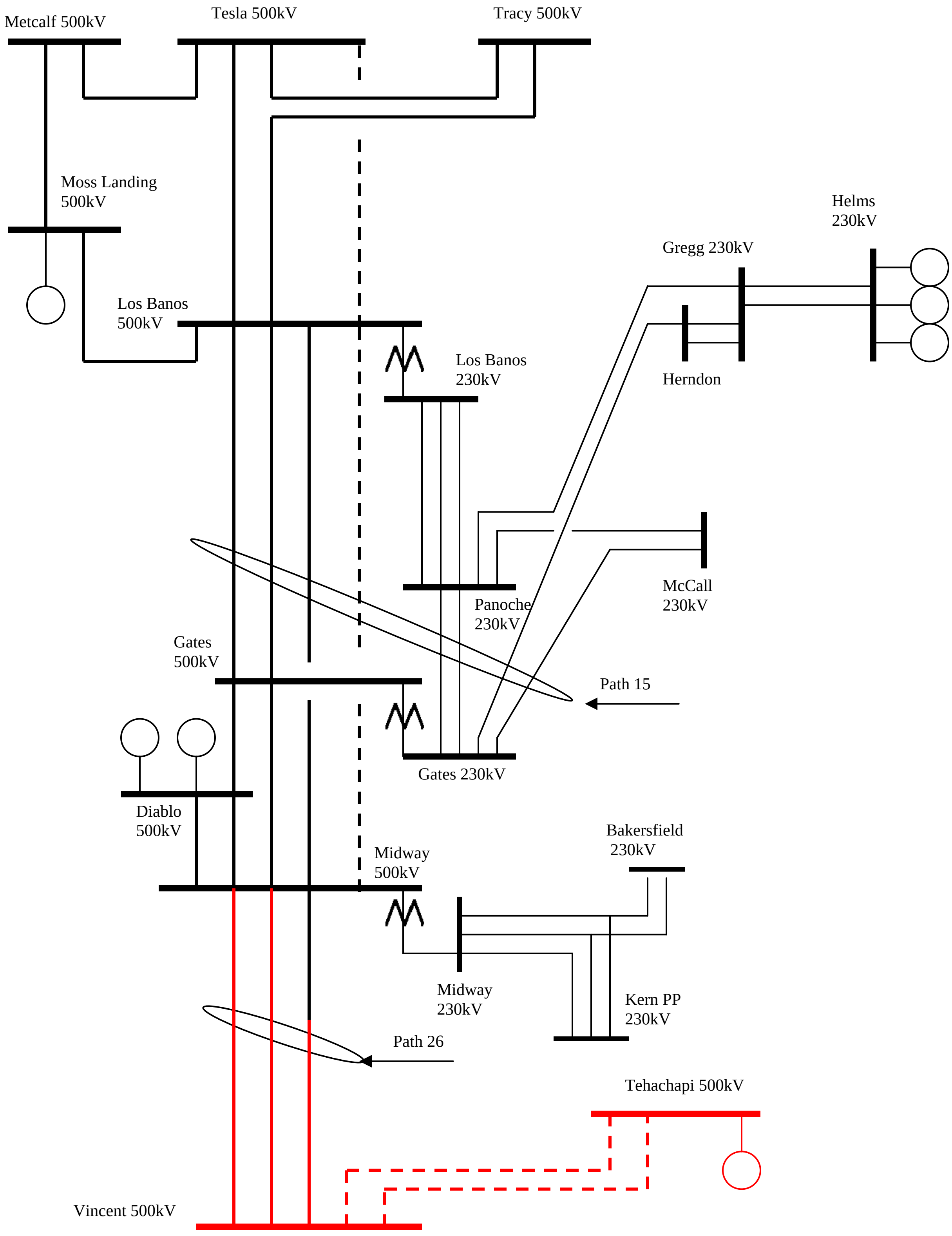
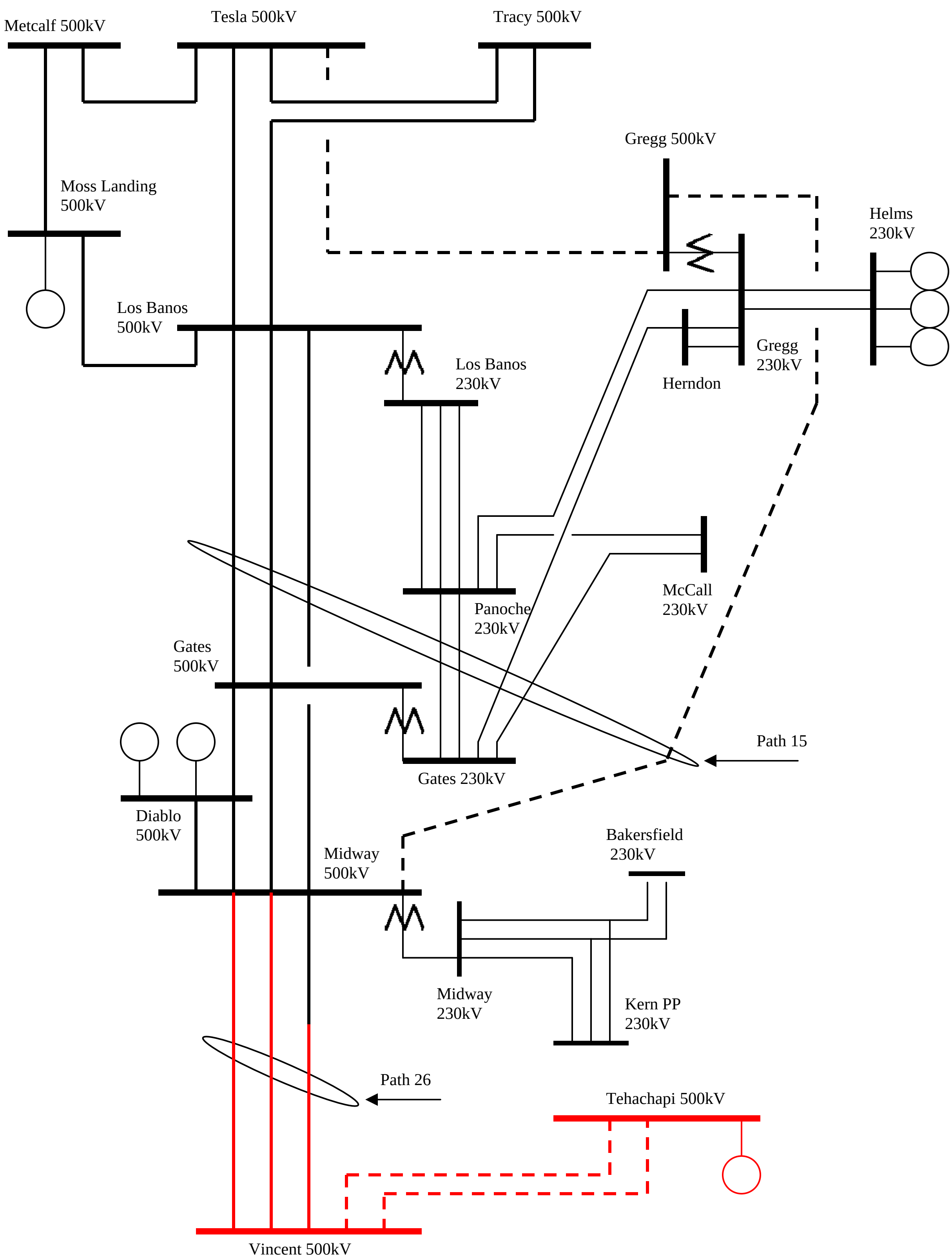


Figure A2.3 - PG&E Alternative 5: Tesla – Gregg – Midway 500 kV line



Attachment 3
Preliminary Power Flow Study Results for PG&E Alternative 2
(2010 Summer Peak conditions with Helms Generation = 1200 MW)

Table A3-1
Steady State Power Flow Study Results for PG&E Alternative 2
(2010 Summer Peak Conditions with Helms Generation = 1200 MW)

	Transmission Facilities		Base (sumpk_alt2.sav)		Alt 2A (pk_3g2a-300.sav)		Alt 2A (pk_alt2a-600.sav)		Alt 2B (pk_3g2b-600.sav)	
		SN Rating	Import = 0 MW		Import = 300 MW		Import=600MW		Import = 600 MW	
		(Amps)	(Amps)	(%)	(Amps)	(%)	(Amps)	(%)	(Amps)	(%)
1	GREGG-PGE_1_W #1 230KV LINE	1907.8	1502.4	78.8%	1879	98.5%	1512	79.3%	1889	99.0%
2	GREGG-PGE_1_W-1 #2 230KV LINE	1907.8	1502.4	78.8%	1879	98.5%	1512	79.3%	1889	99.0%
3	GREGG-PGE_1_W #3 230KV LINE (1)	1907.8	n/a	n/a	n/a	n/a	1512	79.3%	n/a	n/a
4	BORDEN - GREGG 230KV LINE	675.2	558.1	82.7%	734	**108.8%**	862	**127.7%**	779	**115.4%**
5	STOREY 1 - GREGG 230KV LINE	675.2	302.3	44.8%	n/a	<95%	673	99.6%	n/a	<95%
8	HERNDON - CHLDHOSP 115KV LINE	823.4	692.0	84.0%	n/a	<95%	n/a	<95%	n/a	<95%
9	WOODWARD - CHLDHOSP 115KV LINE	823.4	673.8	81.8%	n/a	<95%	n/a	<95%	n/a	<95%
10	MC CALL-PGE_2_W #1 230KV LINE	753.1	378.7	50.3%	n/a	<95%	n/a	<95%	740	98.2%
11	MC CALL-PGE_2_W #2 230KV LINE	753.1	378.7	50.3%	n/a	<95%	n/a	<95%	740	98.2%

(1) A new Gregg – PGE_1_W #3 230 kV line was modeled in the base case to avoid an 18.7% normal overload for Alt. 2A importing 600MW.
(2) This study assumes +/-45 degree is the maximum phase angle range for the phase shifters installed at the Fresno Switching Station that would be able to import about 600 MW from SCE to PG&E under summer peak conditions studied.

Table A3-2
Steady State Power Flow Study Results for PG&E Alternative 2
Sensitivity Study for Kings River Generation at Pmax = 520 MW
(2010 Summer Peak Conditions with Helms Generation = 1200 MW)

	Transmission Facilities	SN Rating	Base (pk_3g2b-0_kings.sav)		Alt 2B (pk_3g2b-600_kings.sav)	
			Import = 0 MW		Import = 600 MW	
	MC CALL - PGE_2_W #1 230KV LINE	753	540	71.6%	913	**121.2%**
	MC CALL - PGE_2_W #2 230KV LINE	753	540	71.6%	913	**121.2%**

Table A3-3
230 and 115 kV Contingencies for PG&E Alternative 2
(2010 Summer Peak Conditions with Helms Generation = 1200 MW)

			SE Rating	Base (sumpk_alt 2.sav)	Alt 2A (pk_3g2a-300.sav)	Alt 2A (pk_3g2a-600.sav)	Alt 2B (pk_3g2b-600.sav)
Case #	Overloaded Transmission Facilities	Worst "B" and "C" Contingency		Impor t= 0MW	Impor t= 300MW	Impor t= 600MW	Impor t= 600MW
			(Amps)	(%)	(%)	(%)	(%)
F-B214	Borden - Gregg 230kV line	Melones #1; Wilson - Storey 1 - Gregg 230kV line	793.2	<95%	<95%	**108.9%**	<95%
F-B61	Corcoran 115/70KV BK-2 (MVA)	Guernsey - Henrietta 70kV line	33.8	120.4%	120.4%	120.4%	120.4%
F-B151	Henrietta - Jacob Corner 70kV line	GWF- Hanford (lose 23 MW)	346.4	107.9%	108.0%	107.7%	107.9%
F-B123	Herndon - Woodward 115kV line	Kerckhoff #2 PH (lose 129 MW)	823.4	105.0%	110.1%	117.7%	100.3%
F-B112	Herndon 230/115kV Bk-1	Herndon 230/115kV Bk-2	462	108.8%	117.0%	128.6%	103.1%
F-B111	Herndon 230/115kV Bk-2	Herndon 230/115kV Bk-1	463.7	108.6%	116.0%	128.2%	102.4%
F-B138	McCall - Wahtoke 115kV line	Kings River PH (lose 47 MW)	492	100.6%	<95%	<95%	102.9%
F-B36	McCall - Wahtoke 115kV line	Kings River - Sanger - Reedley 115kV line	562.3	106.0%	104.2%	101.2%	107.5%
F-B106	McCall 230/115 kV Bk-1 (MVA)	McCall 230/115 kV Bk-2	133	108.3%	103.8%	97.0%	114.1%
F-B213	Storey 1 - Gregg 230kV line	Melones #1; Wilson - Storey 2 - Borden 230kV line	793.2	<95%	<95%	**105.8%**	<95%
Y-C1	Atwater Jct-Cressey Jct 115kV line	Wilson-Atwater and El Capitan-Wilson 115kV Lines	512	166.3%	166.7%	165.4%	167.0%
F-C20	Borden - Gregg 230kV line	Herndon-Kearney and Herndon-Ashlan 230kV lines	793.2	<95%	<95%	**111.9%**	<95%
F-C19	Gregg-Ashlan 230kV line	Gregg-Herndon #1 and #2 230kV lines	850	182.0%	209.3%	233.0%	195.6%
F-C3	Herndon - Woodward 115kV line	Herndon-Barton and Herndon-Manchester 115kV lines	974	106.6%	116.9%	129.9%	<95%
F-C19	Herndon-Ashlan 230kV line	Gregg-Herndon #1 and #2 230kV lines	850	115.3%	141.3%	167.1%	127.9%
F-C6	Le Grand-Chowchilla 115kV line	Kerckhoff-Clovis-Sanger #1 and #2 115kV lines	396.6	110.9%	<95%	<95%	<95%
F-C8	McCall-Wahtoke 115kV line	Kings R-Sanger-Reedley and Balch-Sanger 115kV lines	562.3	106.3%	104.6%	101.5%	107.8%
Y-C1	Merced-Atwater Jct 115kV line	Wilson-Atwater and El Capitan-Wilson 115kV Lines	738	138.2%	138.6%	137.5%	138.8%
Y-C1	Wilson A-Merced 115kV line	Wilson-Atwater and El Capitan-Wilson 115kV Lines	471.9	137.2%	137.0%	122.7%	137.0%
Y-C1	Wilson B-Merced 115kV line	Wilson-Atwater and El Capitan-Wilson 115kV Lines	471.9	124.0%	123.5%	136.2%	123.4%

Notes:

1. Case # F-B61 should be modified to reflect that Guernsey – Henrietta 70 kV line will not close circuit breaker No. 52 follow this outage. As a result, the Corcoran 115/70 kV transformer loading should reduce to within its ratings for the base alternative.

2. Case # F-B151 should use the emergency rating of the Henrietta – Jacobs Corner 70 kV line, which is 395 Amps. As a result, the Henrietta – Jacobs Corner 70 kV line will not overload for the base alternative.

3. Case # F-B123 should use the emergency rating of the Herndon – Woodward 115 kV line, which is 974 Amps. As a result, the Herndon – Woodward 115 kV line will not overload for the base alternative.

4. Cases #F-B138, F-B36 and F-C8, the Mc Call-Wahtoke 115 kV line is comprised of 1113 AAC with (SN/SE) 825/975 amps. As a result, the Mc Call-Wahtoke 115 kV line is not projected to overload for the base alternative.

5. Case #F-B106, Mc Call 230/115 kV Transformer No. 2 was re-rated for 150 MVA emergency. Therefore, Mc Call 230/115 kV Transformer No. 2 is not expected to overload for the base alternative.

6. Case #F-C19 and C6, there are existing SPS' that are in place to mitigate thermal overloads on the identified transmission lines.

Table A3-4
500 kV Contingencies for PG&E Alternative 2
(2010 Summer Peak Conditions with Helms Generation = 1200 MW)

					Base (pk_alt2-0.sav)		Alt 2A (pk_alt2a-300.sav)		Alt 2A (pk_alt2a-600.sav)		Alt 2B (pk_alt2b-600.sav)	
							IMPORT = 300 MW		IMPORT = 600 MW		IMPORT = 600 MW	
	Outages Facilities	Overloaded Facilities	RAS	SE Rating	post-outag Flow		post-outag Flow		post-outag Flow		post-outag Flow	
	Single Contingency (Category "B")		(MW)	(A)	(A)	(%)	(A)	(%)	(A)	(%)	(A)	(%)
PK-B1	Tesla-Los Banos 500kV line	Borden-Gregg 230kV line	none	793	612	77.2%	733	92.5%	868	**109.4%**	785	**99.0%**
PK-B2	Los Banos-Gates #3 500kV line	Borden-Gregg 230kV line	none	793	613	77.3%	733	92.4%	865	**109.0%**	782	98.6%
PK-B3	Los Banos-Midway 500kV Line	Borden-Gregg 230kV line	none	793	608	76.6%	725	91.4%	857	**108.1%**	775	97.7%
PK-B4	Gates-Midway #1 500kV Line	Borden-Gregg 230kV line	none	793	614	77.5%	725	91.5%	856	**107.9%**	775	97.8%
PK-B5	PDCI Bipole	Borden-Gregg 230kV line	none	793	533	67.2%	610	76.9%	735	92.7%	665	83.9%
	Double contingency (Category "C")											
PK-C1	Tesla-Los Banos, Tracy-Los Banos 500kV lines	Borden-Gregg 230kV line	none	793	608	76.6%	735	92.6%	877	**110.6%**	795	**100.3%**
PK-C2	Los Banos-Gates #3, Los Banos-Midway #1 500kV lines	Borden-Gregg 230kV line	none	793	607	76.5%	725	91.4%	859	**108.3%**	777	98.0%
PK-C3	Gates-Midway, Los Banos-Midway 500kV lines	Borden-Gregg 230kV line	none	793	611	77.0%	713	89.9%	845	**106.6%**	768	96.8%
PK-C4	Diablo Canyon G-2	Borden-Gregg 230kV line	none	793	549	69.3%	665	83.8%	794	**100.1%**	711	89.7%
PK-C5	Palo Verde G-2	Borden-Gregg 230kV line	none	793	550	69.4%	647	81.6%	777	98.0%	700	88.3%

Attachment 4
Preliminary Power Flow Study Results for PG&E Alternative 2
(2010 Summer Off-Peak Conditions with Helms off-line)

Table A4-1
Steady State Power Flow Study Results for PG&E Alternative 2
(2010 Summer Off-peak Conditions with Helms Offline)

	Transmission Facilities	SN Rating	Base (sumopk_r2.sav)		Alt 2A (opk_alt2a-600.sav)		Alt 2A (opk_alt2a-1200.sav)		Alt 2B (opk_alt2b-600.sav)		Alt 2B (opk_0p2b-1200.sav)	
			Import = 0 MW		Import = 600 MW		Import = 1200 MW		Import = 600 MW		Import = 1200 MW	
		(Amps)	(Amps)	(%)	(Amps)	(%)	(Amps)	(%)	(Amps)	(%)	(Amps)	(%)
1	WARNERVL - COTTLE B 230KV LINE	675.2	290.6	43.0%	473	70.1%	692	**102.5%**	432	63.9%	611	90.5%
2	BELLOTA - COTTLE B 230KV LINE	675.2	261.2	38.7%	444	65.7%	661	98.0%	403	59.6%	581	86.1%
3	McCall-PGE_2_W #1 230kV line	753.1	27.4	3.6%	n/a	<95%	n/a	<95%	403	53.5%	770	**102.2%**
4	McCall-PGE_2_W #1 230kV line	753.1	27.4	3.6%	n/a	<95%	n/a	<95%	403	53.5%	770	**102.2%**

Table A4-2
230 and 115 kV Contingencies for PG&E Alternative 2
(2010 Summer Off-Peak Conditions with Helms Offline)

Case #	Overloaded Transmission Facilities	Worst Contingency	SE Rating	Base (opk_op2a -0.sav)	Alt 2A (opk_0p2a -300.sav)	Alt 2A (opk_0p2a -600.sav)	Alt 2A (opk_0p2a -1200.sav)	Alt 2B (opk_0p2b -600.sav)	Alt 2B (opk_0p2b -1200.sav)
					Import = 300MW	Import = 600MW	Import = 1200MW	Import = 600MW	Import = 1200MW
			(Amps)	(%)	(%)	(%)	(%)	(%)	(%)
F-B207	Borden - Gregg 230kV line	Exchequer PH; Wilson - Storey 1 - Gregg 230kV line	793.2	<95%	<95%	<95%	**121.7%**	<95%	<95%
F-B146	Borden - Gregg 230kV line	Friant PP (22.5 MW)	675.3 (1)	<95%	<95%	<95%	**101.3%**	<95%	<95%
F-B100	Gates – Midway 230kV line	Gates 500/230kV bank	1390	<95%	<95%	<95%	<95%	<95%	<95%
F-B6	Storey 1 – Gregg 230kV line	Borden – Gregg 230kV line	793.2	<95%	<95%	<95%	**119.9%**	<95%	<95%
F-B207	Storey 2 – Borden 230kV line	Exchequer PH; Wilson – Storey 1 – Gregg 230kV line	793.2	<95%	<95%	<95%	**102.9%**	<95%	<95%
F-B6	Wilson – Storey 1 230kV line	Borden – Gregg 230kV line	851	<95%	<95%	<95%	**106.9%**	<95%	<95%
F-C12	Helm-McCall 230kV line	Gates-Gregg and Gates-McCall 230kV lines	850	**106.3%**	<95%	<95%	**138.7%**	<95%	<95%
F-C16	Henrietta-GWF_HEP 115kV line	Gates-McCall and Helm-McCall 230kV lines	743	**105.0%**	<95%	<95%	<95%	<95%	<95%
F-C13	Henrietta-McCall 230kV line	Gates-Gregg and Panoche-Kearney 230kV lines	975	**107.9%**	<95%	<95%	<95%	<95%	<95%

(1) Summer normal rating for G-1 contingency.

Table A4-3
500 kV "B" Contingencies for PG&E Alternative 2
(2010 Summer Off-Peak Conditions with Helms Offline)

					Base (sumopk_r2.sav)		Alt 2A (opk_alt2a-600.sav)		Alt 2A (opk_alt2a-00.sav)		Alt 2B (opk_alt2b-600.sav)		Alt 2B (opk_alt2b-200.sav)	
							Import=600 MW		Import =1200 MW		Import=600 MW		Import =1200 MW	
					Post-outage Flow		Post-outage Flow		Post-outage Flow		Post-outage Flow		Post-outage Flow	
	Outages Facilities	Overloaded Facilities	RAS (MW)	SE (A)	(A)	(%)	(A)	(%)	(A)	(%)	(A)	(%)	(A)	(%)
OPK-B1	Tesla-Los Banos 500kV line	Cottle B-Warnerville 230kV line	none	793	395	49.8%	596	75.2%	819	**103.2%**	555	69.9%	745	94.0%
OPK-B2	Los Banos-Gates #3 500kV line	Warnervill-Wilson 230kV line	none	793	n/a	<95%	119	15.0%	447	56.3%	70	8.8%	309	39.0%
OPK-B3	Los Banos-Midway 500kV Line	Gates-Midway 500kV Line	none	3556	3489	98.1%	3504	98.5%	3598	**101.2%**	3493	98.2%	3543	**99.6%**
OPK-B3	Los Banos-Midway 500kV Line	Gates-Midway 230kV line	none	1390	736	52.9%	684	49.2%	653	47.0%	676	48.6%	627	45.1%
OPK-B3	Los Banos-Midway 500kV Line	Arco-Midway 230kV line	none	1390	668	48.1%	627	45.1%	602	43.3%	619	44.5%	580	41.7%
OPK-B4	Gates-Midway #1 500kV Line	Los Banos-Midway 500kV Line	none	3556	2922	82.2%	2948	82.9%	3058	86.0%	2940	82.7%	3021	85.0%
OPK-B4	Gates-Midway #1 500kV Line	Gates-Midway 230kV line	none	1390	886	63.7%	819	58.9%	785	56.4%	807	58.1%	751	54.0%
OPK-B4	Gates-Midway #1 500kV Line	Arco-Midway 230kV line	none	1390	791	56.9%	737	53.0%	709	51.0%	726	52.3%	681	49.0%
OPK-B5	PDCI Bipole	Cottle B-Warnerville 230kV line	none	793	431	54.4%	675	85.1%	875	**110.4%**	630	79.4%	815	**102.8%**
OPK-B5	PDCI Bipole	Borden-Gregg 230kV line	none	793	220	27.7%	547	69.0%	836	**105.4%**	452	57.0%	637	80.3%
OPK-B5	PDCI Bipole	Storey 1-Gregg 230kV line	none	793	166	21.0%	490	61.8%	800	**100.9%**	403	50.8%	614	77.4%

Table A4-4
500 kV “C” Contingencies for PG&E Alternative 2
(2010 Summer Off-Peak Conditions with Helms Offline)

					Base (sumopk_r2.sav)		Alt 2A (opk_alt2a-00.sav)		Alt 2A (opk_alt2a-00.sav)		Alt 2B (opk_alt2b600.sav)		Alt 2B (opk_alt2b-00.sav)	
							Import=600 MW		Import =1200 MW		Import=600 MW		Import =1200 MW	
					Post-outage Flow		Post-outage Flow		Post-outage Flow		Post-outage Flow		Post-outage Flow	
	Outages Facilities	Overloaded Facilities	RAS (MW)	SE (A)	(A)	(%)	(A)	(%)	(A)	(A)	(%)	(A)	(%)	(A)
OPK -C1	TSL-LSB, TCY-LSB 500kV line	Cottle B-Warnerville 230kV line	3369	793	384	48.4%	585	73.8%	834	**105.2%**	545	68.8%	761	96.0%
OPK -C1	TSL-LSB, TCY-LSB 500kV line	Los Banos-Panoche #1 230kV line	3369	825	75	9.1%	34	4.2%	121	14.7%	50	6.1%	144	17.5%
OPK -C1	TSL-LSB, TCY-LSB 500kV line	Los Banos-Panoche #2 230kV line	3369	742	71	9.6%	34	4.6%	112	15.1%	48	6.5%	134	18.0%
OPK -C1	TSL-LSB, TCY-LSB 500kV line	Los Banos-Panoche #3 230kV line	3369	742	72	9.7%	33	4.5%	114	15.3%	48	6.5%	136	18.3%
OPK -C1	TSL-LSB, TCY-LSB 500kV line	Los Banos-Westley 230kV line	3369	2000	1731	86.6%	1926	96.3%	2276	**113.8%**	1970	98.5%	2345	**117.3%**
OPK -C1	TSL-LSB, TCY-LSB 500kV line	Los Banos 500/230kV bk	3369	1050	749	71.3%	719	68.5%	718	68.4%	722	68.8%	722	68.8%
OPK -C2	LSB-GTS #3, LSB-MDY #1 500kV lines	Los Banos-Gates #1 500kV line	1832	3556	3068	86.3%	3264	91.8%	3531	99.3%	3277	92.2%	3547	99.7%
OPK -C3	GTS-MDW, LSB-MDW #1 500kV lines	Gates-Midway 230kV line	2057	1390	1329	95.6%	1176	84.6%	1195	86.0%	1144	82.3%	1107	79.7%
OPK -C3	GTS-MDW, LSB-MDW #1 500kV lines	Arco-Midway 230kV line	2057	1390	1157	83.2%	1031	74.2%	1048	75.4%	1003	72.2%	975	70.2%
OPK -C4	Diablo Canyon G-2	None	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
OPK -C5	Palo Verde G-2	None	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Attachment 5
Preliminary Power flow Study Results for PG&E Alternative 4

Table A5-1
Steady State Power Flow Study Results for PGE Alternative 4
(2010 Summer Off-Peak Conditions with Helms = -600 MW)

	Transmission Facilities	SN Rating (1)	Base (sumopk_r1_2p.sav)		Alt 4A (opk_alt4c-500.sav)		Alt 4B (opk_alt4a-1100.sav)		Alt 4C (opk_alt4b-2k.sav)	
			Import = 0 MW		Import=500MW		Import=1100MW		Import=2000MW	
		(Amp)	(Amp)	(%)	(Amp)	(%)	(Amp)	(%)	(Amp)	(%)
1	Gates - Midway #1 500 kV line	2230	2088	93.6%	2197	**98.5%**	1844	82.7%	**2173**	**97.4%**
2	Los Banos - Midway #1 500 kV line	2230	1805	80.9%	1895	85.0%	1561	70.0%	1858	83.3%
3	Los Banos - Gates #1 500kV line	2230	1605	72.0%	1678	75.2%	1370	61.4%	1631	73.1%
4	Los Banos-Gates #3 500kV line	4332	800	18.5%	832	19.2%	690	15.9%	811	18.7%
5	Panoche-McMulln1 230kV line	825	785	95.2%	797	96.6%	816	98.9%	792	96.0%
6	McMulln1 - Kearney 230kV line	825	765	92.8%	779	94.4%	795	96.4%	771	93.4%
7	McCall - Hentap2 230kV line (1)	825	780	94.6%	777	94.2%	808	97.9%	**822**	**99.6%**
8	Los Banos - Westley 230 kV line	1484	784	52.8%	1001	67.4%	1056	71.1%	895	60.3%
9	Tesla-Los Banos #2 500kV line (new)	2230	n/a	n/a	n/a	n/a	n/a	n/a	1563	70.1%
10	LosBanos-Midway #2 500kV line (new)	2230	n/a	n/a	n/a	n/a	1802	80.8%	2134	95.7%
11	LosBanos-Midway #2 500kV line operate at 230kV (new)	2230	n/a	n/a	1723	69.5%	n/a	n/a	n/a	n/a

(1) The SN ratings are in ampere for line and MVA for transformer.

Table A5-2
500 kV Category "B" Contingencies for PG&E Alternative 4
(2010 Summer Off-Peak Conditions with Helms = -600MW)

				Base		Alt 4A		Alt 4B		Alt 4C	
				Import = 0 MW		Import=500MW		Import=1100MW		Import=2000MW	
	Outages Facilities	Overloaded Facilities	SE Rating (A)	post-outag Flow (A)	post-outag Flow (%)	post-outag Flow (A)	post-outag Flow (%)	post-outag Flow (A)	post-outag Flow (%)	post-outag Flow (A)	post-outag Flow (%)
B1	Tesla-Los Banos 500kV line	Gates-Henrietta Tap1 230kV line	1600	n/a	<95%	n/a	<95%	1564	97.7%	n/a	<95%
B2	Los Banos-Gates #3 500kV line	Gates-Henrietta Tap1 230kV line	1600	n/a	<95%	n/a	<95%	n/a	<95%	n/a	<95%
B2	Los Banos-Gates #3 500kV line	Los Banos-Midway #2 500kV Line operate at 230 kV (new)	3556	n/a	n/a	1718	48.3%	n/a	n/a	n/a	n/a
B3	Los Banos-Midway 500kV Line	Gates-Midway 500kV Line	3556	3433	96.5%	3556	**100%**	n/a	<95%	n/a	<95%
B3	Los Banos-Midway 500kV Line	Gates-Henrietta Tap1 230kV line	1600	n/a	<95%	n/a	<95%	n/a	<95%	1530	95.7%
B3	Los Banos-Midway 500kV Line	Los Banos-Midway #2 500kV Line operate at 230 kV (new)	3556	n/a	n/a	1713	48.2%	n/a	n/a	n/a	n/a
B3	Los Banos-Midway 500kV Line	Los Banos-Midway #2 500kV Line (new)	3556	n/a	n/a	n/a	n/a	n/a	<95%	n/a	n/a
B4	Gates-Midway #1 500kV Line	Los Banos-Midway 500kV Line	3556	2847	80.1%	n/a	<95%	n/a	<95%	n/a	<95%
B4	Gates-Midway #1 500kV Line	Los Banos-Midway #2 500kV Line operate at 230 kV (new)	3556	n/a	n/a	1717	48.3%	n/a	n/a	n/a	n/a
B4	Gates-Midway #1 500kV Line	Los Banos-Midway #2 500kV Line (new)	3556	n/a	n/a	n/a	n/a	n/a	<95%	n/a	<95%
B7	PDCI Bipole	Gates-Henrietta Tap1 230kV line	1600	1573	98.3%	1575	98.4%	1624	**101.5 %**	**1635**	**102.2 %**

Table A5-3
500 kV Category “C” Contingencies for PG&E Alternative 4
(2010 Summer Off-Peak Conditions with Helms = -600 MW)

				Base			Alt 4A			Alt 4B			Alt 4C		
				Import = 0 MW			Import=500MW			Import=1100MW			Import=2000MW		
	Outages Facilities	Overloaded Facilities	SE (A)	post-outage Flow (A)	post-outage Flow (%)	RAS (MW)				post-outage Flow (A)	post-outage Flow (%)	RAS (MW)	post-outage Flow (A)	post-outage Flow (%)	RAS (MW)
C1	Tesla-Los Banos, Tracy-Los Banos 500kV lines	Los Banos-Westley 230kV line	2000	1378	68.9%	3369	1671	83.6%	3368	2106	**105.3 % (1)**	3369	n/a	<95%	1985
C1	Tesla-Los Banos, Tracy-Los Banos 500kV lines	Los Banos 500/230kV xfr bank	1050	n/a	n/a	3369	989	94.2%	3368	1073	**102.2 % (1)**	3369	n/a	<95%	1985
C2	Los Banos-Gates #3, Los Banos-Midway #1 500kV lines	Los Banos-Gates #1 500kV line	3556	3324	93.5%	1532	3458	**97.3%**	1532	2255	63.4%	1532	n/a	<95%	1532
C3	Los Banos-Midway #1 and #2 500kV lines (Alt 4)	Gates-Midway 500kV line	3556	n/a	n/a	2648	n/a	n/a	n/a	3362	94.5%	2648	3511	**98.7%**	**4319 (2)**
C3	Los Banos-Midway #1 and #2 500kV lines (new)	Los Banos-Gates #1 500kV line	3556	n/a	n/a	2648	n/a	n/a	n/a	n/a	<95%	2648	2758	77.6%	**4319 (2)**
C4	Gates-Midway, Los Banos-Midway 500kV lines	Gates-Midway 230kV line	1390	1216	87.5%	2648	1208	86.9%	2648	707	50.9%	2648	817	58.8%	2984
C4	Gates-Midway, Los Banos-Midway 500kV lines	Los Banos-Midway #2 500kV Line (new)	3556	n/a	n/a	2648	n/a	n/a	2648	2917	82.0%	2648	3519	**99.0%**	2984
C5	Palo Verde G-2	none	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
C6	Diablo Canyon G-2	none	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

(1) Upgrade the Los Banos 500/230 kV transformer bank and the Los Banos – Westley 230 kV lines to relieve the emergency overloads.
(2) The RAS includes 2578 MW of generation, 691 MW of pumps and 1050 MW of loads. The net generation drop is 837 MW.

Attachment 6
Preliminary Power flow Study Results for PG&E Alternative 5

Table A6-1
Steady State Power Flow Study Results for PGE Alternative 5
(2010 Summer Off-Peak Conditions with Helms = -900MW)

	Transmission Facilities	SN Rating (1)	Base (sumopk_r1_2p.sav)		Alt 5A (opk_alt5a-500.sav)		Alt 5B1 (opk_alt5b1-1100.sav)		Alt 5C1 (opk_alt5c1-2k.sav)	
			Import = 0 MW Helms=-600MW		Import=500MW		Import=1100MW		Import=2000MW	
		(Amp)	(Amp)	(%)	(Amp)	(%)	(Amp)	(%)	(Amp)	(%)
1	Gates - Midway #1 500 kV line	2230	2088	93.6%	**2124**	**95.3%**	2085	93.5%	2152	96.5%
2	Los Banos - Midway #1 500 kV line	2230	1805	80.9%	1838	82.4%	1907	85.5%	1943	87.1%
3	Los Banos - Gates #1 500kV line	2230	1605	72.0%	1637	73.4%	1767	79.2%	1781	79.8%
4	Los Banos-Gates #3 500kV line	4332	800	18.5%	816	18.8%	879	20.3%	884	20.4%
5	Panoche-McMulln1 230kV line	825	785	95.2%	701	85.0%	350	42.4%	369	44.7%
6	McMulln1 - Kearney 230kV line	825	765	92.8%	680	82.4%	331	40.2%	347	42.1%
7	McCall - Hentap2 230kV line	825	780	94.6%	746	90.4%	609	73.8%	652	79.1%
8	Los Banos - Westley 230 kV line	1484	784	52.8%	806	54.3%	1036	69.8%	984	66.3%
11	Tesla-Gregg 500kV line (new)	2230	n/a	n/a	n/a	n/a	n/a	n/a	1042	46.7%
12	Gregg-Midway 500kV line (new)	2230	n/a	n/a	n/a	n/a	1238	55.5%	**2195**	**98.4%**
13	Gregg-Midway 500kV line operate at 230kV (new)	2478	n/a	n/a	1304	52.6%	n/a	n/a	n/a	n/a
14	Gregg 500/230kV Transformer (new)	1122	n/a	n/a	n/a	n/a	**1113**	**99.2%**	990	88.2%

(1) The SN ratings are in ampere for line and MVA for transformer.

Table A6-2
500 kV Category "B" Contingencies for PG&E Alternative 5
(2010 Summer Off-Peak Conditions with Helms = -900MW)

				Base		Alt 5A		Alt 5B1		Alt 5C1	
				Import = 0 MW Helms=-600MW		Import=500MW		Import=1100MW		Import=2000MW	
	Outages Facilities	Overloaded Facilities	SE Rating (A)	post-outag Flow (A)	post-outag Flow (%)	post-outag Flow (A)	post-outag Flow (%)	post-outag Flow (A)	post-outag Flow (%)	post-outag Flow (A)	post-outag Flow (%)
B1	Tesla-Los Banos 500kV line	Gates-Henrietta Tap1 230kV line	1600	n/a	<95%	1368	85.5%	n/a	<95%	n/a	<95%
		Gregg 500/230kV bank (new)	1260	n/a	<95%	n/a	n/a	1170	92.8%	n/a	<95%
		Gregg-Midway 500kV line (new)	3556	n/a	<95%	n/a	n/a	n/a	<95%	n/a	<95%
B2	Los Banos-Gates #3 500kV line	Gates-Henrietta Tap1 230kV line	1600	n/a	<95%	1331	83.2%	n/a	<95%	n/a	<95%
		Gregg 500/230kV bank (new)	1260	n/a	n/a	n/a	n/a	1134	90.0%	n/a	<95%
B3	Los Banos-Midway 500kV Line	Gates-Midway 500kV Line	3556	3433	96.5%	3457[13]	**97.2%**	3390	95.3%	3312	93.1%
		Gates-Henrietta Tap1 230kV line	1600	n/a	<95%	1374	85.9%	n/a	<95%	n/a	<95%
		Gregg 500/230kV bank (new)	1260	n/a	n/a	n/a	n/a	1259	**100.0%**	n/a	<95%
		Tesla-Gregg 500kV line (new)	3556	n/a	n/a	n/a	n/a	n/a	<95%	n/a	<95%
		Gregg-Midway 500kV line (new)	3556	n/a	n/a	n/a	n/a	n/a	<95%	n/a	<95%
		Gregg-Midway 500kV line operate at 230kv (new)	2962	n/a	n/a	1383	46.7%	n/a	<95%	n/a	<95%

[13] A sensitivity case modeling the import of 600 MW was run. The Gates-Midway 500 kV line would load up to 3550 amperes (99.8% of SE rating of 3556A) for the Los Banos – Midway 500 kV line outage.

Table A6-2 (continue)
500 kV Category "B" Contingencies for PG&E Alternative 5
(2010 Summer Off-Peak Conditions with Helms = -900 MW)

				Base		Alt 5A		Alt 5B1		Alt 5C1	
				Import = 0 MW Helms=-600MW		Import=500MW		Import=1100MW		Import=2000MW	
	Outages Facilities	Overloaded Facilities	SE Rating (A)	post-outag Flow (A)	post-outag Flow (%)	post-outag Flow (A)	post-outag Flow (%)	post-outag Flow (A)	post-outag Flow (%)	post-outag Flow (A)	post-outag Flow (%)
B4	Gates-Midway #1 500kV Line	Los Banos-Midway 500kV Line	3556	2847	80.1%	2863	80.5%	2840	79.9%	n/a	<95%
		Gregg 500/230kV bank new)	1260	n/a	n/a	n/a	n/a	1292	102.5 %	n/a	<95%
		Gregg-Midway 500kV line (new)	3556	n/a	n/a	n/a	n/a	n/a	<95%	n/a	<95%
		Gregg-Midway 500kV line operate at 230kV (new)	2962	n/a	n/a	1403	47.4%	n/a	<95%	n/a	n/a
B5	Tesla-Gregg 500kV line	Gregg 500/230kV bank (new)	1260	n/a	n/a	n/a	n/a	n/a	n/a	1341	106.4 %
B6	Gregg-Midway 500kV line	McCall-Hentap2 230kV line	975	n/a	n/a	n/a	<95%	972	99.7%	n/a	<95%
		Panoche-McNulln1 230kV line	975	n/a	n/a	n/a	<95%	1050	107.7 %	n/a	<95%
		McMUlln1-Kearney 230kV line	975	n/a	n/a	n/a	<95%	1031	105.7 %	n/a	<95%
		Warnerville-Wilson 230kV line	793	n/a	n/a	n/a	<95%	801	101.0 %	n/a	<95%
		Gates-Henrietta Tap1 230kV line	1600	n/a	n/a	n/a	<95%	1785	111.5 %	1558	97.4%
B7	PDCI Bipole	Gates-Henrietta Tap1 230kV line	1600	1573	98.3%	1442	90.1%	n/a	<95%	n/a	<95%
		McCall-Hentap2 230kV line	975	n/a	<95%	845	86.7%	n/a	<95%	n/a	<95%
		Gregg 500/230kV bank (new)	1260	n/a	<95%	n/a	n/a	1262	100.1 %	988	78.4%

Table A6-3
500 kV Category "C" Contingencies for PG&E Alternative 5
(2010 Summer Off-Peak Conditions with Helms = -900 MW)

				Alt 5a			Atl 5b			Alt 5c		
				Import = 500 MW			Import=1100MW			Import=2000MW		
	Outages Facilities	Overloaded Facilities	SE Rating (A)	post-outag Flow (A)	post-outag Flow (%)	RAS (MW)	post-outag Flow (A)	post-outag Flow (%)	RAS (MW)	post-outag Flow (A)	post-outag Flow (%)	RAS (MW)
C1	Tesla-Los Banos, Tracy-Los Banos 500kV lines	Los Banos-Westley 230kV line	2000	1879	93.9%	1951	1815	90.8%	3369	1837	91.8%	1951
C1	Tesla-Los Banos, Tracy-Los Banos 500kV lines	Tesla-Gregg 500kV line (new)	3556	n/a	n/a	n/a	n/a	n/a	n/a	n/a	<95%	1951
C1	Tesla-Los Banos, Tracy-Los Banos 500kV lines	Gregg-Midway 500kV line (new)	3556	n/a	n/a	n/a	n/a	<95%	3369	n/a	<95%	1951
C2	Los Banos-Gates #3, Los Banos-Midway #1 500kV lines	Los Banos-Gates #1 500kV line	3556	3424	**96.3%**	1832	3276	92.1%	2948	3378	95.0%	1832
C2	Los Banos-Gates #3, Los Banos-Midway #1 500kV lines	Gates-Midway 500kV line	3556	2865	80.6%	1832	2591	72.9%	2948	n/a	<95%	1832
C2	Los Banos-Gates #3, Los Banos-Midway #1 500kV lines	Tesla-Gregg 500kV line (new)	3556	n/a	n/a	n/a	n/a	n/a	n/a	n/a	<95%	1832
C2	Los Banos-Gates #3, Los Banos-Midway #1 500kV lines	Gregg-Midway 500kV line (new)	3556	n/a	n/a	n/a	n/a	<95%	2948	n/a	<95%	1832
C4	Gates-Midway, Los Banos-Midway 500kV lines	Gates-Midway 230kV line	1390	1298	93.4%	2057	1061	76.3%	2948	1108	79.7%	2057
C4	Gates-Midway, Los Banos-Midway 500kV lines	Tesla-Gregg 500kV line (new)	3556	n/a	n/a	n/a	n/a	n/a	n/a	n/a	<95%	2057
C4	Gates-Midway, Los Banos-Midway 500kV lines	Gregg-Midway 500kV line (new)	3556	n/a	n/a	n/a	n/a	<95%	2948	3222	90.6%	2057
C4	Gates-Midway, Los Banos-Midway 500kV lines	Gregg 500/230kV bank (new)	1260	n/a	n/a	n/a	1251	**99.3%**	2948	715	56.7%	2057
C5	Palo Verde G-2	Panoche-Kearney 230kV line	975	n/a	<95%	None	n/a	<95%	None	n/a	<95%	None
C5	Palo Verde G-2	Warnerville-Wilson 230kV line	793	n/a	<95%	None	n/a	<95%	None	n/a	<95%	None
C6	Diablo Canyon G-2	Panoche-Kearney 230kV line	975	n/a	<95%	None	n/a	<95%	None	n/a	<95%	None
C6	Diablo Canyon G-2	Warnerville-Wilson 230kV line	793	n/a	<95%	none	n/a	<95%	None	n/a	<95%	None

APPENDIX 3

APPENDIX 3

SCE Study Alternatives

SCE filed a report titled "Development Plan for the Phased Expansion of Transmission in the Tehachapi Wind Resource" (Report) on behalf of the TCSG in March 16, 2005 as directed by the Commission. The Report presented alternative transmission concepts for interconnecting and delivering Tehachapi wind generation to various load centers. The Report recommended that the study be continued in order to select the best alternative from the four candidate options and to further evaluate the potential for a new interconnect between SCE and PG&E in the Fresno area. This section provides SCE's modifications to these four alternatives plus the results of the SCE-PG&E Fresno area connection study.

It was assumed that a local Tehachapi Area 230 kV system would be developed to support the large amount of wind generation potential identified in the CEC Report. These facilities are common to all project alternatives and can only be developed once more information is made available as to exact wind generation locations and amounts. It is therefore impossible to properly develop the local area network at this point in time.

1. TRANSMISSION PLANS INTERCONNECTING WIND RESOURCES IN THE TEHACHAPI AREA TO THE GRID

The four alternatives that remained open from the original TCSG share the same Tehachapi local area wind collector facilities as discussed in Chapter 2, Section 2.2 of the March 16, 2005 TCSG Final Report and differed slightly in the facilities identified to be necessary to connect the wind resource areas to the main bulk power system. These four Tehachapi Interconnection facilities were summarized in Section 1 of Appendix A of the March 16, 2005 TCSG Final Report. SCE has conducted further review of these alternatives and has concluded that modifications are needed to these alternatives due to lack of available undeveloped land to support additional right-of-way requirements. As an example, SCE found it necessary to reroute Segment 2 of the Antelope Transmission Project (Phase 1) in the supplemental CPCN Application (A.04-12-008) filing submitted to the CPUC on September 2005. This reroute was needed to accommodate new housing projects developing adjacent to the existing Antelope-Vincent right-of-way. The following sections provide a detailed discussing of impacts to the four alternatives that were to be further reviewed.

1.1. Discussion of Modifications to Proposed Alternatives

1.1.1. Antelope-Substation #5 Transmission Section

The conceptual transmission plans identified in the March 16, 2005 TCSG Final Report were based on the assumption that only 300 MW of wind generation was to be located in the Cottonwood Creek area and connected to a proposed Cottonwind 230 kV Switching Station (a.k.a. Substation #5). All four alternatives included a reconductor of the existing Antelope-Magunden No.2 230 kV transmission line section between Antelope and the new switching station assuming the use of a Special Protection System (SPS) could be implemented and approved by the CAISO.

The use of an SPS was found to be unacceptable based on the study results obtained in a system impact study (SIS) performed for the 300 MW wind generation project. The SIS identified that the amount of monitoring points, number of outages, and the total amount of generation tripping required to maintain system reliability violated established CAISO Guidelines for implementing an SPS. Consequently, the recommended upgrade involves replacing an existing single circuit transmission line with a new double-circuit 230 kV transmission line. In addition, recent generation interconnections have been submitted which identify this substation as the point of interconnection. The total amount of wind generation proceeding through the CAISO interconnection process totals 1,110 MW. As a result, both existing single-circuit 230 kV transmission lines will need to be replaced with two double-circuit
230 kV transmission lines. It may be necessary to include additional transmission upgrades due to the large amount of generation interconnection requests in this area.

1.1.2. Antelope-Vincent Transmission Section

A detailed review of available land in the area was performed in support of the Antelope Transmission Project Segment 2 and 3 CPCN Supplemental Application. This detailed review concluded that only two 500 kV transmission facilities can be accommodated between Antelope and Vincent without significant impacts to existing residential owners or housing developments currently under construction. Alternative one shown below in Figure 3-1 included one 500 kV and two 230 kV transmission lines between Antelope and Vincent. Alternatives two and three shown below in Figure 3-2 and 3-3 respectively included two 500 kV and two 230 kV transmission lines between Antelope and Vincent. Alternative four included one 500 kV and three 230 kV transmission lines between Antelope and Vincent. In order to maximize capability between Antelope and Vincent, it is recommended that the conceptual transmission plan be modified to include an alternative with two 500 kV transmission lines.

1.1.3. Vincent-Rio Hondo/Mesa Transmission Section

SCE has been conducting studies in support of a new Mira Loma-Vincent 500 kV transmission line. The need for this new 500 kV line into the Mira Loma area was identified as part of the SCE CAISO Annual Expansion Program and is required to serve growing load demand in the Mira Loma area. This new line will provide an added benefit of supporting delivery of Tehachapi area wind generation to the SCE load center.

Since last year's report, SCE has integrated this line with the Phase 2 of last year's TCSG Final Report, rebuild of the Antelope-Mesa 230 kV transmission line, in order to minimize the number of facilities and amount of new land disturbance that would otherwise result with building separate transmission projects.

In order to integrate the Vincent-Mira Loma 500 kV transmission line with the Antelope-Mesa Upgrades, the following upgrades are required:

- Rebuild the portion of the existing Antelope-Mesa 230 kV single circuit transmission line between Vincent and the southern boundary of the Angeles National Forest (City of Duarte) with single circuit 500 kV transmission line

- Replace a small section of the existing Vincent-Rio Hondo 230 kV transmission line outside of the Vincent Substation (approximately five miles) with single circuit 500 kV transmission (part of the Mira Loma-Vincent 500 kV transmission line project) to allow operation of this line at 500 kV

- Rebuild the portion of the existing Antelope-Mesa 230 kV single circuit transmission line between the City of Duarte and the Mesa Substation with double-circuit 500 kV transmission line

- Develop and permit a new Mesa 500 kV substation

Previous conceptual studies identified the utilization of the Rio Hondo substation as the 500 kV entry point to the Los Angeles Basin. Further review of this substation site has concluded that insufficient property is available to increase the underlying 230 kV capability needed to support a 500 kV substation. As a result, SCE is currently evaluating the Mesa substation for converting it to 500 kV. This substation site provides sufficient 230 kV transmission capacity to support a 500 kV substation. The substation site could provide for up to twelve 230 kV transmission lines, which serve the Los Angeles Basin, if necessary, without the need to construct new transmission on new right-of-way. In comparison, the Rio Hondo substation site allowed for only three 230 kV transmission lines to serve the Los Angeles Basin load center. Additional 230 kV transmission lines in new right-of-way would be necessary to support a Rio Hondo 500 kV substation site. These new 230 kV transmission lines would be extremely difficult, if not impossible, to construct given the land right-of-way restrictions that exist in the area (i.e. no available land). The new Mesa 500 kV substation will require three 500/230 kV transformers initially due to the large amount of load demand in the area.

1.1.4. Mesa-Chino Transmission Section

As part of the Mira Loma-Vincent 500 kV transmission line project, SCE had been evaluating requirements to bring the new 500 kV line all the way into the Mira Loma 500 kV Substation. With the integration of the Mira Loma-Vincent and Antelope-Mesa, SCE is now evaluating the utilization of an existing Mira Loma-Serrano 500 kV transmission line to avoid having to construct the new Mira Loma-Vincent 500 kV transmission line all the way into Mira Loma. This requirement is supported by preliminary study results, which have identified that outage of the new Mesa-Vincent 500 kV transmission line (part of the Antelope-Mesa Upgrade) results in rerouting a significant amount of power flow towards Mira Loma via Lugo through the step-down transformers at Mira Loma and finally through the underlying 230 kV network towards the Mesa area. As a result, the potential for a voltage collapse and thermal overloads were identified with high deliveries from the north (Path 26, Big Creek Corridor, Ventura area and the Tehachapi area) under loss of the new Mesa-Vincent 500 kV transmission line.

In order to provide continued reliable service to the Mesa local area loads, a second line to Mesa will be required. This line can be added by constructing the Mira Loma-Vincent 500 kV transmission line with double circuit 500 kV standard transmission design from the Mesa area to the Chino area (Mira Loma-Serrano right-of-way). The existing Mira Loma-Serrano 500 kV line can be "cut" and at the point where the new double circuit line joins the existing Mira Loma-Serrano 500 kV transmission line. Utilizing the Mira Loma section of the existing Mira Loma-Serrano 500 kV transmission line can then form the Mira Loma-Vincent 500 kV transmission line. The Mesa-Serrano 500 kV transmission line can be formed by adding a second circuit on the double-circuit 500 kV transmission line between the Mesa area and the Chino area and utilizing the Serrano section of the existing Mira Loma-Serrano 500 kV transmission line.

1.1.5. Second Mesa-Vincent Transmission Section

Depending on the overall increase of power deliveries to the south (i.e. SCE, SDG&E, LADWP, CFE, or Arizona utilities) and corresponding study results under loss of both the new Mesa-Vincent and Mira Loma-Vincent 500 kV transmission lines (same corridor through the Angeles National Forest and same tower from the City of Duarte to the Mesa substation), a second 500 kV transmission line from Vincent may be required in a separate right-of-way. Feasibility studies for the recent batch of interconnection requests will commence shortly (Study Agreement provided to customer), which will result in clarifying timing need for this additional upgrade. As a conceptual plan, SCE envisions utilizing the existing 500 kV transmission line section on the existing Vincent-Santa Clara 230 kV transmission line between Pardee and Vincent and operating it at 500 kV by sectionalizing line and terminating 230 kV section at the Pardee 230 kV bus and 500 kV section at the Pardee and Vincent 500 kV buses. The second 500 kV transmission line to Mesa can then be added by replacing a portion of the existing Pardee-Eagle Rock 230 kV transmission line (second smallest line south of Vincent) towards the Gould area and ultimately down to Mesa. This upgrade could also minimize the amount of loop flow from SCE to LADWP resulting from the addition of significant levels of Tehachapi wind generation.

1.2. Common Facilities in Alternatives (Not Modified)

1.2.1. 500 kV Transmission Line between Antelope and Pardee

This 500 kV transmission line is also referred to as Segment 1 of the Antelope Transmission Project (Phase 1). The CPCN Application (A.04-12-007) for this transmission line has been filed with the CPUC since December 9, 2004. The application is currently under review by the CPUC with approval anticipated before the end of the year.

1.2.2.500 kV Transmission Line between Antelope and Vincent

This 500 kV transmission line is also referred to as Segment 2 of the Antelope Transmission Project (Phase 1). The CPCN Application (A.04-12-008) for this transmission line has been filed with the CPUC since December 9, 2004. A supplemental filing was made by SCE on September 2005 in order to augment environmental information. The application review has recently been initiated by the CPUC and as such SCE does not currently have an anticipated approval date.

1.2.3.Initial Transmission Facilities between Antelope and Tehachapi

A new 500 kV transmission line from Antelope to a new Tehachapi area substation site, two new Tehachapi area substations, and a 230 kV transmission line connecting the two new substations collectively are referred to as Segment 3 of the Antelope Transmission Project (Phase 1). The CPCN Application (A.04-12-008) for this transmission line has been filed with the CPUC since December 9, 2004. A supplemental filing was made by SCE on September 2005 in order to augment environmental information. The application review has recently been initiated by the CPUC and as such SCE does not currently have an anticipated approval date.

1.2.4.Second 500 kV Transmission Line between Antelope and Tehachapi

This 500 kV transmission line is similar to the 500 kV transmission line identified in Segment 3 of the Antelope Transmission Project but would utilize a separate right-of-way to provide sufficient separation thus avoiding conditions which could result in simultaneous loss of both transmission lines. Putting the second Antelope-Tehachapi 500 kV transmission line on the same right-of-way would limit the amount of Tehachapi area wind generation that can be supported to 1,400 MW due to CAISO Spinning Reserve requirements.

1.2.5. Additional Reactive Resources

Additional reactive resources may need to be added throughout the network in order to restore bus voltages to levels identified prior to adding and dispatching the Tehachapi area wind resources. With all the transmission upgrades needed to support the Tehachapi area and new Mira Loma-Vincent 500 kV transmission line, it is unclear exactly how much and where such reactive support should be located. Therefore, these resources where not included into this conceptual transmission plan. SCE will identify how much and where such reactive support should be installed as part of the detailed interconnection studies currently underway. If additional permitting is required, due to the need for substation expansion to support additional reactive resources, SCE will identify such requirements as part of the CPCN Applications to be submitted as required per CPUC Resolution E-3969.

1.3. Uncommon Facilities in Alternatives (Not Modified)

1.3.1. Third 500 kV Transmission Line between Antelope and Tehachapi

Alternative 2 included a third 500 kV transmission line between Antelope and Tehachapi. This line is similar to the 500 kV transmission line identified in Segment 3 of the Antelope Transmission Project Separation would only be required if the amount of generation tripping under loss of both 500 kV lines in the same right-of-way exceeds 1,400 MW. Without the benefit of detailed studies (power flow, post-transient voltage, and transient stability), the assumption can be made that this third line could potentially be placed in the same right-of-way as the second 500kV transmission line between Antelope and Tehachapi.

1.3.2. New 500 kV Transmission Line from Tehachapi to PG&E

SCE's Alternatives 1, 3, and 10 included a new 500 kV transmission line north of Tehachapi towards PG&E. For evaluation of the SCE network, Alternatives that involve a 500 kV transmission line to the north from Tehachapi were assumed to terminate at Midway. However, evaluation of the PG&E network considered terminating the transmission line further north due to anticipated potential transmission problems North of Midway Substation. Such an increase is likely to occur for two reasons:

1. The first involves transferring 2,000 MW more power on an already constrained path if Tehachapi area wind generation is to displace existing generation resources located in northern and central PG&E system.

2. The second is attributed to reduction in Path 15 transfer capability from 5,400 MW down to 4,100 MW if Tehachapi area wind generation is to displace existing generation resources located in the Midway area. Such reduction is necessary since the 5,400 MW rating can only be supported when the Midway area generation is dispatched as part of the Path 15 Remedial Action Scheme (RAS). Displacing this generation in order to accommodate the Tehachapi wind resource will result in reducing the support provided in the RAS, thus adversely impacting Path 15 transfer capability and will lead to increased congestion.

From an SCE perspective, conceptual study results are not anticipated to differ much regardless of where PG&E ultimately terminates the new 500 kV transmission line, or whether there would be a new PG&E 500 kV line, since study results from all parts of the systems will be overlaid to develop the integrated conceptual plans.

Figure 3.1.1
TCSG Alternative 1 Identified in the March 16, 2005 TCSG Final Report

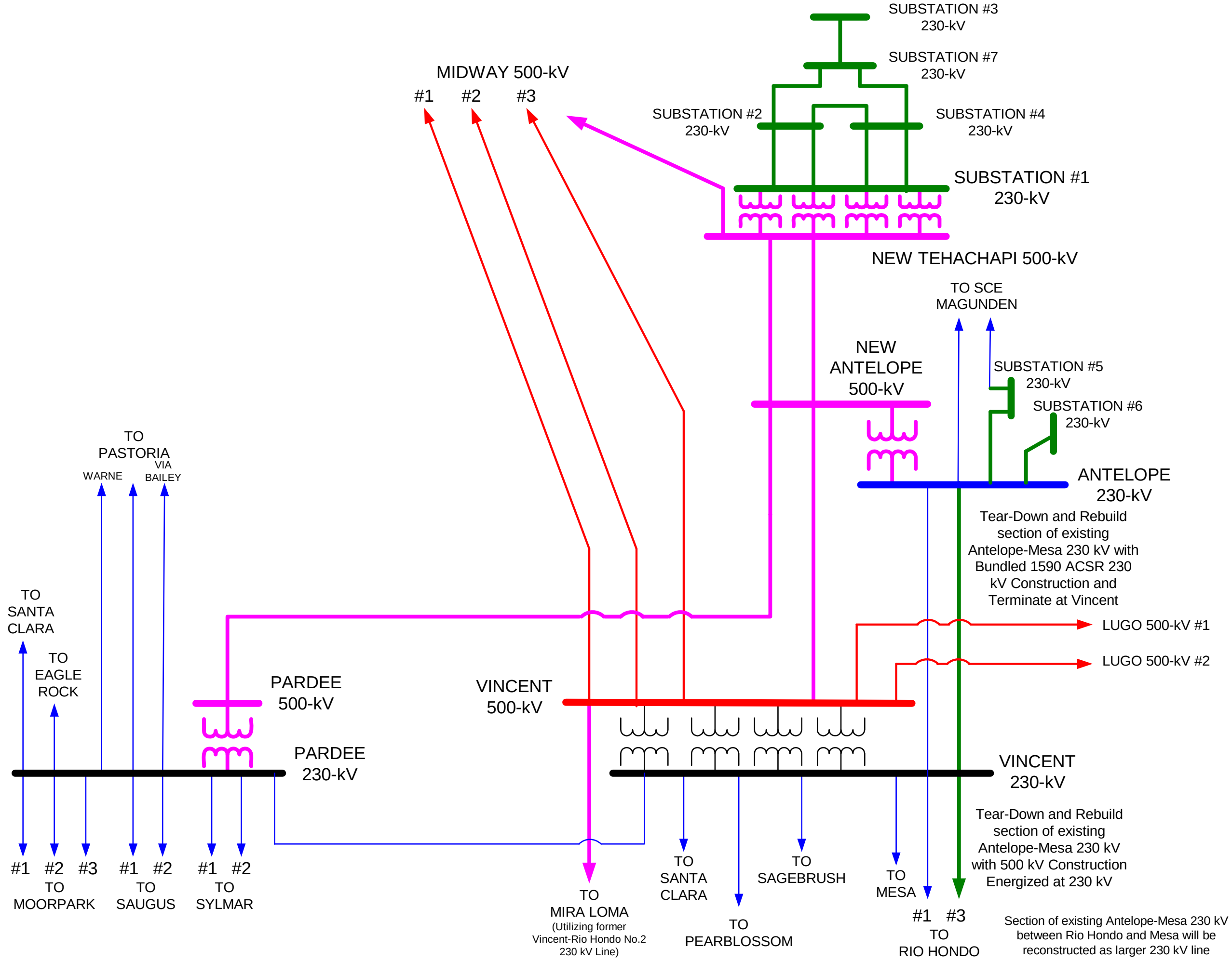


Figure 3.1.2
TCSG Alternative 2 Identified in the March 16, 2005 TCSG Final Report

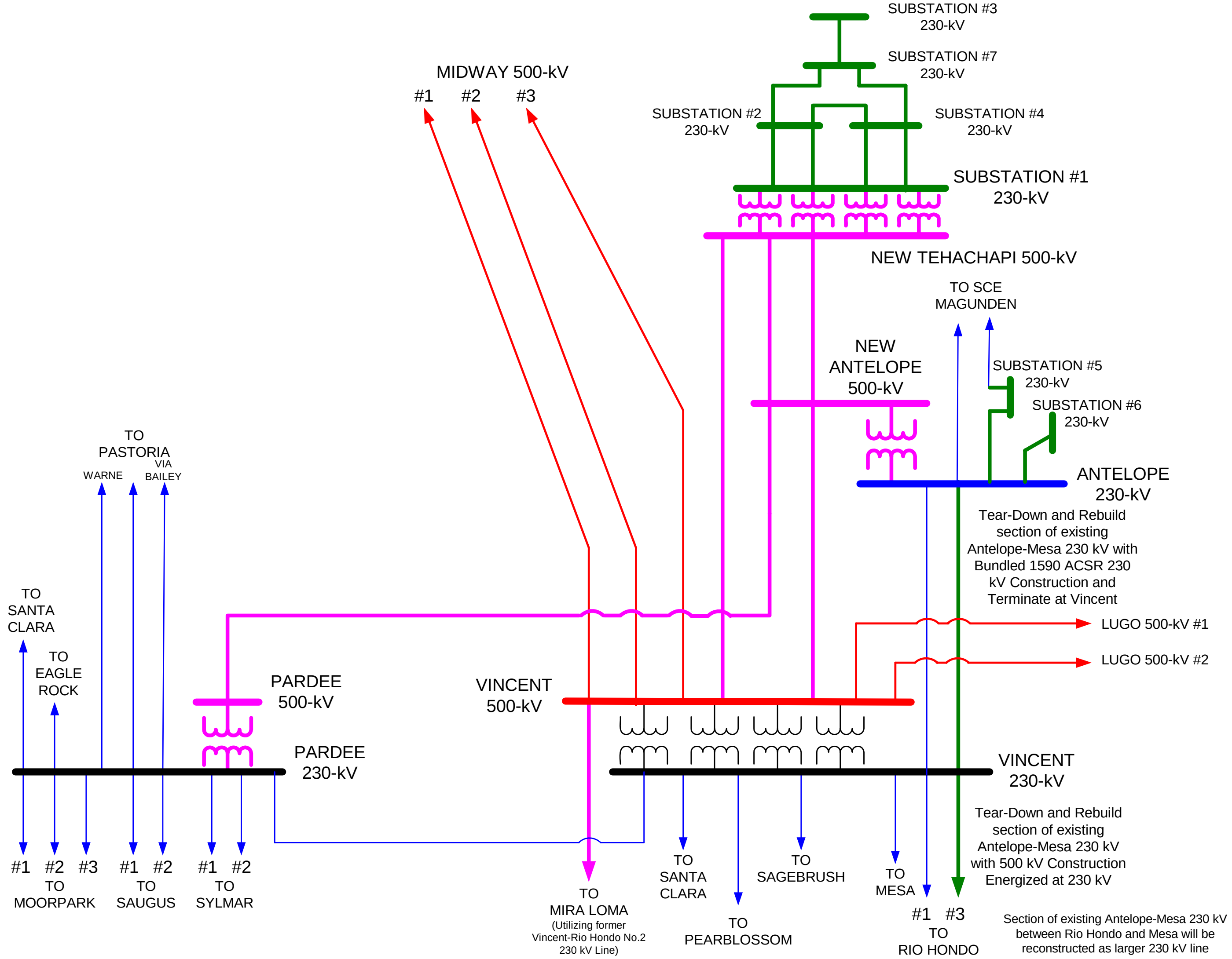


Figure 3.1.3
TCSG Alternative 3 Identified in the March 16, 2005 TCSG Final Report

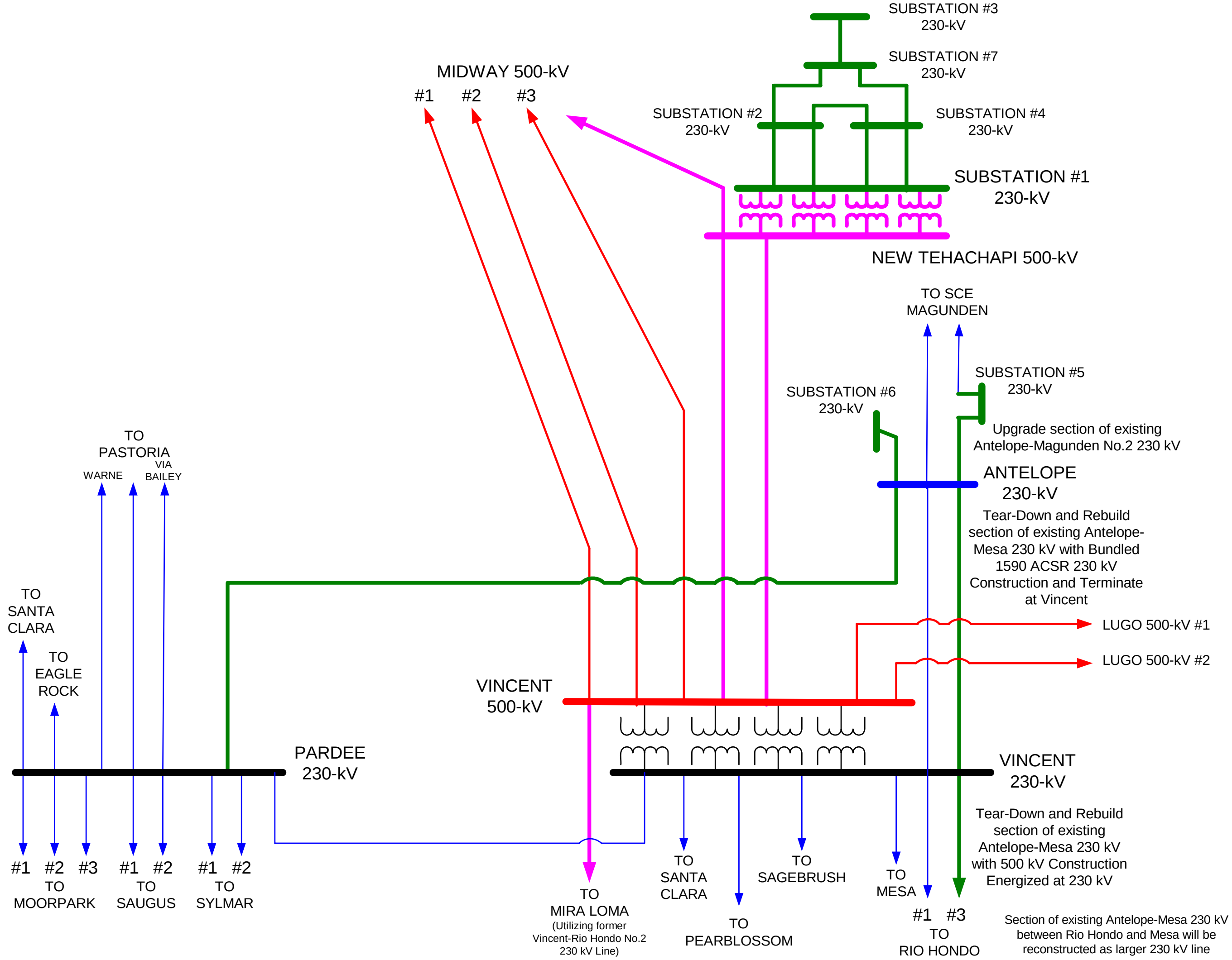


Figure 3.1.4
TCSG Alternative 10 Identified in the March 16, 2005 TCSG Final Report

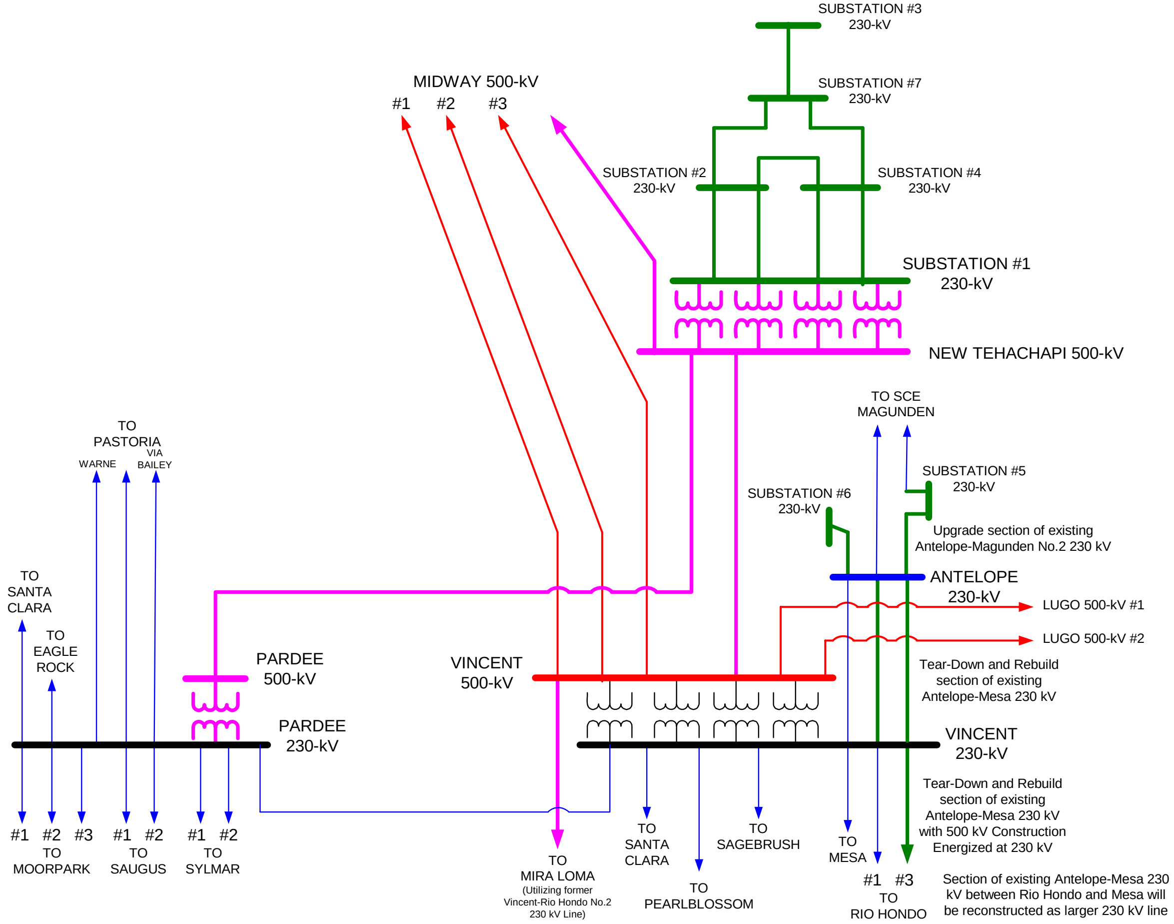
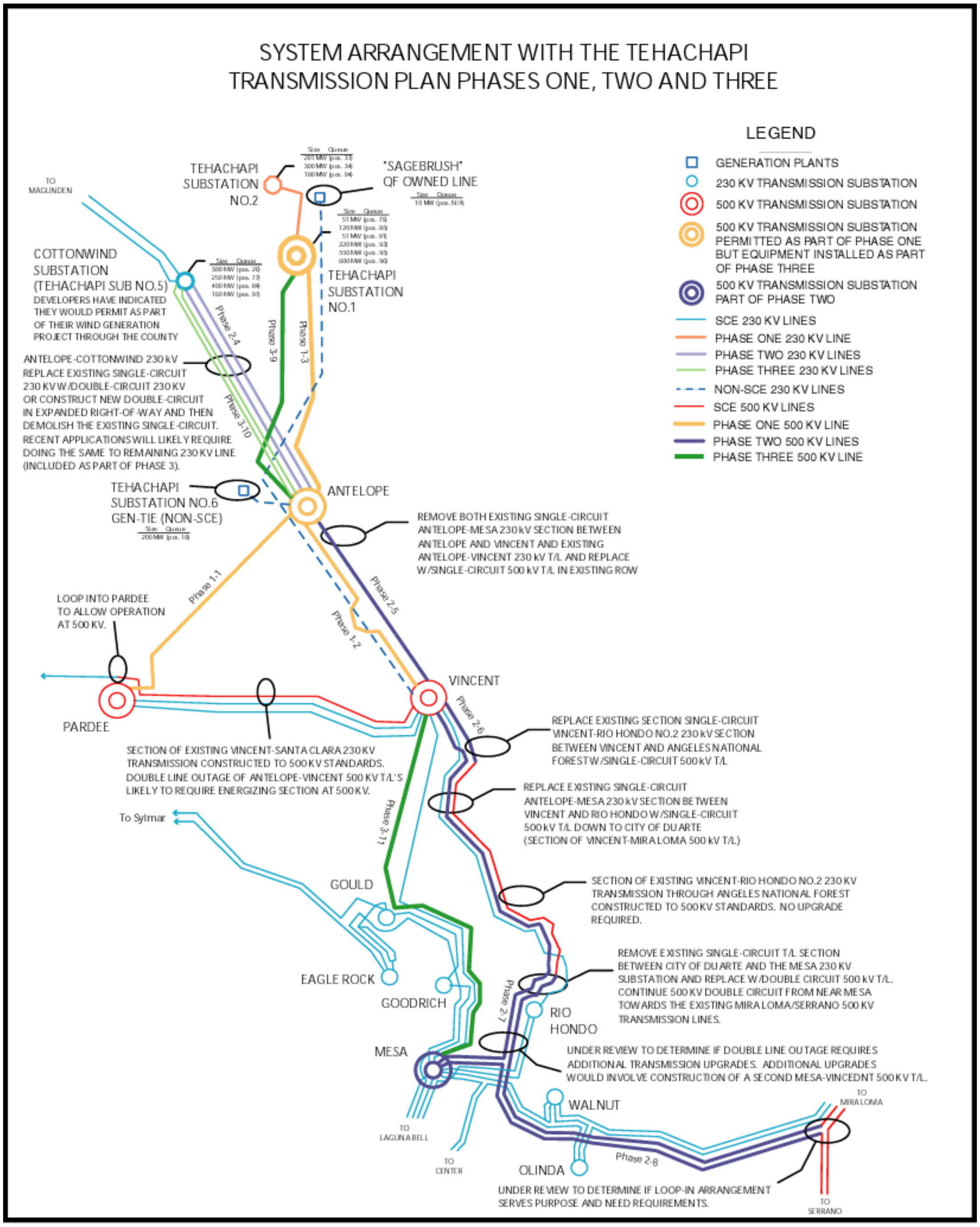


Figure 3.1.5
Revised Tehachapi Transmission Plan



2. GRID UPGRADES TO DELIVER TEHACHAPI WIND RESOURCES – STUDY RESULTS

SCE is in the process of performing Feasibility, System Impact, and Facilities Studies for a number of wind generation projects proceeding through the interconnection process. As a result, SCE did not revisit the previous conceptual power flow studies associated with the four alternatives remaining on the table. Instead, SCE utilized the study results from a limited number of Feasibility studies conducted to modify the previous transmission plans as presented above in Section 1.

With the modification included into the study case, SCE identified a few additional impacts that may need additional upgrades. The first is that increase power deliveries into the Cottonwind Substation (i.e. Substation #5) results in power flow "loop flow" up towards the SCE Magunden Substation and down the west leg of the corridor towards the Pastoria and Pardee Substations. The second is the potential for "loop flow" to impact three LADWP 230 kV transmission lines from Sylmar to Rinaldi.

2.1. Loop Flow on the Magunden-Pastoria-Pardee and Sylmar-Rinaldi Transmission Corridors

2.1.1. Loop Flow on the Magunden-Pastoria-Pardee Corridor

Depending on which generation resources are displaced, the amount of "loop-flow" increases loading on the three Magunden-Pastoria 230 kV transmission lines as well as the three transmission lines south of Pastoria. Two of the three transmission lines between Magunden and Pastoria are small conductored lines, which have a limited capability of 825 amps (approximately 325 MVA). The third line is a larger conductored line with a 1240 amp capability (approximately 490 MVA). As far as transmission south of Pastoria, two of these three lines are in the process of being reconductored with a trapezoidal ACSS conductor in order to increase capacity from 885 amps (approximately 350 MVA) up to 1,500 amps (approximately 600 MVA). The remaining line is conductored with 1240 amp capability (approximately 490 MVA) and is not being reconductored at this time. Reconductoring of the two smaller Magunden-Pastoria 230 kV and the Pastoria-Pardee-Warne 230 kV transmission lines may be required to support the large amount of generation interconnection at the Cottowind Substation. Such determination will be made as part of the detailed studies currently underway.

2.1.2. Loop Flow on Los Angeles Department of Water and Power (LADWP) Sylmar-Rinaldi Transmission Corridor

Imports from the north to the main Los Angeles Basin is delivered by a number of 500 and 230 kV transmission lines as well as through the Pacific DC Intertie. Since the network is an integrated network, schedules and actual flows may not coincide. This is due to the fact that there exist certain amounts of "loop-flow." In other words, power deliveries will follow the path of least resistance (impedance) from the source to the load.

The addition of significant amounts of Tehachapi wind generation results in increasing deliveries from the north to the Los Angeles Basin. This increase in deliveries from the north increases loadings on the following transmission lines:

- 500 kV transmission lines from Vincent to Lugo and ultimately down to Mira Loma
- 230 kV transmission lines from Pardee to Sylmar and from Pardee to Gould
- 230 kV transmission lines from Vincent to Rio Hondo and from Vincent to Mesa
- 230 kV transmission lines from Sylmar to Rinaldi (LADWP) due to loop flow
- 500 kV transmission line from Rinaldi to Victorville (LADWP) and ultimately to Lugo due to loop flow.

These increases in flow results in the potential to overload the 230 kV transmission lines between Sylmar and Rinaldi (LADWP). SCE does not know exact nature of transmission limitation, as LADWP did not actively participate in the collaborative study process. Consequently, mitigation requirements within the LADWP electrical system were not explored. However, SCE has identified the need for adding a second Vincent-Mesa 500 kV transmission line and operating transmission between Pardee and Vincent at 500 kV. SCE envisions utilizing the existing 500 kV transmission line section on the existing Vincent-Santa Clara 230 kV transmission line between Pardee and Vincent and operating it at 500 kV by sectionalizing line and terminating 230 kV section at the Pardee 230 kV bus and 500 kV section at the Pardee and Vincent 500 kV buses. The second 500 kV transmission line to Mesa can then be added by replacing a portion of the existing Pardee-Eagle Rock 230 kV transmission line (second smallest line south of Vincent) towards the Gould area and ultimately down to Mesa. It is expected that this upgrade would minimize the amount of loop flow through the Sylmar-Rinaldi 230 kV transmission lines.

2.2. Big Creek-Fresno Tie Evaluation

The CPUC and PG&E demonstrated interest in determining if this interconnection can supplement capability to move power from SCE to PG&E or possibly eliminate the need for transmission upgrades from PG&E to the Tehachapi area. The interconnection involves constructing a new 230 kV switching station at the crossing of the PG&E-owned and SCE-owned transmission lines. The existing SCE-owned Big Creek-Rector 230 kV and PG&E-owned Gregg-Helms 230 kV transmission lines are proposed to be looped into this new switching station as shown below in Figure 3.2.1. Power flow control devices such as phase-shifting transformers or unified power flow controllers (UPFC) will be required to "push" power from the SCE network to the PG&E network thereby appearing as additional load in the SCE Big Creek 230 kV corridor north of Magunden.

To evaluate the north of Magunden portion of the Big Creek Corridor, parametric studies covering 8,760 hourly load and generation conditions based on historical data were conducted. These studies were performed utilizing a simplified equivalent power flow case reflecting only the north of Magunden SCE facilities and the facilities from PG&E's Gregg Substation to the Helms Pump Storage Facilities. These facilities are all connected radial and can therefore be "cut-out" to examine local area problems. Complete WECC base cases were subsequently utilized to examine overall system performance and validate the local area problems identified in the parametric studies. Two methods were used in examining the local area. The fist method involved modeling a fixed power flow from the SCE network to the PG&E network throughout the entire calendar year while the second method involved modeling a fixed tap setting.

Fixed Tap Setting Model

This model reflects the use of traditional phase-shift transformers to connect the PG&E and SCE systems together. Several limitations exist with use of traditional phase-shift transformers that affect system operations. The limitations are summarized as follows:

- Phase-shift transformers have mechanical moving load taps that are used to adjust amount of flow through the transformer
- These load taps are generally set and adjusted on a seasonal basis
- Load taps are slow moving and thus do not respond well to system dynamics
- Load taps require frequent maintenance if they are constantly used.
- Phase-shift transformers increase reactive losses on the system adversely affecting system voltages

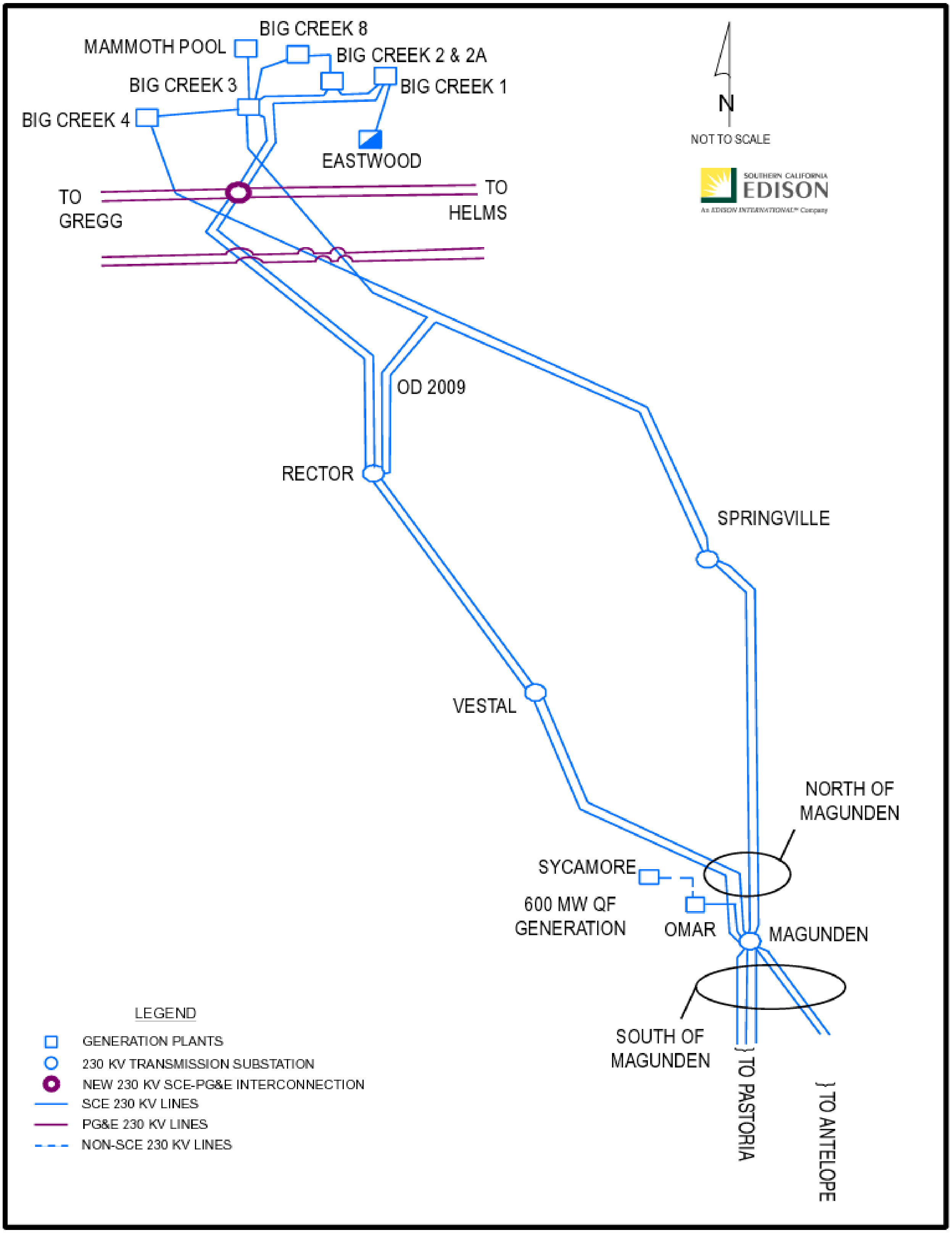
These limitations can subject the system to unintended performance. As a result, a robust transmission system is required to support a transformer phase-shifted system.

Fixed Power Flow Model

This model reflects the use of Flexible AC Transmission System (FACTS) technology to connect the PG&E and SCE systems together. Implementing a system tie with a FACTS device eliminates all of the limitations identified above. The benefits of utilizing a FACTS device are summarized as follows:

- Power electronics eliminate all mechanical moving parts
- The absence of mechanical moving parts allows for dynamic settings not possible with a phase-shift transformer
- FACTS devices respond well to system dynamics
- FACTS devices can be developed as to provide reactive resources improving system voltages

Figure 3.2.1
Big Creek-Fresno System Tie



2.2.1. Big Creek-Fresno Tie Study Results – Fixed Power Flow Model

2.2.1.1. Impacts to South of Magunden Line Flows

The addition of a new system tie between SCE and PG&E with a device to “push” fixed power from SCE to PG&E has the equivalent effect of increasing load in the San Joaquin Valley. This increase is graphically illustrated below in Figures R-1 through R-6. Figure R-1 illustrates the hourly South of Magunden line flows prior to adding the new system tie with adjusted San Joaquin Valley load to reflect 2014 forecast. Figures 3.2.2 through 3.2.5 illustrate the hourly South of Magunden line flows with the inclusion of a 300 MW, 500 MW, 1,000 MW, and 1,200 MW new system tie. Figure 3.2.7 provides the corresponding load duration curves for various system tie levels. SCE notes that adding a 300 MW system tie has the equivalent effect as 30 years of local load growth.

Figure 3.2.2
South of Magunden Flow Patterns Adjusted for 2014 Load

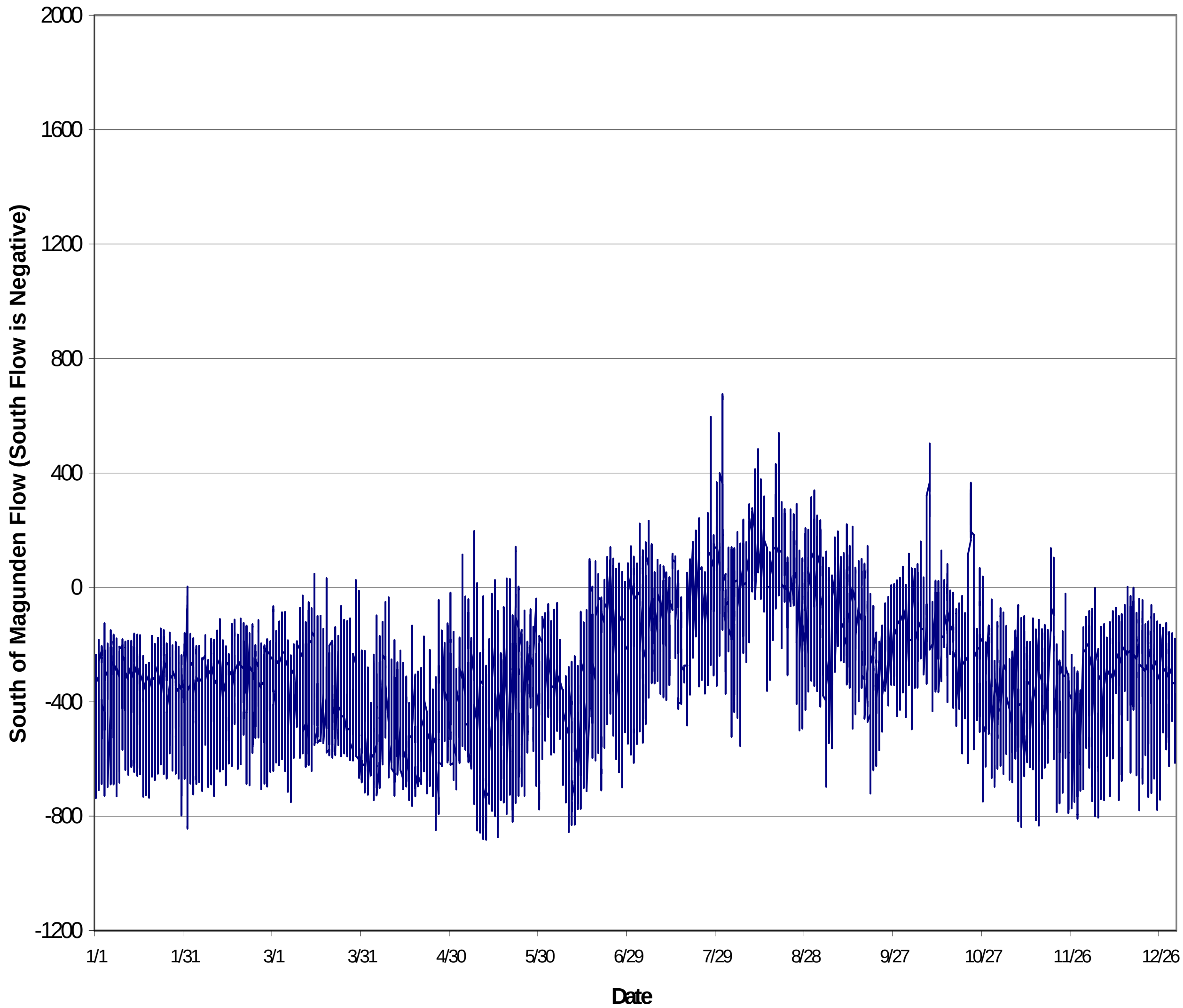


Figure 3.2.3
South of Magunden Flow Patterns with 300 MW System Tie

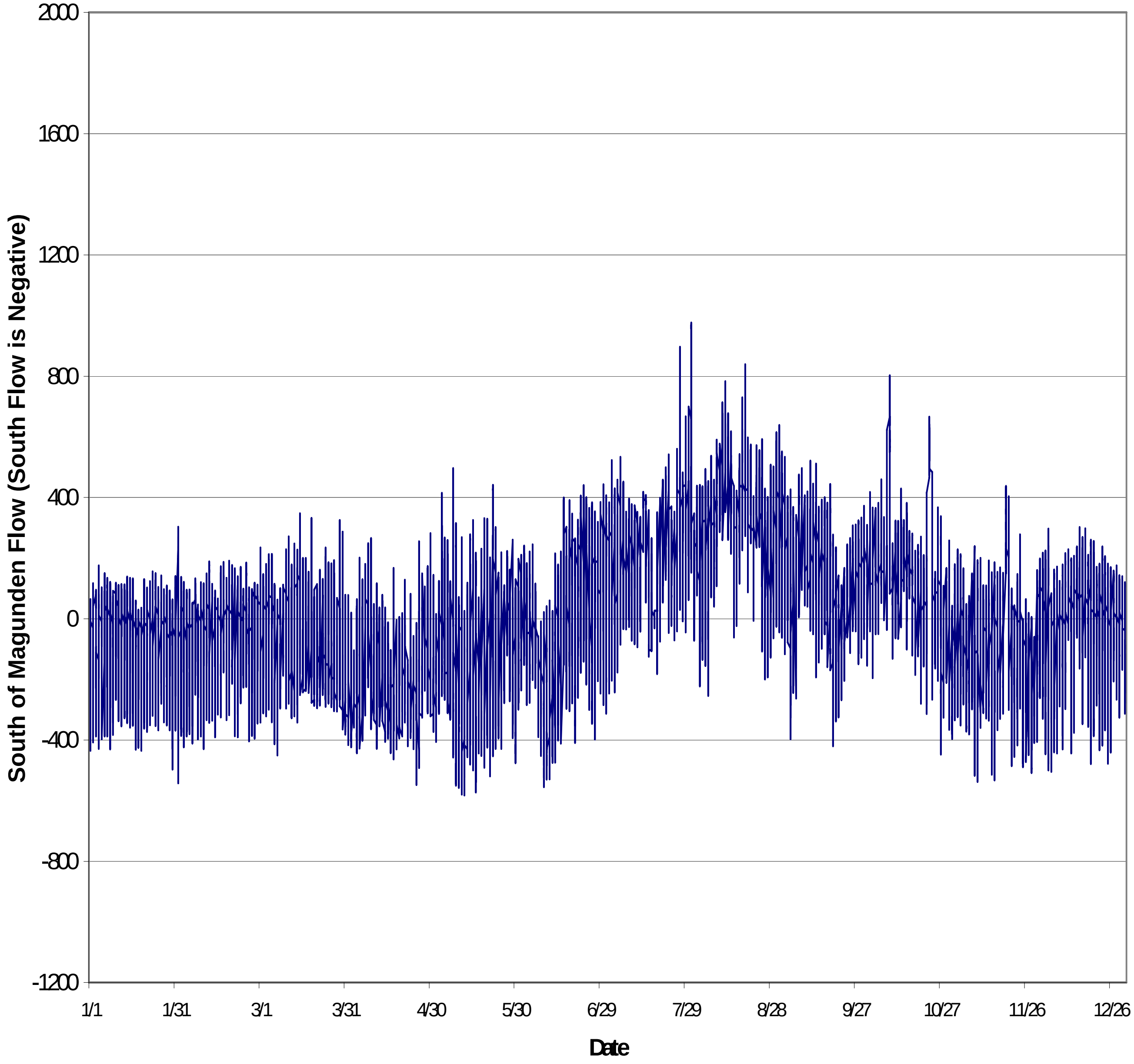


Figure 3.2.4
South of Magunden Flow Patterns with 500 MW System Tie

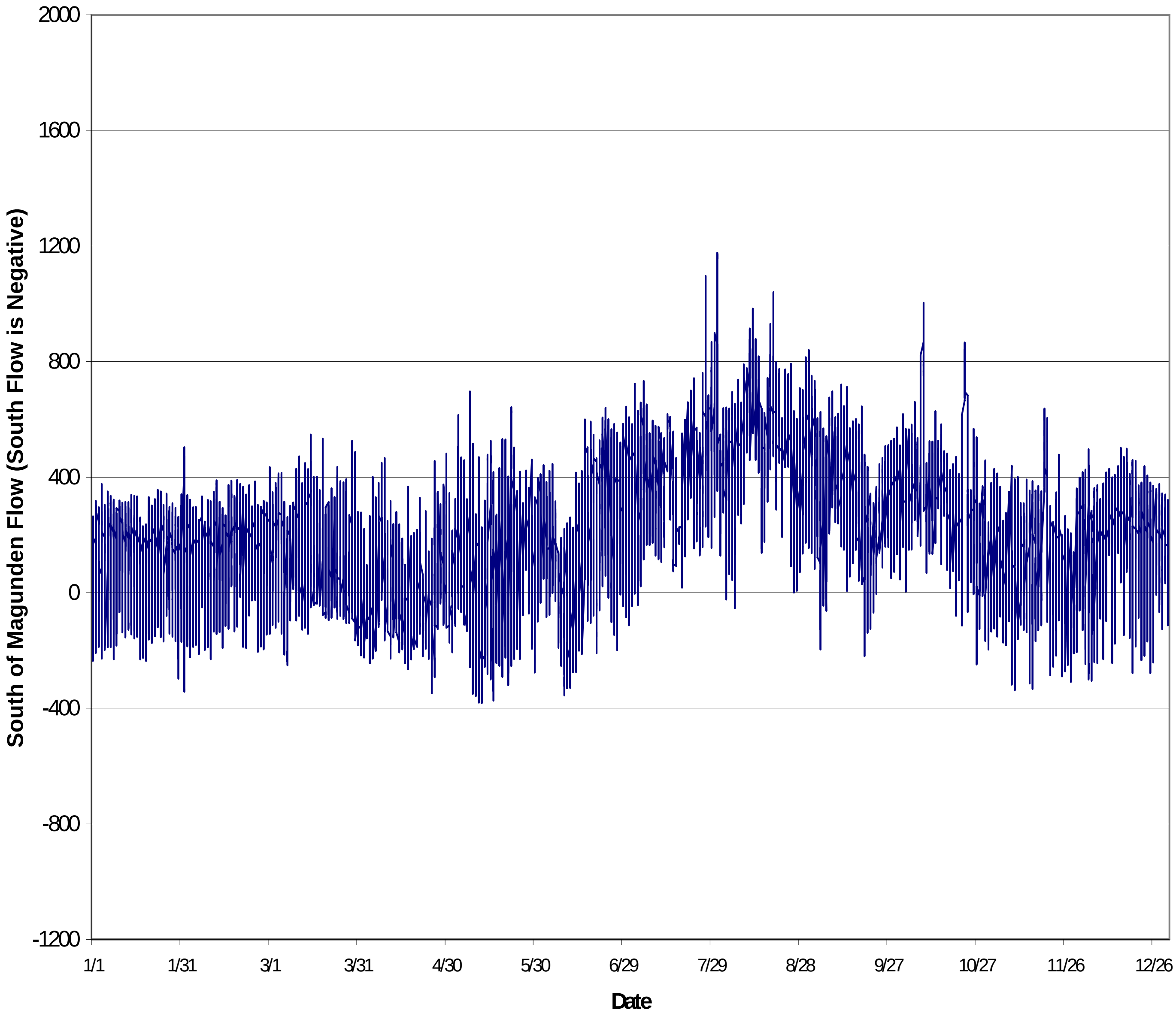


Figure 3.2.5
South of Magunden Flow Patterns with 1,000 MW System Tie

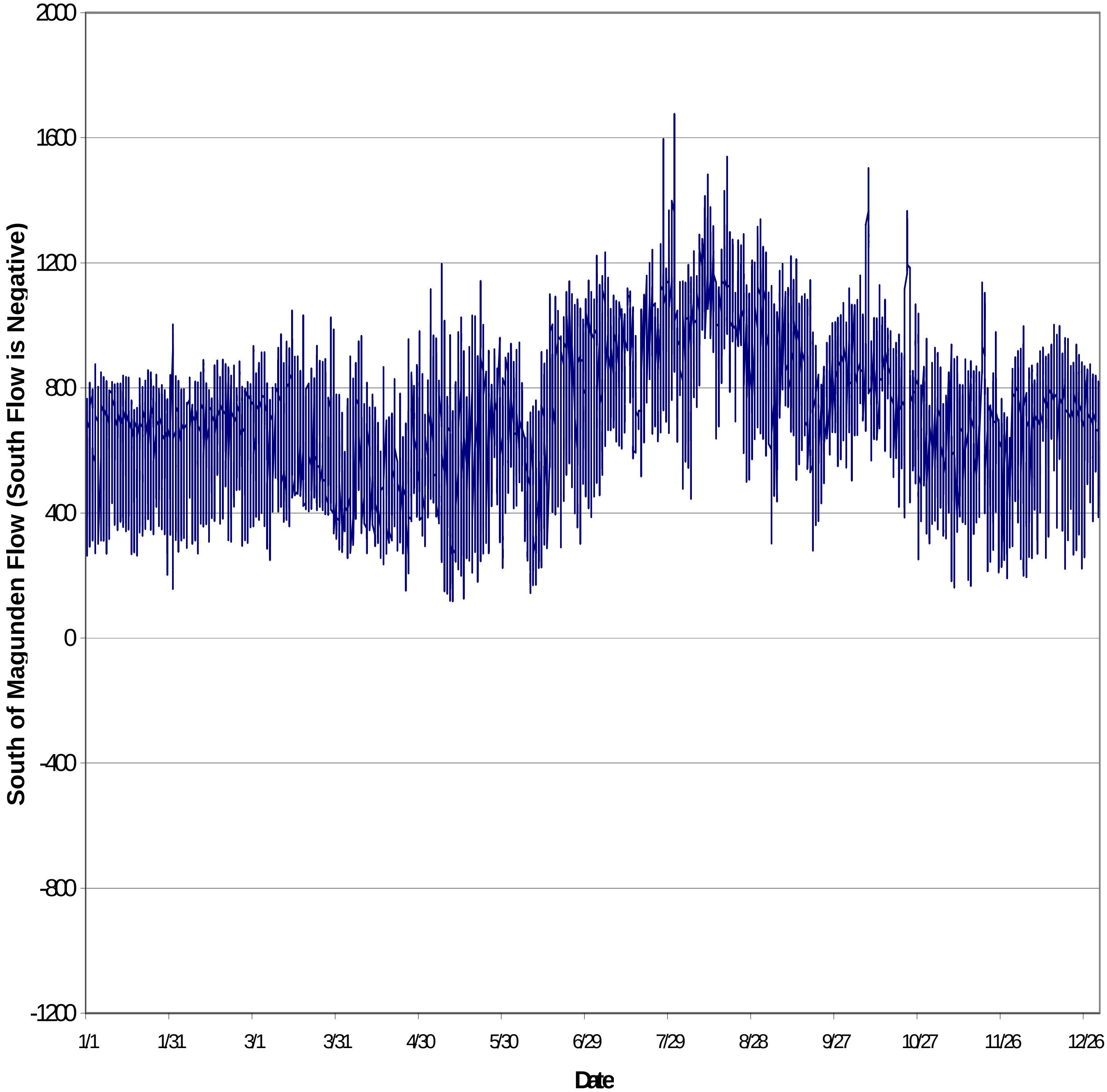


Figure 3.2.6
South of Magunden Flow Patterns with 1,200 MW System Tie

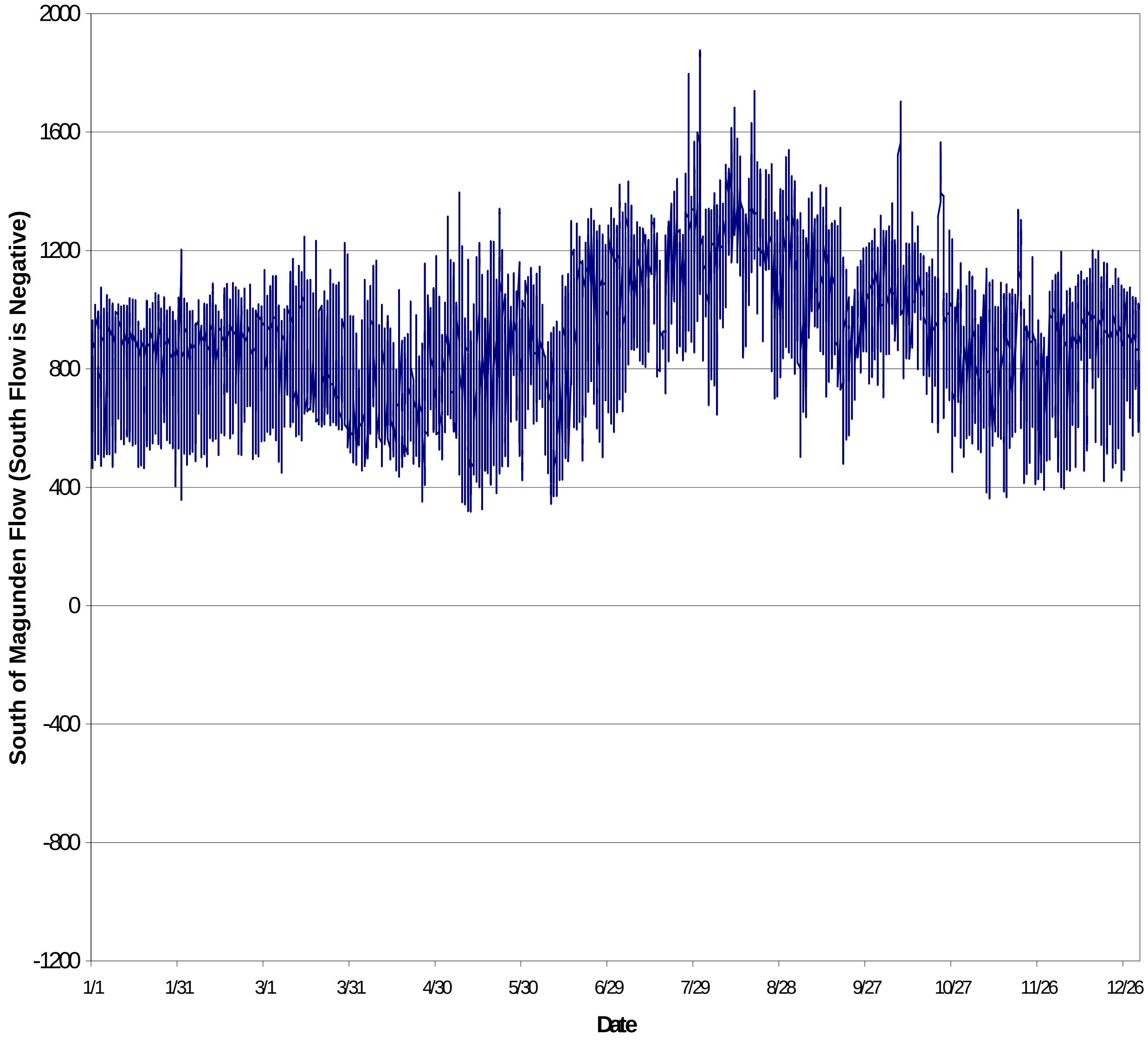
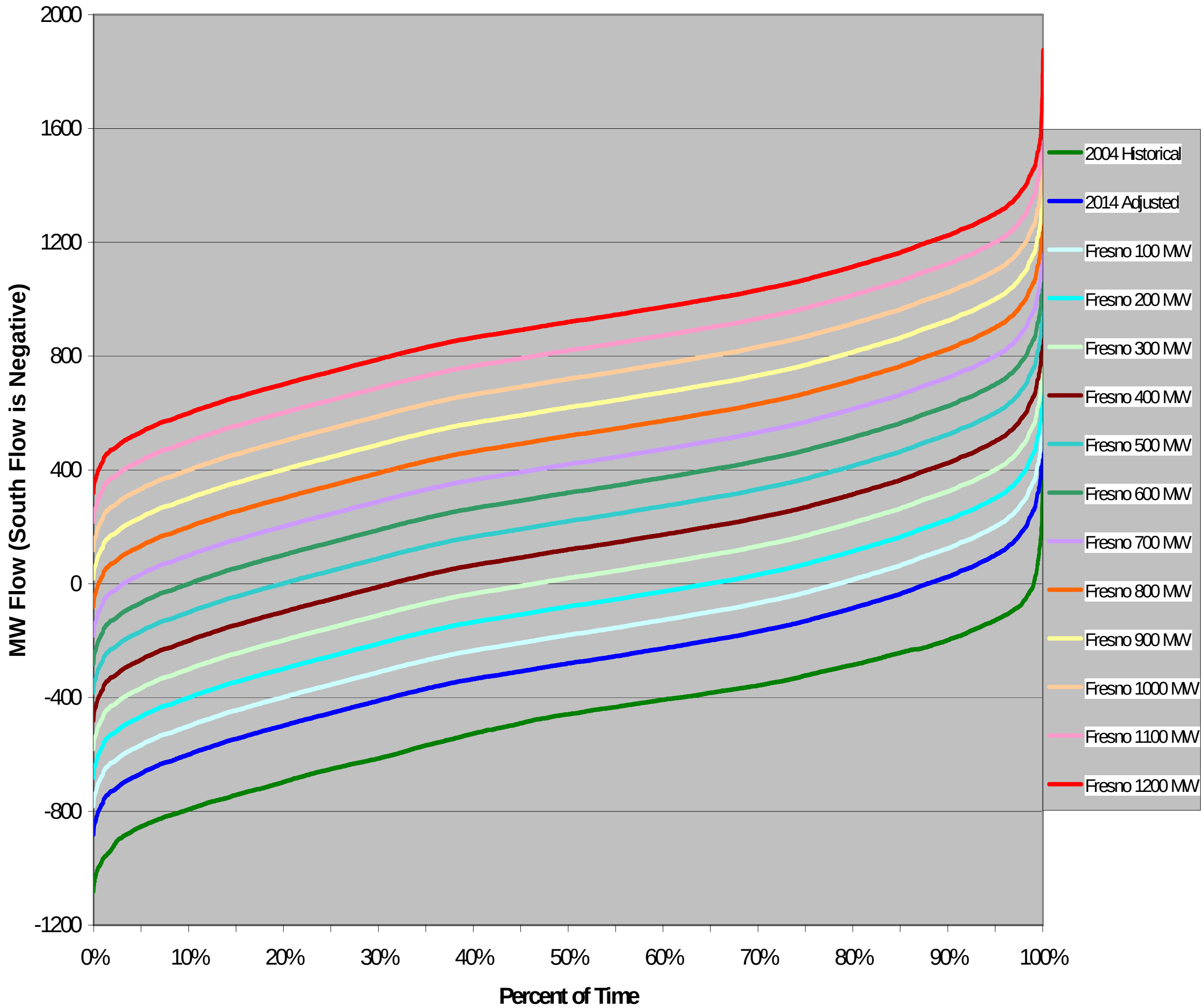


Figure 3.2.7
South of Magunden Flow Patterns with 1,200 MW System Tie

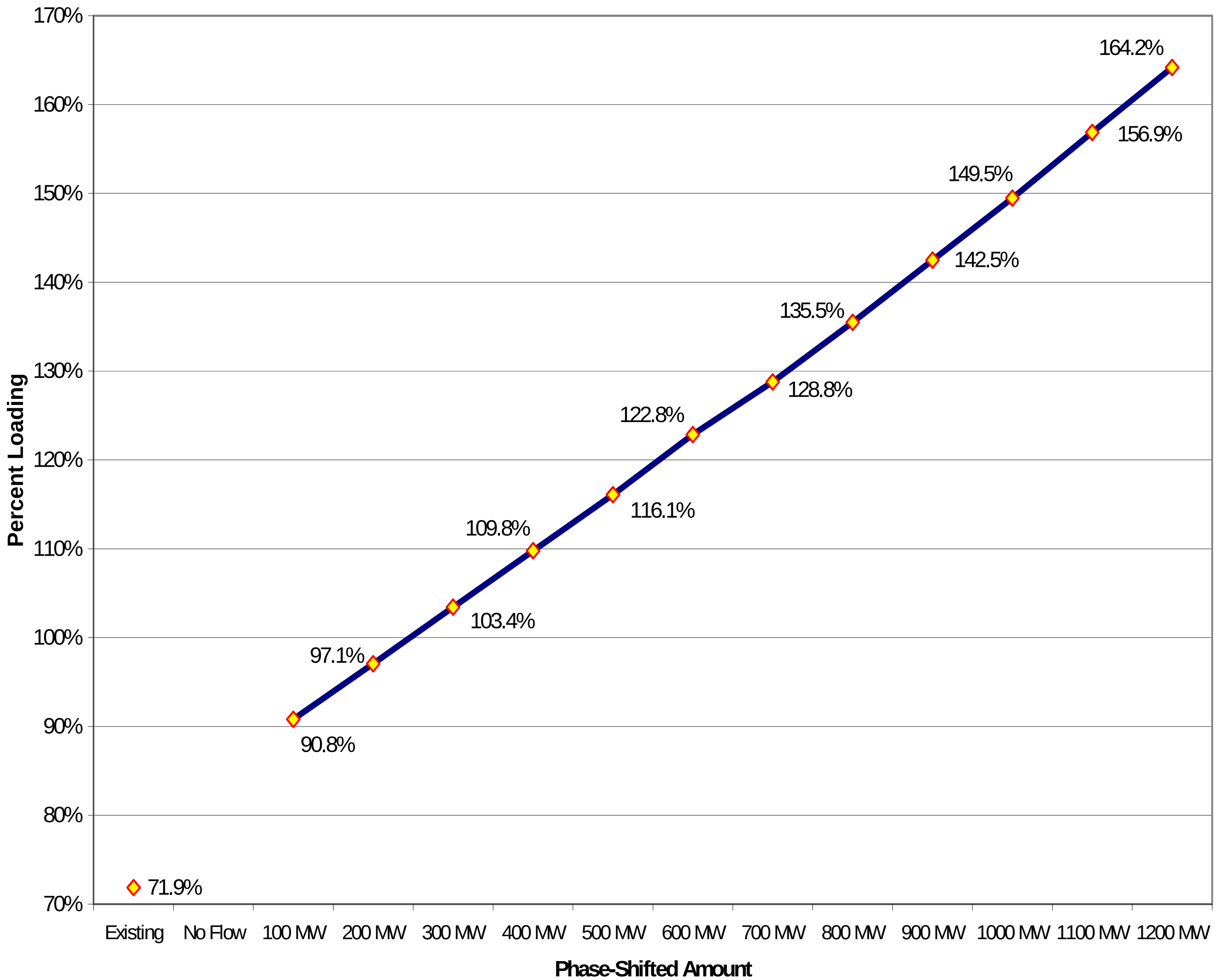


2.2.1.2. North of Magunden 230 kV Transmission Line Loadings Under Base Case Conditions

Four 230 kV transmission lines connect the Big Creek hydro complex, located in northern Fresno County, to the rest of the SCE network. Two of the four lines connect Big Creek to the SCE Rector 230 kV Substation, continue south towards the SCE Vestal 230 kV Substation and finally connect to the SCE Magunden 230 kV Substation. The other two lines connect Big Creek to the SCE Springville 230 kV Substation and continue south to the SCE Magunden 230 kV Substation.

The new system tie is proposed to connect to the two SCE 230 kV transmission lines heading towards the SCE Rector Substation, as shown above in Figure 3.2.1. Power flow study results indicate that additional system upgrades will be necessary to mitigate thermal overload problems identified with the addition of the new system tie represented as a fixed power flow model. Loading on the section of the existing Big Creek3-Rector 230 kV line between Big Creek 3 and the new system tie was found to exceed the maximum allowable thermal limits with all facilities in-service. Depending on the amount of power "pushed" from SCE to PG&E, thermal loading was identified to increase from 91% of the normal conductor limit up to 164% as shown below in Figure 3.2.8. To mitigate this overload, rebuild of a section of the existing Big Creek3-Rector 230 kV transmission line will be necessary to support a larger conductor.

Figure 3.2.8
Section of Existing Big Creek3-Rector 230 kV (BC to Fresno Tie)
Line Loading with All Facilities In-Service



Figures 3.2.9 through Figure 3.2.13 illustrate loading on the other transmission facilities in the Big Creek Corridor north of the SCE Magunden 230 kV Substation.

Figure 3.2.9
Section of Existing Big Creek1-Rector 230 kV (BC to Fresno Tie)
Line Loading with All Facilities In-Service

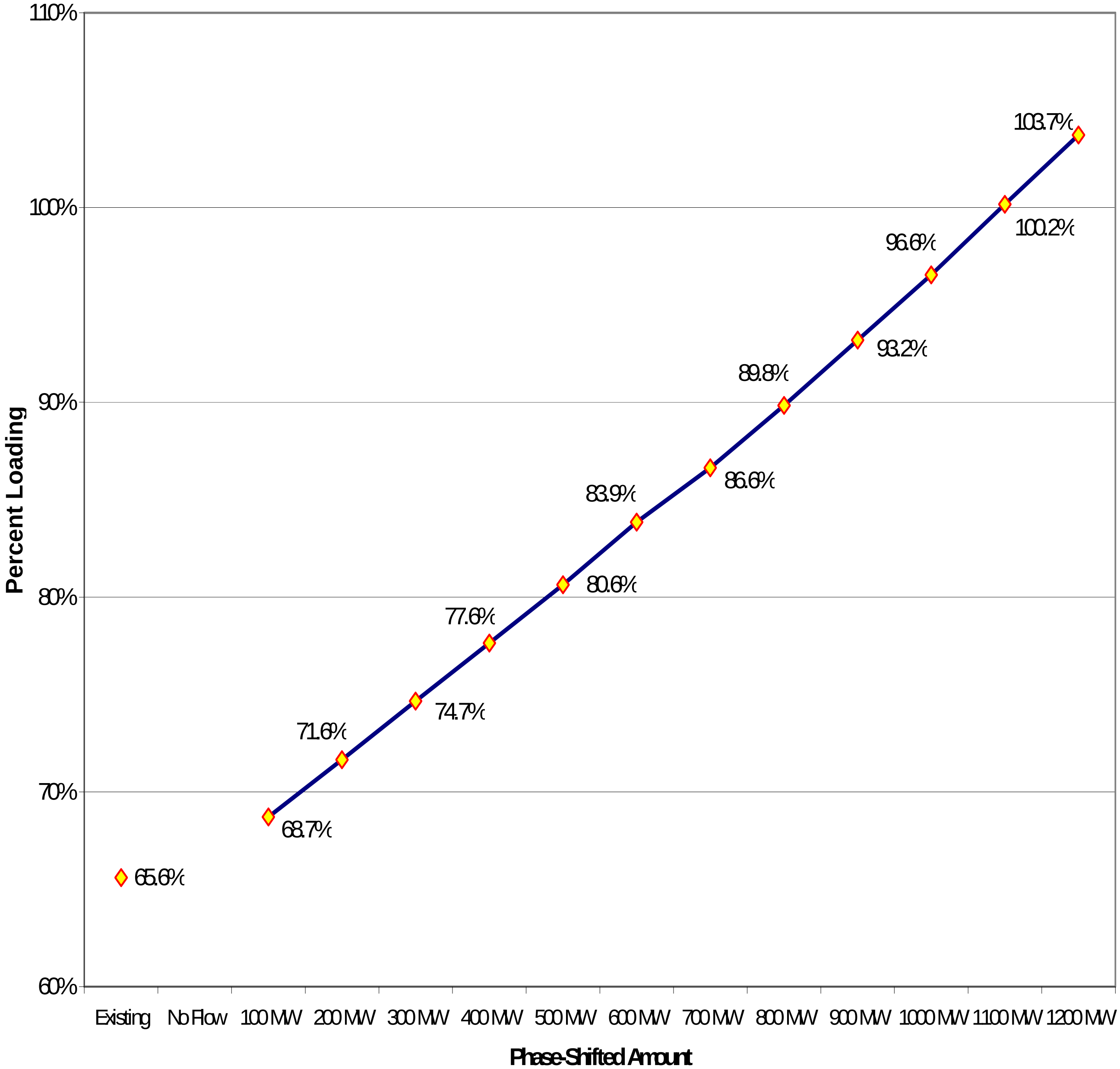


Figure 3.2.10
Section of Both Existing Big Creek-Rector 230 kV (Rector to Fresno Tie)
Line Loading with All Facilities In-Service

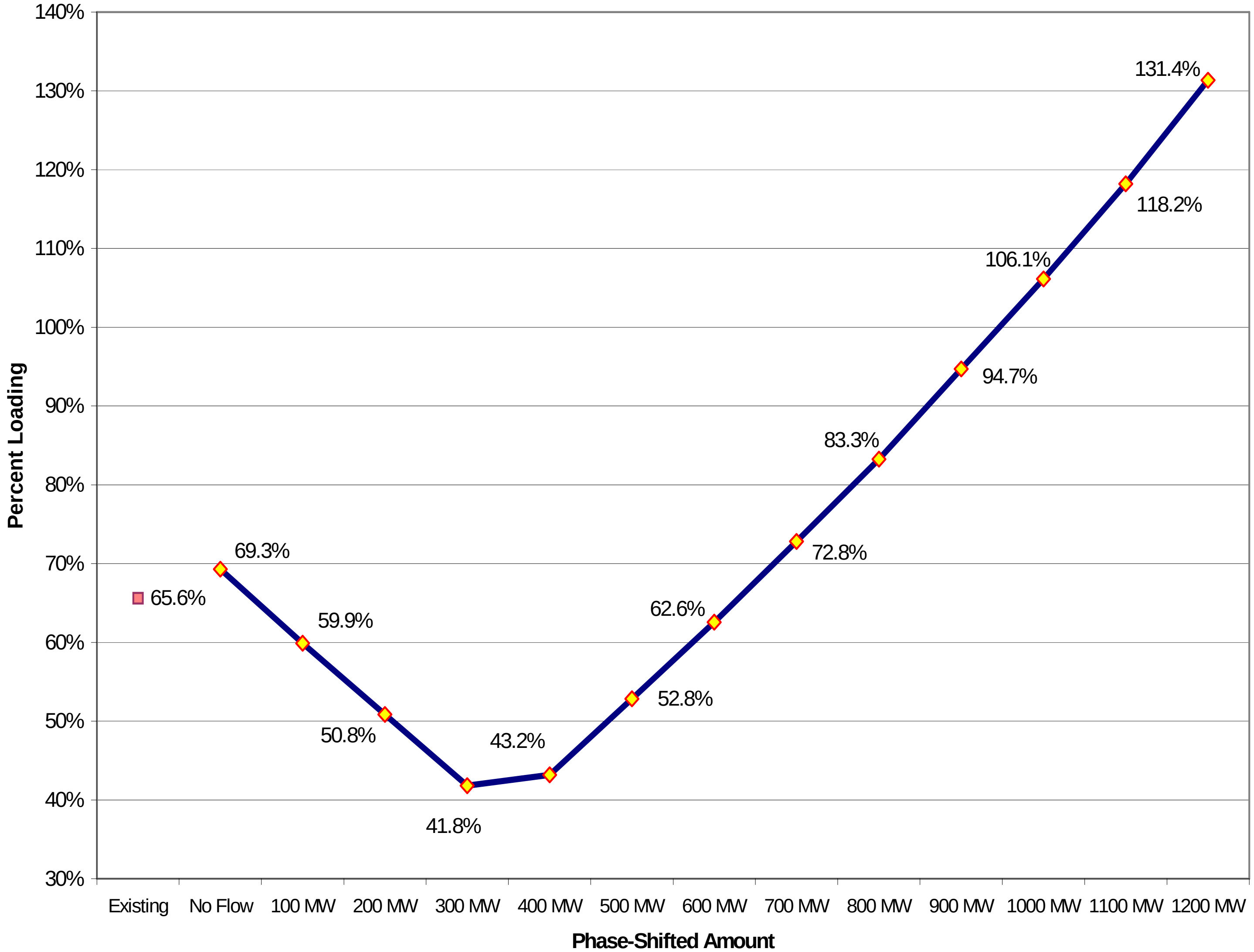


Figure 3.2.12
Both Existing Vestal-Rector 230 kV
Line Loading with All Facilities In-Service

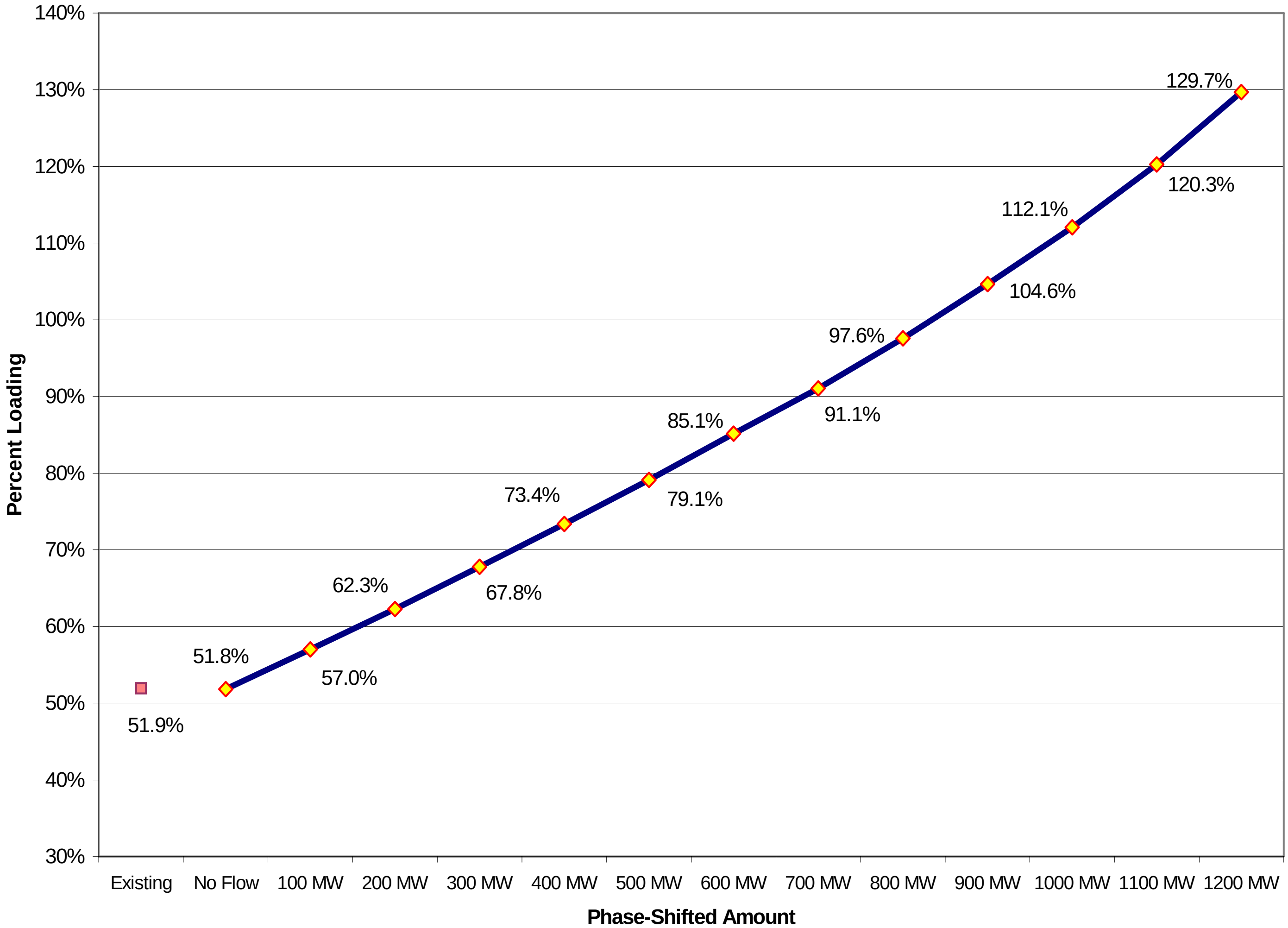
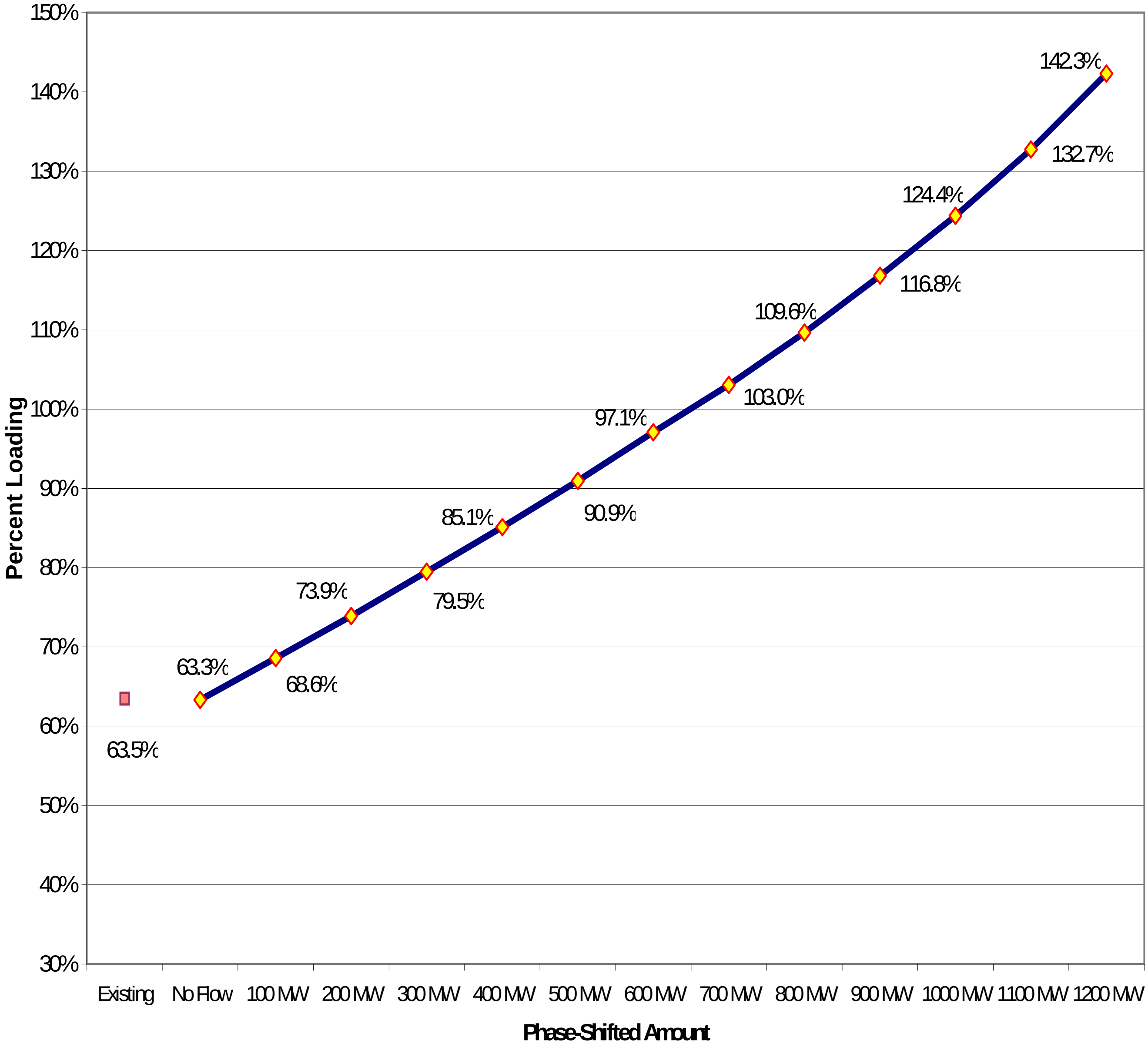


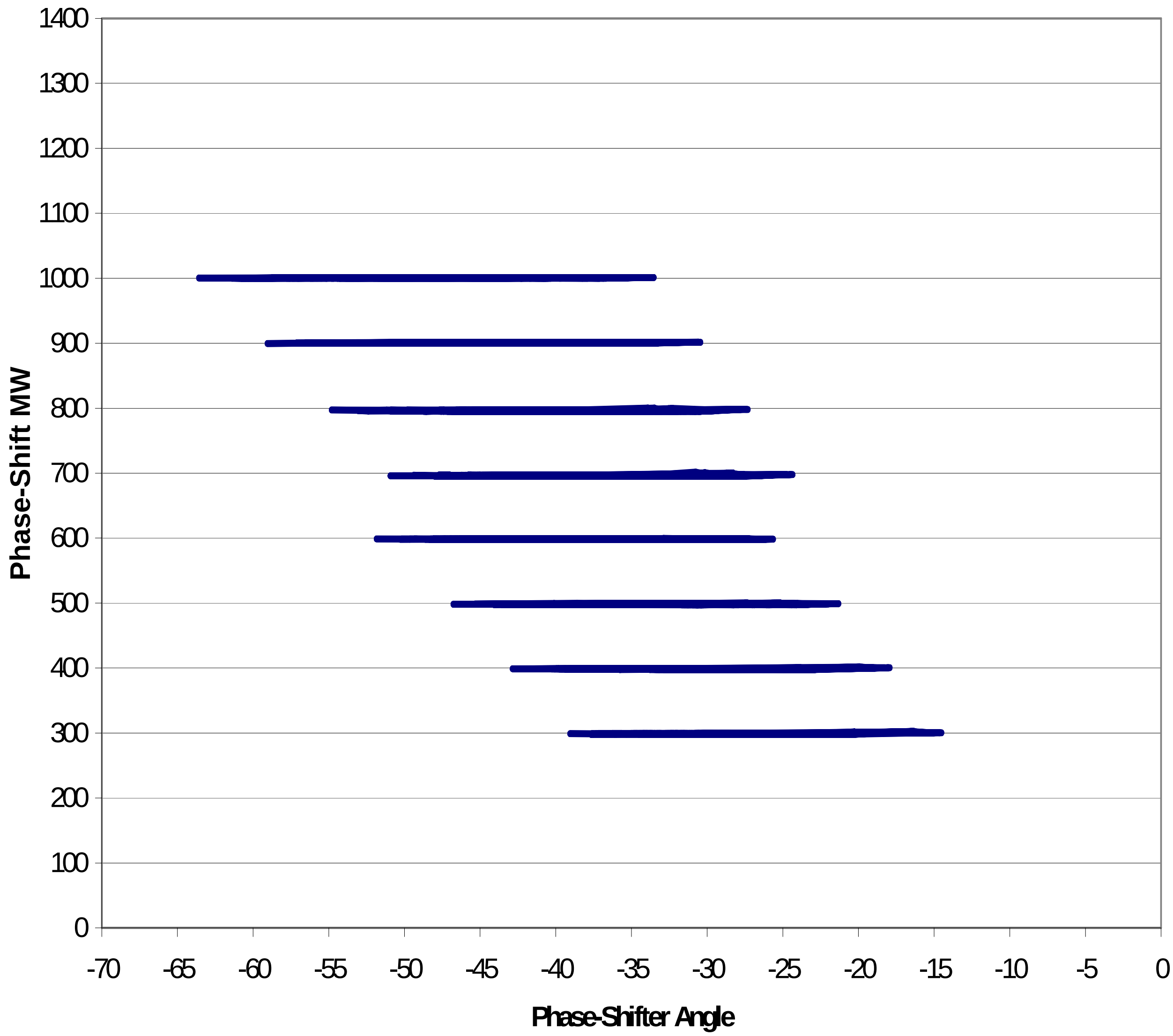
Figure 3.2.13
Both Existing Magunden-Vestal 230 kV
Line Loading with All Facilities In-Service



2.2.1.3. Phase-Shift Angle Requirements

Detailed system studies indicate a wide range of phase-shift operation in order to maintain the specified power level. Such operation is indicative of a need to install a unified power flow controller which utilizes power electronics to maintain the specified power flow instead of a traditional phase-shift transformer which cannot be manage to maintain a constant flow. The amount of phase-shift angle capability required depends on numerous factors. These factors involve SCE local area load and generation conditions (San Joaquin Valley load demand and Big Creek hydro generation output), PG&E local area load and generation conditions (Fresno area load demand and Helms operations), as well as major path flows (Pacific Intertie, Path 26, Path 15, etc.). For purposes of identifying potential angle bandwidth requirements, SCE performed parametric studies, which adjusted only the SCE local area load and generation. All other system conditions were held constant. Based on these studies, SCE determined that a phase-shift capability in excess of 60 degrees would be needed to support such a phase-shifted system tie. A summary of these findings is provided below in Figure 3.2.14.

Figure 3.2.14
Constant Power Phase-Shift Requirements



2.2.1.4. Reactive Resource Requirements

With the inclusion of the new phase-shifted system tie, loadings on the existing transmission lines are increased resulting in additional reactive losses, which adversely impact local system voltage performance. To determine the amount of additional reactive resources required under base case conditions to maintain pre-existing voltage levels, bus voltages at the Rector, Magunden and the new Fresno Tie Substations were maintained at unity by adding an assumed synchronous condenser at each location. Studies were then conducted for each hour of the year based on historical performance. The studies captured output of the synchronous condensers without the new phase-shifted system tie and with the new phase-shifted system tie so that an adequate comparison could be made. Reactive requirements identified without the addition of the new phase-shifted system tie were subtracted from the reactive requirements identified with the addition of the new phase-shifted tie in order to properly capture the incremental reactive resource required due to the addition of the new phase-shifted system tie. Study results for a 200 MW phase-shifted system tie are shown below in Figure 3.2.15. The 600 MW phase shift analysis was conducted with and without a new 230 kV transmission line from Magunden to Rector and is provided in Figure 3.2.16. As can be seen, the reactive requirements needed to support a 200 MW system tie is approximately 125 MVARs while the requirements needed to support a 600 MW system tie is approximately 500 MVARs. With the inclusion of a new line, the reactive requirement needed to support the 600 MW system tie is reduced down to approximately 200 MVARs. Additional resources may be required to maintain adequate voltages under outage conditions.

Figure 3.2.15
Reactive Requirements to Support a 200 MW Phase-Shifted System Tie

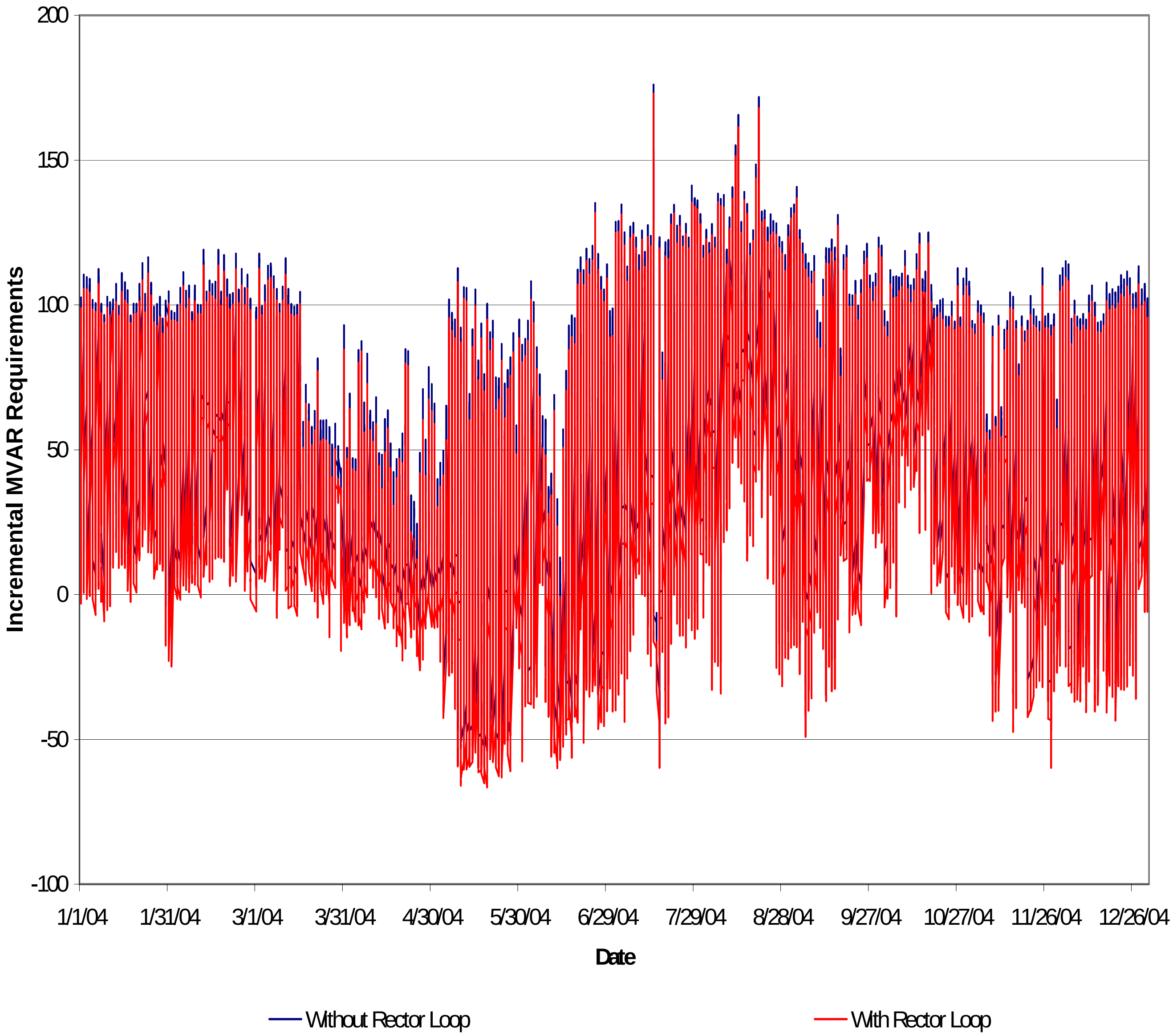
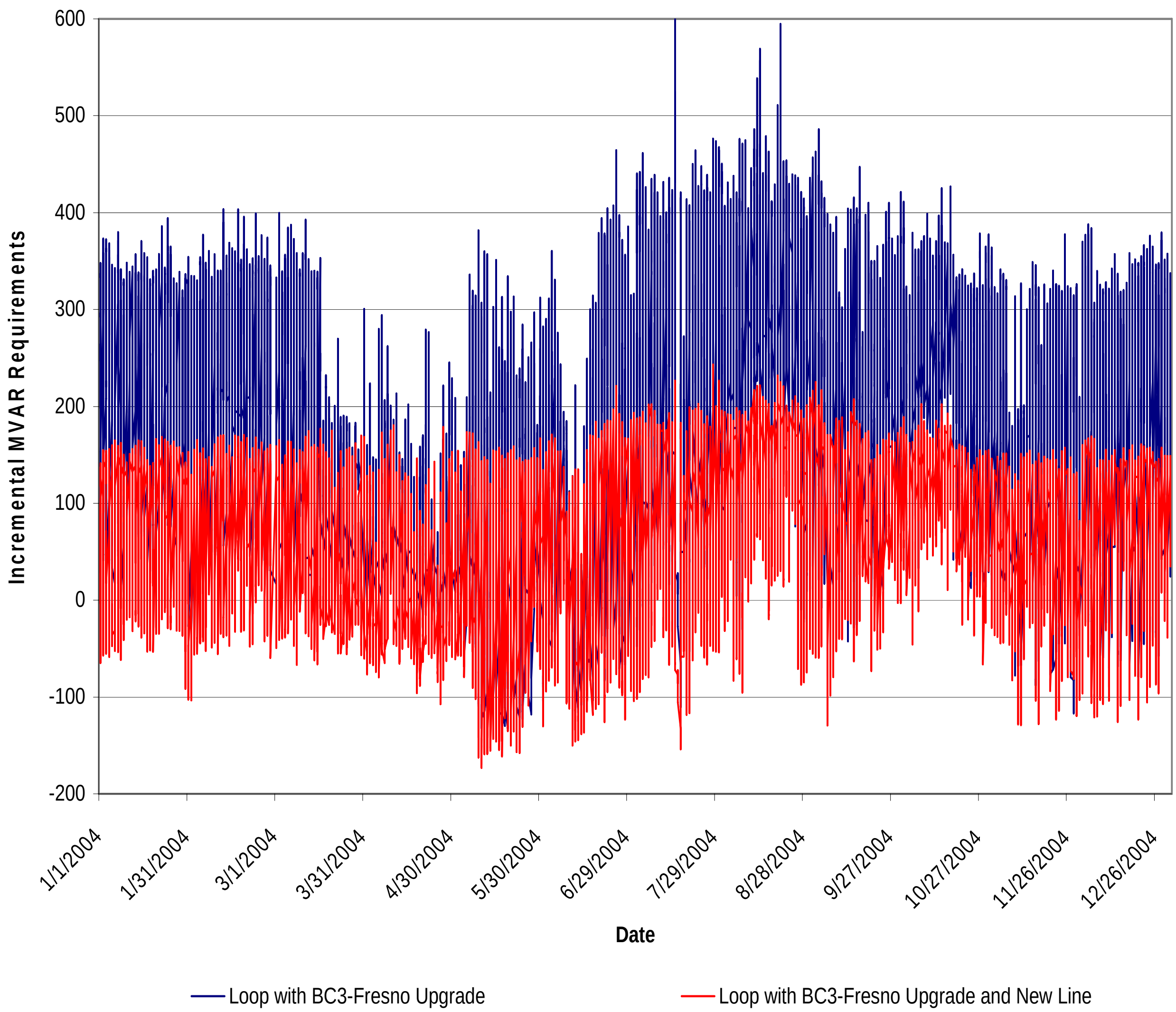


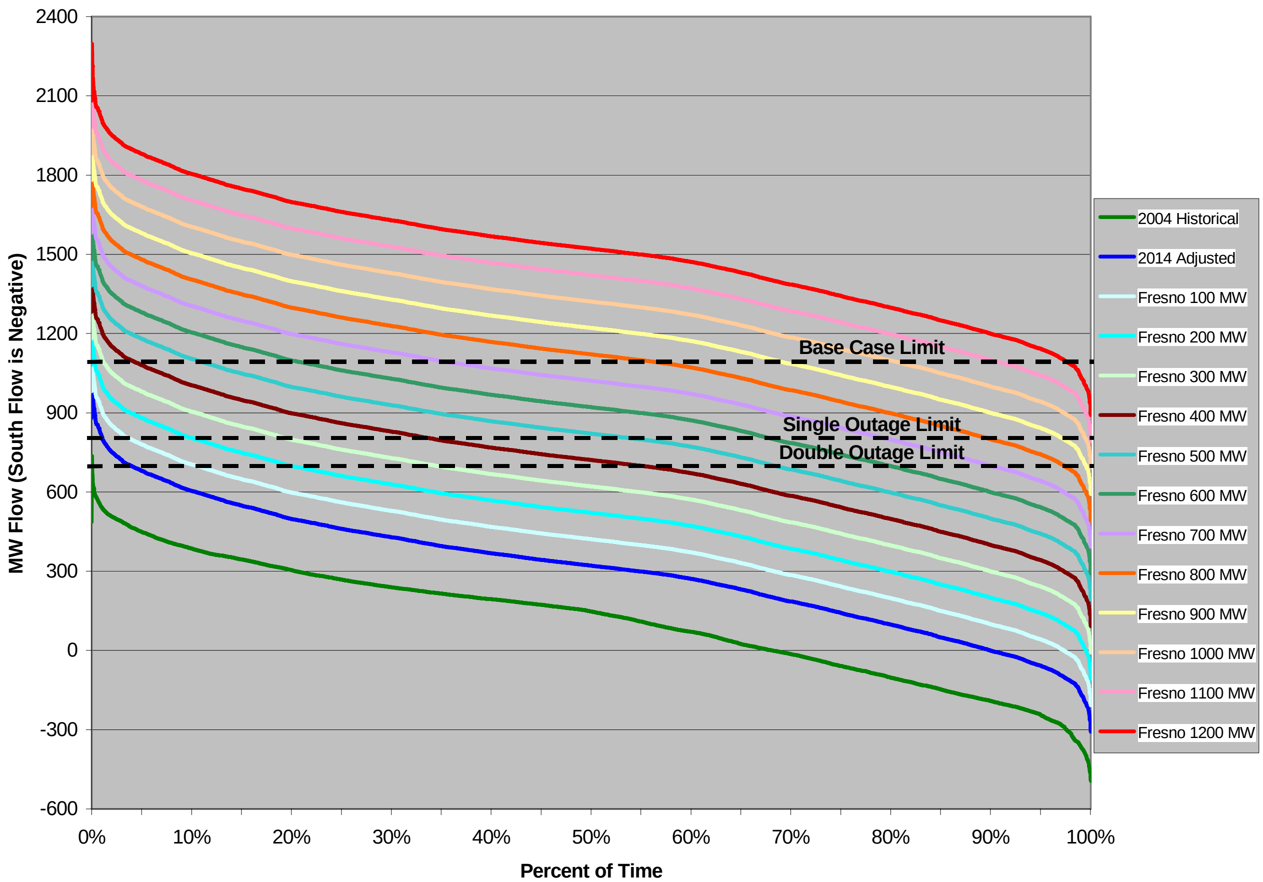
Figure 3.2.16
Reactive Requirements to Support a 600 MW Phase-Shifted System Tie



2.2.1.5. Study Results Under Loss of One Transmission Line

As previously discussed, adding a new system tie to "push" power from SCE to PG&E has the equivalent effect of increasing load in the San Joaquin Valley. With this increase in load, base case and outage conditions will result in higher thermal overload problems than are currently anticipated. Currently, the existing 230 kV transmission lines north of Magunden are anticipated to be fully utilized to support forecast load demand. Without new facilities, the existing system cannot support the new system tie at any level. Figure 3.2.17 provides the north of Magunden flow duration curves for various system tie levels and includes system limitations. As can be seen, adding a 300 MW system tie results in potentially exposing the system to thermal loading levels above the current single contingency limit for approximately 20 percent of the time. Increasing the system tie from 300 MW up to 600 MW will result in further increasing the overload exposure from 20 percent to 55 percent.

Figure 3.2.17
North of Magunden Flow Duration Curve



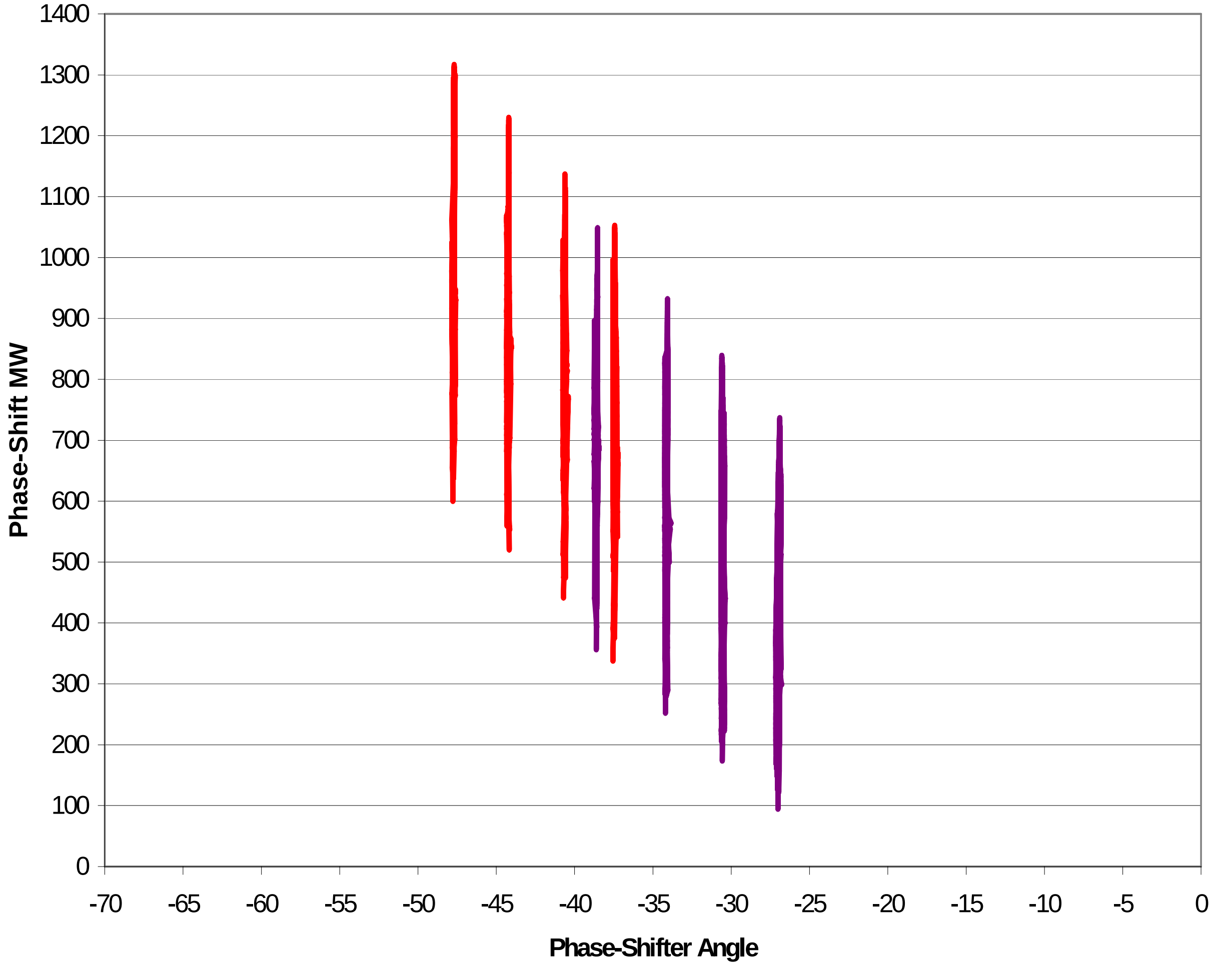
A proposed solution of opening the system tie under outage conditions may not be a workable solution. Generally, WECC supports the establishment of Operating Nomograms developed to limit the amount of power that can be scheduled through a WECC Path. In other words, the Path rating will be established based on limiting elements during outage conditions. As a result, upgrades will be required to support a new Phase-Shifted System Tie. These upgrades will involve adding a new transmission line(s) between Magunden and Big Creek. The exact amount of system tie capability that can be accommodated with this transmission in-service is unknown at this time. Detailed WECC Path Rating studies will be required to make this determination. Conceptually, SCE anticipates a maximum constrained capability (Operating Nomogram) of 400 MW with the addition of a new line. This value is derived by considering the existing base case limitation of 1,150 MW, which is expected to be the new limit under loss of the new line. The total north of Magunden flows under non-summer conditions will exceed the 1,150 MW limit when considering higher phase-shift transfer levels. The CAISO should review all other conditions where the use of the system tie could result in loadings that exceed the 1,150 MW limit. This should be done to determine if the use of congestion management (i.e. use of an Operating Nomogram) is an acceptable means for limiting flows on a system tie that is actively managed (i.e. constant power flow model).

2.2.2. Big Creek-Fresno Tie Study Results – Fixed Tap Setting Model

2.2.2.1. Impacts to Power Flows

The fixed power flow model results for each phase-shift level examined were used as the basis for conducting the fixed tap setting power flow studies. Resulting angles were examined and an average value was selected for each phase-shift capacity scenario to represent the "best" tap setting to use for that scenario. This assumption, while not perfect, captures system behavior when selecting a particular tap setting. Results of this study indicate that any given tap setting has the potential to operate within a 700 MW bandwidth as shown below in Figure 3.2-18. As an example, the curve corresponding to an angle of approximately 30 degrees can result in phase-shifting anywhere between 200 MW and 850 MW.

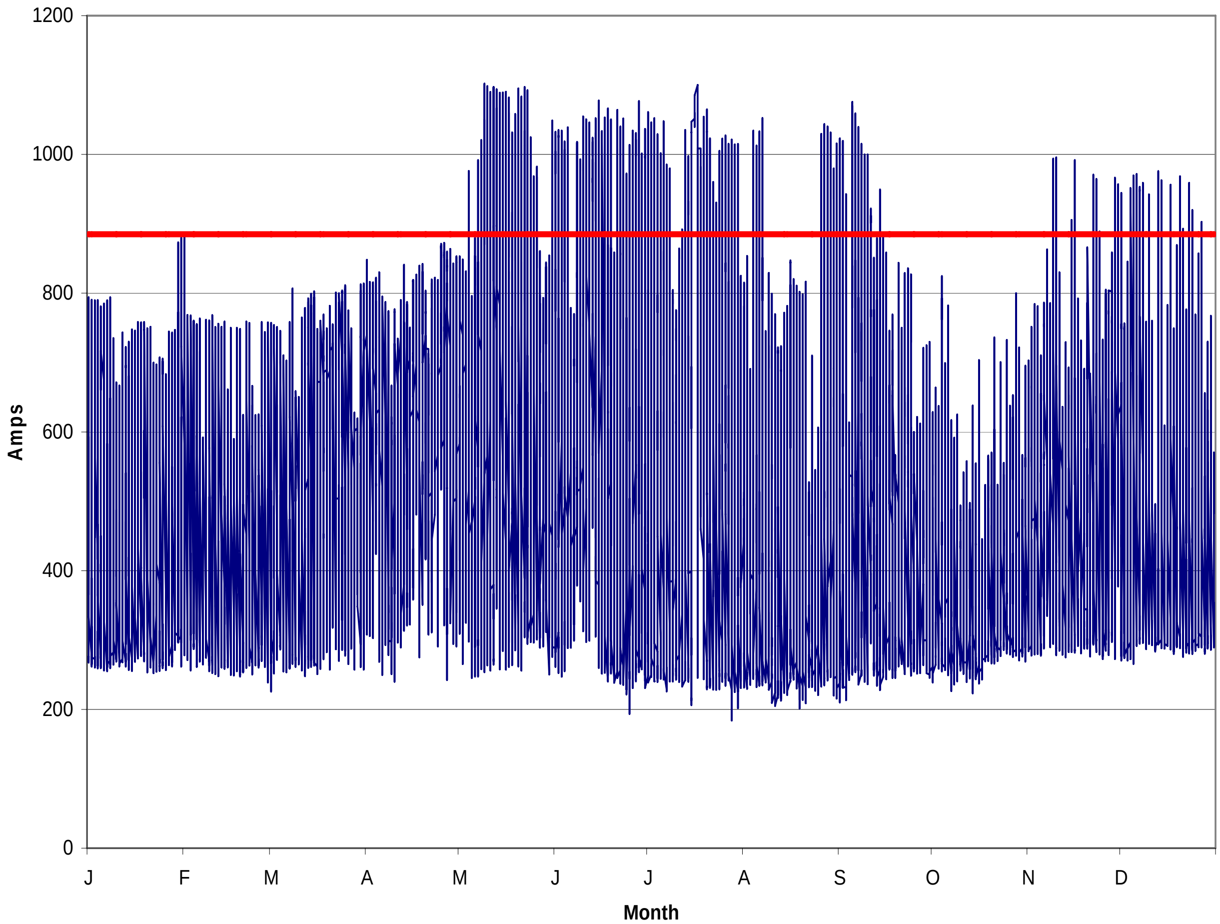
Figure 3.2.18
Fixed Angle Phase-Shifted Power



2.2.2.2. North of Magunden 230 kV Transmission Line Loadings Under Base Case Conditions

As shown below in Figure 3.2.19, loading on a section of the existing Big Creek3-Rector 230 kV line (between Big Creek and the Fresno System Tie) was identified to exceed the maximum allowable limit under base case conditions with a fixed tap setting of 30 degrees. Complete tear-down and rebuild of this transmission facility will be necessary as the current infrastructure does not support use of a larger conductor. This tear-down and rebuild will necessitate environmental review to comply with both the California Environmental Quality Act (CEQA) and the National Environmental Policy Act (NEPA) since the line traverses the Sierra National Forest.

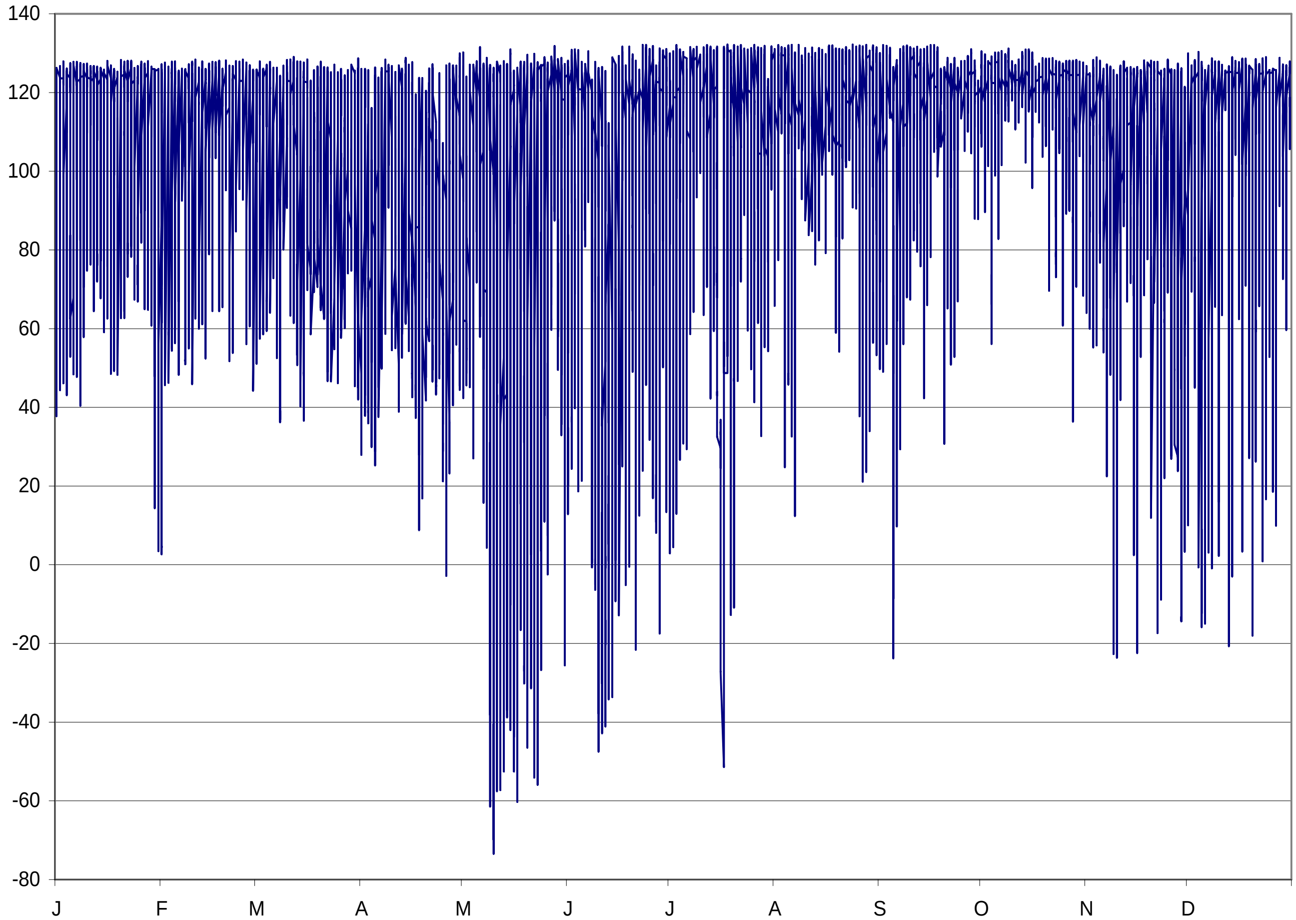
Figure 3.2.19
Loading on the Big Creek3-Rector 230 kV Transmission Line



2.2.2.3. Reactive Resource Requirements

With the inclusion of the new fixed tap phase-shifted system tie set to 30 degrees, loadings on the existing transmission lines are increased resulting in additional reactive losses, which adversely impact local system voltage performance. The same methodology utilized above for a fixed power level was used to determine the amount of additional reactive resources required under base case conditions. Study results for a fixed tap phase-shifted system tie set to 30 degrees are shown below in Figure 3.2.20. As can be seen, the reactive requirements needed to support a fixed tap phase-shifted system tie set to 30 degrees is approximately 130 MVARs. Additional resources may be required to maintain adequate voltages under outage conditions

Figure 3.2.20
Reactive Requirements to Support a Fixed Tap Phase-Shifted System Tie
Tap Setting Set to 30 Degrees



2.2.2.4. Fixed Power Flow Model Under Loss of One Transmission Line

As discussed above in the assumptions section, the fixed tap setting model does not respond well to system outage conditions. As a result, it is extremely difficult to forecast system behavior during faulted conditions. What can be said is that a surge of power through phase-shift transformer is likely due to system impedance change under the outage conditions and very slow moving load tap changers (if automated). This surge in power could lead to additional thermal overloads on the existing Big Creek 230 kV transmission lines that have not been identified under the base case conditions. System upgrades needed to support the full range of flow patterns as identified above for base case conditions should include sufficient capability to accommodate outage conditions. Detailed WECC Path Rating studies will be required to make an exact determination as to how much capacity can be made available with the addition one or more 230 kV transmission lines. Conceptually, SCE estimates that use of a fixed tap setting model will require complete upgrade of the western side of the Big Creek corridor which includes adding two new 230 kV transmission lines.

2.2.3. Big Creek-Fresno Tie Study Points of Discussion

Study Assumptions

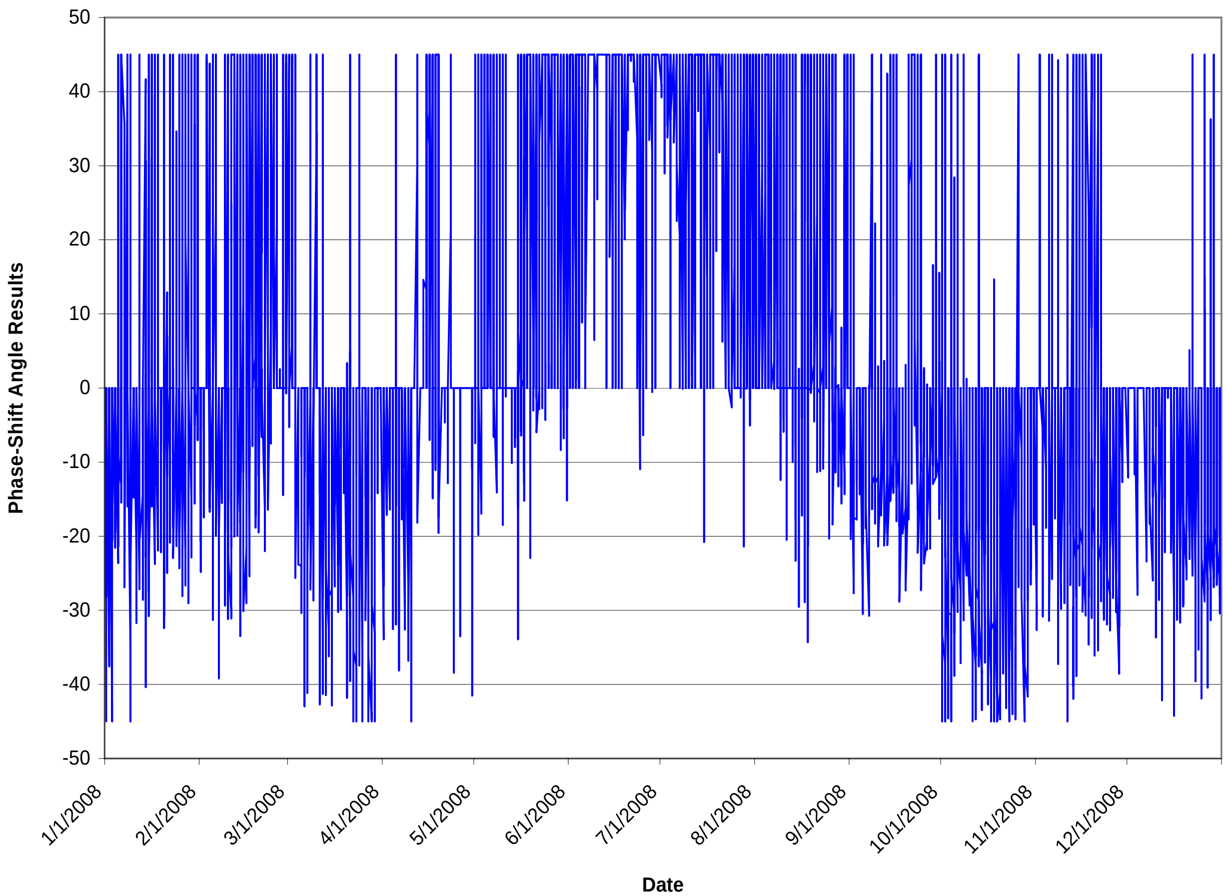
The CPUC Energy Division staff participating in the collaborative study has expressed concerns with the study assumptions implemented in performing this study. Specifically, the concerns centered on modeling of proper operating conditions for the new system tie assuming power flows could be managed. In a letter from the CPUC Energy Division to SCE dated July 9, 2005, the following was expressed:

> "From our recollection of the presentation [June 28, 2005], it consisted largely of a determination of the characteristics of a phase shifting transformer to deliver power to PG&E in a Northerly direction from the Big Creek-Rector lines under conditions of summer peak load. It is our understanding that under these conditions the flow across Path 26 is in the opposite direction, from North to South, which would explain the high angle shift required of the transformer. Forcing flow from SCE to PG&E under these conditions appears to us to be undesirable. More relevant to the study are the off-peak conditions under which the Path 26 flow is from South to North. Under off-peak conditions a phase-shifting transformer or flow controller is needed only to augment existing South to North flow in Path 26 to accommodate delivery of Tehachapi generation to the grid."

The study assumptions utilized in conducting these parametric studies included all operating conditions by simulating an entire year using historical metered data. Based on the results of the study, the phase-shift angle problems identified are not limited to summer peak conditions. With minimal flows on the new system tie, the phase-shift angle problems were also identified under spring run-off conditions (April and May) when Big Creek hydro is at maximum. With greater flows on the new system tie, the problems were found to occur year round. The reason for this is that local area loads and generation dispatch patterns play a dominant role in defining the phase-shift angle requirements necessary to deliver power from SCE to PG&E. In other words, the flow direction of the Pacific intertie does not necessarily dictate local phase-shift angle requirements.

This conclusion has been validated by the CAISO in the economic dispatch studies performed to evaluate system performance with the inclusion of a 600 MW phase-shifted system tie. SCE requested and reviewed the data supporting the study results presented by the CAISO at the September 19, 2005 Tehachapi Collaborative Study Meeting. Based on SCE's review of the data, the phase-shift angle problems identified are anticipated to occur throughout the year as shown below in Figure 3.2.21.

Figure 3.2.21
CAISO Economic Dispatch Study Results
600 MW Fresno Phase-Shift System Tie

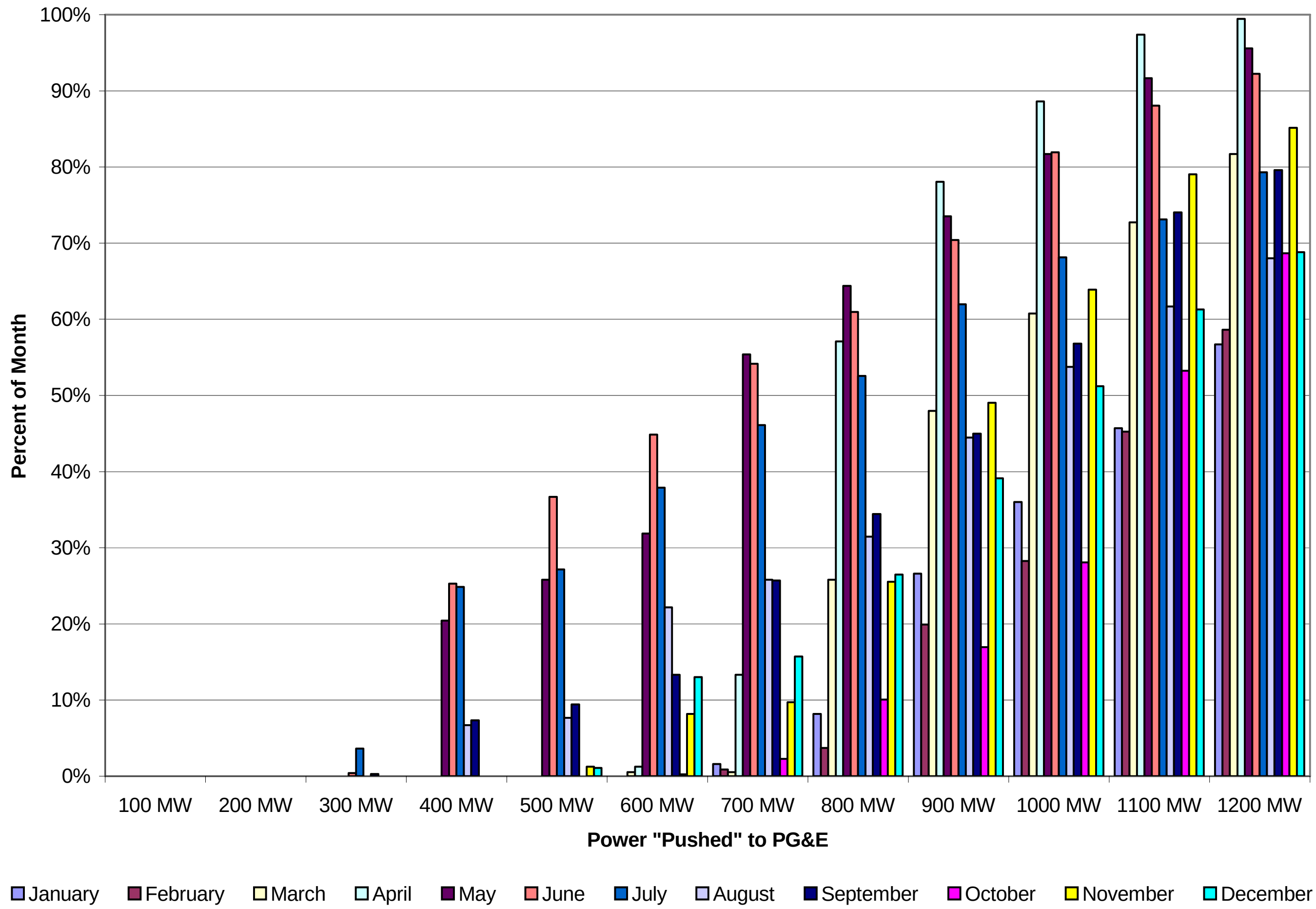


Power Flow Validation

Several of the Tehachapi Collaborative Study Group participants have expressed concerns with the study results portraying loadings that would not occur when the phase-shift transformer would be in service or would be "pushing" power from SCE to PG&E.

To determine when such overloads would occur, output data obtained from the thousands of power flow studies conducted was reviewed. The results of this data review are presented below in Figure 3.2.22. As can be seen, exposure to the thermal overload problem identified on the section of Big Creek3-Rector 230 kV transmission line between Big Creek and the Fresno system tie begin when the system tie is at 300 MW. This overload problem initially occurs during May, June and August but extends out for the entire year as the system tie is increased. Based on these results, SCE will require upgrades to mitigate this identified base case overload.

Figure 3.2.22
Section of Existing Big Creek3-Rector 230 kV (BC to Fresno Tie)
Overload Frequency



Operating Procedure to Open System Tie

Several participants suggested that an Operating Procedure be implemented to open the system tie anytime the Big Creek3-Rector 230 kV transmission section between Big Creek and the Fresno Tie is thermally overloaded.

The proposed solution of opening the system tie anytime there is an overload is not a workable solution. Since the system tie will be a new established WECC Path, the tie will need to remain in service under all normal operating conditions. A thermal overloads caused by the daily dispatch of the system does not constitute an abnormal operating condition. The CAISO has provided their comments on this subject matter in an e-mail issued on September 9, 2005. The CAISO states the following:

> "Generally, in regard to operation of a new phase-angle regulator, it would not be advisable to propose a new facility that would need to be periodically taken out-of-service to limit flows."

In addition, a Special Protection Scheme is currently in place which runs back Big Creek generation whenever either of the Big Creek-Rector 230 kV transmission lines is overloaded. Adding this system tie without upgrades can lead to unintended operation of this run-back scheme. WECC RAS Task Force requires that impacts to special protection schemes resulting from the addition of new facilities be mitigated. In this case, the mitigation would be the upgrade to the overloaded facility and operate the system within the limits of the next limiting component. Additional transmission upgrades will be necessary to accommodate a larger fixed power model.

Reasons for Power Flow Patterns

One of the participants questioned why the transmission section between Big Creek and the Fresno Tie would thermally overload.

As can be seen in Figure 3.2.1, the distance from the Big Creek 1,000 MW hydro facility to the new system tie is relatively short. "Pushing" power from SCE towards PG&E will result in increasing Big Creek hydro generation flows on the two lines from Big Creek to the Fresno Tie. The reason for this can be explained by applying Ohm's Law, which basically states that current is inversely proportional to the apparent impedance. In other words, current follows the path of least resistance (i.e. Big Creek generation is a shorter distance to the new system tie as compared to Tehachapi generation and therefore has a much smaller impedance). For this reason, the Fresno phase-shifted system tie cannot be directly linked to Tehachapi since Tehachapi power will never flow on the system tie unless the size of the tie is in excess of the total Big Creek hydro generation.

2.2.4. Big Creek-Fresno Tie Study Conclusions

Because of the complexities associated with the use of a traditional phase-shift transformer, design of a system tie with such facility, while cheaper than a FACTS device, will require significantly much more transmission line upgrades to allow for reliable operation. The use of a FACTS device on the other hand reduces the amount of transmission line upgrades required and improves overall operability of the system tie. The CAISO should be consulted as to which alternative can be supported from an operations perspective considering scheduling difficulties as well as hour-to-hour operations.

Conceptually, the study results indicate that the use of a traditional phase-shift transformer needed to "push" 200 MW needs to be designed sufficient to accommodate 850 MW. In comparison, the use of a FACTS device to "push" 200 MW requires sufficient upgrades to accommodate only 200 MW. Table 1 below summarizes the facilities needed to accommodate each type of system tie.

Table 3.1
Transmission Facilities Needed to Support New System Tie

Fixed Power System Tie FACT Device Designed for 200 MW	**Traditional Phase-Shift Transformer Fixed Tap System Tie Designed for 850 MW**
Currently Planned San Joaquin Valley Rector Loop 230 kV Project	Currently Planned San Joaquin Valley Rector Loop 230 kV Project
New 60 mile Antelope-Magunden 230 kV Transmission Line	New 60 mile Antelope-Magunden 230 kV Transmission Line
New 135 mile Magunden-Vestal-Rector-FresnoTie-Big Creek Transmission Line with connections to each of the substations	New 135 mile Magunden-Vestal-Rector-FresnoTie-Big Creek Transmission Line with connections to each of the substations
Magunden, Vestal, Rector, and Big Creek Substation Expansion	Magunden, Vestal, Rector, and Big Creek Substation Expansion
Supplemental Shunt Capacitor Banks since most dynamic supply can be provided by the FACTS device	Dynamic Reactive Resources such as SVC
	Second new 135 mile Magunden-Vestal-Rector-FresnoTie-Big Creek Transmission Line with connections to each of the substations
	Additional Magunden, Vestal, Rector, and Big Creek Substation Expansion

SCE notes that regardless of which facility is ultimately selected, much more study work is required to support establishment of an official path rating. This study work will include short-circuit duty analysis as well as transient stability review. This study should only be undertaken if this alternative appears to be cost effective when compared against other Conceptual plans and with formal approval from the CAISO Operations Group. Conceptually, the cost estimate for this new system intertie is in excess of $450 million.

APPENDIX 4

APPENDIX 4

CAISO STUDIES

Production Cost Simulation Methodology and Tool

ABB's GridView production cost simulation software was used to evaluate the relative ranking of the transmission alternatives under consideration. This tool provides an economic optimization of the generation dispatches to minimize the total hourly production cost for the transmission system that is subject to generation, transmission and operational constraints. The output of the production simulation tool is processed to estimate the comparative production cost, loss and congestion savings of each of the alternatives, to assist in determining differences, if any, of the transmission alternatives.

The program input data includes:

- Generation data such as capacity, fuel costs, heat rates, maintenance schedule, start up cost, shut down cost, up time, down time, forced outage rate and outage duration.
- Transmission data such as network topology, thermal limits and operational constraints.
- Hourly demand data and distribution.
- Hourly hydro and wind dispatch.

The program output result includes hourly dispatch for each generation unit, hourly production cost, hourly transmission line flows and Locational Marginal Prices (LMP) at each node.

The production cost simulation was performed to determine annual production costs of the entire WECC system for the various alternatives being considered to incorporate over 4000 MW of wind potential in the Tehachapi area. These simulations provide both economic and operational information to assist in determining a relative ranking of the transmission alternatives. The analysis was used to compare differences in the WECC production cost, power losses and congestion hours resulting from the alternative transmission configurations being considered. The analysis did not consider other potential benefits such as reduction in reliability-must-run generation cost, reduction in emission and increased operational flexibility. It should also be noted that potential concerns involved with the intermittency of wind and its potential impacts on system operation such as regulation and reserve are not part of this evaluation. The analysis is based on all lines in-service and does not consider any contingency or loss of facility conditions.

Base Case Assumptions

The 2008-SSG-WI (Seams Steering Group-Western Interconnection) base case developed by SSG-WI Planning Work Group (PWG) and also used in the recent is Imperial Valley Study[14] was used as a starting case to maintain consistent assumption between similar studies. Summarized below are the assumptions used in the starting base case that are common to both the Tehachapi and the Imperial Valley studies:

- The base case included the generation and transmission infrastructure that may be assumed to be in place by 2008. Generation units with official retirement dates prior to 2008 were modeled out of service.
- SSG-WI PWG developed approximate industrial figures for variable and non-variable operation and maintenance costs, minimum and incremental heat rates, forced outage rate and outage duration for different generation units based on fuel type, technology, size and age. SSG-WI generation assumptions also include start up/shut down costs, minimum up time/down time and maintenance duration for different generation units. Table 1 summarizes SSG-WI generation assumptions.
- SSG-WI base case assumed average hydro conditions. Hydro generation outputs were modeled as an hourly resource. Similarly, all wind generators were modeled as an hourly resource. Hourly resources are considered as must-take resource and are therefore not optimized. The existing wind generation dispatch was based on historical data.
- SSG-WI base case transmission representation model is based on the WECC 2008 HS2-SA approved case, dated February 2004. An updated case developed by the SSG-WI received 8/5/2005 was used for the analysis.
- SSG-WI PWG used publicly available data including WECC load and resources report to construct 2008 monthly peak and energy amounts for each of the power flow area. The area loads were then spatially spread to the entire WECC network using load distribution factors as used in power flow model.
- Average monthly fuel (Gas, Coal, Uranium) prices for generation plants were forecasted for 2008. The prices were adjusted to account for the cost of delivering the fuel to the generation plant. Detailed description of SSG-WI fuel pricing assumptions is available at http://www.ssg-wi.com/documents/.

The Tehachapi wind generation dispatch profile shown in Figure 3 was provided by National Renewable Energy Laboratory (NREL) and is based on 70 meter rotors, 7.5 m/s wind speed and a 2% unavailability (45% capacity factor). Based on a potential of 4500 MW in the area, this wind profile was scaled and assumed a total annual production of 17,209,942 MWH from the Tehachapi and Antelope wind. For simplicity the 4500 MW was modeled at the Tehachapi bus. The Tehachapi wind was dispatched as base load generation - modeled hourly and represented no fuel or maintenance cost.

[14] Development Plan for the Phased Expansion of Transmission to Access Renewable Resource in the Imperial Valley, dated September 30,2005

Table 1 SSG-WI Generation Assumptions

<table>
<tr><th>Fuel Type</th><th>Technology</th><th>Size/MW</th><th>Vintage</th><th>Min. Heat Rate (Btu/kWh)</th><th>Variable O&M Cost ($/MWh)</th><th>Forced Outage Rate</th><th>Forced Outage Duration (hrs)</th></tr>
<tr><td rowspan="4">Gas/Oil</td><td rowspan="4">Steam</td><td><100</td><td rowspan="2"><1960</td><td>12,194</td><td rowspan="3">5.001</td><td rowspan="4">0.071</td><td rowspan="4">55</td></tr>
<tr><td>>100</td><td>9,125</td></tr>
<tr><td><100</td><td rowspan="2">>1960</td><td>9,214</td></tr>
<tr><td>>100</td><td>6,856</td><td>3.001</td></tr>
<tr><td rowspan="5">Gas</td><td>SCCT</td><td>-</td><td rowspan="2"><1985</td><td>11,403</td><td>8.001</td><td>0.036</td><td>89</td></tr>
<tr><td>CCCT</td><td>-</td><td>9,600</td><td rowspan="3">5.001</td><td>0.055</td><td>22</td></tr>
<tr><td>SCCT</td><td><70</td><td rowspan="2">>1985</td><td>14,114</td><td rowspan="2">0.036</td><td rowspan="2">89</td></tr>
<tr><td>SCCT</td><td>>70</td><td>12,106</td></tr>
<tr><td>CCCT</td><td>-</td><td>>1985</td><td>8,815</td><td>2.000</td><td rowspan="4">0.055</td><td rowspan="4">22</td></tr>
<tr><td>Gas/Oil</td><td>CCCT-Frame F</td><td>-</td><td>>2001</td><td>3,620</td><td>2.000</td></tr>
<tr><td rowspan="2">Gas</td><td rowspan="2">DT</td><td rowspan="2">-</td><td><1985</td><td>9,600</td><td rowspan="2">5.001</td></tr>
<tr><td>>1985</td><td>10,695</td></tr>
<tr><td rowspan="2">Oil</td><td>IC</td><td>-</td><td>-</td><td>9,125</td><td>13.250</td><td rowspan="2">0.036</td><td rowspan="2">55</td></tr>
<tr><td>SCCT</td><td>-</td><td>-</td><td>11,403</td><td>8.001</td></tr>
<tr><td rowspan="4">Coal</td><td rowspan="4">Steam</td><td><100</td><td rowspan="2"><1960</td><td>12,000</td><td>4.000</td><td rowspan="4">0.066</td><td rowspan="5">38</td></tr>
<tr><td>>100</td><td>11,500</td><td>2.000</td></tr>
<tr><td><100</td><td rowspan="2">>1960</td><td>11,000</td><td>3.001</td></tr>
<tr><td>>100</td><td>10,500</td><td>2.000</td></tr>
<tr><td>Bio/WH/Wood</td><td>Steam</td><td>-</td><td>-</td><td>12,194</td><td>5.001</td><td>0.071</td></tr>
<tr><td>Geothermal</td><td>GE</td><td>-</td><td>-</td><td>-</td><td>4.000</td><td>0.071</td><td>16</td></tr>
<tr><td>Uranium</td><td>Nuclear</td><td>-</td><td>-</td><td>-</td><td>-</td><td>0.070</td><td>298</td></tr>
</table>

The SSG-WI base case was modified with the CAISO load level to reflect forecasted 2010 conditions. In addition, the following new transmission projects in southern California that are approved and planned to be online by 2010 were included in the model:

- Harquahala-Devers 500 kV line
- New 500 kV Substation to be located at the Midpoint of Palo Verde- Devers and Harquahala-Devers 500 kV lines
- Blythe I and II Combined Cycle plant (1000 MW) connecting to Midpoint Substation
- Reconductoring of four West of Devers 230 kV lines

Table 2 provides specific non-simultaneous interface limits enforced in the production cost optimization runs for interfaces within the immediate area of the study.

Table 2: Non-Simultaneous Interface Limits

Interface	North-South Flow (MW)	South-North Flow (MW)
COI	4800	3675
Path 15	3265	5000[1]
Path 26	3700[2]	3000

Notes:
1) Path 15: 5,000 MW S-N is supported by RAS that trips generation connected to Midway. The Path 15 limit will be decreased by 1 MW for every 2 MW decrease in Midway generation (La Paloma, Sunrise, Elk Hills).
2) Path 26: Power flow between 3,000 MW and 3,700 MW N-S is supported by a RAS that trips Midway area generation. The Path 26 limit will be decreased by 1 MW for every 2 MW decrease in Midway generation (La Paloma, Sunrise, Elk Hills). Assumed Path 26 capability N-S increased to for 4000 MW as provided SCE for Alternatives 1, 3 and 10 that include a new 500 kV Tehachapi-Midway line. Detail studies are required to determine actual capability with the new transmission.

In addition, the following transmission facility assumptions were simulated as part of the study.

- Transmission models and ratings used for alternatives were provided by SCE and PG&E.
- With a new Midway-Tehachapi 500 kV line, the Path 26 N-S thermal capability was assumed to be 4000 MW for production cost simulation studies.
- All WECC transmission paths were modeled according to 2005 Path rating catalog
- Limits for all 500 kV transmission facilities were enforced.
- Lower voltage (230 kV and below) limits were not enforced.
- SCIT limit was modeled at 17900 MW
- EOR limit was modeled at 9255 MW
- WOR limit was modeled at 11318 MW
- All AC transmission lines monitored were limited to 95% of their thermal capacity or applicable rating in order to accommodate reactive flows which are absent in this production simulation studies.
- Nomograms were used to reflect transmission system constraints.
- Transmission losses were modeled.
- Transmission line/Path limit violation penalty of $1000 per MWh was applied.

The following figures supplement the productions cost simulation analysis and are provided for informational purposes.

Figure 1 - Interface Definitions
Figure 2 - Path 15 and Path 26 Historical Flows
Figure 3 – Tehachapi Wind Load Duration Curve
Figure 4 – Flows During a Peak Summer Day With Tehachapi Wind
Figure 5 – Flows During a Off-Peak Summer Day With Tehachapi Wind
Figure 6 – Comparison of Path 26 Flows With 4500 MW Tehachapi Wind
Figure 7 – Comparison of Path 15 Flows With 4500 MW Tehachapi Wind
Figure 8 – 600 MW Fresno Phase Shifter Power Flow With 1600 MW Tehachapi Wind
Figure 9 – 600 MW Fresno Phase Shifter Angle Range With 1600 MW Tehachapi Wind
Figure 10 – Scenario E Oneline
Figure 11 – Scenario F Oneline
Figure 12 – Scenario G Oneline
Figure 13 – Scenario H Oneline
Figure 14 – Scenario H Oneline
Figure 15 – Scenario J Oneline

The following Figure 1 illustrates the Path 15 and Path 26 interfaces with the existing and new transmission under the various alternatives Path 15 includes additional underlying 230 kV transmission not shown.

Figure 1 – Interface Definitions

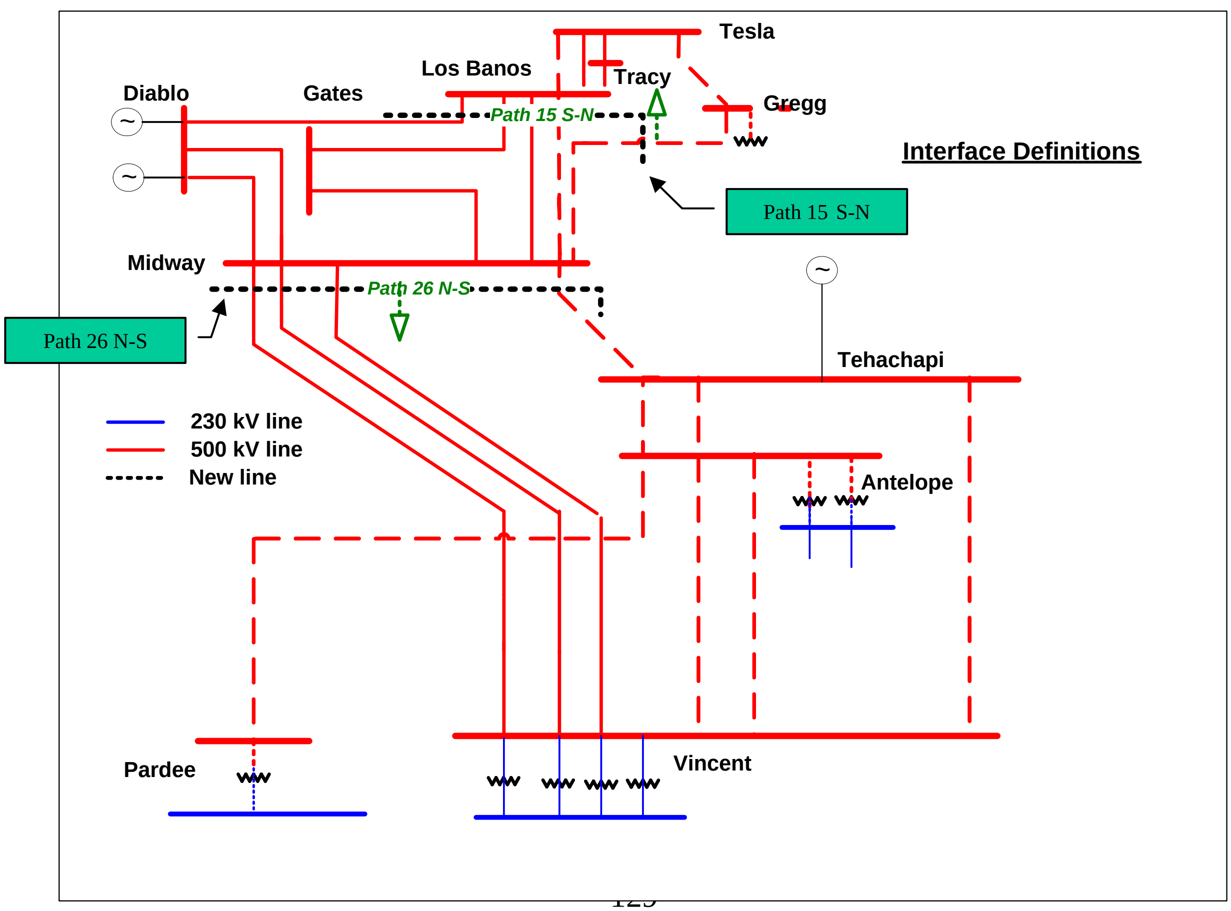


Figure 2 – Path 15 and Path 26 Historical

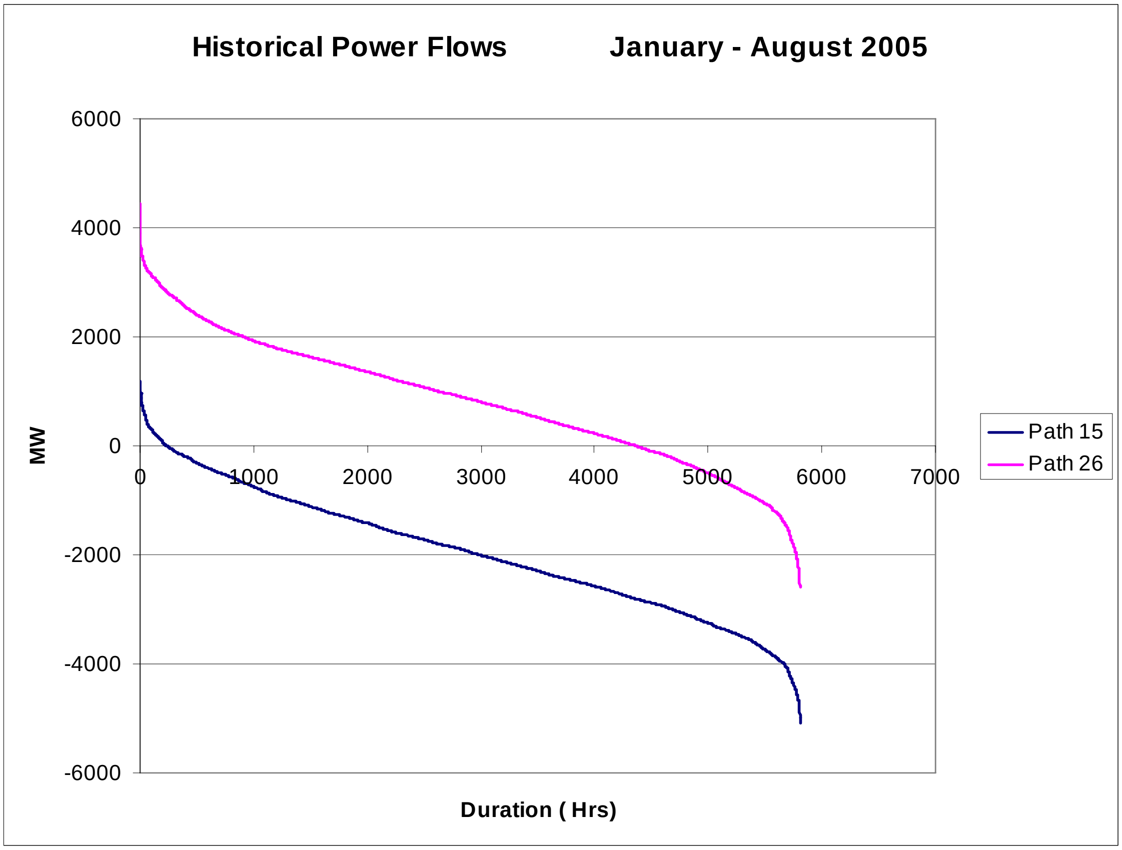


Figure 3 – Tehachapi Wind Load Duration Curve

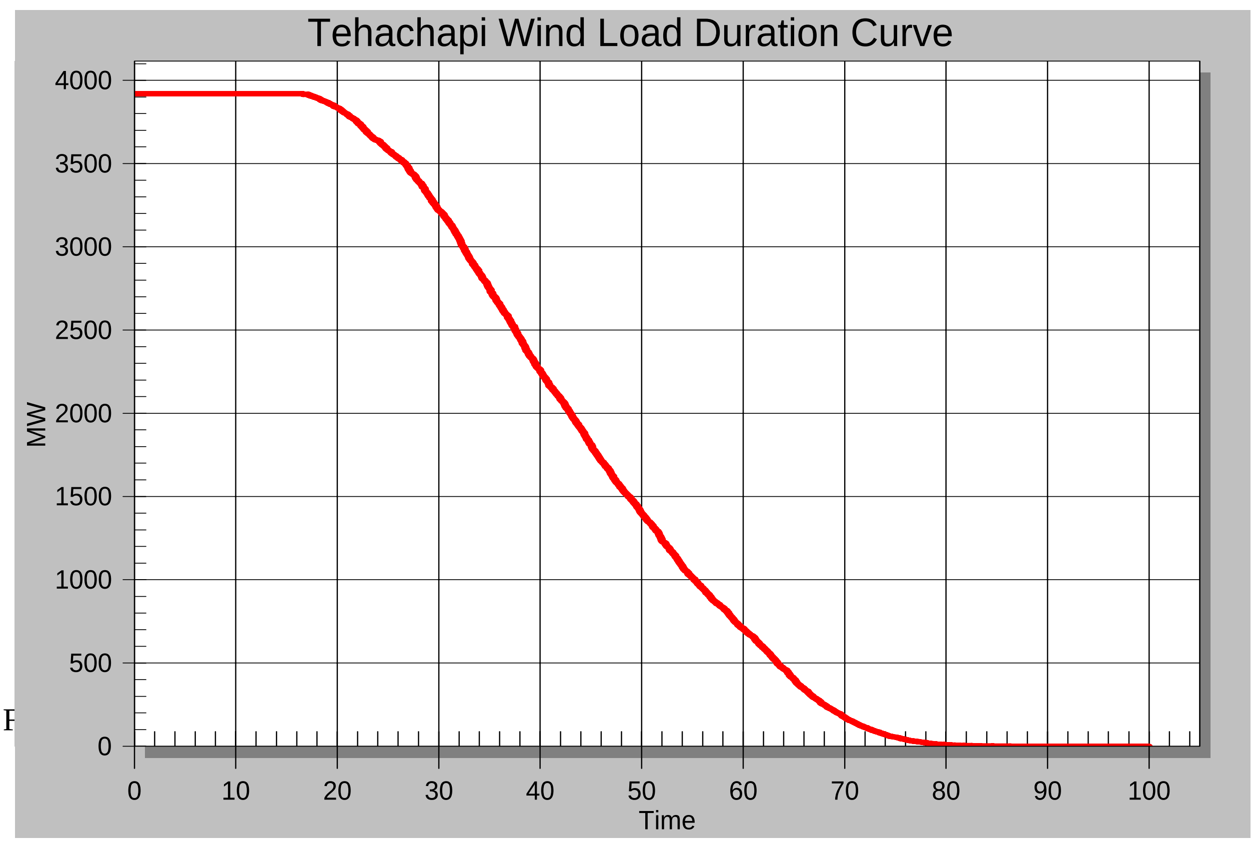


Figure 4 – Flows During a Peak Summer Day With Techachapi Wind

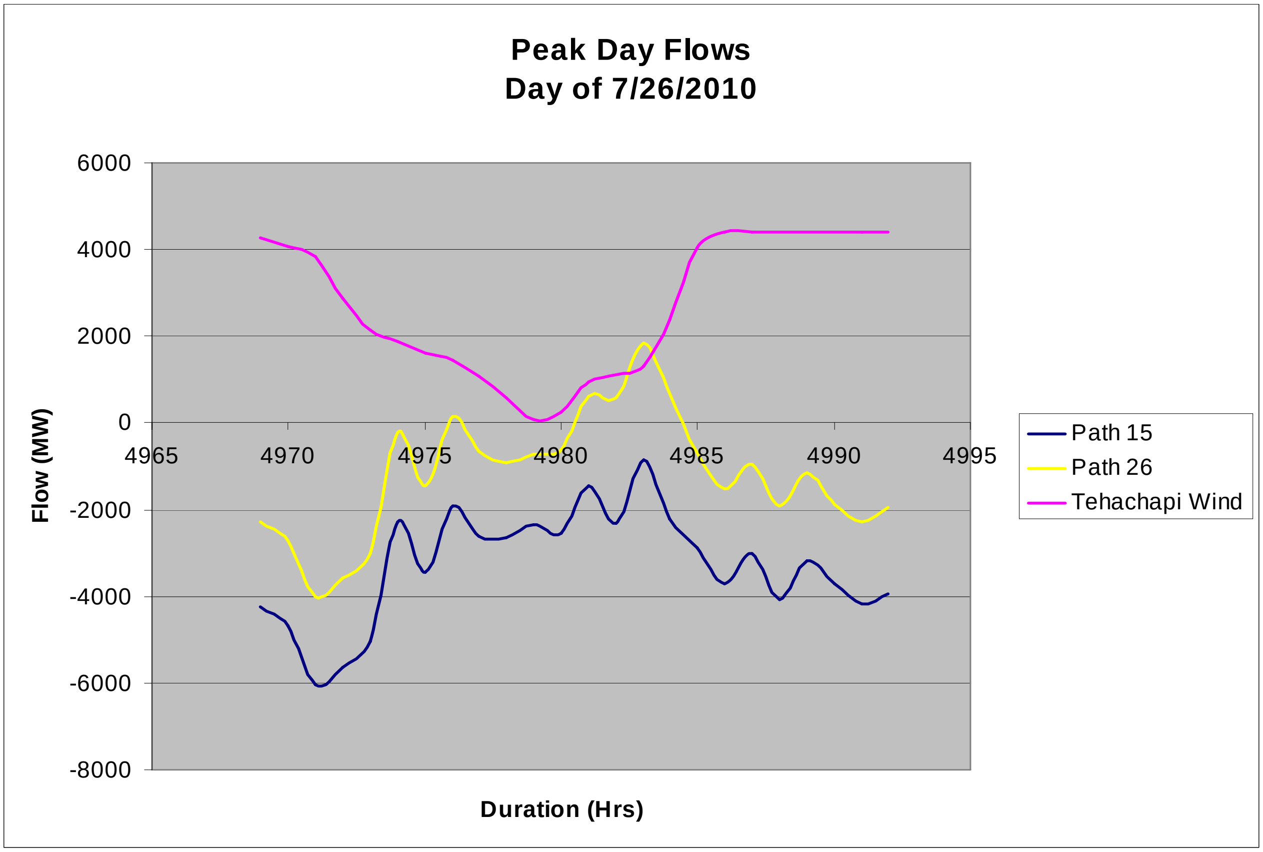


Figure 5 – Flows During a Off-Peak Summer Day With Tehachapi Wind

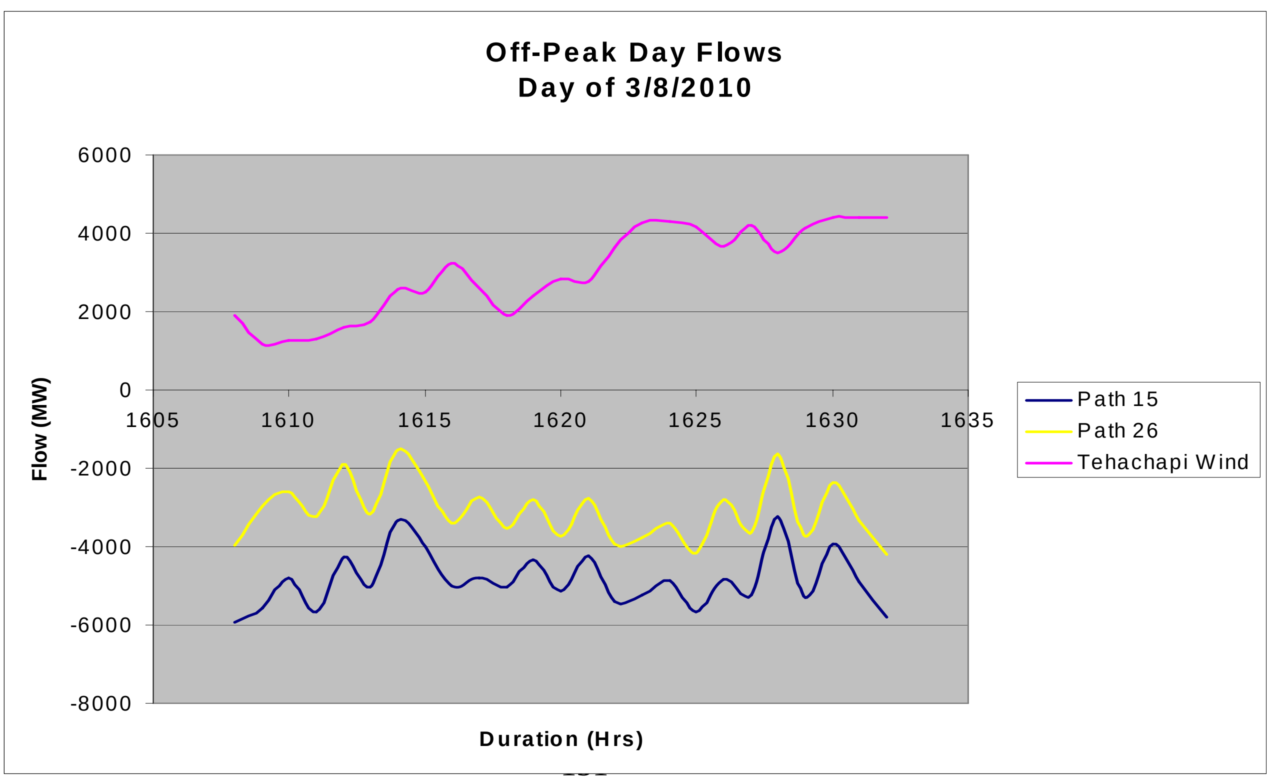


Figure 6 – Comparison of Path 26 Flows With 4500 MW Tehachapi Wind

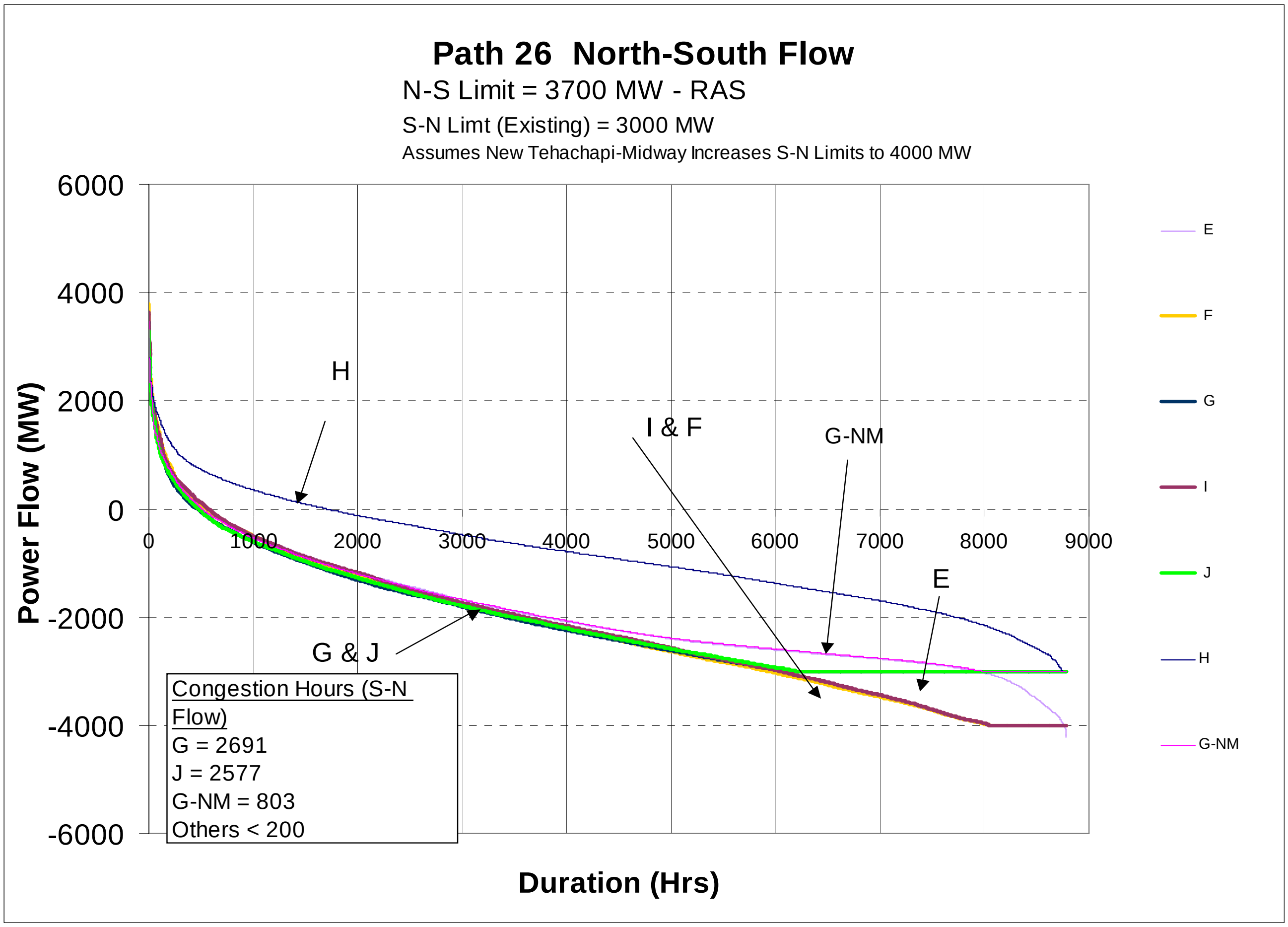


Figure 7 – Comparison of Path 15 Flows With 4500 MW Tehachapi Wind

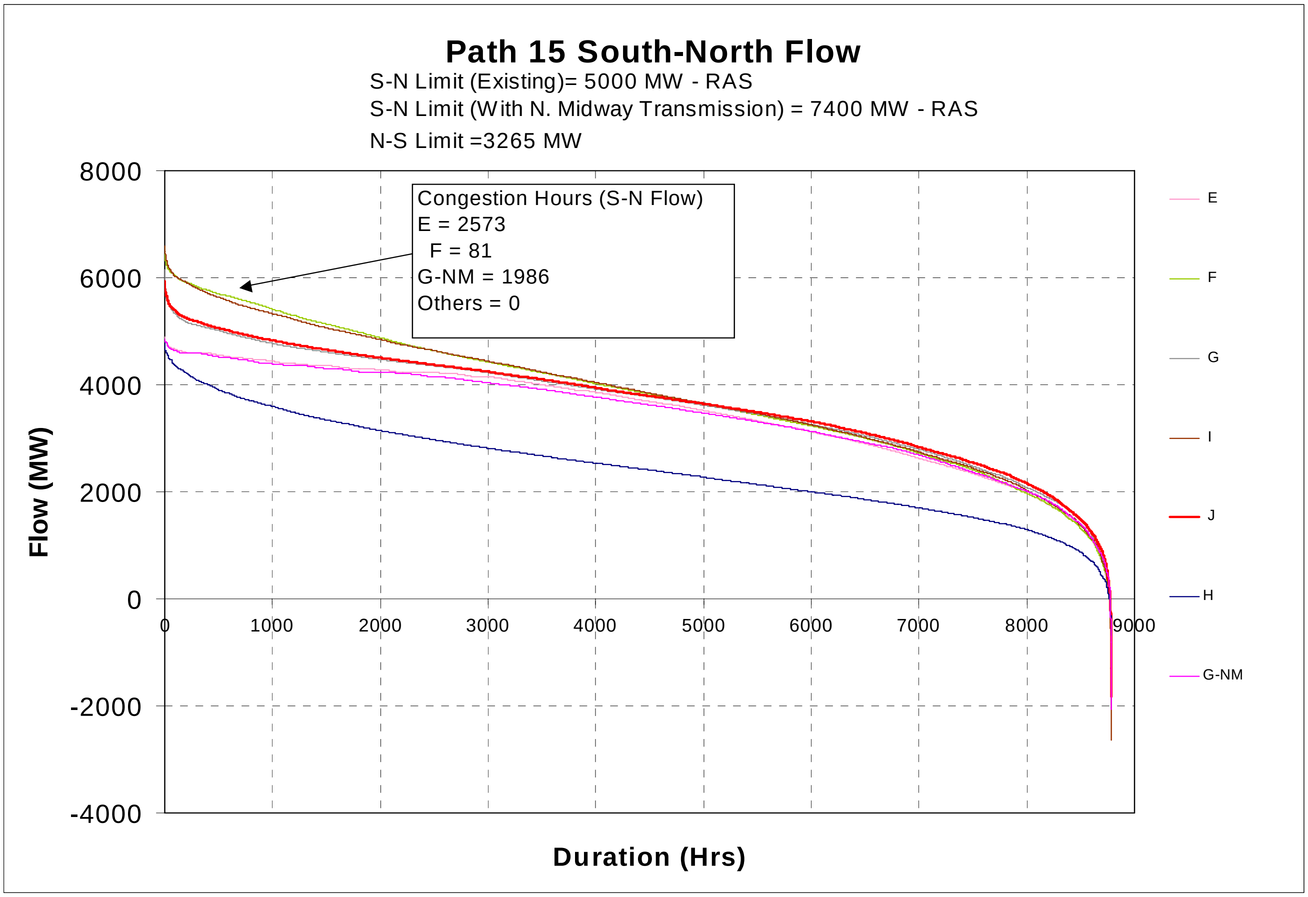


Figure 8 – +/- 600 MW Fresno Phase Shifter Power Flow With 1600 MW Tehachapi Wind

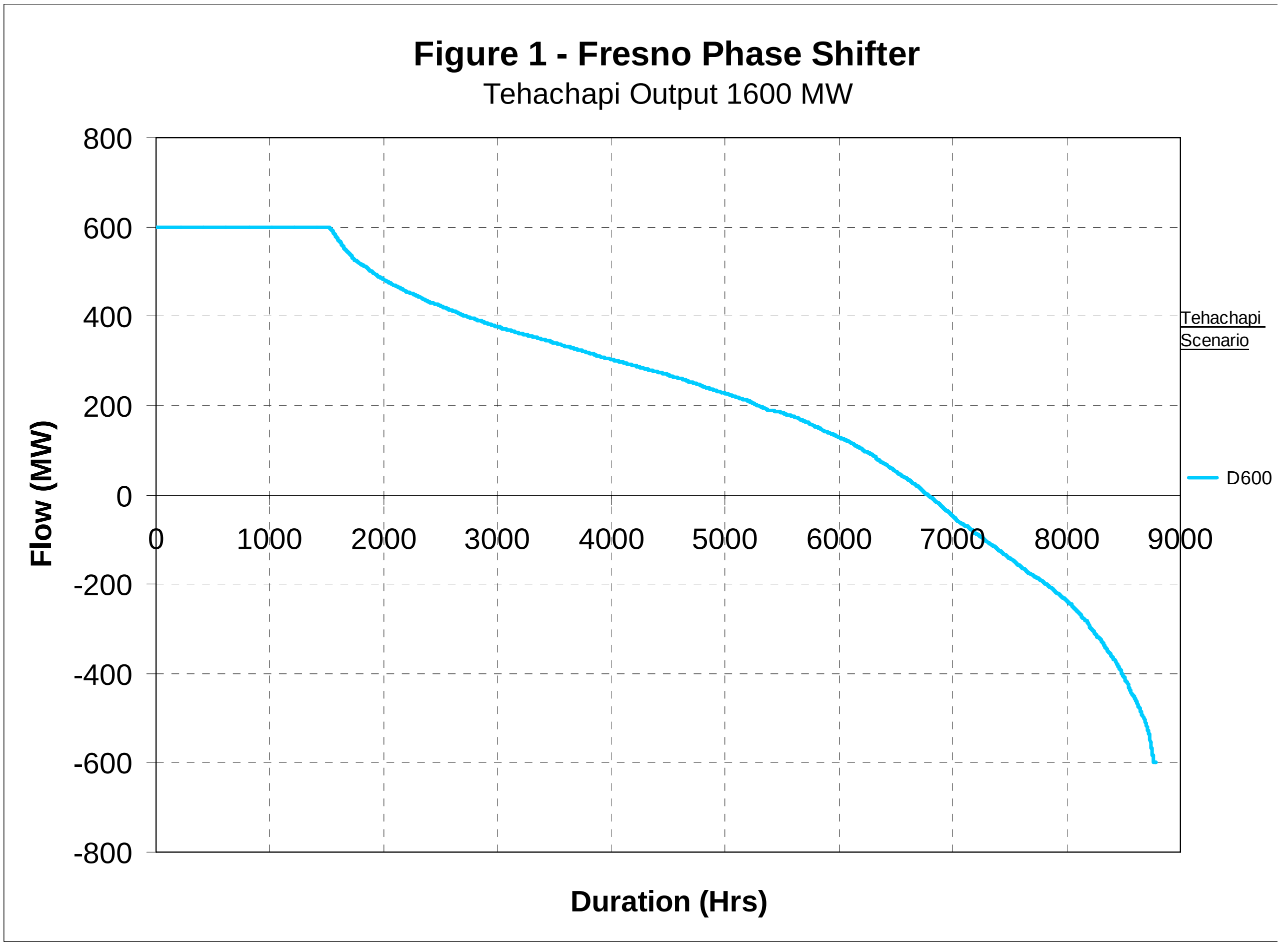


Figure 9 – +/- 600 MW Fresno Phase Shifter Angle Range With 1600 MW Tehachapi Wind

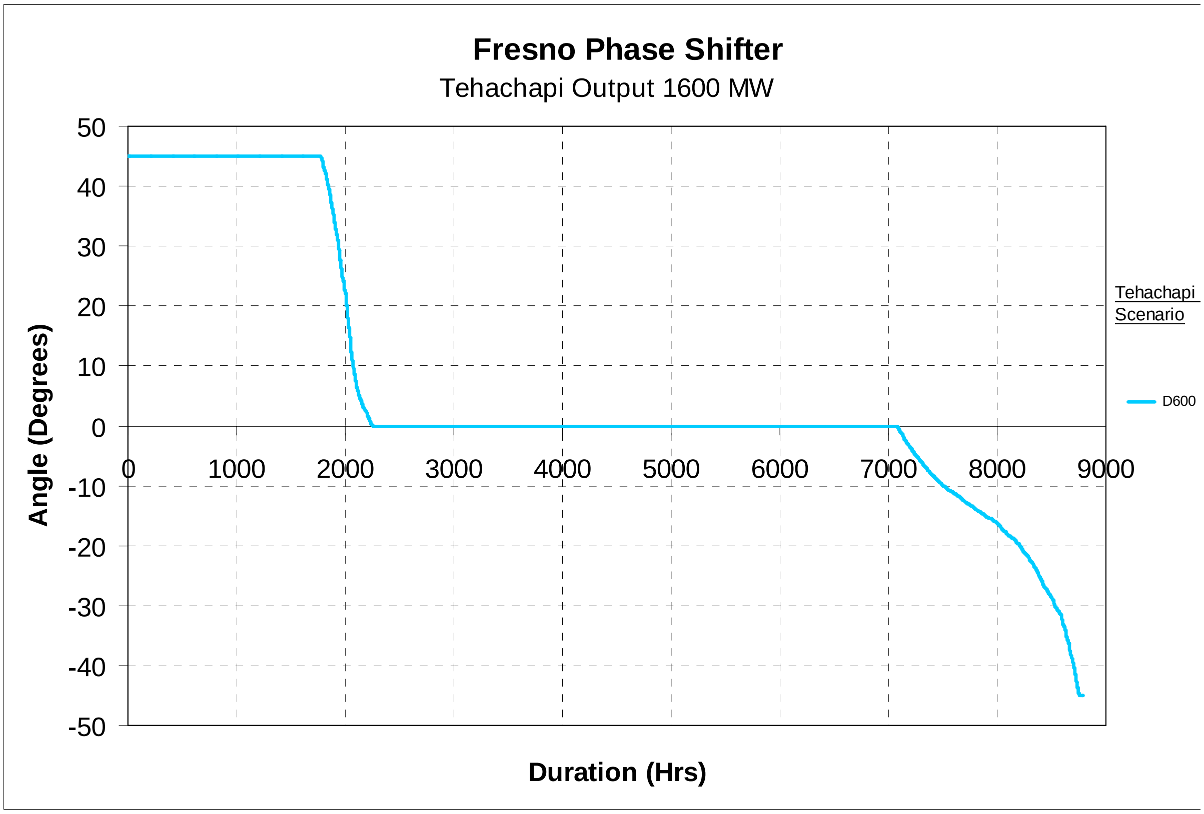


Figure 10 – Scenario E Oneline

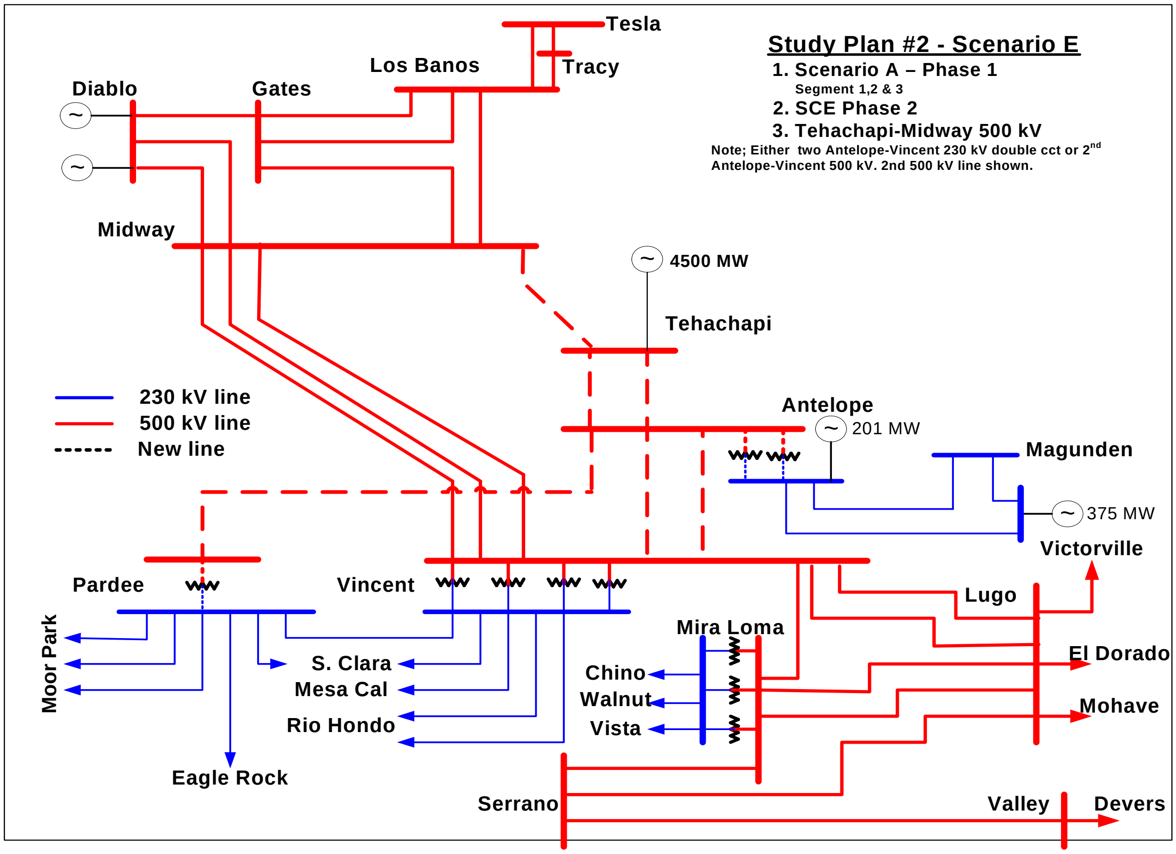


Figure 11 – Scenario F Oneline

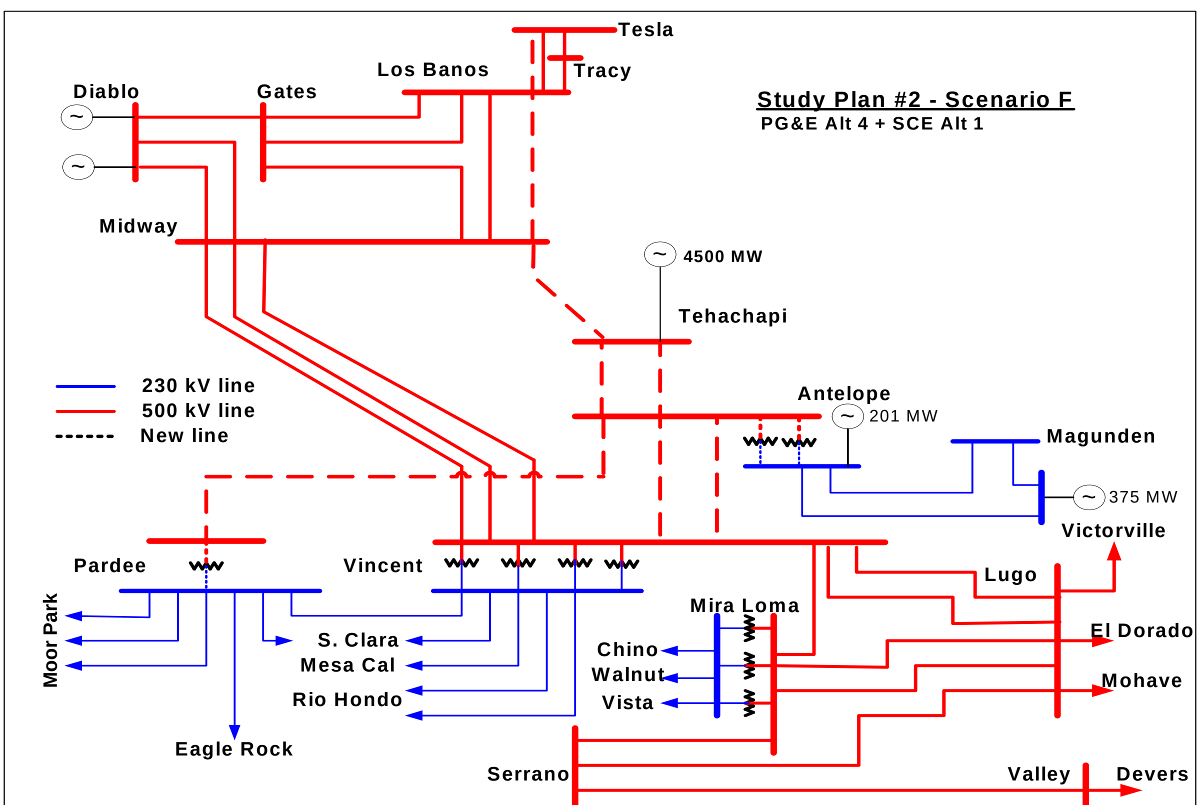


Figure 12 – Scenario G Oneline

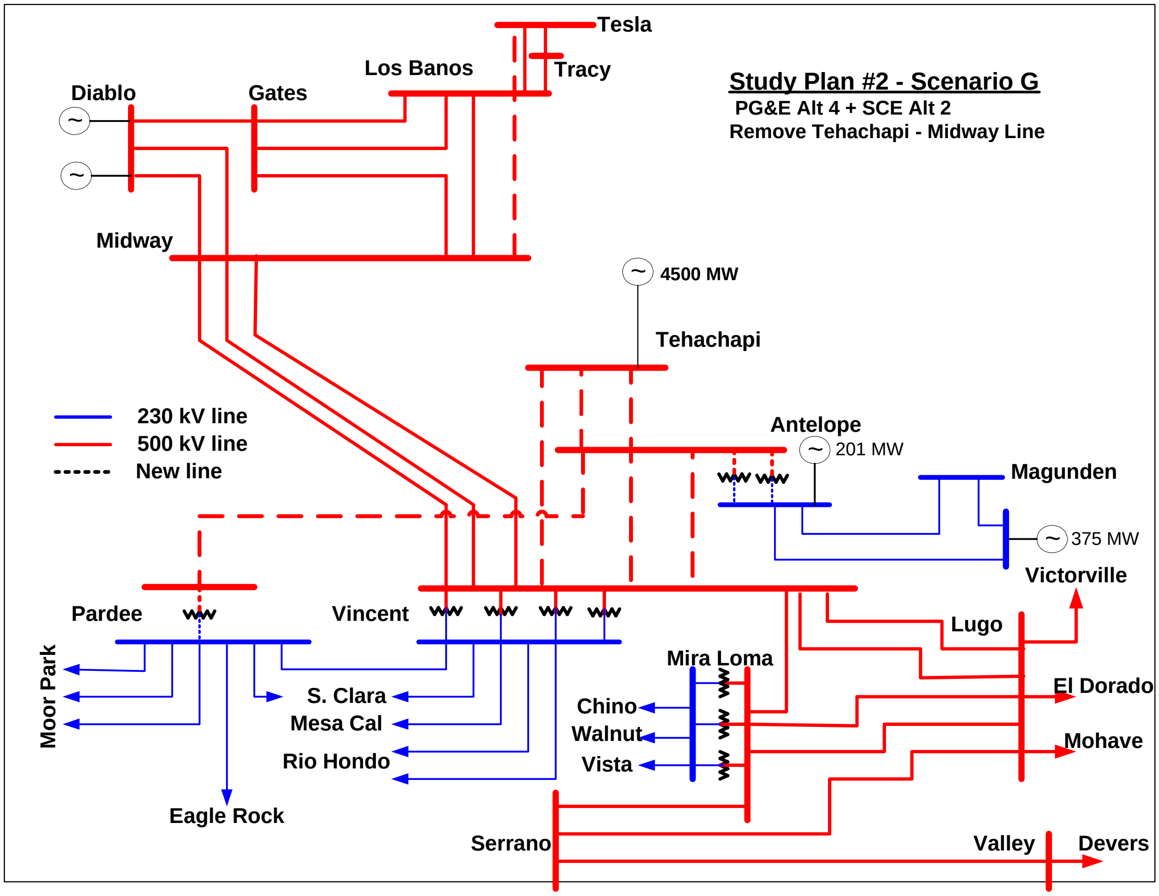


Figure 13 – Scenario H Oneline

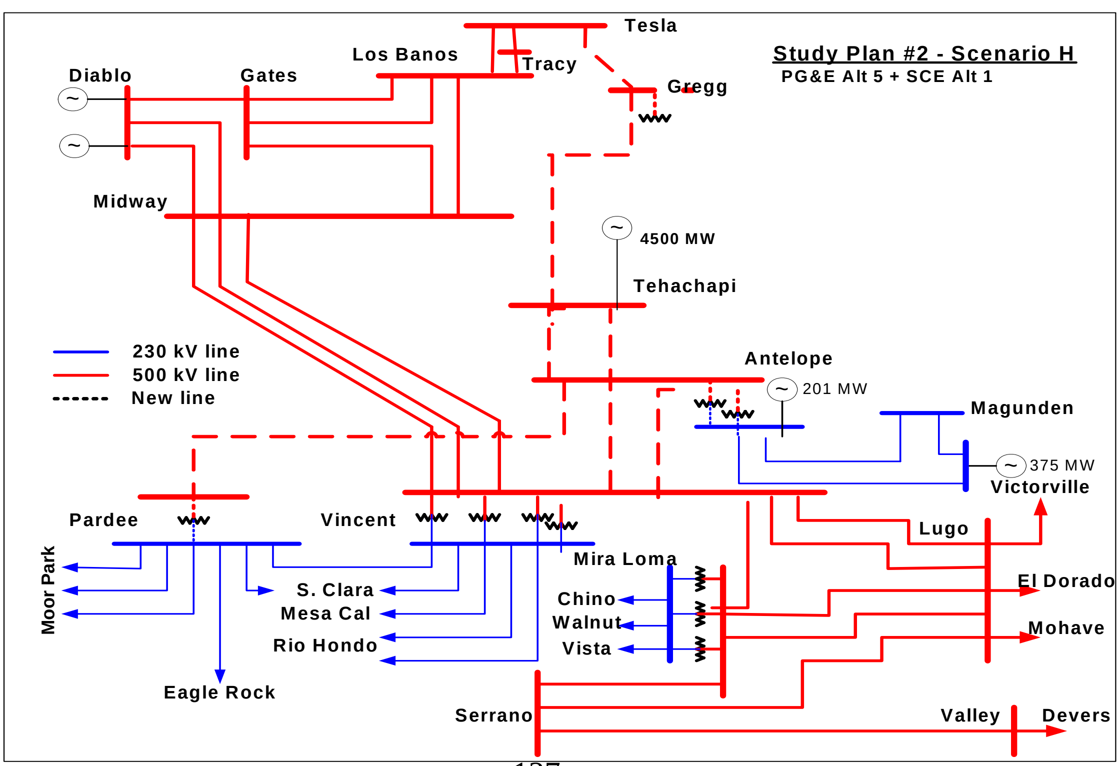


Figure 14 – Scenario I Oneline

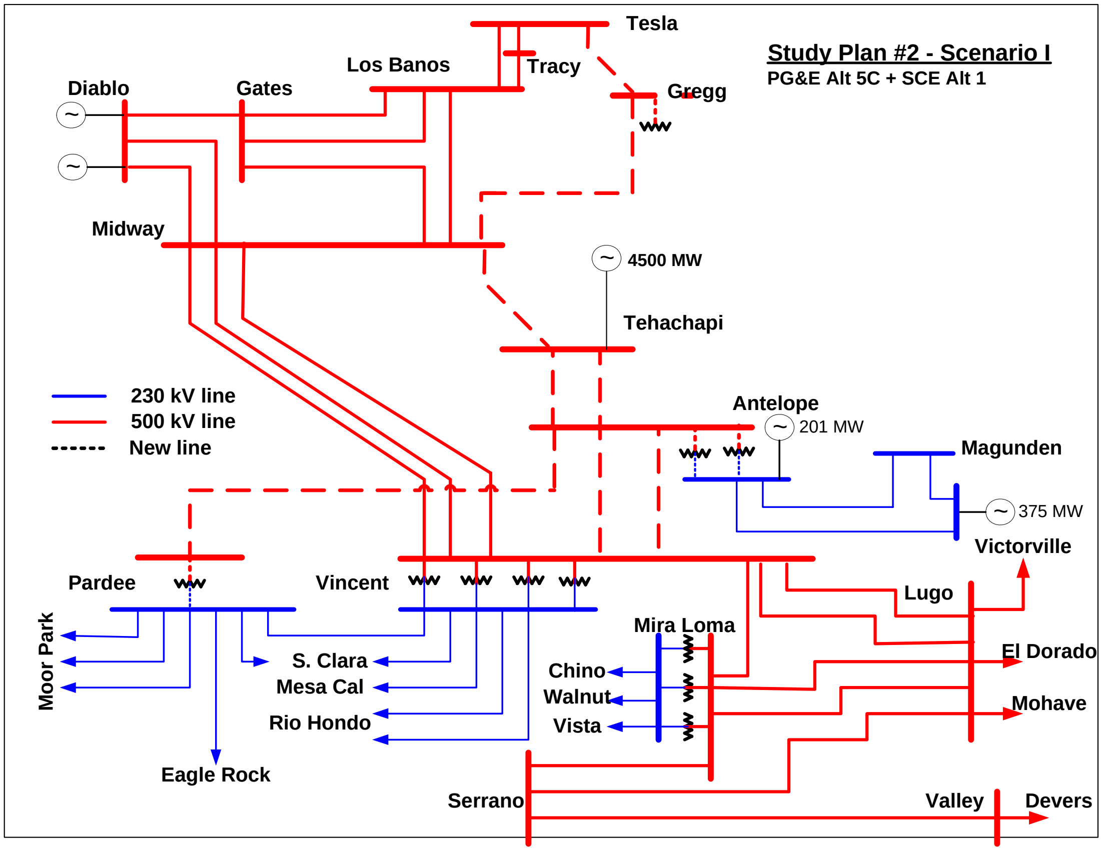
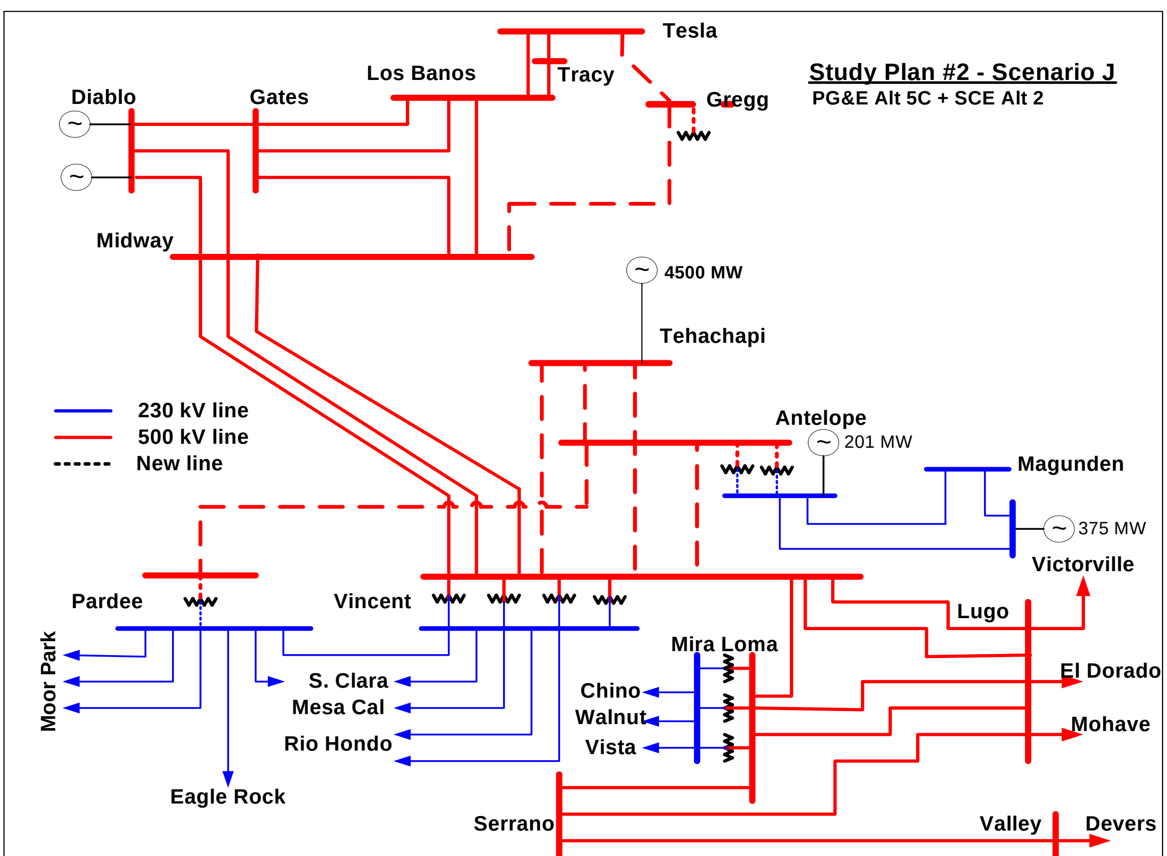


Figure 15 – Scenario J Oneline



APPENDIX 5

APPENDIX 5

Fresno 230kV Tie

A5.1 Purpose
If the output of the Tehachapi Wind Farm were to be in the order of 2000MW with half of that to be transmitted to PG&E, a low cost tie that would require a minimum investment, supplemented by flow over Path 26 would be cheaper than any EHV alternative. As indicated in the Executive Summary, the likely development of Tehachapi is now in the order of 3600MW and, as shown in Chapter 1, power bought by PG&E does not have to be delivered into the PG&E service area. The evaluation of the Fresno 230kV Tie was a blind alley which the TCSG went up and the following description is presented for academic interest only.

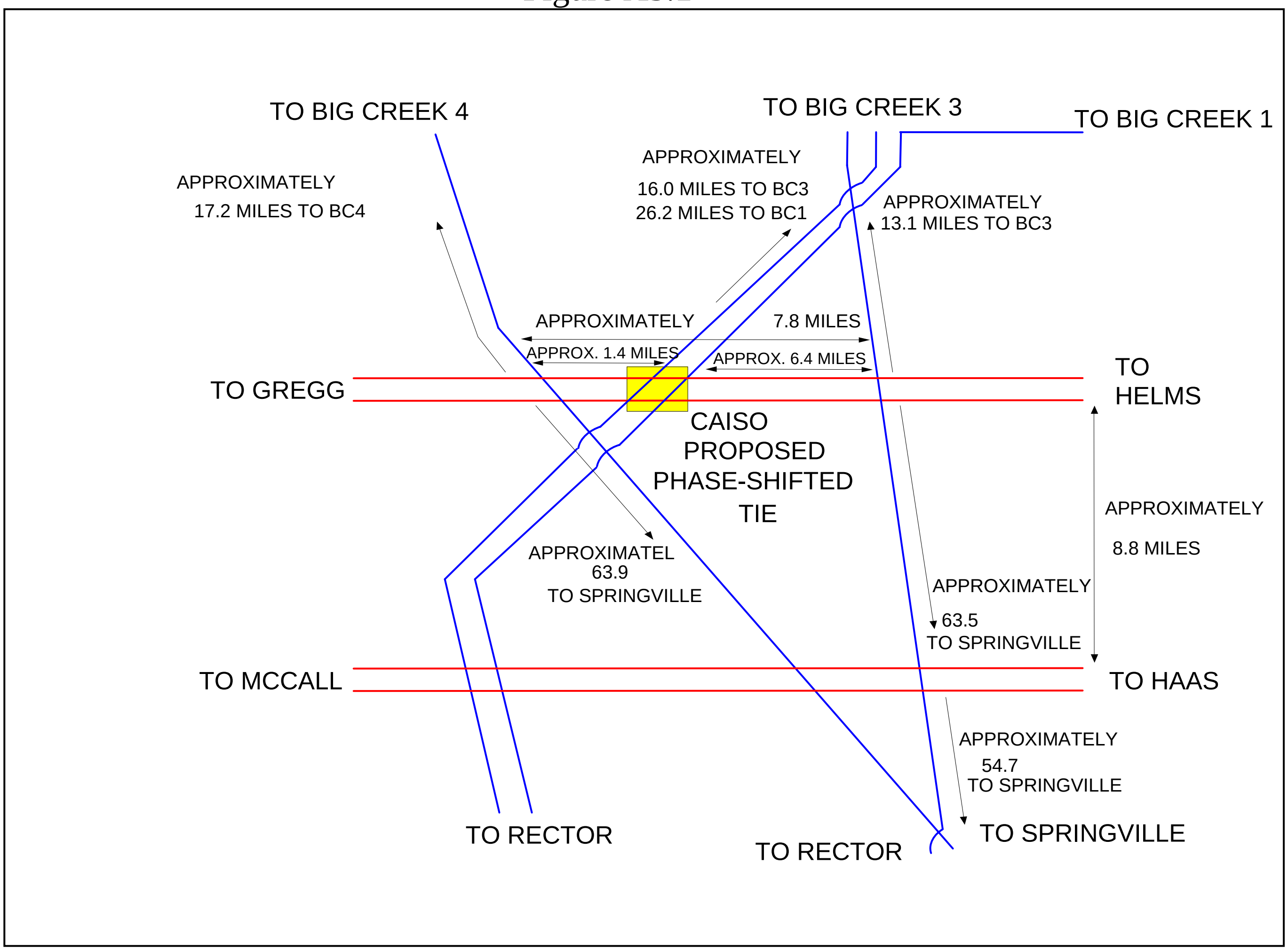
A5.2 Description, Figure A5.1
Two 230kV lines connect SCE's Antelope Substation with Magunden and four such circuits connect Magunden with the Big Creek hydroelectric plants. Two 230kV circuits connect PG&E's Helms pumped storage plant with Gregg Substation. These lines run west to east and cross the four Magunden to Big Creek lines which run south to north. A connection between the Helms-Gregg lines and two of the Magunden-Big Creek lines would transmit Tehachapi generation to PG&E with little modification to the grids. Because of the difference in the power angle between the two systems in this area, the connection would have to include a phase shifter, which could be a fixed or variable phase shifting transformer, or a solid state device. With a capacity of 300MW, no upgrade of the networks would have to be made other than voltage support. At higher capacities, varying levels of upgrade to the highly loaded SCE network would be needed depending on the incremental capacity of the tie and the loading of the lines at the time the Tehachapi generation was available. Power flow computer runs to determine the relationship between the amount of Tehachapi power flowing over the lines to the tie and line loading due to loads in the Fresno area were not made, so that it was not possible to determine the optimum capacity of the tie.

A5.3 Production Cost Study
Production cost simulation runs were made modeling variable phase shifting transformers of 300MW, 500MW and 1000MW capacities. The 300MW transformer reduced the production cost by a small amount, but with the two larger capacities the cost actually increased over the cost of identical conditions without the tie. The fact that the addition of a network component would increase production cost is hard to understand and leads to the question of whether the program is correctly modeling the device. The limitations of the program in modeling the performance of the pumped storage, which in the real world would be coordinated with the wind generation, also contributes to the perception that the effect of the phase shifting transformer was short shrifted by the program.

A5.4 Conclusions

1. With the level of production presently expected from Tehachapi and the fact that it does not need to be delivered into the PG&E system, the 230kV tie is not needed.
2. The ABB GridView production simulation program needs to be improved to correctly simulate the phase shifting transformer and to optimize the performance of pumped storage.

Figure A5.1



APPENDIX 6

Path 26 Impacts

Introduction

When wind generation in Tehachapi is connected to the grid with new transmission lines, wind power will flow on existing lines as well. Since Path 26 is a vital transmission link between Northern and Southern California, the TCSG investigated how power flows from Tehachapi will affect Path 26 and submitted the report reproduced below.

The ability of Southern California to import power from the North through Path 26 on hot summer days, when air conditioning loads are highest, is especially important. The TCSG's analysis therefore focused on Path 26 flows and Southern California imports during this peak period.

Since wind generation is variable, the amount of Tehachapi power flowing on Path 26 will also be variable. As discussed in Chapter 5, grid operators will have be able to adjust other flows on Path 26 to ensure reliability limits will not be exceeded. However, the TCSG did not attempt to analyze the impact of Tehachapi wind generation on grid operations for any of the alternatives studied.

Summary of findings

The TCSG examined the effects on Path 26 for two alternative ways of connecting Tehachapi to the grid: the Expanded Path 26 option (Alternative 1) and the Gen-tie option (Alternative 2). The Expanded Path 26 option adds a fourth 500 kV tie between Northern and Southern California; the Gen-tie configuration connects Tehachapi only to Southern California and provides no additional connection between the regions.

In combination with Tehachapi generation both the expanded Path 26 option and the Gen-Tie option increase the capacity into the south above the amount existing today.

Alternative 2 (Gen-tie option) – south-to-north flows.

When power is flowing from Southern California to Northern California, i.e., south-to-north on Path 26 (generally during off-peak periods), some power from Tehachapi will also flow north on this path. At the present time, south-to-north flows are limited by the capacity of Path 15 (north of PG&E's Midway substation) rather than by the capacity of Path 26. Therefore, although some of the capacity of Path 26 will be used by Tehachapi generation, system impacts are minimal.

Alternative 2 (Gen-tie option) –north-to-south flows

When Southern California is importing power, i.e., power is flowing north-to-south on Path 26 (generally during on-peak periods), this path is unaffected by Tehachapi generation. Power from Tehachapi simply adds to power flowing south on Path 26.

Alternative 1 (Expanded Path 26 option) – south-to-north flows

When power is flowing south-to-north in the Expanded Path 26 configuration, Tehachapi generation flows on Path 26, but as mentioned above, south-to-north flows are limited by the capacity of Path 15 at the present time. The system impacts of Tehachapi generation therefore are expected to be minimal, as with the Gen-tie option.

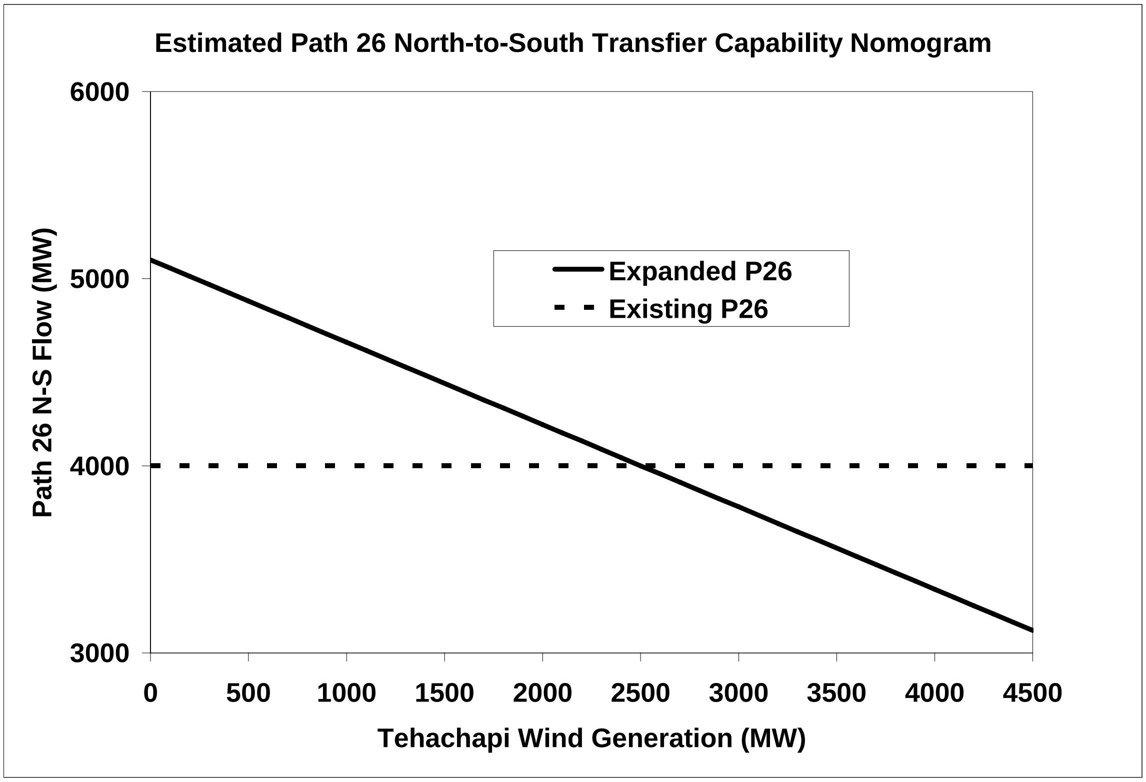
Alternative 1 (Expanded Path 26 option) – north-to-south flows

When Southern California is importing power and flows are north-to-south on Path 26, the effects of Tehachapi generation on Path 26 become important. As described below in a report by the TCSG Path 26 subcommittee, these effects differ depending on whether Tehachapi generation is high or low, i.e., whether the wind is blowing hard in Tehachapi or not.

When Tehachapi wind generation is low, the additional link between Northern and Southern California provided by the Expanded Path 26 configuration allows more power to flow between the regions than can be accommodated today. Even though some Tehachapi power flows north-to-south on Path 26 (see figure 4 in the subcommittee report below), there is a net increase in transfer capability due to the additional 500 kV link. When Tehachapi wind generation is high, the power transfer from Northern California to Southern California is less than when wind generation is low. This is because the amount of Tehachapi power flowing on Path 26 is enough to reduce the net transfer capacity of the Path. Even in this case, however, the net power delivered to Southern California is higher than is possible today, because of the new generation added at Tehachapi. The transfer capacity of Path 26 as a function of Tehachapi generation is shown on Figure A6.1[15]**.**

[15] The data shown in this chart assumes 70% series compensation on the Midway-Tehachapi line.

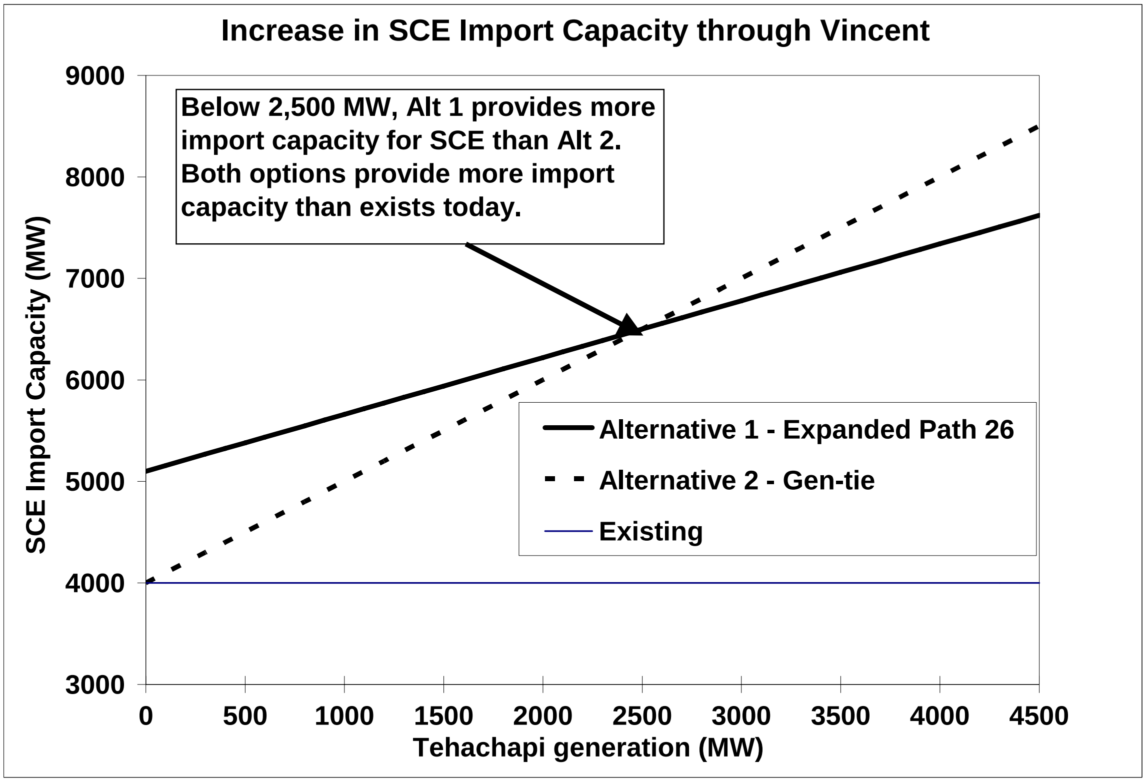
Figure A6.1



The decline in Path 26 transfer capability for the Expanded Path 26 shown above indicates that as Tehachapi wind generation increases and uses some of the capacity in Path 26, the amount of power that can be exported from Northern California south through Path 26 decreases.

However, the import capacity into Southern California *increases* over existing levels for both options, as shown on Figure A6.2.

Figure A6.2



Concerns over the variability of wind generation are often expressed as "What happens when the wind doesn't blow?" As the above chart indicates, even when Tehachapi wind generation is zero, the Expanded Path 26 option provides Southern California with additional import capacity while the Gen-tie option does not. When Tehachapi generation is above 2,500 MW, the Gen-tie option provides Southern California with more import capacity than does the Expanded Path 26 option.

The key conclusion is that both alternatives provide more import capacity than exists at present, because of the addition of new generation at Tehachapi and new 500 kV lines to connect it.

TCSG Path 26 Subcommittee Report Is Reproduced Below.

Comparison of the Effects on the Transfer Capability of Path 26 of Alternatives 1 and 2 for Delivering Tehachapi Power to the Grid Taking Into Account the Variability of Wind Generation

The evaluation of the effects of the proposed Tehachapi wind development on Path 26[16] is based on the following two alternatives considered:

> Alternative 1 – consists of one 500kV line between Tehachapi and Midway, and two 500kV lines between Tehachapi and Antelope, see Figure 1.
>
> Alternative 2 - consists of three 500kV lines between Tehachapi and Antelope, see Figure 2.

Conclusions

1. South-to-North Capability: During off-peak hours when the power flow is from South to North (S-N) across Path 26, Path 26 transfer capability is limited by Path 15 capability, therefore there is no difference between Alternative 1 and Alternative 2 under this condition.
2. North-to-South Capability with No Wind: During peak hours when the power flow is from North to South (N-S), when Tehachapi wind generation is zero, the thermal transfer capability with Alternative 1 will be increased from 4000MW[17] to 5100MW and 4500MW given 70% and no series compensation, respectively, on the Tehachapi- Midway line. However, the usefulness of this capability is dependent on an increase in generation North of Midway. With Alternative 2, the transfer capability is unchanged by the level of generation at Tehachapi and remains at 4000MW.
3. North-to-South Capability with Wind: During peak hours when the power flow is from N-S and the wind is generating maximum output, the thermal transfer capability of Path 26 with Alternative 1 and 4000MW at Tehachapi will decrease from 4000MW to 3400MW and 3700MW with 70% and no series compensation, respectively, see Figure 3 for the case of 70% series compensation. The transfer capability as a function of varying levels of Tehachapi generation is shown on

---

[16] The existing Path 26 transfer capabilities are determined by power flow and stability studies. The new values provided in this evaluation are estimated thermal transfer capabilities based on power flow analysis only. Detailed thermal, voltage and stability studies are needed to determine actual capabilities.

[17] The existing Path 26 North-to-South capability is 3700 MW. This is expected to increase to 4000 MW by Summer 2006, pending final approval. This increase to 4000 MW is currently in Phase II of the WECC Path Rating Process. WECC Procedure for Project Rating Review requires projects that have achieved a Phase II status be considered in the study of all project potential projects, therefore, this analysis assumes a 4000 MW N-S transfer capability for Path 26.

Figure 4. With Alternative 2, the transfer capability remains at 4000MW and is unchanged by the level of Tehachapi generation.

4. Alternative 1 would provide benefit during scheduling clearance for maintenance by providing additional transmission facilities over the interface assuming wind generation at Tehachapi are off-line compared to the existing system or Alternative 2.

BOTTOM LINE: The estimated Path 26 thermal transfer capability is impacted only by Alternative 1 (with the Tehachapi-Midway line) and only in the North-to-South direction. The North-to-South thermal transfer capability is increased for Tehachapi generation up to about 2500MW; above this value, the line would degrade the thermal transfer capability. South-to-North thermal transfer capability would remain unchanged because it is limited by the Path 15 South-to-North transfer capability. Alternative 2 would not impact the Path 26 thermal transfer capability.

Figure 1

Alternative 1

Power flow with One Tehachapi-Midway and Two Tehachapi – Antelope lines

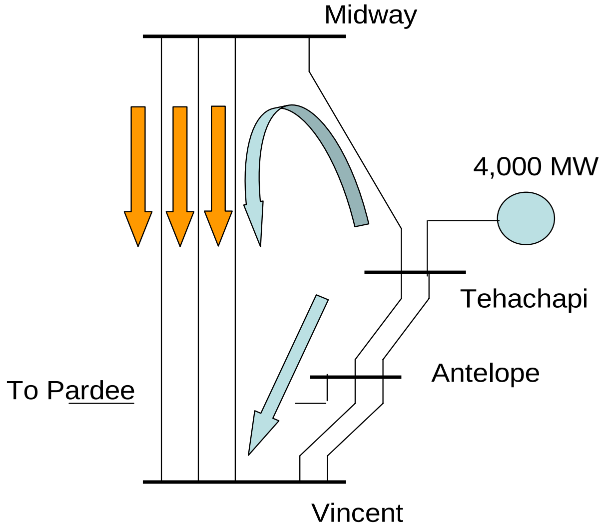


Figure 2

Alternative 2

Power flow with Three Tehachapi – Antelope lines

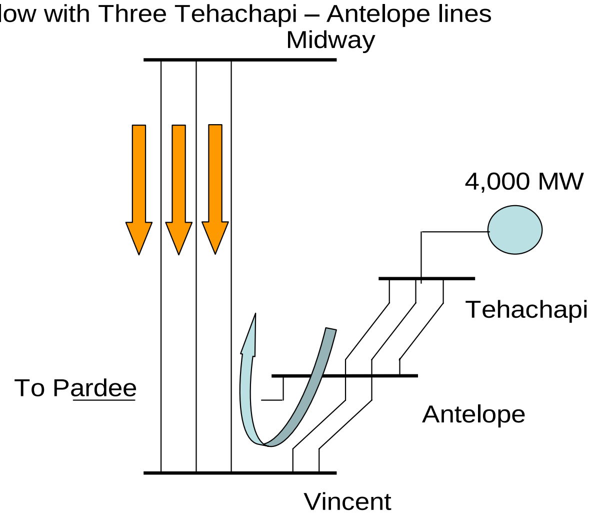


Figure 3

PF Plot: 2010 Summer Peak; P26 N-S=3400MW, Tehachapi Gen = 4000MW
Midway-Tehachapi 500 kV line with 70% series compensation

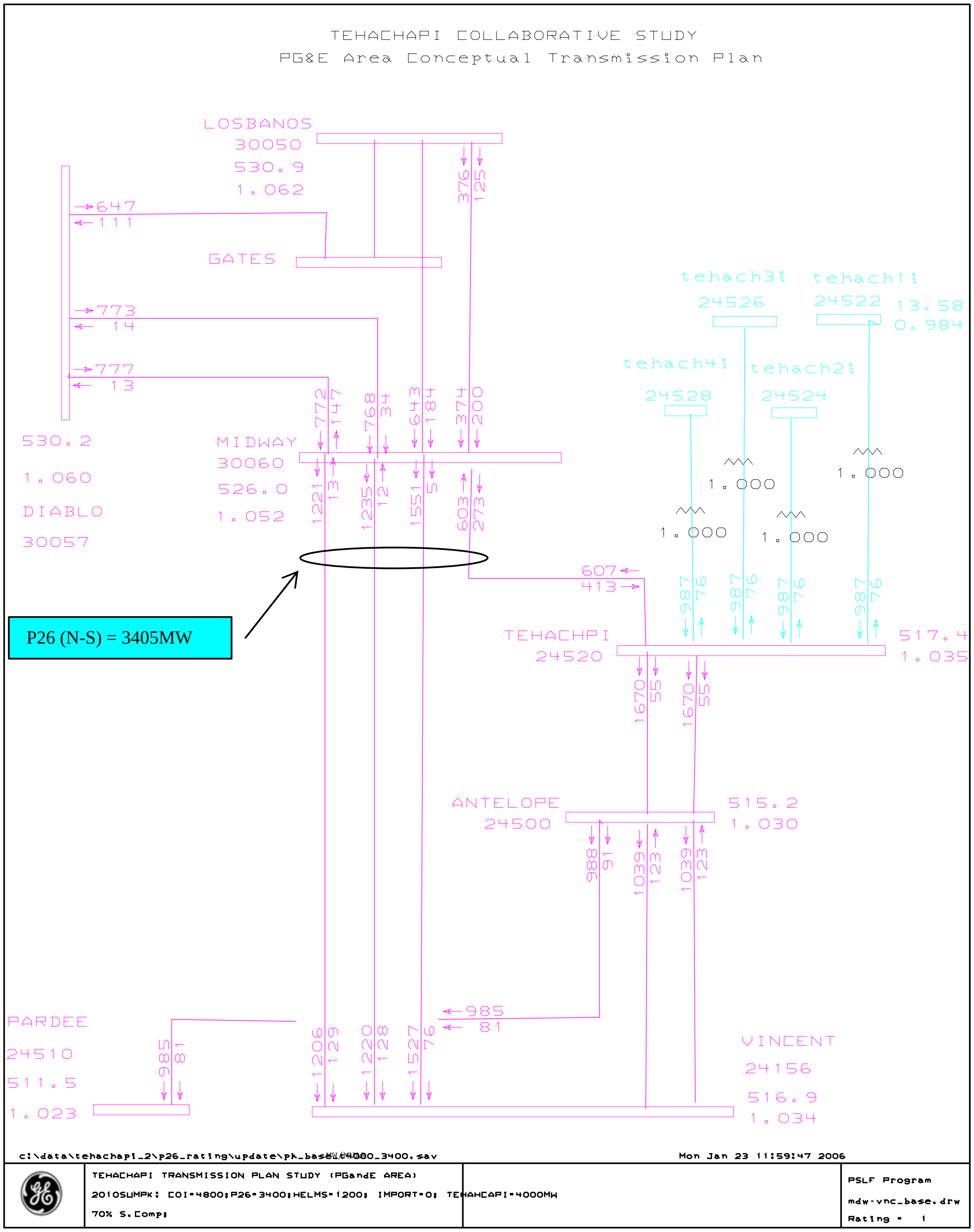
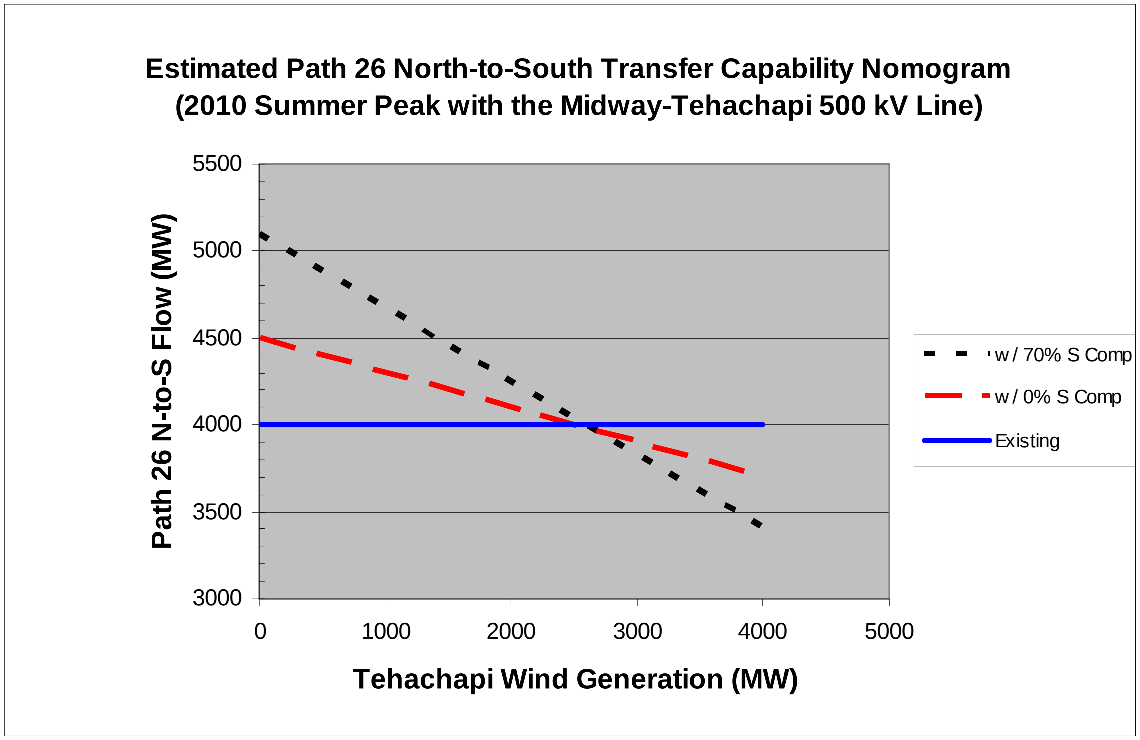


Figure 4



The Alternatives

The only existing transmission link between northern and southern California are the three 500 kV lines between PG&E's Midway Substation and SCE's Vincent Substation which define the Path 26 interface. The existing non-simulataneoussimultaneous Path 26 transfer capability in either the North to South (N-S) or South to North (S-N) direction is determined by normal and emergency loading on the Midway – Vincent #3 500 kV line or voltage criteria violations. The limiting facilities are the 1736A summer normal rating of the #3 line conductors and the existing 3500 A emergency rating of the series capacitor banks on the Midway-Vincent #3 line. The most limiting credible contingency is the loss of both the Midway-Vincent #1 and #2 lines.

The existing maximum Path 26 N-S transfer limit of 4000 MW is based on heavy summer conditions and requires a Remedial Action Scheme (RAS) to trip 1400 MW[18] of Midway area generation and 500 MW of load in Southern California following the loss of the Midway-Vincent #1 and #2 lines. Without the RAS, existing maximum Path 26 N-S transfer limit is 3000 MW. The maximum existing Path 26 S-N transfer limit is 3000 MW and does not require RAS to support this limit. Path 26 S-N flows are typically limited to below 3000 MW due to congestion on Path 15.

[18] Maximum amount of generation rejection for loss or two elements under CAISO planning guidelines.

With the Tehachapi wind generation electrically near the Path 26 interface, there is a potential to impact the transfer capability depending on the 500 kV transmission reinforcements selected. Figure 1 shows SCE's proposed Alternative 1, which provides two 500kV circuits from Tehachapi Substation 1 to Antelope Substation and a 500 kV line from Midway to Tehachapi, thereby creating a 4th path from Midway to Vincent in parallel with the existing Path 26 interface. As such, the Path 26 interface would need to be redefined to include this new transmission path. The transfer capability of this path would be dependent on the level of Tehachapi wind power injected into the new Midway-Tehachapi-Vincent line at Tehachapi and also by the level of series compensation on the line. Due to the variability of the wind, the wind generation output may range from 0 to the maximum of 4000 MW. Under peak load conditions, when the prevailing power flow is from North to South, part of the Tehachapi power would flow North to Midway, then use the existing North-to-South transfer capability to flow back South over the existing Path 26 lines. That would decrease the available North-to-South transfer capability for transporting power from North of Midway to Southern California.

Figure 2 shows SCE's proposed Alternative 2, which consists of three 500kV lines from Tehachapi Substation 1 to Antelope/Vincent. This alternative would not affect the present Path 26 thermal transfer capability in either the North-to-South or South-to-North direction.

Comparison of the Effects of the Alternatives

The following table provides a comparison of the estimated Path 26 thermal transfer capability. Detailed thermal, voltage and stability studies are needed to definitively determine actual capabilities.

Estimated Path 26 Thermal Transfer Capability

SCE Alternative	Tehachapi Wind Output (MW)	Path 26	
		N-S (MW)	S-N (MW)
Existing System	-	4000[1]	3000[2]
Alt. 1 – 500 kV, one Midway-Tehachapi, two Tehachapi-Antelope-Vincent	0	4500[1] –5100[3]	3000[2]
	4000	3400-3700[1]	3000[2]
Alt. 2 – Three 500 kV Tehachapi-Antelope-Vincent	0	4000[1]	3000[2]
	4000	4000[1]	3000[2]

Notes:

1) Path 26 RAS will trip 1400 MW of Midway generation and 500 MW of Southern California load for Midway – Vincent #1 and #2 500 kV double-line outage.
2) No RAS required. Path 26 S-N transfers may be limited by Path 15 capability.
3) Range indicates without series compensation and with a high level of series compensation (70%) on the Midway-Tehachapi 500 kV line. Appropriate series compensation needs to be determined through additional studies.

4) Does not consider any limitation resulting from SCIT transfer capability.

Alternative 1 would provide a significant increase in the North-to-South transfer capability of Path 26 when there is no generation at Tehachapi. However, it would also decrease the existing N-S capability when Tehachapi is at full output, see Figure 3 for the transfer capability as a function of varying levels of Tehachapi generation. However, in order to take advantage of any increased capability, CAISO Operations would need sufficient advance forecast of the wind generation output to allow for rescheduling of Path 26 power flow. This may be problematic until better forecasting methods are implemented.
The upper range of this capability depends on use of the Midway RAS. Since the existing Path 26 interface RAS arms the maximum amount of generation for rejection for the limiting N-2 contingency plus 500MW of load rejection, no additional generation, such as Tehachapi wind, may be armed unless it is accompanied with a further equivalent amount of load rejection on the SCE system.

Alternative 1 S-N: Without an upgrade of Path 15, there will be no increase in Path 26 S-N capability since Path 26 would be limited by the existing Path 15 capability
Alternative 1 would provide benefit by increased flexibility during scheduling clearance for maintenance by providing additional transmission facilities over the interface assuming wind generation at Tehachapi are off-line compared to the existing system or Alternative 2.

Alternative 2 would not provide any new transfer capability for Path 26, as it does not involve reinforcement or upgrade of the existing path.

Comparison of the Effects on the Transfer Capability of Path 26 of Alternatives 1 and 2 for Delivering Tehachapi Power to the Grid Taking Into Account the Variability of Wind Generation

APPENDIX

Study Plan

I. Purpose: To determine the effect of the variability of wind generation and a Tehachapi-Midway 3,400MVA line on the non-simultaneous <u>thermal</u> transfer capability of Path 26.

II. Introduction: In the December 19, 2005 TCSG meeting it was decided that a subgroup be formed to develop a collaborative statement on variability of wind and its impact and that of the Tehachapi-Midway line on Path 26 transfer capability. Power flow studies will be performed to provide the supporting data for this statement by establishing the approximate nomogram relationship between Tehachapi wind generation and Path 26 thermal transfer capability.

III. Limitations: It should be noted that Transfer Capability must be determined based on power flow, transient dynamic stability studies and post-transient voltage stability studies taking into account relationships with other interfaces such as SCIT, as well as the non-simultaneous power flow studies undertaken here. Such stability studies and studies to account for simultaneous transfer will not be performed here due to the lack of time and specific generator data. In addition, further studies with more detailed information may identify other more limiting contingencies. As such, the "thermal transfer capabilities" determined in this study must be adjusted when more specific information becomes available.

IV. Assumptions:
1. Starting Base Cases (same as the TCS Phase 2 study plan):
    a. 2005 PG&E Grid Expansion Study, 2010 Heavy Summer North Peak case
    b. 2005 PG&E Grid Expansion Study, 2010 Summer Off-peak case
2. Loss of Midway – Vincent 500 kV lines # 1 and #2 is the most limiting contingency.
3. Existing RAS are available to support 3700 MW of existing North-to-South power transfer on Path 26, and to support the existing 5,400 MW (or the most recent Operating Transfer Capability as determine by the WECC) of South-to-North power transfer on Path 15.
4. Decreasing generation that provide RAS to support the power transfer will be accompanied by:
    a. Decreasing Path 26 operating limit in the North-to-South direction at the rate of 1 MW for every 2 MW decrease in generation in the vicinity of Midway Substation

b. Decreasing Path 15 operating limit in the South-to-North direction at the rate of 1 MW for every 2 MW decrease in generation in the vicinity of Midway Substation

V. Criteria: NERC/WECC Planning Standards and CAISO Planning Standards.

VI. System Operating Scenarios: The following reasonably adverse operating scenarios will be examined:

2. Peak conditions with 3700 MW of normal power flow in a North-to-South direction on Path 26 and 0 MW of PG&E's import at Midway from Southern California:
    a. Existing system with Tehachapi wind generation at 0 MW to establish benchmark case.
    b. Case E1-New Rating (i.e., SCE Alternative 1 with Tehachapi – Midway 500 kV line rated at 3,400 MVA without series compensation)
        i. Tehachapi wind generation at 0 MW
        ii. Tehachapi wind generation at 4,000 MW
    c. Case G-NNM (i.e., SCE Alternative 2)
        i. Tehachapi wind generation at 0 MW
        ii. Tehachapi wind generation at 4,000 MW

3. Off-Peak conditions with normal power flow in a South-to-North direction on Path 15 and Path 26, and with Path 26 loading increased (in the South-to-North direction) by 50% of Tehachapi generation.
    a. Existing system with Tehachapi wind generation at 0 MW to establish benchmark case.
    b. Case E1-New Rating (i.e., SCE Alternative 1 with Tehachapi – Midway 500 kV line rated at 3,400 MVA without series compensation)
        i. Tehachapi wind generation at 0 MW
        ii. Tehachapi wind generation at 4,000 MW
    c. Case G-NNM (i.e., SCE Alternative 2)
        i. Tehachapi wind generation at 0 MW
        ii. Tehachapi wind generation at 4,000 MW

4. Repeat Steps 1.b and 2.b with Tehachapi – Midway 500 kV line series compensated at 70%

VII. Methodology:

1. Examine each scenario above and run power flow program to determine the thermal transfer capability allowable on Path 26 under normal operating conditions by adjusting the power schedule under normal conditions at Midway until a transmission facility on Path 26 or Path 15 is loaded to 100% of its normal rating.

For each scenario above run Governor Power Flow program to simulate Midway – Vincent #1 and #2 double line outage to examine system

2. conditions after the transient oscillations have subsided, all automatic actions are completed but before operator intervention.
3. Determine the thermal transfer capability of Path 26 by adjusting the power schedule under normal conditions at Midway until a transmission facility on Path 26 or Path 15 is loaded to 100% of its emergency rating after the Midway – Vincent 500 kV lines #1 and #2 double line outage. Record this power schedule at Midway. (To the extent applicable, the most recent Operating Transfer Capability as determined by the WECC can be used for the benchmark cases.)
4. Repeat for the remaining system scenarios
5. Develop nomogram relating Path 26

APPENDIX 7

APPENDIX 7

Tehachapi-Midway Cost Estimate

for TCSG Report, April 7, 2006

One major export path for Tehachapi generation is to connect to the state backbone grid at the Vincent substation at the southern end of Path 26. The TCSG has relied on the cost estimates for the Tehachapi-Vincent connections contained in SCE's CPCN Applications for the Antelope-Pardee (Application No. 04-12-007), and Antelope-Vincent and Antelope-Tehachapi Transmission Projects (Application No. 04-12-008).

Another major transmission alternative for connecting Tehachapi generation to the grid considered by the TCSG, outside of Tehachapi-Vincent corridor routings, is a line from Tehachapi to the Midway substation, at the southern end of Path 15, west of Bakersfield.

The Midway substation is roughly 90 miles west of the proposed Tehachapi substation #1. At this point, Tehachapi-Midway is only a conceptual routing. Neither SCE nor PG&E has yet identified any physical routings for such a connection. Without a physical routing, line distance can only be roughly estimated; no environmental studies have been performed. With so many factors unknown, any such conceptual cost estimate can only be roughly approximate.

PG&E estimates the cost of acquiring the land, doing the permitting work and building the line to be $508 million. SCE estimates this cost to be $315 million. This large disparity in conceptual cost estimates led the TCSG to appoint a subcommittee to better understand the basis of each company's estimate. The subcommittee held several meetings via conference call with the land and permitting experts of both utilities. Notes of the subcommittee conference call meeting of January 10, 2006 explain the components of each, and document the basis for cost estimate. These notes are available from the CPUC coordinator of the TCSG.

For purposes of evaluating a Tehachapi-Midway conceptual routing, the subcommittee recommended that the TCSG use the SCE estimate of $315 million for the 90-mile project.

The SCE estimate is in line with the cost estimates of the other components of the Tehachapi transmission projects proposed to date.

Tehachapi-Midway Conceptual Cost Estimates
$, millions

	PG&E	SCE
Land Acquisition, Planning and Permitting (includes PEA, CPUC CPCN process)	$245.9	$90.4
Construction	$262.1	$225.0
Total Conceptual Cost Estimate	$508.0	$315.4