Development Plan for the
Phased Expansion of

Transmission
in the
Tehachapi Wind Resource Area

Report
of the
Tehachapi Collaborative Study Group

California Public Utilities Commission

OII 00-11-001
March 16, 2005

EXECUTIVE SUMMARY
GLOSSARY

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ACE	Area Control Error
AGL	Above Ground Level
CAISO	California Independent System Operator
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CFE	Comision Federal de Electricidad
CFERT	Center for Energy Efficiency and Renewable Technologies
COI	California-Oregon Interconnection
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
Definitive Plan	A transmission line and facilities specified well enough that it could be approved by regulatory agencies for ratemaking and construction, versus a Conceptual Plan.
EIR	Environmental Impact Report
FERC	Federal Energy Regulatory Commission
FS	Facility Study
Gen-tie	Transmission line connecting a generator to the grid
IID	Imperial Irrigation District
IOU	Investor Owned Utility
IVSG	Imperial Valley Study Group
kWh	Kilowatt-hour
Looping	Connecting a new third point between two existing points already connected.
MW	Megawatt
NERC	North American Electric Reliability Council
NP15	North of Path 15
PEA	Proponent's Environmental Assessment
PG&E	Pacific Gas & Electric
Phase Shifted Tie	Connection between PG&E and Edison requiring a special transformer
PPA	Power Purchase Agreement
PSP	Pumped Storage Plant to absorb surplus power by pumping water uphill to a reservoir and returning that power less losses to the grid at a later time.
RAS	Remedial Action Scheme
RMR	Reliability Must Run
ROW	Right Of Way
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
Sec 399.25	Section of California Public Utilities Code
SIS	System Impact Study
SMUD	Sacramento Municipal Utility District
SPS	Special Protection System
TCSG	Tehachapi Collaborative Study Group
TTP	Tehachapi Transmission Project
WECC	Western Electricity Coordinating Council

Executive Summary

Background

The Tehachapi region is one of the richest wind energy resource areas in California. Transmission capacity that provides Tehachapi wind power generators access to the state's electricity markets is an important step in enabling the state to attain its renewable energy goals. In Decision 04-06-010 the CPUC formed the Tehachapi Collaborative Study Group (herein TCSG) to provide guidance to the Commission on how to proceed with transmission planning. This report provides the Commission with the TCSG's recommendations together with background information on which the recommendations are based. The Executive Director extended the original due date for filing this report by one week by letter dated March 4, 2005.

The potential wind power generation in the Tehachapi region is believed to be in excess of 4,000 megawatts (MW), an amount of power equal approximately to all of the state's nuclear capacity. Building the transmission facilities needed to provide market access for this generation is a daunting task, indeed. In its instructions to the TCSG, the Commission wisely acknowledged that the Tehachapi transmission project (TTP) would be built in phases as generation was developed in the region.

The process of planning and building major transmission lines is a lengthy one, as the recently completed Path 15 upgrade illustrates. For each phase of TTP development, several years will be required to specify in detail exactly what is to be constructed, ensure that the plans are consistent with grid reliability rules and environmental protection requirements, obtain permits, acquire rights of way and construct facilities. The TCSG recommends that the complete transmission plan consist of four phases of development, each of which has several components. Since each of the phases requires several years of work by the utilities and regulators, the entire Tehachapi transmission development is expected to require at least six years. Because of the long lead-time required, the need for and justification supporting specific transmission facilities can change; there must be flexibility to modify the transmission plan to accommodate such changes.

Based on power flow analysis performed by the TCSG, the conceptual transmission plan outlined in this report appears capable of connecting over 4,000 MW of wind generation to the California grid. Transmission planning must meet the reliability standards as set by the North American Electric Reliability Council (NERC), the Western Electricity Coordinating Council (WECC), and the California ISO. The time required to perform the analyses necessary to determine if the proposed facilities are sufficient to meet these standards was unavailable to the TCSG. In addition, operational considerations and integration costs have not been addressed in this study and further investigation is needed.

The development plan prepared by the TCSG is therefore a conceptual roadmap to the eventual Tehachapi transmission system rather than a definitive plan. A description of the analytical work on which the TCSG recommendations are based is included in the report together with the results obtained. The report also highlights the decisions the Commission will have to make in order to develop the definitive plan and bring the Tehachapi transmission project to fruition.

All components of this conceptual plan assume that transmission-owning utilities are assured recovery of costs associated with planning, permitting and constructing the transmission facilities. The success of this plan depends on FERC approving these transmission facilities as eligible for cost recovery in transmission rates. If FERC does not approve creation of a new regulatory category for renewable transmission facilities in advance of interconnection requests, or otherwise determines the cost of these facilities to be recoverable in transmission rates, the State of California and the CPUC must establish an alternative mechanism, consistent with the Federal Power Act, to provide cost recovery certainty for the IOUs in order for this plan to be realized. Taking those steps in advance of a FERC decision would minimize further dedays should FERC deny SCE's petition. To that end, the CPUC must find in the respective CPCN order that the facilities discussed in this plan provide network benefits and take all other steps required under Sec. 399.25.

Phasing Of Transmission Development

The transmission plan developed by the consists of four major phases, designed to provide market access for approximately 4,000 MW, identified in the California Energy Commission Renewable Resources Development Report[1], of wind generation in the Tehachapi region. These phases are described briefly below and more completely in Chapter 2.

[1] The renewable resources development report (RRDR) was issued by the California Energy Commission (CEC) on September 30, 2003. This RRDR updated the preliminary renewable resource assessment (PRRA) issued by the CEC on July 1, 2003

The permitting process for Phase 1 has begun with the filing of two CPCN applications by SCE in December 2004. Acquisition of rights-of-way (ROW) and construction on Phase 1 facilities is expected to begin as soon as the permitting process is complete. The TCSG endorses Phase 1 as a prudent first phase necessary to interconnect renewable resources located in the Tehachapi and Antelope Valley areas, consistent with development of all renewable resources to meet RPS goals.

Permitting of subsequent phases should not delay construction of transmission lines necessary to support expected wind generation. Therefore, planning and permitting of phases 2-4 should be done with sufficient lead-time to ensure that construction can be completed in time to accommodate expected future generation. In order to fulfill the EAP goal of 3700 MW[2] in the Tehachapi area by the end of 2010, further transmission planning must start now, with permitting activities to follow in accordance with the recommendations in Section 6.3.

Planning and permitting activities can be done at relatively little expense (perhaps tens of millions of dollars for the four phases), and early completion minimizes the risk that construction will be delayed. But early permitting incurs the risk that plans or permits may require revision or renewal. The Commission must use its discretion to balance these risks based on anticipated need for additional transmission facilities.

The construction of each phase should be completed by the time it is needed to accommodate additional generation. Wind projects need the certainty that transmission capacity will be available in order to bid their power into RPS auctions. However, the Commission must also minimize the risk that facilities remain underutilized. Acquisition of ROW and construction require expenditure of substantial sums, and the Commission must balance the risk of underutilization against the risk of having inadequate transmission capacity. After the permits have been obtained, ROW acquisition and construction of phases 2-4 would be postponed if there were insufficient committed generation. Since the facilities would already have received permits, ROW acquisition and construction could begin without delay when the Commission "pulls the trigger."

Determining the level of Tehachapi wind generation development that should trigger the beginning of the next phase of transmission development will be a major decision for the Commission. The TCSG's recommendation on this determination is discussed below.

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[2] For explanation of the source of this value, see Section 1.1, below.

Tehachapi Transmission Facilities

This plan to connect 4060 MW of wind generation in the Tehachapi region to the grid includes three high capacity transmission lines connecting one central substation in the Tehachapi region to existing substations on the backbone grid. When the plan is completed, each of these lines will be able to carry approximately 1500 MW, one-third of the total. In addition, each phase requires additional infrastructure, such as substations, upgrades of existing lines and ancillary transmission equipment.

In addition to the infrastructure required simply to connect Tehachapi generation to the grid, other transmission facilities will be needed to relieve congestion and enable this power to reach load centers. This report describes alternatives for network upgrades with the understanding that further analysis is required to determine which projects are most cost effective and when they are needed.

The transmission plan as envisioned by the TCSG consists of a local network of substations in the wind resource area connected to a central substation (Tehachapi Substation #1) by 230 kV transmission lines. Generators in each group of projects in the region will connect to one of these substations via collector tie lines at various voltage levels. Power collected in the local network will be transferred from Substation #1 to the grid at the Vincent, Antelope and Midway or Gregg Substations.

To the extent that the infrastructure in Phases 2, 3 and 4 can be identified at the present, the major components in each phase are:

Phase 1 Estimated export capacity = 700 MW Estimated cost = $207 millions (M) (Application filed 12/9/04 by SCE)
Transmission lines, Antelope-Pardee and Tehachapi-Antelope-Vincent, 500 kV, initially operated at 230 kV
Antelope Substation, expansion and uprate
Tehachapi Substations #s 1 & 2[3]
Collector line, 230 kV, Tehachapi Substations #1-#2

Phase 2 Estimated export capacity increase of 900 MW (1,600 MW Total) Estimated cost = $281 M
Transmission line, Antelope-Mesa, 500 kV, initially operated at 230 kV

Phase 3 Estimated export capacity increase of 1,700 MW (3,300 MW Total) Estimated cost = $1,038 M
Transmission line, Tehachapi-Vincent, 500 kV, initially operated at 230 kV
Tehachapi substations and collector lines as needed
Substation facilities to operate 500 kV lines at 500 kV
SCE network upgrades as needed
PG&E network upgrades as needed

Phase 4 Estimated export capacity increase of 1,200 MW (4,500 MW Total) Estimated cost = $750 M
Transmission line, Tehachapi-PG&E (Midway, Gregg or other), 500 kV
PG&E system upgrades as needed

[3] Substations 5 and 6, which are also needed for the export of 700 MW, are not part of the SCE Phase 1 filing, but will be part of another proceeding.

Tehachapi Development Timeline

The following table summarizes a timeline for development of the four phases described above that the TCSG believes is aggressive but feasible, should it be determined that the completion of all four phases is required by 2010. Chapter 2 includes a more detailed timeline.

Phase	Task	Begin	Complete
1	CPCN Application/PEA[4] preparation	6/03	12/04 and 6/05
	CPCN Approval Process	12/04	6/06
	Construction[5]	1/06[6]	7/08
2	CPCN Application/PEA preparation	7/05	4/06
	CPCN Approval Process	4/06	4/07
	Construction	4/07	4/09
3&4	Planning Studies	3/05	12/05
	CPCN Application/PEA preparation	1/06	12/06
	CPCN Approval Process	1/07	12/07
	Construction	1/08	12/10

Criteria for triggering permitting and construction

When the definitive plan is established, including resolution of integration and operational issues, and cost recovery issues have been addressed, each phase of the plan will require two decisions from the Commission: the first to order the preparation and filing of the CPCN application and the second to approve construction. The first order for Phase 1 was issued on June 9, 2004, in D.04-06-010.

Delays in ordering permit applications to be filed and permitted facilities to be constructed incurs the risk that the people of California will not receive the benefits of Tehachapi wind power as soon as possible. On the other hand, orders to construct facilities commit significant amounts of ratepayer money. Even orders to prepare

[4] Proponent's Environmental Assessment
[5] Refers to post CPCN permitting, final engineering, land acquisition, procurement and construction.
[6] SCE's CPCN Application indicates construction start in June 2006. However, construction can start earlier if the CPCN can be granted earlier.

and file CPCN applications commit ratepayer money and involve the public in potentially contentious proceedings. If each phase is to be built in advance of need, there is a risk that these costs will result in facilities that are not fully utilized.

The Commission will therefore need to consider each order carefully. The TCSG has not been able to devise quantitative formulas for the Commission to use as benchmarks for triggering its decision to issue these orders. However, the TCSG recommends that the Commission consider the following criteria for deciding when to initiate permitting activities and construction of each successive phase of the definitive plan:

- Need for additional Tehachapi wind power to meet the State's renewable goals
- Level of utilization of or commitment for previously constructed Tehachapi transmission facilities
- Level of commitment from prospective Tehachapi wind developers for new projects
- Potential market for additional Tehachapi wind power

Conclusions

- The TCSG was unable to formulate a definitive transmission plan in the time available. Alternatives for the connection of Tehachapi generation to the network and alternative network upgrades to transmit the generation to load centers in the PG&E and SCE service areas have been defined. Further study is required to select among these alternatives a definitive plan for implementation.

- It is possible to build the transmission facilities for the delivery of Tehachapi power to help meet the EAP goal of 20% supply from renewable sources by 2010. Completion of all components of the plan by the end of 2010 requires aggressive action by the Commission, the utilities and the wind developers. Should the Commission conclude that all 4,060 MW are not necessary to meet EAP goals, or that doing so is not cost effective, this plan can be implemented under a less aggressive schedule. This would still allow development of the full 4,060 MW before RPS implementation date of 2017.

- Implementation of the plan under any schedule will require adequate assurance that utility investments will be recovered.

- The investment required for delivery of 4,060 MW of Tehachapi generation to load centers is on the order of $2 billion.

Recommendations

- The conceptual plan recommended in this report consists of alternatives for the delivery of Tehachapi power to load centers, but not a definitive plan that can be used as the basis for permitting (CPCN) applications. The alternatives require further planning evaluation in order to formulate a single plan for implementation. To do this, further planning studies (specific rather than generic) need to be performed and facility cost estimates refined. Final plans for the Tehachapi collector system will require information concerning actual wind project locations. Because of the urgency imposed by the EAP goal, this work should proceed as a seamless continuation of the study work undertaken herein. To meet the overall schedule envisioned in this report, planning studies must be completed by the end of this year. We recommend that the CPUC issue another ruling as soon as possible ordering a continuation of this study. The ruling should state that a definitive implementation plan is to be the end product, designate the agencies to do the work and establish a timeframe with milestones for checking progress.

- The CPUC should streamline its permitting process by hiring its CEQA consultant by the time the application is filed. In addition, applications for several facilities should be combined into a single permit.

- The CPUC should promptly confirm that all necessary costs incurred in the implementation of any component of this plan are eligible for recovery under Section 399.25, consistent with the Federal Power Act. However, in light of FERC's exclusive jurisdiction over transmission rate making as well as the recent Court of Appeals decision in SCE vs. CPUC (No.B171050), it is critical that the CPUC encourage and support FERC to approve cost recovery and associated amendments to the CAISO Tariff to allow for approval of transmission facilities for renewable resources in advance of interconnection requests.

- The CPUC must find in the respective CPCN order that the facilities discussed in this plan provide network benefits and take all other steps required under Sec. 399.25.

1. Background

1.1 Regulatory History and California's Renewable Energy Goals

Senate Bill 1078, passed in 2002, requires electrical corporations (investor-owned utilities) starting in 2003 to increase procurement of renewables-based generation such that the consumption from this source is increased by 1% per year until 20% consumption is reached no later than the end of 2017. Senate Bill 1038, enacted in the same year, required the Energy Commission to prepare a plan for the development of renewable resources. This plan was submitted to the Legislature in December of 2003. It identifies 8,000 MW of potential renewables generation available to meet the SB1078 goal of 20% in 2017. One-half of this amount is wind generation in the Tehachapi Mountains and another 475 MW is wind generation in nearby Antelope Valley in north Los Angeles County. Decision 04-06-010 identifies the amount of wind power in Tehachapi to be 4060 MW.

In 2003 the California Power and Conservation Financing Authority, the Energy Commission and the CPUC jointly adopted the Energy Action Plan, which accelerated achievement of the 20% procurement goal to 2010. To reach this goal, a total of about 6,600 MW of renewables generation is needed, of which a little more than half, 3,700 MW, was identified by the Energy Commission as Tehachapi wind power. The megawatt values for 2010 are lower than the corresponding values for 2017 because projected load growth between 2010 and 2017 results in a larger base in 2017 to which the 20% criterion is applied.

To achieve these goals, transmission infrastructure is needed to deliver power from the remote Tehachapi region to the load centers. Accordingly, in June of this year, the CPUC filed Decision 04-06-010, entitled "Interim Opinion on the Transmission Needs in the Tehachapi Wind Resource Area." This decision mandates the convening of "a collaborative study group to develop a comprehensive development plan for the phased expansion of transmission capabilities in the Tehachapi area." The study group is to be coordinated by the CPUC with assistance from the CAISO, and with the participation of the IOUs, wind power developers and other stakeholders. This report and the plans contained herein are the product of this collaborative effort.

1.2 Tehachapi Wind Resources and RPS Implementation

1.2.1 Resource Size and Quality

Tehachapi is a mountain pass area spreading into the adjacent Mojave Desert. Cooler valley air is drawn through the pass to fill the void left by the naturally rising hot desert air. The natural conditions are enhanced by weather patterns and the jet stream that commonly passes over and through Tehachapi. The native Indian meaning of Tehachapi is strong winds.

In the late 1970s and early 1980s the CEC conducted wind resource evaluations throughout the state, and discovered promising sites in the Tehachapi pass and in the adjacent Antelope Valley. Wind energy development started on a substantial scale in Tehachapi in early 1982, and by 1985 the development was massive, the transmission grid became saturated, and development of the rich resource stalled. Widespread long term monitoring of the resource, in addition to actual production, has been ongoing, and this resource has proven to be widespread and rich. Some developers and operators have long term high quality meteorological data spanning more than 15 years, creating a higher degree of certainty to the resource than currently can be obtained in newer resource areas.

Currently 730 MW of wind generation is on line with annual production near two billion kWh. Much of the production is from first and second generation wind turbines, now 15 to 25 years old. These older machines achieve an overall capacity factor near 30%. One quarter of the installed capacity is now powered with third and fourth generation wind turbines, generally having capacity factors near 40%. [7]

The current wind energy development has occurred in eastern Kern County in a limited area defined by a Master Environmental Assessment with project land zoned with a Wind Energy overlay. An expanded wind energy development area, mostly in eastern Kern County, but reaching into Northern Los Angeles County, has been defined and is believed to be adequate to support additional development up to 4,500 MW of wind energy.

The land in the expanded Tehachapi Wind Resource Area is diverse, ranging from high desert floor to mountain pass, to tall mountains. Elevation spans from 2,500

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[7] See Chapter 12, *Wind Power in Power Systems*, Edited by T. Ackermann, © 2005 John Wiley & Sons, Ltd, ISBN 0-470-85508-8 http://www.windpowerinpowersystems.info/index.html.

feet to near 8,000 feet. The wind resource appears to be similarly diverse, a factor that should further improve the favorable capacity characteristics of the resource. The currently developed resource is has a strong prevailing energy direction with propagation through the day as the air temperature rises in the desert, and peak energy in late spring and early summer. The future resources are expected to include components that expand the propagation pattern, and that peak in different months. The result of such mixing of energy patterns is anticipated to produce a combined energy profile that is superior for grid integration purposes.

1.2.2 Access to the Resource for RPS Implementation

Much of the new Tehachapi wind resource capacity is anticipated to be used to meet the RPS needs of PG&E and SDG&E. If the RPS level remains at 20%, SCE may need little additional renewable energy. Tehachapi, however, is located in SCE service territory. From the perspective of the wind developers, the RPS process, to date, has dealt poorly with energy sources not within the service territory of the procuring utility, and as a result, Tehachapi wind projects have not participated to a significant degree in bid solicitations.

The Tehachapi Transmission Plan proposed in this report is intended to give regional wind resources access to statewide markets. It remains important for the RPS process to accommodate remote wind transactions fairly, and in a way that does not unnecessarily complicate developer bids, to minimize the cost of energy from this rich resource area. The Commission is mandated by SB 1078 to provide for the selection of renewable resources with the least-cost and best-fit. The RPS process must be fair to all renewable resources and promote compliance with the least cost-best fit principal.

1.2.3 Land Use Planning

In Kern County, wind energy developments are commonly constructed on lands specifically zoned for wind energy. The "WE Wind Energy" zone category serves as an overlay onto low-density regular use zones. The wind energy zoning ordinance has been updated in 2005 to accommodate the new larger wind turbines, and the heretofore commonly used zone variance process will be less necessary to facilitate the design of efficient projects that make effective use of the local wind resource.

In Los Angeles County, wind energy permitting follows a Conditional Use Permit process, and the land use planning process is more difficult and time consuming. Approximately 10% of the planned new wind resource capacity for the Tehachapi area is expected to be in Los Angeles County.

1.2.4 Low Level Military Flight Interference

Edwards Air Force Test Flight Center and the China Lake Naval Weapons Center are both located in eastern Kern County adjacent to the Wind Resource Area. The Tehachapi Wind Resource Area underlies the 2508 Military Operations Area that has flight test and training operations down to 200 feet AGL. Current wind turbines have tip heights in the range of 340 to 400 feet AGL. By 2007 many new wind turbines will have a tip height of nearly 600 feet. There has been recognition by the military and wind developers that a potential conflict of substantial impact may develop between the two potentially conflicting uses. If such a conflict developed on a large scale, it could impact the ability to develop the 4,060 MW in Tehachapi, and could impact military facilities.

The wind industry and the military have completed successful negotiations to find a mutually workable solution to the potential interference issue. A map for the entire Kern County has been developed to detail areas suitable for wind energy development without material impact to the military mission. The map provides for a substantial area having no military interference issues, and for another substantial area where 400-foot wind turbines are acceptable to the military. There is a third substantial area where large wind turbines are generally considered to interfere with the military mission, and projects will generally be excluded from those areas. This map has been adopted into the Kern County Ordinance, and serves to protect the military mission while allowing substantial wind energy development consistent with these RPS and transmission plans.[8]

1.3 Study Group Process and Participants

The study group formed as ordered in D.04-06-010 met four times between June and December 2004. A Pre-Hearing Conference in August 2004 provided additional guidance to the study group. Participation was open to all stakeholders; participants are listed below.

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[8] Kern County Ordinance Chapter 19.64 and Chapter 19.08.160.B Military airspace constraint map figure 19.08.160.

A subgroup of the study participants was formed to lead the study process, review the power flow analyses of transmission alternatives performed by PG&E and SCE and the costing of these alternatives, and to write this report. This planning subgroup met nine times in person, and the development of this plan required the near full-time effort of several of its members. The alternatives studied and the technical bases for the study group's recommendations are described in Chapter 3.

The subgroup consists of representatives of the CAISO, CEC, CEERT, CPUC, Oak Creek Energy, PG&E, PPM Energy, and SCE.

A draft of this report was written by the subgroup and sent to all parties on the I.00-11-001 service list with a request for comment. The comments were then reviewed by the subgroup and incorporated into the report as deemed appropriate.

The following organizations participated in one or more study group meetings:

- Aspen Environmental Group
- Caithness Energy
- California Energy Resources Conservation and Development Commission
- California Independent System Operator
- California Public Utilities Commission
- California Wind Energy Association
- Cal Wind Resources
- Center for Energy Efficiency and Renewable Technologies
- EnXco
- FPL Energy
- GE Wind Energy
- GE Transmission & Distribution
- Hays Consulting
- Kern Wind Energy Association
- Los Angeles Department of Water & Power
- Navigant
- Oak Creek Energy Systems
- Pacific Gas & Electric Company
- Russell Associates
- San Diego Gas & Electric Company
- Southern California Edison
- PPM Energy
- Pacific Gas & Electric Company
- Seawest Wind Power

San Diego Gas & Electric Company
Tehachapi Resource Conservation District
Tejon Ranch Corporation
Trans-Elect
U.S. Air Force Flight Test Center
U.S. Naval Air Systems Command
Western Wind

1.4 Imperial Valley Study Group and Transmission Access to Other Renewable Resource Areas

As directed by D.04-06-010 and with further guidance from ALJ TerKeurst, the TCSG convened a committee to consider formation of a stakeholder collaborative planning process to develop a phased transmission access plan capable of exporting 2,000 MW of geothermal power from the Imperial Valley region of the state. The Imperial Valley Study Group (IVSG) was subsequently formed in October 2005, in close collaboration with the California Energy Commission.

IVSG participants include SDG&E, the Imperial Irrigation District, SCE, Arizona Public Service, Western Area Power Administration, Comisión Federal de Electricidad, Salt River Project, the CA ISO, CEC, CPUC, geothermal generation developers and several other stakeholders. SDG&E and IID Energy have made the IVSG transmission planning process a priority. The Study Group's meeting notes and working documents may be viewed on its website, www.energy.ca.gov/ivsg/. The IVSG is expected to issue its recommended phased development plan in July 2005.

Similar stakeholder planning collaboratives may be helpful in leading the development of consensus transmission solutions to access other renewable resources areas, including Mojave solar resources and northern California wind, geothermal and biomass resources. Recommendations to improve the organization and performance of any future transmission planning collaboratives are presented in Chapter 7, below.

2. Recommended Conceptual Plan

2.1 Summary

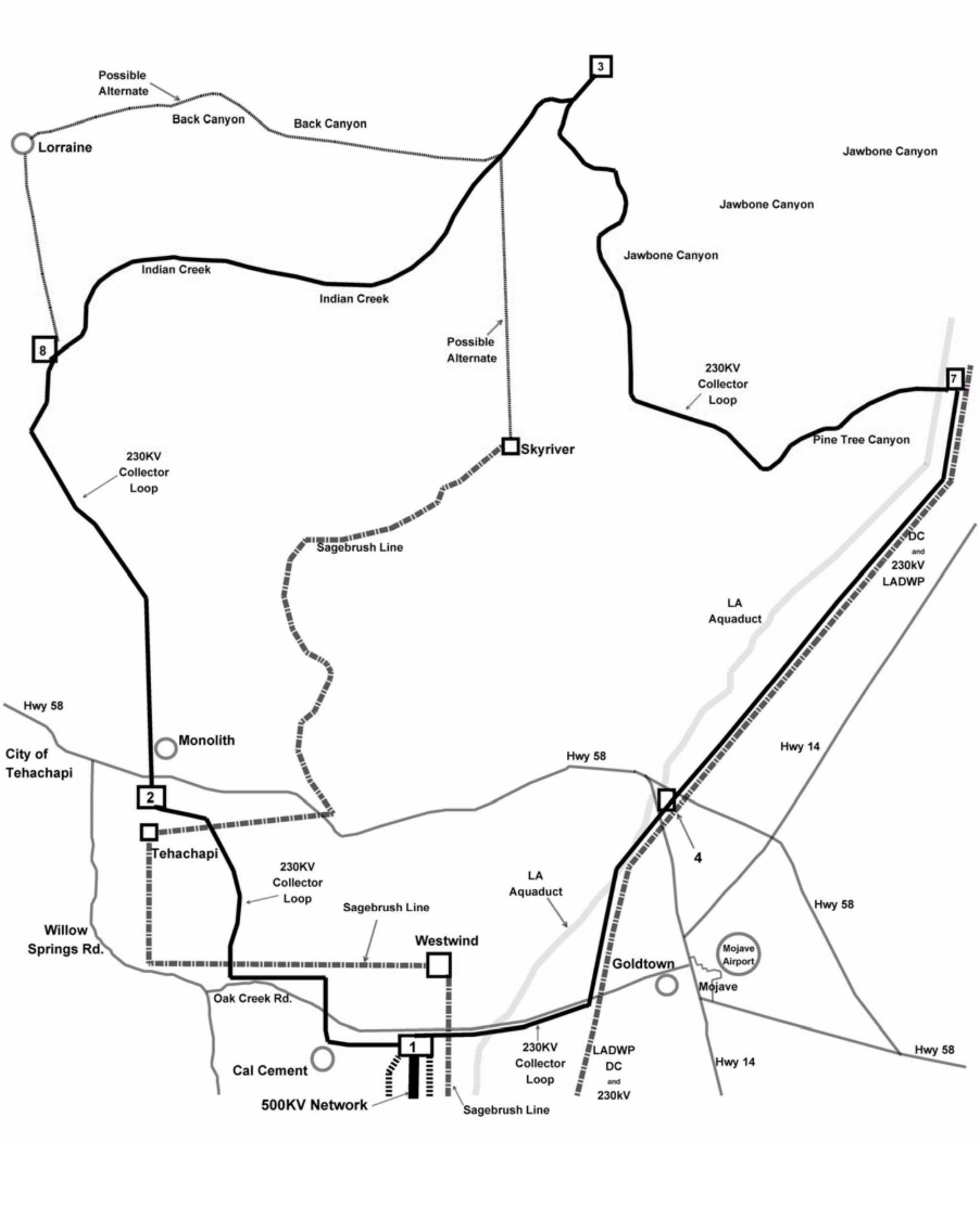
The recommended conceptual transmission plan consists of facilities to collect power from Tehachapi area wind projects, interconnection facilities to connect that power into the state's backbone grid, and network upgrades to reliably deliver that power to load centers. Three major 500 kV transmission lines are needed to connect the anticipated 4,060 MW of wind generation to the grid. Two of these lines connect the Tehachapi area to Antelope and Vincent substations, and the third major line is expected to connect the area to the PG&E system at the Midway, Gregg, or other substation to be identified in future studies. A connection to Midway would provide additional capacity in Path 26, and a connection to Gregg would reduce demand on that Path.

The plan is designed in four phases to provide flexibility in planning, designing, and constructing the facilities as shown in *Table 2.5 - Elements of Phased Development.* By establishing appropriate benchmarks to identify when work should begin on activities in each phase, the Commission can assure that facilities will be available when needed while simultaneously minimizing the risk that effort will be wasted or that facilities will be underutilized.

2.2 Tehachapi area collector system

The main collector system will consist of 230 kV transmission lines connecting from 4 to 6 local substations. Depending on the quantity and location of wind projects developed, these substations may eventually be connected to form an electrical loop. The power generated in the Tehachapi area collected in this loop will be connected to the backbone grid through a single 500 kV substation, Tehachapi Substation #1. Additional wind power will enter the system at other substations connected to the grid at Antelope. A map the conceptual collector system is shown on Fig. 2.1, below and a single line diagram is shown on Fig. A-10 in Appendix A.

Fig. 2.1 Map of the Proposed Tehachapi Collector System



2.3 Tehachapi Interconnection Facilities

The following facilities are required to connect the Tehachapi collector system and the Antelope Valley generation into the existing grid.

2.3.1 Antelope-Pardee 500 kV Transmission Line (Antelope Transmission Project - Segment 1)

TTP Phase 1: the PPM Fairmont Wind Project (201 MW) in the Antelope Valley is the first Tehachapi area wind generation project in the CAISO queue with completed System Impact and Facilities studies. The results of the System Impact and Facilities studies have identified the need for a new Antelope-Pardee transmission line to eliminate thermal overload problems on the existing Antelope-Mesa 230 kV transmission line caused by the addition of the wind project. The CAISO planning department has reviewed results of studies and approved interconnection of the Fairmont Wind Project with the condition that the Antelope-Pardee transmission line be designed for 500 kV but initially energized at 230 kV.

2.3.2 Antelope-Vincent 500 kV Transmission Line (Antelope Transmission Project – Segment 2)

TTP Phase 1: Segment 2 consists of a new 500 kV transmission line, initially energized at 230 kV, between Vincent and Antelope Substations.

2.3.3 Tehachapi Substation #1-Antelope 500 kV Transmission Line (Antelope Transmission Project – Segment 3)

TTP Phase 1: Segment 3 consists a new 500 kV transmission line initially energized at 230 kV between Antelope and the new Tehachapi area Substation 1 (near Cal Cement).

2.3.4 Antelope-Mesa 230 kV Transmission Line Upgrade between Vincent and Mesa

TTP Phase 2: the necessary upgrades involve teardown and rebuild since the existing facilities cannot support a larger conductor type. The teardown and rebuild can be sectionalized into three segments: (1) Rio Hondo to Mesa, (2) Vincent to Rio Hondo, and (3) Antelope to Vincent. The section between Rio Hondo and Mesa should be reconstructed as a double-circuit 230 kV transmission line since it is not envisioned to convert Mesa to 500 kV. The section between Vincent and Rio Hondo should be 500 kV construction standard initially energized at 230 kV to avoid waste since there exists the potential for a future Rio Hondo 500 kV substation. Finally, the section between Antelope and Vincent can be reconstructed with either double-circuit 230 kV or single-circuit 500 kV depending on the upgrade alternative selected.

2.3.5 Tehachapi Substation #1-Vincent 500 kV Transmission Line

TTP Phase 3: this 500 kV transmission line is similar to the 500 kV transmission line identified in Section (2.3.3), Segment 3 of the Antelope Transmission Project.

2.3.6 Tehachapi Substation #1-Midway or Gregg

TTP Phase 4: a 500 kV transmission line between Tehachapi Substation #1 and either Midway or Gregg Substation may be needed when the Tehachapi generation taken by PG&E exceeds 1500 MW.

2.4 Network upgrades

In addition to the collector system and interconnection facilities, additional facilities will be needed to relieve congestion and enable power from Tehachapi to be delivered to load centers.

2.4.1 New Vincent-Mira Loma 500 kV Transmission Line

The need for a new 500 kV line into the Mira Loma area was identified as part of the SCE CAISO Annual Expansion Program. SCE is currently pursing a plan that involves converting the existing Vincent-Rio Hondo No.1 230 kV transmission line to 500 kV and building a new 500 kV section between Rio Hondo and Mira Loma. The line will bypass the Rio Hondo substation and continue to Mira Loma. Such arrangement will facilitate future development of Rio Hondo 500 kV substation. This new line will provide an added benefit of supporting delivery of Tehachapi area wind generation to the SCE load center. Since the project is needed for load serving purposes, it has been added to the conceptual transmission plans but has not been assigned directly to the addition of Tehachapi area wind generation. It should be noted that if a different 500 kV transmission line were constructed to satisfy load-serving requirements, additional costs would be incurred directly assigned to Tehachapi in order to convert the Rio Hondo substation to 500 kV.

2.4.2 Pardee-Pastoria Transmission Line Reconductor

This project is an infrastructure replacement project which was identified in the 2004-2008, 2013 CAISO Controlled SCE Transmission Expansion plan. Since the project is needed for other purposes, it has been added to the conceptual transmission plans but has not been assigned directly to the addition of Tehachapi area wind generation.

2.4.3 Fresno 230 kV Tie

PG&E is investigating an upgrade in the Fresno area consisting of a 300 MW phase shifter to connect to the SCE Big Creek system. It would provide a path for 300 MW of power from Tehachapi to reach the PG&E system.

The capacity of this tie is limited by the requirement for simultaneous full generation of the Helms pumped storage plant. If the output of this plant were coordinated with Tehachapi wind power production such the Helms Pump Storage Plant is operated in the pumping or nonoperating mode when there is generation at Tehachapi, a tie of greater capacity might be justified. This possibility requires study in conjunction with the CA ISO system dispatcher.

2.4.4 PG&E 500 kV Lines

In addition to the Fresno tie, PG&E believes that substantial upgrades of its system will be necessary to make 2,000 MW of Tehachapi power deliverable to PG&E load centers. These may include additional upgrades of Path 15 (Midway-Los Banos-Tesla), or new 500 kV lines from Tehachapi to the Gregg substation or Midway-Gregg. Potential network upgrade alternatives and a potential main line from Tehachapi to Gregg will be studied as part of Phases 3 and 4.

Fig. 2.4 Schematic of Tehachapi Connections to 500 kV System

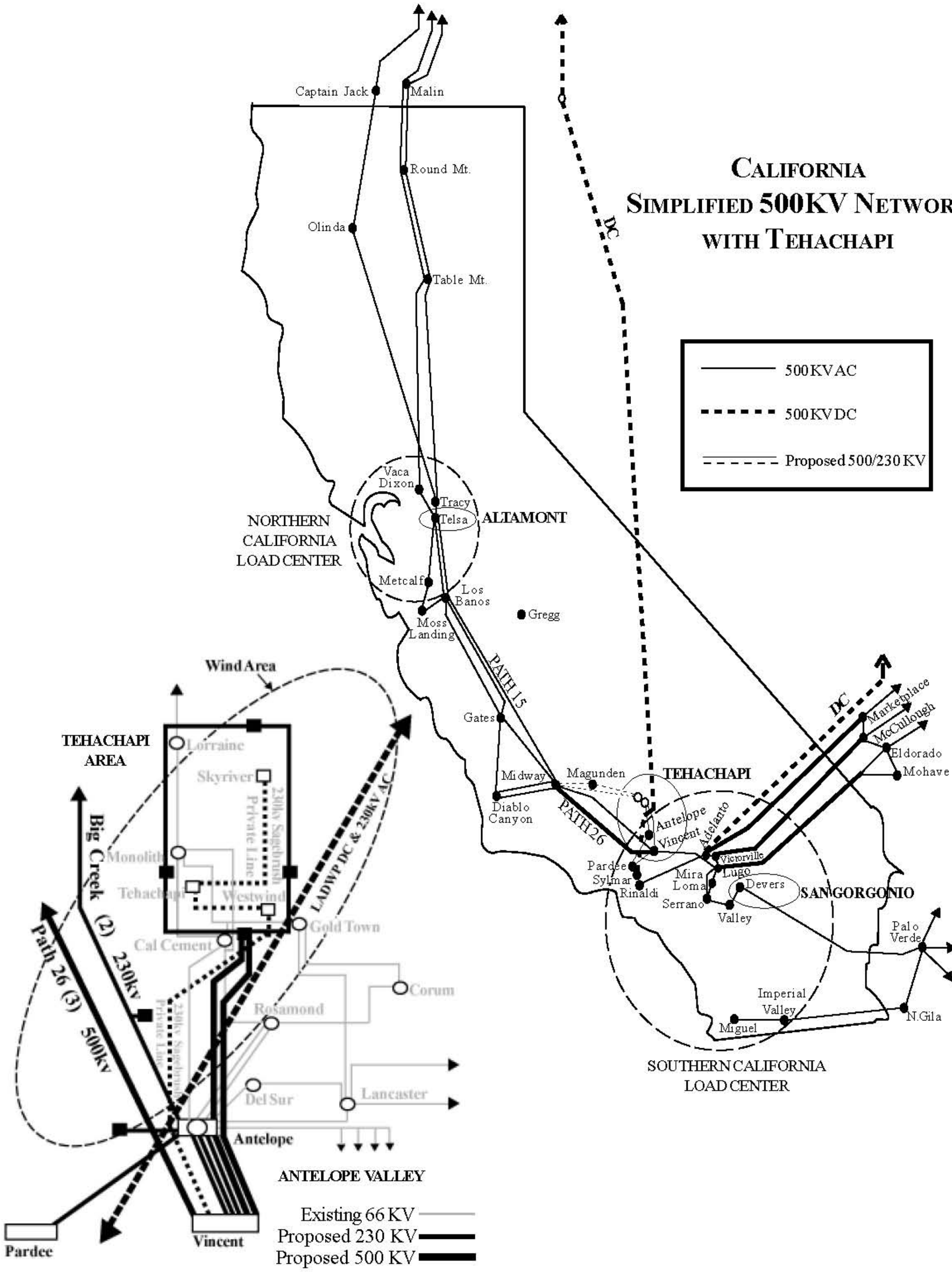


Table 2.5 Elements of Phased Development

The four phases which make up the conceptual plan, with the corresponding import capacities and costs, are given in the table below. Note that the Fresno phase-shifted tie, which requires further study, is not included below.

Phase	Antelope Valley		Tehachapi Area	Total MW		Estimated Cost $Millons	
	South	North		Phase	Cumulative	Phase	Cumulative
1. Antelope Segments 1, 2, 3	200	300	200	700	700	$207	$207
All of the following also require PG&E Network Upgrades							
2. Antelope-Mesa 230 kV Line Upgrade	75	75	750	900	1600	$281	$488
3a. Tehachapi–Vincent Line #2 500 kV Line operated at 230 kV	0	0	750	750	2350	$66	$554
3b. Add substations to operate 500 kV lines at 500 kV, components	0	0	950	950	3300	$972	$1,526
4. Tehachapi #1 to PG&E (Midway, Gregg, or other substation)	0	0	1,200	1200	4500	$750	$2,276

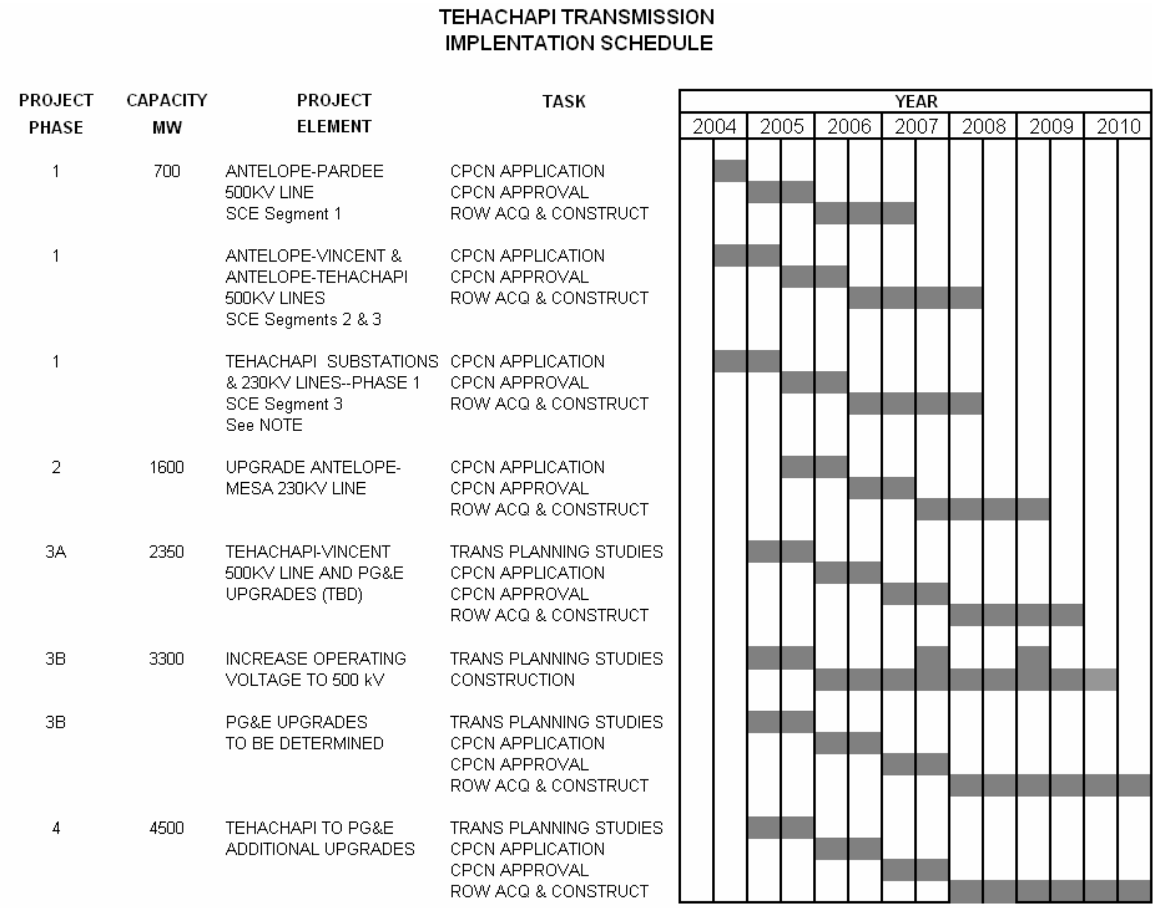
NOTES Assumes: 1) import limit of 2,000 MW to PG&E; 2,500 MW delivered to south; and 2) MW ratings shown assume Substations 1, 2, 5 and 6 are built.

2.6 Development Schedule

The fastest practicable schedule for completion of the entire plan to accommodate 3,700 MW of Tehachapi-area generation by the end of 2010 is shown below on *Chart 2.6 Tehachapi Conceptual Schedule*.

PG&E and SCE believe that the schedule shown would require deployment of engineering and other resources to support other transmission projects required to ensure grid reliability or to interconnect other generation projects. Such other generation projects include renewable and other generators that have made, or will make, application to interconnect to the ISO-controlled grid through the ISO Interconnection Process ahead of the wind generation believed to be available in the Tehachapi area. As such, to accommodate this schedule, the study and other related costs could increase (for example due to hiring consultants) and/or other important projects would be delayed.

Chart 2.6 Tehachapi Conceptual Schedule



NOTE: TEHACHAPI AREA COLLECTOR LOOP WILL BE DEVELOPED AS REAL PROJECTS MATERIALIZE

2.7 Current Status

On December 9, 2004, SCE filed CPCN applications for the first three segments of Phase 1. One CPCN upgrades the transmission line between Antelope and Pardee to 500 kV (initially to be energized at 230 kV). The CA ISO has approved this upgrade, and the Commission is currently processing SCE's CPCN application.

SCE is expected to complete the Propoenets Environmental Assessment (PEA) for the second CPCN that includes Segments 2 and 3 before July 2005. Segments 2 and 3 include these new facilities:

- 500 kV line from Tehachapi to Antelope (initially energized at 230 kV)
- 500 kV line from Antelope-Vincent (initially energized at 230 kV)
- 500 kV substation at Tehachapi (substation #1);
- 230 kV substation at Tehachapi (substation #2);
- 230 kV line, Tehachapi substation #1 - Tehachapi substation #2.

These applications for permits to build the projects above will complete the applications for Phase 1 of the conceptual plan.

3. Basis of this Conceptual Plan

In response to CPUC Decision 04-06-010, SCE and PG&E performed a conceptual study to accommodate approximately 4,060 MW of wind generation in the Tehachapi area. The transmission alternatives to interconnect Tehachapi resources to SCE's service area are based on the SCE Renewable Conceptual Transmission Plan submitted to the CPUC on August 29, 2003.

3.1 Planning Assumptions

A draft study plan (dated July 14, 2004) was developed by SCE and adopted by the TCSG[9] (Appendix E). This Study Plan outlined the study assumptions used and, among other things, the types of study to be performed in identifying the transmission upgrades necessary to interconnect and deliver the full amount of CEC-estimated Tehachapi area wind generation resources.

These study assumptions are identical to those used in performing the CAISO Annual Expansion Assessment and those used when conducting detailed System Impact Studies. The study assumptions therefore treated the Tehachapi area wind resources on par with studies performed for non-renewable generation resources. These assumptions are included in Appendix E.

This study was a conceptual study and not a System Impact Study (SIS) or a Facility Study (FS) as those are defined in the CAISO Interconnection Procedure.[10] Other specific studies will be needed to establish the definitive plan and, later, to obtain ISO and WECC approval. The areas needing future study are identified in Chapter 5.

For the purpose of the plan, it has been assumed that there will always be sufficient generation to fully utilize the transmission capacity constructed in each phase, and that this generation will meet the IOUs' least-cost, best-fit criteria for selection. Timing of the development and construction of wind generation projects cannot now be forecasted with precision, in large part because IOU procurement schedules and renewables bid solicitation timing are dependent on decisions of the CPUC. This means that the development schedule provided in Section 2.6 is driven by the time needed for the planning, permitting and building of transmission rather than the installation of generation. If either the developers are not there with timely generation projects, or the IOUs find non-Tehachapi renewable resources that better

[9] Dated July 14, 2004.

[10] http://www.caiso.com/docs/2001/04/02/200104021630021868.html

meet the least cost, best fit criteria, less new transmission capacity may be needed in later phases of the recommended plan.

Another parameter is the proportion of Tehachapi power that will flow north into the PG&E system versus the proportion flowing south to SCE and SDG&E. At this time, before any new wind power has been purchased, one can only guess as to how the power will actually be divided, but to meet the 20% renewables goal more energy may be needed by PG&E. For the purpose of formulating the plan, it was assumed that the division of flow is half north and half south. This assumption is important because it affects the location and type of facilities needed. For example, based on power flow study results to date, if less than 1500 MW goes to PG&E, only transmission facilities north of Midway would need upgrading and the 500 kV line from Tehachapi to Midway or from Los Banos to Tesla would not be needed.

SCE utilized the latest heavy summer and light spring power flow cases developed for there 2004-2008, 2013 Annual CAISO Assessment. The cases were adjusted to accommodate the additional wind generation modeled in the Tehachapi area in order to reflect anticipated reasonably adverse stress conditions on SCE transmission facilities consistent with the ISO Grid Planning Criteria. The adjustments were made by displacing PG&E and Pacific Northwest generation to capture delivery of wind generation north of Path 15 and displacing SCE, SDG&E, CFE, and Arizona area generation to capture delivery to the south of Path 26, as shown in Section 3.1.1.

3.1.1 Assumed Direction of Power Flows and Generation Displacement

To identify the facilities necessary to interconnect and deliver Tehachapi resources to load centers, the projected 4,060 MW was scheduled to plausible locations. As a result, in accordance with the Study Plan (Appendix E) the power flow studies assumed that 50% of the Tehachapi area wind generation was delivered to the system north of Path 26 and the remaining 50% delivered to the system south of Path 26. This was accomplished by redispatching generation as follows (assuming a precision of 4,000 MW was adequate for this purpose):

- COI by 7.5 % of 4,000 MW (import north of Path 26)
- NP-15 by 42.5% of 4,000 MW (north of Path 26)
- SCE by 17.5% of 4,000 MW (south of Path 26)
- SDG&E by 17.5% of 4,000 MW (south of Path 26)
- CFE by 2.5% of 4,000 MW (import south of Path 26)

- West-of-River by 12.5% of 4,000 MW (import south of Path 26)

3.2 Study Procedure

System performance must meet Applicable Planning Criteria (which includes the NERC/WECC Planning Standards[11] and CAISO Planning Criteria[12]) for system conditions studied. There are four basic steps in developing a transmission plan:

i. Assess system performance under various system conditions against Applicable Planning Criteria.
ii. Where system performance does not meet Applicable Planning Criteria, formulate potential alternative solutions (or mitigating measures) to meet such Criteria.
iii. Evaluate and rank feasible alternative solutions. Recommend the alternative solution based on least cost to the ratepayers.

Mitigation measures could include changes in generation dispatch pattern, use of RAS, and construction of new transmission facilities. However, because dynamic stability and voltage stability studies were not performed, the feasibility of some mitigating measures identified, such as the increased use of RAS, has not been determined.

To assess transmission performance associated with power delivered into the PG&E system, power delivered into the PG&E system is assumed to displace generation in the San Francisco Bay Area (which would be reduced down to what is needed to support RMR requirements) and import at the COI. Power delivered south of Path 26 is assumed to displace generation in the Los Angeles Basin, San Diego area, Baja California (Tijuana) area, and in the Phoenix area. This is being done for two reasons:

i In accordance with common transmission planning practices, the power delivery under study must displace generation outside the immediate study area in the initial system performance assessments. This is because this assessment must identify all potential problems so required mitigation measures can be developed.

[11] http://www.wecc.biz/documents/library/procedures/planning/WECC-NERC_Planning%20Standards_4-10-03.pdf

[12] http://www2.caiso.com/docs/09003a6080/14/37/09003a608014374a.pdf

ii In accordance with the reason for promoting renewable resources, renewable resources will be used to displace generation from older, more polluting generators. For PG&E, these are the gas-fired generating units located mostly in the San Francisco Bay Area. For SCE these are in the Los Angeles Basin.

Based on the assessment of the performance of the transmission system, where system performance does not meet Applicable Planning Criteria following the addition of new renewable generation, potential mitigation plans (alternative solutions) are developed to bring the system performance into compliance. The requirements for each alternative solution for it to meet Applicable Reliability Criteria will be further discussed in Appendices A, B and C. It must be noted that because of this limitation of the studies, all potential transmission problems may not have been identified.

3.3 Development of Transmission Study Alternatives

3.3.1 SCE Transmission Alternatives

A total of ten alternatives (see Appendix A) to upgrade or build new transmission lines and substations were developed by SCE and the CAISO to interconnect the Tehachapi area wind generation resources into the CAISO controlled network. These alternatives included a new transmission line towards the north, extending and connecting (looping) the existing Midway-Vincent No.3 500 kV line into Tehachapi or into Antelope, and all transmission constructed to the south. At its October 27, 2004 meeting, the Tehachapi Collaborative Study Group decided to narrow further study to four of the ten transmission alternatives. The rationale for limiting the study scope was based on input provided by the CAISO indicating that there was no value gained in looping the existing Midway-Vincent No.3 500 kV transmission line into Tehachapi.

The four alternatives examined share the same Tehachapi local area wind collector facilities discussed in Section 2.2 and differ slightly in the facilities identified as necessary to interconnect the wind resource areas. Appendix A describes these Tehachapi interconnection facilities in detail.

3.3.2 Transmission Facilities in all four SCE Alternatives (Appendix A):

- New Vincent-Mira Loma 500 kV Transmission Line

- Pardee-Pastoria Transmission Line Reconductor
- Antelope Transmission Project - Segment 1: New Antelope-Pardee transmission line be designed for 500 kV but initially energized at 230 kV.
- Antelope Transmission Project – Segments 2 and 3: Segment 2 consists of a new 500 kV transmission line, initially energized at 230 kV, between Vincent and Antelope. Segment 3 consists a new 500 kV transmission line initially energized at 230 kV between Antelope and the new Tehachapi area Substation 1 (near Cal Cement). Segment 3 also includes certain local Tehachapi area facilities discussed in Appendix A
- Second 500 kV Transmission Line between Antelope and Tehachapi
- Antelope-Mesa 230 kV Transmission Line Upgrade between Vincent and Mesa: The teardown and rebuild can be sectionalized into three segments (1) Rio Hondo to Mesa, (2) Vincent to Rio Hondo, and (3) Antelope to Vincent.
- Antelope-Conceptual Substation 5 Line Upgrade: involving the existing Antelope-Magunden No.2 230 kV transmission line
- Additional Reactive Resources in SCE system

3.3.3 Transmission Facilities not common in all four SCE Alternatives:

- New Pardee 500 kV Facilities associated with SCE Alternatives 1, 2 and 10
- New Antelope 500 kV Facilities associated with SCE Alternatives 1 and 2
- Third 500 kV Transmission Line between Antelope and Tehachapi associated with SCE Alternative 2
- Second 500 kV Transmission Line between Antelope and Vincent associated with SCE Alternatives 2 and 3
- Antelope-Mesa 230 kV Transmission Line Upgrade between Antelope and Vincent. This line would require upgrading to 500 kV if either SCE Alternatives 1 or 2 is selected; and would require upgrading to double circuit 230 kV if SCE Alternatives 3 or 10 is selected.
- New 500 kV Transmission Line from Tehachapi to PG&E: SCE's Alternatives 1, 3, and 10 include 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. 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. These PG&E alternatives were discussed in Section 2.4.4 and 2.4.5.

3.3.3 PG&E Transmission Alternatives (Appendix B)

Under summer peak conditions, the import of Tehachapi wind generation to serve the Bay Area loads would schedule power flow in the south-to-north direction (counter to the prevalent flow) on Path 15 and Path 26 and is not expected to cause normal or emergency overloads on the existing PG&E system. Power flow studies show that under summer on-peak operating conditions when the prevalent power transfer is typically from north to south on Path 26, addition of generation south of Midway would tend to decrease power transfer into Southern California. In addition, since La Paloma, Elk Hill, and Sun Rise combined-cycle plants were released for commercial operation in 2003, Path 15 power flow is typically lightly loaded under summer peak conditions. (See Table B-2, Appendix B.)

Accordingly, all PG&E alternatives investigated are for mitigating expected off-peak transmission problems when the prevalent power transfer is in the south to north direction. PG&E investigated three alternatives 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.

PG&E's conceptual transmission alternatives are listed below. These include the status quo base case with no or minimum transmission upgrades to the PG&E system added. The study results, possible phasing and technical requirements associated with each alternative are further discussed in Appendix B. Note that the PG&E alternatives do not include shunt voltage support devices because no voltage stability studies, which are required for this determination, were performed. Further studies will be needed to explore opportunities to adjust each remaining alternative, so they can be ranked for future consideration.

3.3.4.1 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 6% to 44% over the ratings (or allowable limit) of eight transmission facilities under normal (all facilities in service) operating conditions (see Table B-4, Appendix B). As a result, this alternative would expand the times and conditions under which curtailment of generation would be required and, therefore, reduces operating flexibility. It would 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. Compliance with FERC Open Access rules, and agreement from the CAISO, among other requirements would also be needed.

3.3.4.2 PG&E Alternative 2: Big Creek-Fresno 230 kV Phase-Shifted Tie.
This Alternative would establish a new interconnection point between PG&E and SCE by building a Big Creek-Fresno 230 kV Phase Shifter Tie to tie together PG&E's Gregg-Helms PSP with SCE's Big Creek-Rector 230 kV lines at a new switching station. This alternative would allow a 300 MW power transfer in to the PG&E system. SCE's Big Creek system would require additional network upgrades to support the transfer (see Appendix C). This alternative would also require contractual arrangements between PG&E and SCE on issues such as inadvertent flow, and agreement between PG&E, SCE and the CAISO governing the dispatch and operation of the existing generators, resolution of any physical limitation of Helms PSP and other operating issues. Potential power quality impacts on Fresno Area customers would also need to be addressed.

3.3.4.3 PG&E Alternative 3: Magunden-Bakersfield 230 kV Phase-Shifted Tie.
This alternative was dropped from further consideration because it could not provide the intended 300 MW of power transfer.

3.3.4.4 PG&E Alternative 4: Tesla-Los Banos-Midway 500 kV lines, divided into 3 Phases.

Phase A would build a Los Banos – Midway 500 kV line with 65% series compensation and upgrade transmission facilities between the Los Banos and Westley substations. This addition would allow import of about 1,100 MW.

Phase B would in addition to Phase A build a Tesla – Los Banos 500 kV line. This addition would allow a total import of 1,500 MW.

Phase C would, in addition to Phase B, also install a Remedial Action Scheme (RAS) to trip about 1,000 MW of Tehachapi generation during contingencies that would allow a total import of 2,000 MW. (The existing Path 26 south-to-north rating could be upgraded to 3,400 MW for importing 2,000 MW of Tehachapi wind generation).

The increase use of RAS in Phase C must be approved by the WECC and CAISO. A new type of RAS with the accompanying relaying and communications facilities would be required because the existing RAS controller cannot estimate intermittent generation to determine the generators to be tripped in anticipation of the next contingency. If a RAS cannot be implemented, then new transmission facilities could be required between Tehachapi and Midway.

3.3.4.5 PG&E Alternative 5: Tesla-Gregg-Tehachapi 500 kV lines, divided into 3 Phases.

Phase A would build a Gregg – Tehachapi 500 kV line with 62% series compensation and a new Gregg 500 Substation. This addition would allow import of about 1,100 MW.

Phase B would in addition to Phase A build a Tesla – Gregg 500 kV line. This addition would allow a total import of 1,500 MW.

Phase C would in addition to Phase B install 62% series compensation on the Tesla – Gregg 500 kV line that would be able to import a total of 2,000 MW.

Contractual arrangements must be worked out between PG&E and SCE to establish a new interconnection point, and to work out issues such as inadvertent flow. Agreement also needs to be established between PG&E, SCE and the CAISO regarding dispatch and use of existing generation. The impact of balancing and integrating the initial 1,100 MW of an intermittent energy such as wind generation in Phase A on the Fresno area customers and resolution of any physical limitation of Helms PSP would also need to be addressed.

3.4 Power flow studies

Power flow study results show the conceptual transmission plan to be capable of exporting 4,500 MW of Tehachapi generation to major interconnection points on the SCE and PG&E systems. Study results also indicate that network upgrades are required to make the power deliverable to major load centers.

Power flow study results for both the SCE and PG&E study alternatives are included in Appendices A, B and C. As explained there, SCE's studies did not include analysis of the simultaneous loss of two transmission lines (N-2 contingencies); much of the data necessary is not available for conceptual-level studies. PG&E did include analysis of selected N-2 contingencies on some study alternatives addressing major network upgrades.

3.5 Study Limitations

Limitations of the technical studies on which the recommended conceptual transmission plan is based include these issues:

1. Economic analysis was not performed to select the lowest cost alternatives.
2. Cost estimates were prepared utilizing standard off-the-shelf unit-cost guides, but the costs of the collector system cannot be estimated accurately until detailed Facilities Studies are conducted.
3. Right-of-Way cost estimates are generic and may not reflect actual/likely costs of land acquisition.

Development of the definitive plan will require consideration of these issues.

4. Tehachapi Wind Power and Operation of the CAISO Grid

Wind power output varies with meteorological conditions. Wind speed forecasts are increasingly accurate but still fall short of providing the output certainty available with traditional generating resources. The proposed FERC Grid Code[13] (and similar proposed WECC standard) for wind power resources requires wind turbines to provide low-voltage ride-through capability, voltage support and voltage based power factor control, and some ability to control or shape output. Nonetheless, integrating intermittent output requires careful planning of electrical integration details. Connecting a very large amount of intermittent wind power at one location, as planned with the Tehachapi development, poses special challenges to the operation of the California grid, which will need to be addressed.

For the last several years, wind power has been the fastest growing generation resource worldwide. As a result, operating performance data is increasingly available, and the effects and costs of integrating significant penetrations of wind power into state and national electric systems are becoming better understood. Wind integration has been studied on the several European systems, and on the PacifiCorp, Bonneville Power Administration, Xcel, New York ISO and other US grids. The California Energy Commission directs an on-going study of wind integration issues and costs for the California grid. References to this work are provided in Appendix F.

This chapter outlines the key issues that a large penetration of wind power, in combination with the changing characteristics of other generation sources, poses to operation of the California grid and describes the need for further studies to resolve these issues.

4.1 Wind Generation Operating Issues

The Western Interconnection is divided into 34 Control Areas. Each Control Area is required to continually match generation with load plus interchange. If generation does not equal load plus interchange, then an "Area Control Error" or ACE is the

[13] Appendix G of Order 2003A. The proposed FERC and WECC wind turbine generators standards are very similar to those in place in Europe.

result. Each control area has the responsibility to keep the 10-minute average of ACE within certain limits as specified in the standards that are developed by NERC and WECC. In the California ISO control area, generation is matched with load in three time frames. In the day ahead scheduling process, generation and interchange schedules are developed for each hour of the next day. In the hour ahead scheduling process additional changes in load and interchange are accounted for with generation changes for the next hour. In real-time load and generation are matched every four seconds.

Regulation. On a second to second basis, load and generation are matched to each other by adjusting generation that can quickly vary its output. The resources used to meet this need are called regulating resources. Hydro generation is particularly useful in meeting this regulation need as its output can usually be easily and quickly changed, often without substantial impacts to unit efficiency. While useful for regulation, hydro generation is also a limited resource that varies with precipitation, storage capability, and down stream water flow schedules. Slower responding thermal generation must also participate in regulating the interchange schedules and system frequency and matching second to second load changes. If the variation in intermittent generation changes, as may occur as the amount of wind generation on the system increases or decreases, then the amount of regulation needed for balancing a control area could also increase and lead to increased regulation costs. These issues are currently being studied by the CEC. Additionally, as regulation requirements increase, more and more thermal generation must bid into the regulation market and perform up to standards. Thermal units are typically increasingly slow moving, three to five MW per minute, and so to maintain NERC and WECC control standards, much more regulation must be procured.

Ramp Rates. Throughout a day, system load varies greatly. On a typical day, the morning load increases at a very fast rate and in the evening it decreases at a fast rate. Resources need to be dispatched in near real-time to match these ramps. All generation is limited by how much it can increase or decrease over time. As the ramp requirements increase, additional generators are needed to match these increases. To the extent that wind generation increases these ramps, or creates new ramps within an hour, this could lead to increases in the amount of generation needed to respond to these ramps and lead to increased costs.

Load Following In Real-Time. When planning for the next day or hour, load is forecasted and a corresponding amount of generation is planned. However, there will be some error in the load forecast and the actual amount of generation delivered will vary from what was planned. To correct for this mismatch between load and generation, it is necessary to have dispatchable resources available to the operators. Integrating wind generation into the system could increase the difference between planned and actual generation and increase the need for other generating resources to follow load.

Accommodating the Daily Load Pattern. System load varies substantially through the day. There is a base amount of load that exists throughout the day, which is normally served by large and efficient base load generation (e.g., nuclear and coal plants). The remaining load varies throughout the day and is met with intermediate (e.g., thermal gas plants, combined cycle gas plants and hydro) and peaking resources (e.g., simple cycle gas turbines and hydro). Thermal plants and hydro generation are the primary resources used to fill this need. Wind generation in certain resource areas—like Tehachapi—operates at high levels during the times when load is low, and operates at low output levels during the time when system load is at a peak. As a result, the need for other (off peak) base load generation is decreased and the need for intermediate and peaking generation can be increased. This, together with other system factors, can lead to the need to cycle thermal units that are not designed for that purpose.

The vast majority of new generation being constructed is combined cycle generation, which is typically designed as a base load generation source and is not intended for following a daily load cycle. Combined cycle generation has substantial startup costs ($8,000 to $50,000), high minimum load requirements (50% to 70%), long startup times (e.g., six hours), and reduced efficiency and higher emissions when operating at reduced capability.

Energy storage, such as a pumped storage hydro plant, offers one potential solution to shape the wind generation to better match the load pattern, as well as to accommodate other system needs. Wind generation could be used during the off-peak periods to pump water to the pumped storage project's upper reservoir and during the peak period, the water can be used to generate electricity. Given the amount of wind generation proposed for the Tehachapi area, energy storage may be needed. As a result of this issue, one of the transmission options studied for the Tehachapi area is a line to Gregg Substation, which is directly connected to the 1200 MW Helms pumped storage plant. Whether or not it is feasible or desirable to use the Helms plant, or potential new storage projects, to shape the Tehachapi generation remains to be studied.

Over-Generation Concerns. During the spring, primarily as a result of the abundance of hydro generation that cannot be stored and low system load levels, the system can be in a state of over generation. During these periods, it is not uncommon for a control area to actually pay another entity to accept generation and relieve an over generation problem. In the case of wind generation, it may become necessary to take the turbines out of service during these periods.

Frequency Response Issues. When a disturbance occurs that results in the loss of generation or load, the generators that remain connected to the grid automatically initiate changes in their output to correct the mismatch between generation and load, and to maintain system frequency. This is accomplished by equipping generators with devices called governors that track system frequency and automatically increase or decrease generation to maintain a constant frequency (i.e., 60 Hertz). When a generator trips on the system, the other generators on the system will see a drop in frequency, and their governors will act to increase their power output and correct the drop in frequency. Wind generation is normally unable to increase output in this way so it cannot contribute to system frequency control. If there is an area of the system with a large amount of generation that does not provide frequency response, then generators in other areas will meet this need and this will result in additional power transfers from those other areas to the area where the disturbance occurs. For example, if a generator trips in southern California, and the amount of generation in that area that can respond to frequency is lowered, then increased power transfers will occur from other areas. In this case, additional transfers would occur between the northwest and California and increase technical concerns such as voltage collapse. This would lead to the need to reduce power transfer between the northwest and California so that the system performance would be satisfactory should the outage actually occur.

4.2 Need for Further Study of Operational Integration Issues

The CAISO and CEC are now analyzing the effects of Tehachapi wind generation on frequency control, ramp rates, regulation, the possible displacement of the central California generation necessary to support existing Remedial Action Schemes (RAS), and other operational integration issues. Once these issues are better understood, any necessary solutions can be developed. These could include connecting Tehachapi directly to NP 15 (to facilitate integration with the regulating resources available in that region), imposition of operational constraints (e.g., ramp rate limits) on Tehachapi wind projects, procurement of load-following resources, and other mechanisms to provide operators with adequate tools for maintaining reliable grid performance.

Because the CAISO and California Energy Commission operational integration studies are still in process, the TCSG was not able to consider such operational effects or solutions. As a result, the Tehachapi conceptual plan may need to be modified when these operational effects and their solutions are better understood. TCSG assumes that implementation of the definitive plan will incorporate mechanisms to resolve the operational concerns described above.

5. Further Studies Needed

This report provides a preliminary, conceptual development plan to export Tehachapi wind power. Additional technical studies are necessary to finalize a definitive development/construction plan. This chapter specifies the additional analytical work necessary to complete this plan.

5.1 Further Technical Studies

The preliminary conceptual plan outlined in this report provides a framework for the necessary further analytical work. A final Tehachapi plan must be substantially more detailed, and demonstrated to be electrically reliable and least-cost. Further studies are needed in three major areas:

5.1.1 Improve and Confirm the Conceptual Plan

We recommend that the alternative ways of giving Tehachapi wind resources access to statewide markets be subject of further study to determine a definitive plan. These studies should include connecting Tehachapi to NP 15 at Midway or Gregg as well as the status quo (no change) transmission alternative. There should also be studied a connection between PG&E's Helms system and SCE's Big Creek system, which would take into account an operating regime for the Helms pumped storage plant and perhaps some of the Big Creek hydro resources, supportive of integrating wind onto the CAISO grid while meeting NERC and WECC Planning Standards and CAISO Planning Criteria, as well as PG&E and SCE operating requirements. This alternative might support a robust tie between the SCE and PG&E systems while providing a North-South path outside the Path 15/26 corridor.

Such studies will shed light on the major routing issue still to be resolved: whether Tehachapi should be connected only to the south/SCE, or whether one of the new 500 kV interconnections should be to the PG&E system at Midway or Gregg.

Flows across the LADWP system (over its Owens Gorge-Rinaldi corridor), and across the privately owned Sagebrush line, should also be evaluated. Efforts to involve LADWP in coordinated development of Tehachapi wind resources should continue.

Network upgrades on the PG&E system must be evaluated in detail to identify the most cost-effective ones. These upgrades must be tied to PG&E's procurement plans, and/or the procurement plans of other potential power purchasers north of Tehachapi.

The definitive plan should also consider the impacts on the entire statewide grid (i.e., including the IID, LADWP and SMUD control areas) of connecting 4,060 MW of wind in Tehachapi simultaneously with 2,000 MW of geothermal power in Imperial Valley alongside the other new generation, retirements and increased inter-regional flows forecast by the WECC over the planning horizon. The CEC, in its 2005 Integrated Energy Policy Report, has arranged to perform this analysis through the Public Interest Energy Research (PIER) program.

5.1.2 Economic Modeling to Identify the Least-Cost Alternative

Production cost simulations based on the conceptual studies should be done to evaluate how flows affect congestion costs, increase or decrease system losses and displace alternative generation. The combination of power flow analysis and production cost simulations will provide a basis for selecting the definitive plan.

5.1.3 Dynamic Analysis

Transmission planning studies, including dynamic stability, voltage stability and short-circuit studies, are necessary to determine the feasibility and cost of connections to the CAISO system, and are necessary to formulate the definitive plan. These detailed transmission planning studies will confirm the plan's ability to operate reliably over the entire range of conditions specified by the CAISO. They should include specification of any Special Protection Systems or Remedial Action Schemes found to be necessary or prudent. These studies may need to be performed in conjunction with any operating or ramp-rate constraints imposed by the CAISO, as discussed in Section 4.1 above.

For example, the feasibility of the RAS can impact whether new transmission lines are needed for the transmission system to meet Applicable Planning Standards. Generator-specific data will be needed to conduct the dynamic studies to design the RAS. If the RAS were designed based on assumptions made on generator information, the assumptions will either become requirements in the generator design, or new transmission facilities will be needed. Such new transmission facilities will need to be determined on a case-by-case basis as the generator-specific data become known.

5.2 Additional Issues for Further Study

The portions of the study performed by PG&E and SCE involved only power flow simulations, and did not include dynamic stability, voltage stability, or short circuit studies, which are commonly required in a SIS or a FS. These studies are outside the scope of a conceptual plan. In addition, the study did not cover many of the simulations commonly required to be performed in a comprehensive progress report required by the Western Electricity Coordination Council (WECC)[14] to account for impacts on the Western Interconnected System. The findings in this report therefore represent a subset of the possible impacts of the recommended conceptual plan. In addition, some of the suggested mitigation measures involve the use of Remedial Action Schemes (RAS) or Special Protection Systems (SPS). Because of the impacts of such RAS on the operations of the Western Interconnected System, they must be approved by the WECC before they can be implemented. Approval cannot be obtained until the RAS proponents demonstrate to the satisfaction of WECC that the RAS is technically feasible.

The following issues may affect the scope of facilities, the phasing of the identified facilities, the cost, and the viability of the transmission alternatives identified in this conceptual study:

1 Exact project locations and generators' project specifications are not fully available.[15]

2 Detailed studies in accordance with WECC Procedures for Regional Planning Project Review and Rating Transmission Facilities[16] and the WECC Progress Report Policies and Procedures[17] need to be performed for those alternatives that impact the operation of the Western Interconnected System (e.g., Path 15 and Path 26).

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14 http://www.wecc.biz/documents/library/procedures/Progress_Report_Procedures_2002.pdf

15 http://www2.caiso.com/docs/2002/06/11/2002061110504928318.doc

16 http://www.wecc.biz/documents/library/procedures/planning/NEWRPPR_402_Revised.pdf

17 http://www.wecc.biz/documents/library/procedures/Progress_Report_Procedures_2002.pdf

3 Detailed studies in accordance with WECC Procedures for Regional Planning Project Review and Rating Transmission Facilities and the WECC Progress Report Policies and Procedures need to be performed for those alternatives that result in new interfaces between SCE and PG&E to identify and mitigate impacts on the operation of the Western Interconnected System.

4 Detailed substation site review beyond the two substations for which a CPCN Application was submitted by SCE on December 9, 2004 will be needed.

5 Detailed rights-of-way review will be needed for transmission line routes excluding those for which a CPCN Application was submitted by SCE on December 9, 2004.

6 Detailed environmental assessments will need to be performed for new sites and new line routes that may be needed to accommodate interconnection of each renewable project, or number of renewable projects, including alternatives for the substation sites and transmission line routing, as well as proposed mitigation measures.

7 Cost estimates were prepared utilizing standard off-the-shelf unit-cost guides and will need to be revised as additional information becomes available.

8 Right-of-Way cost estimates are generic and may not reflect actual/likely costs of land acquisition and will need to be revised as additional information becomes available.

In addition the FERC TO / WDAT tariff interconnection process must be followed by all renewable resources in order to be interconnected to the existing system. Although not required for the finalization of a definitive plan, additional issues may arise as a part of the interconnection process, which may require modifications to the plan. These may include:

1 Detailed system impact studies for each renewable project, or number of renewable projects, need to be performed to identify the actual impacts of the project(s) on the existing electric system in accordance with CAISO Tariff.[18]

[18] http://www2.caiso.com/docs/2002/08/06/2002080609404914643.doc

2 Detailed facilities studies for each renewable project, or number of renewable projects, need to be performed to properly engineer, design, and estimate actual costs of the facility upgrades required in accordance with CAISO Tariff.

3 Detailed economic analysis needs to be performed to properly select the lowest cost alternatives for meeting the interconnection requirements for each renewable project, or number of renewable projects, from a ratepayer perspective.

6. Critical Policy Issues and CPUC Actions

This chapter identifies the critical policy support required to enable the state to reach its renewable energy development goals and outlines needed CPUC action. The following Chapter 7 covers additional actions needed by the California Energy Commission, the CAISO, FERC and the Governor.

Current interconnection policy is organized to consider transmission to connect individual generating projects to the grid one at a time, in a sequence determined by interconnection requests and executed Power Purchase Agreements. In D.04-06-010, the Commission recognized that, especially for resource-rich areas like Tehachapi, this approach could result in piecemeal transmission additions that could inflate total transmission costs, environmental impacts and the overall cost of meeting RPS goals. Further, organizing transmission development to connect clusters of relatively small renewable energy projects may deliver significant economies of scale, thus reducing the cost of interconnecting Tehachapi-area generators.

6.1 Cost Recovery

All components of this conceptual plan assume that transmission-owning utilities are assured recovery of costs associated with planning, permitting and constructing the transmission facilities. The success of this plan depends on FERC approving these transmission facilities as eligible for cost recovery in transmission rates. If FERC does not approve creation of a new regulatory category for renewable transmission facilities in advance of interconnection requests, or otherwise determines the cost of these facilities to be recoverable in transmission rates, the State of California and the CPUC must establish an alternative mechanism, consistent with the Federal Power Act, to provide cost recovery certainty for the IOUs in order for this plan to be realized. To that end, the CPUC must find in the respective CPCN order that the facilities discussed in this plan provide network benefits and take all other steps required under Sec. 399.25.

The CPUC should promptly confirm that all necessary costs incurred in the implementation of any component of this plan are eligible for recovery under section 399.25, consistent with the Federal Power Act. However, in light of FERC's exclusive jurisdiction over transmission rate making as well as the recent Court of Appeals decision in SCE vs. CPUC (No.B171050), it is critical that the CPUC encourage and support FERC to approve cost recovery and associated amendments to the CAISO Tariff to allow for approval of transmission facilities for renewable resources in advance of interconnection requests.

6.2 Continue the Study

The conceptual plan recommended in this report consists of alternatives for the delivery of Tehachapi power to load centers, but not a definitive plan that can be used as the basis for permitting (CPCN) applications. The alternatives require further planning evaluation in order to formulate a single plan for implementation. To do this, further planning studies for specific projects, including operational integration studies, need to be performed and facility cost estimates refined. Final plans for the Tehachapi collector system will require information concerning actual wind project locations. Because of the urgency imposed by the EAP goal, this work should proceed as a seamless continuation of the study work undertaken herein. To meet the overall schedule envisioned in this report, planning studies should be completed by the end of this year. We recommend that the CPUC issue another ruling as soon as possible ordering a continuation of this study. The ruling should state a definitive implementation plan to be the end product, designate the agencies to do the work and establish a timeframe with milestones for checking progress.

6.3 Expedite Permitting

6.3.1 Consolidate the CEQA Process[19]

The Tehachapi Project consists of a number of facilities to be built over time. Most of these facilities will need CPCN approval from the CPUC. The norm for a CPCN being approved is 18-24 months. In order for the Tehachapi wind generation to progress expeditiously, the CEQA review process and Commission decision on the CPCN need to be approved without delay. The Commission should strive to complete the CPUC review and approval process within twelve months. To accomplish this, the three phases of the Commission's approval process, consisting of consulting contracting, preparation of the CEQA document, and the Commission's Proposed Decision, need to be accelerated.

[19] If there is any federal review required, the Commission should look for ways to coordinate effectively with relevant federal agencies.

To get each phase of the Tehachapi Project approved quickly, there needs to be sufficient time for the utilities to perform their interconnection studies, prepare their CPCN Application and Proponent's Environmental Assessment, and for Commission environmental review and CPCN approval.

Each facility requiring CPCN approval needs to have a well-defined project description for all the elements of the environmental review. The current plan is to include the Antelope-Vincent 500 kV line, Antelope-Tehachapi 500 kV line, Tehachapi Substation 1 and Substation 2 in the first EIR. The CPUC will permit the IOU owned facilities, while the wind turbines and their generation ties lines will be under Kern and Los Angeles County jurisdiction.

6.3.2 Maintain flexibility in the CEQA Review Process

Because of the size and the phasing of the Tehachapi build-out, there is a need for flexibility in the CEQA review. One specific need is for the CPUC Energy Division hiring and the approval of an Environmental Consultant to review SCE's PEA and to start work on the CEQA document. The time to hire and get a contract approved is between three to four months. Currently, a consultant cannot start work on the CEQA document until a Utility has filed a complete PEA. To maintain flexibility, the CPUC Energy Division should hire a consultant for each successive phase by the time each respective application is filed.

6.4 Criteria for triggering permitting and construction

When the definitive plan is established, including resolution of integration and operational issues, and cost recovery issues have been addressed, each phase of the plan will require two decisions from the Commission: the first to order the preparation and filing of the CPCN application and the second to approve construction. The first order for Phase 1 was issued on June 9, 2004, in D.04-06-010.

Delays in ordering permit applications to be filed and permitted facilities to be constructed incurs the risk that the people of California will not receive the benefits of Tehachapi wind power as soon as possible. On the other hand, orders to construct facilities commit significant amounts of ratepayer money. Even orders to prepare and file CPCN applications commit ratepayer money and involve the public in potentially contentious proceedings. If each phase is to be built in advance of need, there is a risk that these costs will result in facilities that are not fully utilized.

The Commission will therefore need to consider each order carefully. The TCSG has not been able to devise quantitative formulas for the Commission to use as benchmarks for triggering its decision to issue these orders. However, the TCSG recommends that the Commission consider the following criteria for deciding when to initiate permitting activities and construction of each successive phase of the definitive plan:

- Need for additional Tehachapi wind power to meet the State's renewable goals
- Level of utilization of or commitment for previously constructed Tehachapi transmission facilities
- Level of commitment from prospective Tehachapi wind developers for new projects
- Potential market for additional Tehachapi wind power.

6.5 Balance Cost Recovery, Ratepayer Protection, and Wind Development

6.5.1 IOU Concerns

The IOUs' main concern is to complete any required Tehachapi development in a way that minimizes ratepayer impacts, environmental impacts, and ensures adequate cost recovery. Costs incurred in developing transmission and substation facilities discussed in this plan must be found reasonable and prudent even if these facilities are constructed without generator commitments to use them fully or are otherwise underutilized. These costs may include but not limited to: engineering and land use studies, permitting, environmental mitigation, procurement, and construction.

Another IOU concern is that the Commission's decisions concerning implementation of this plan be consistent with federal and state law concerning transmission planning, interconnection policy, and energy policy. To that end, the TCSG recommends modifications to existing federal interconnection policy that would allow the ISO to approve for addition to the grid the facilities discussed in this plan. However, to the extent that these changes do not occur or that different changes occur, the various authorities in this area must be reconciled.

6.5.2 Ratepayer Concerns

Potential Risks/Costs of ordering permitting/construction in advance of need

Changing the regulatory approval process to support bundled development introduces the risk that development costs may be incurred for transmission facilities that are never built, and that some transmission line segments and transmission facilities may go underutilized. The costs of transmission facility engineering design and of environmental studies needed to complete a CPCN application fall into the millions or low tens of millions of dollars, while costs of right of way (ROW) and of materials and construction contracts are in the high tens or hundreds of millions.

These risks, while material, may appear small in comparison to the potential benefits. Moreover, they can be tightly limited by tying initiation of permit activities and construction approvals closely to market demand and other factors mentioned in Section 6.4, thereby achieving the potential savings offered through bundled development.

6.5.3 Developer concerns

Knowing the criteria for triggering actual transmission construction helps developers to assess the risk of buying the land ultimately needed for wind turbine installations. Delay due to uncertain availability of transmission to market can raise land and thus wind power costs.

Several components of the proposed Tehachapi development greatly affect the ability of wind project developers to organize cost-effective generating projects. These include:

- Early determination that local transmission facilities are either network facilities, or gen-ties. A local collector network is one of the major components of the Tehachapi development plan. This network of 230 kV lines will extend from the main 500 kV/230 kV Tehachapi substation (substation #1) throughout the wind resource region. The 230 kV lines will be connected to 230 kV substations in different corners of the region. It will initially consist of radial lines connected together. These lines may eventually form a loop. Individual wind projects will connect to this 230 kV network at points throughout the region.

  The low voltage lines tying individual wind projects to the 230 kV network are understood by all parties to be gen-ties. Building theses gen-ties is the cost responsibility of each wind project developer.

Because of their network attributes and the fact that the collector system is in effect an extension of the renewable energy trunk lines at the center of this plan, wind developers believe that the 230 kV network collector system would most appropriately be classified as a network facility. As such, it would receive the same funding and cost recovery treatment as the trunk lines. Early determination that the collector system will be classified as network facilities will greatly affect the timing and cost of wind development in the region.

Elements of the renewable energy trunk line and collector system likely will be used to raise the reliability of service to currently served load in the area and to shift some existing QF generators to the new system. It would be helpful to the process to identify significant elements of such shifts now, rather than later as currently planned, as such identification would make clearer the network characteristics of the facilities.

- Timely RPS Solicitations. Wind project developers make substantial investments in land acquisition and resource assessment, including installation of anemometers and analysis of wind data, in anticipation of being able to bid their projects into competitive solicitations. The carrying costs of such investments can be substantial. Delay in such solicitations imposes real financial burdens on developers, and can compromise their ability to compete.

- Certainty of transmission development. Knowing the criteria for triggering actual transmission construction helps developers to assess the risk of buying the land ultimately needed for wind turbine installations. Delay due to uncertain availability of transmission to market can raise land costs and thus wind power costs.

- The queue process needs to be improved for renewable RPS projects. The developer has little control over the PPA process and cannot accurately determine likely on line dates, and thus is at risk of falling out of the queue after spending substantial resources. Project information in the queue process needs to be adjusted so as to allow for changes in project configuration associated with the RPS process and evolving turbine characteristics.

6.5.4 Mechanism for limiting risks

The recommended balance of the concerns discussed above is as follows:
In light of developers' need for expedited construction of transmission upgrades necessary to interconnect and finance their projects, the TCSG recommends a modification of existing interconnection policies and the ISO tariff to permit early construction as discussed above.
To minimize the ratepayer risk associated with underutilized facilities, the TCSG recommends that the permitting and construction of the facilities discussed in this

report be phased based on the criteria as discussed in Section 6.3. In this way, the necessary transmission upgrades can be constructed at the earliest possible date, while still providing improved ratepayer protection.

To address the IOUs' cost recovery concerns, the CPUC should adopt the recommendations related to necessary actions by FERC and under Section 399.25 discussed throughout this report. In addition, the Commission should address the IOU's short-term budget and cash flow considerations by establishing accounts for that purpose, either via Memorandum or Balancing Accounts.

7. Policy Actions by Other Agencies

In addition to the CPUC implementation agenda outlined in Chapter 6, the TCSG recommends that other state agencies, the Governor and the Legislature pursue policy actions in key venues.

Current regulatory practice is organized to consider transmission construction to connect individual generating projects to the grid one at a time, in a sequence determined by interconnection requests and executed Power Purchase Agreements. In D.04-06-010, the Commission recognized that, especially for resource-rich areas like Tehachapi, this approach could result in piecemeal transmission additions that could inflate total transmission costs, environmental impacts and the overall cost of meeting RPS goals.[20] This Decision recognizes, further, that organizing transmission development to connect clusters of relatively small renewable energy projects may deliver significant economies of scale, thus reducing the cost of such transmission upgrades while meeting state RPS goals. Unfortunately, the approval and construction of transmission upgrades necessary to accommodate renewable generation outside of the normal interconnection process, as envisioned by D.04-06-010, is inconsistent with the ISO tariff and existing FERC interconnection policy. Therefore, the TCSG recommends that the Commission support the creation of a new regulatory category that will facilitate the development of clusters of renewable energy projects.

Changing the regulatory approval process to support such bundled development introduces the risk that development costs may be incurred for transmission facilities that are never built, and that some transmission line segments and transmission facilities may go underutilized. These risks, while material, may appear small in comparison to the potential benefits. Moreover, they can be tightly limited by tying permitting and construction approvals closely to market demand. Some level of risk is necessary to achieve the potential savings offered through bundled development. The CPUC must balance the potential risks to ratepayers of stranded transmission investment, and the cost of such investment, against the potential benefits of making low marginal cost, stable-priced renewable resources widely available.

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[20] D.04-06-010 (in I.00-11-001) at p. 23.

As recommended above in Section 6.1, by implementing Section 399.25 on an expedited basis, the CPUC can expedite the process at FERC and foster a positive outcome in that forum. Future action by FERC is needed to remove cost recovery risk for any renewables-related transmission built by the IOUs in advance of interconnection requests, modify outdated abandoned plant policies, and resolve inconsistencies between the ISO's current transmission approval process and the recommendation of this plan.[21] If FERC does not approve creation of a new regulatory category for renewable transmission facilities in advance of interconnection requests, implementation of the "backstop" described in Public Utilities Code §399.25, as proposed in Chapter 6, is intended to provide equivalent cost recovery protection. However, in light of FERC's exclusive jurisdiction over transmission ratemaking, and the recent Court of Appeal s decision in *SCE v. CPUC* (No. B171050), it is critical that the CPUC encourage and support FERC to approve of cost recovery and associated amendments to the CAISO tariff to allow for approval of transmission facilities for renewable resources in advance of interconnection requests, in the manner contemplated by D.04-06-010.

7.1 Planning and CA ISO Approval of Proposed Tehachapi Transmission

Renewable generation integration trunk lines are high capacity facilities that will enable a large number of generators to interconnect. The long project lead-time required for the implementation of a trunk line creates serious problems for wind projects. These types of projects cannot identify the specific projects and the specific type of generators that will be used for projects that will be constructed that far in the future. Wind turbines are generally ordered six-nine months prior to construction. Like combustion turbines in the 1990s, wind power technology is evolving rapidly, and new generations of the technology are expected to be introduced at roughly two-year intervals for at least the next decade. As a result, wind generators cannot identify the exact generator technical parameters and exact locations for their projects several years in advance. This means that project specific data is not available to complete the planning studies for major transmission facilities such as trunk lines.

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[21] In this regard, SCE may soon file a proposal with FERC to create a new regulatory category for "renewable energy trunk lines." (Comments of SCE Before the FERC, Docket No. AD04-13-000, January 28, 2005.)

As a result, it is necessary in the planning studies to model typical data for the wind generators and conduct generic studies to assess technical issues like stability, voltage performance, and facility loading. The primary technical concern that drives the construction of new transmission lines is nearly always facility overloading. Fortunately, facility overloading is a technical concern that can be adequately addressed using generic data. However, other technical concerns such as stability performance, voltage performance or short circuit duty requirements cannot be accurately assessed using typical data. For the generic studies of the trunk lines, generic data will be used that assume that the future wind projects meet or exceed the electrical requirements established for wind generators in the FERC wind power "Grid Code."[22] These include Low-Voltage Ride-Through capability, controllable power factor, the ability to provide dynamic VAR support, and other features. For the stability analysis, currently available models, such as the model available for the GE wind turbine, can be used.

Before projects are interconnected to the grid, detailed studies using project specific data will still be required to ensure compliance with reliability standards and FERC interconnection policy. Each project will be processed through the ISO Generator Interconnection process and detailed technical studies for the specific facilities will be completed. This approach will enable the trunk line facilities to move forward and also assure that the resulting facilities will meet all applicable reliability standards. The detailed studies conducted as part of the ISO's generator interconnection process would identify any corrective actions necessary for performance differences between the studies using generic generator data and the detailed studies conducted for specific projects. As a result, the generation project developers may be responsible for correcting technical concerns, such as stability, that are identified in the detailed studies that are conducted for their projects. Typically, technical concerns such as stability and voltage performance can be addressed through the addition of facilities to the projects (e.g., the addition of a static VAR compensator or choosing different wind generation equipment).

This approach is critical to advance the transmission planning and construction approval process to serve Tehachapi area generation. The traditional approach, where transmission facilities are not identified until a generation interconnection application is received, and project specific studies are conducted before facilities are approved, does not work for the trunk line facilities because it creates a chicken-and-

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[22] The Grid Code is described in Appendix G of FERC Order 2003A. Appendix G is expected to be formally adopted by FERC in 2005.

egg problem for new wind generators. Wind projects cannot obtain financing, and so cannot execute PPAs, until the transmission to connect them is approved.

FERC Order 2003A gives transmission system operators the ability to perform "cluster studies." This means the CA ISO will be able to study the impact of projects connecting in the same electrical region (e.g., Tehachapi) all at once. Such clusters might include, for example, the projects bid into RPS solicitations over a one- or two-year period, along with other projects proposed to connect in the same region in the same time period. This directly supports the ability to build the transmission to connect wind power more cost-effectively, and in the larger increments contemplated in D.04-06-010. The CA ISO has proposed to amend its tariff to conform to this provision of Order 2003A, however FERC has not yet accepted the revisions.

However, even if these changes were adopted, FERC interconnection policy would leave generators responsible for funding these upgrades as a condition of their interconnection. Under the ISO tariff, moreover, the ISO can only compel the IOUs to construct projects that are needed to maintain transmission system reliability or to promote economic efficiency. [CA ISO Tariff §§ 3.2 and 5.7 et seq.] Thus, changes to the ISO tariff are likely needed to reconcile the goals of D.04-06-010 with existing transmission planning authorities. An obvious solution exists: assuming FERC approves modifications to the ISO tariff authorizing the ISO to approve renewable trunk line facilities, the ISO could approve the interconnection of trunk line facilities to the grid before all the specific Power Purchase Agreements or Interconnection Agreements are signed – thereby solving the chicken-and-egg problem. The TCSG recommends that the CPUC fully support this effort.

7.2 State Acquisition of Transmission Rights of Way

The expansion of residential and commercial development throughout the state may make acquisition of transmission corridors increasingly expensive and difficult. The CEC has been exploring the possibility of acquiring rights of way in anticipation that transmission construction in certain corridors may be required. This concept could apply, for example, to the bundled transmission development contemplated in D.04-06-010 to support cost-effective RPS implementation.

However, the utilities' ability to acquire ROW through the exercise of eminent domain requires a judicial determination that the land to be condemned will result in the greatest public good with the least private injury. In the case of major transmission projects, this standard is usually met by reference to a prior CPUC finding of need and certification of a CEQA document concluding that the approved route involves the least overall impact. Absent such findings, the IOUs would likely find it difficult if not impossible to acquire ROW necessary to implement this plan in advance of obtaining CPUC siting permits.

As an alternative to IOU acquisition of ROW for potential transmission routings, state acquisition of strategic ROW corridors may be desirable. Such acquisition may be necessary to preserve the ability to timely build essential transmission infrastructure in the future. Legislation conferring such ability on the state and defining how it would be exercised may be introduced in the 2005 legislative session.

The TCSG could not reach consensus agreement on this issue. PG&E and SCE believe it is neither necessary nor prudent to acquire ROW before planned transmission has been found to be needed. Based on their significant recent experience obtaining rights-of-way across large numbers of parcels for major transmission projects, the utilities reported that land acquisition activities are typically completed before, not after, the completion of other post-CPCN activities that are necessary before construction can begin (e.g., local permitting, CPUC mitigation compliance, final engineering, materials procurement, etc.). Land acquisition activities have yet to hold up construction on any of these recent major projects. Moreover, PG&E has in the past obtained transmission ROW in advance of permitting activities, only to be told by the CPUC that some other route is preferable and the previously-acquired ROW could not be used.

TCSG members representing the CEC and wind developers, on the other hand, believe that deferring ROW acquisition for planned Tehachapi upgrades until each wind generating project has been approved may extend the RPS implementation timeline well into the next decade, many years beyond the EAP goal of 2010. All parties intend to closely follow the CEC's ongoing consideration of this important issue and recommend that the Commission do the same.

7.3 Integration with the IEPR Process

The 2005 Integrated Energy Policy Report (IEPR) process being developed by the CEC provides a forum for integrating transmission planning with supply planning on a statewide basis. It addresses public power as well as IOU plans and resources, including the transmission to meet all entities' RPS commitments. It will consider the impacts of RPS implementation on statewide power flows, across both the ISO and public power control areas. The IEPR process should be coordinated with the development of the final Tehachapi development plan.

7.4 Action at FERC and WECC

Bundled development of the transmission necessary to develop Tehachapi related transmission as contemplated in D.04-06-010 will likely require changes in policy at FERC and at the WECC. FERC must approve the amendment of the CA ISO tariff, to enable the ISO to study clusters of electrically-related wind projects as discussed above. The ISO has applied to FERC to amend its tariff to this end.

In addition, SCE has announced that it intends to petition FERC for a declaratory order establishing cost recovery certainty covering the construction of transmission infrastructure built to meet state RPS implementation requirements. The CPUC and the state should make every attempt to support FERC in this effort to develop a workable policy that protects ratepayers as well as IOU shareholders, is fair to all stakeholders, and reconciles the goals of D.04-06-010 with the law governing transmission planning in California.

WECC Progress Report Policies and Procedures require detailed information on proposed generating projects before the transmission necessary to connect those projects can be approved. WECC does accept studies based on assumed generator information for the generators under study. However, if the actual generator information turns to be substantially different from the assumed information, it is the responsibility of interconnecting utility and the generator to demonstrate and make sure that all applicable reliability requirements will be met.

WECC's Progress Report policy may need to be amended in order to support the approval of transmission based on assumed wind project generator information. The CPUC and the state should proactively engage the WECC in seeking any amendment of WECC policy found to be necessary to this end.

In conjunction with this, it may be necessary to seek expedited approval of RPS transmission under WECC Procedures for Regional Planning Project Review and Rating Transmission Facilities. Modification of this procedure could enable WECC to begin its review and ratings process earlier than allowed under current policy. The CA ISO may be the appropriate entity to work with WECC to this end. Any modification of the WECC review process should apply to all transmission infrastructure—publicly owned and IOU-owned—built to meet California RPS requirements.

7.5 Action by the Governor

The Governor's leadership will likely play a critical role in accelerating the development of new generating and transmission resources to meet RPS requirements. The Governor's Office should:

- Encourage LADWP and other public power entities to actively engage in the statewide planning efforts to develop cost-effective transmission access for renewable resources. Cooperative public power-ISO transmission solution would likely reduce the cost—and environmental impact—of such access for all parties. Public power cannot be compelled to join such collaboration. The Governor is uniquely positioned to convince the large municipal utilities of the benefits of a statewide approach to RPS implementation.

- Lead a statewide public education campaign to explain the costs and benefits of RPS policies. Widespread public understanding of and support for new generation and transmission development will likely be essential to overcome the inevitable local opposition to such development.

- Support the legislative and regulatory policy changes outlined in Chapters 6 and 7 of this report necessary to implement the RPS on the Energy Action Plan schedule.

- Help convene the RPS Implementation Group outlined below to coordinate the final planning and approval of the generation and transmission necessary to fulfill statutory requirements.

7.6 RPS Implementation Group

The following concept was presented to the TCSG by a stakeholder, but was not endorsed by all the participants. The state could consider whether the CPUC, the California Energy Commission and the Governor should jointly convene and staff a new collaborative body to ensure timely achievement of the state's Renewable Portfolio Standard (RPS) goals. Such an RPS Implementation Group would coordinate all development activities necessary for the construction of generation and transmission projects, and/or the import of clean power from out of state, in accordance with least cost-best fit principles. It would ensure that the development plans proposed by the Tehachapi Study Group and the Imperial Valley Study Group are supplemented with additional work, reviewed, modified, and finally approved as required by statute or regulation. It would decide whether to convene additional planning collaboratives to identify transmission solutions for connecting Mojave solar resources, Northern California wind, geothermal and biomass resources, and/or other renewable resource areas to the grid.

The RPS Implementation Group (RPS-IG) would specify, commission and oversee all analytical studies necessary to complete detailed development/construction plans for each major renewable resource area. It would coordinate the activities of all state agencies related to implementation of RPS goals. This may include helping to schedule and facilitate decisions of the CPUC, CEC, CA ISO, and the support of the Governor and FERC necessary to establish definitive jurisdictional bases for construction of required facilities.

The RPS-IG would be most effective if organized as a stakeholder collaborative, on the model of the Tehachapi and Imperial Valley Study Groups. Such a structure would help ensure that the final development plans meet statewide interests, and would have widespread support. Senior representatives of the CPUC, the CEC and the Governor must be active participants. Other stakeholder participants should represent senior management of generation project developers, transmission owners, the CA ISO, potential power purchasers, affected landowners and governmental agencies, environmental groups and the public.

The RPS-IG may require a full-time staff, as well as the ability to order (through the authority of one of its convening members) or commission (with funding from an appropriate source) electrical and economic studies. The collaborative should establish a workplan with annual goals. It should report progress toward those goals quarterly, to the CPUC, CEC and Governor.

7.6.1 Public Information and Outreach Campaign

To build public and agency support for final approval of the TTP and other renewable generation and transmission projects, the RPS-IG should prepare and lead a statewide public education campaign. Through public meetings, publications, media appearances and other means as appropriate, this campaign would help targeted audiences and the general public to understand the purposes, costs and benefits of RPS implementation—including especially the Tehachapi and Imperial Valley development plans. Final regulatory approvals will inevitably face local opposition to the proposed transmission siting. A public information and outreach campaign will very likely be essential in building the support necessary to overcome such opposition.

8. Lessons Learned

CPUC Decision 04-06-010 presents two significant policy innovations: planning/building transmission in large increments to connect clusters of wind/renewable resources, while the generating projects are underway but before some of them may be completed; and using a collaborative process to incorporate the interests--and the political support of--diverse stakeholders. The experience of the Tehachapi Study Group provides lessons that can help future collaborative planning efforts to be more productive.

8.1 Recommendations for Future Collaborative Study Groups

Several factors prevented the TCSG from working as effectively as participants hoped. Based on this experience, we believe attention to the following issues will likely enable future planning efforts to be more productive.

1. **The conflict between the objectives of D.04-06-010 and CAISO interconnection requirements need to be resolved.** In this report, the TCSG has identified a potential "disconnect" between 1) the Commission's goal in D.04-06-010 to facilitate the development of Tehachapi-related transmission upgrades outside of normal interconnection policy and 2) existing law governing transmission planning in California. In particular, ISO standards for approval of new transmission facilities to the grid must be expanded to allow for implementation of this Plan. Consistent with this "lesson learned," this report recommends that the Commission take steps to work with other agencies to resolve this issue. If successful, the goals of D.04-06-010 can be implemented in the most timely way, with greatly reduced risk of renewed litigation.

2. **Specify the expectations for collaboration—and the mechanisms to support it—among the parties**. These include transparency of planning assumptions, data access, meeting minutes recorded and approved by all participants, and the ability of all parties to be heard without domination by any party. Effective collaboration is essential to the development of a plan that reflects the interests of a range of stakeholders and consequently earns broad support for its implementation.

3. **Establish a Steering Committee to guide day-to-day work**. Active leadership is essential if the group is to complete its many complex tasks on schedule. The Steering Committee should include representatives of the CPUC, CA ISO, CEC, pertinent IOUs and Publicly Owned Utilities, generators, ratepayer advocates, and other key stakeholders; it must be small enough to communicate quickly and actively among members.

4. **Provide experienced meeting leadership.** The meeting leader should assist the group to develop and maintain respectful behavior and collaborative interaction. S/he should have the authority to prevent any party from dominating discussion and ensure that all participants have the opportunity to be heard, and to guide parties away from posturing and toward effective problem solving. The meeting leader should ensure that minutes are kept and approved by the group. Most important, s/he should ensure that objectives and an agenda are set for every meeting, that discussions stay focused and that meeting objectives and larger study objectives are met on schedule.

5. **Ensure senior management attention**. The heavy Study Group workload requires each participating organization to dedicate significant staff time to the effort. Even more important, it requires each participant to be able to represent the interests of his/her organization in the development of the upgrade plan. Both issues--allocation of adequate staff resources, and quick access to decision-makers--require the Study Group to have visibility with each organization's senior management. Without such attention, there is a real danger that support for Study Group recommendations will be weak or non-existent.

6. **Future studies could benefit from integrating procurement planning with transmission planning**. The TCSG was asked to come up with a plan to connect 4,060 MW of generation at Tehachapi assuming that the generation will in fact be available. Future studies could benefit from the information developed by conducting a production simulation study using methodology similar to the TEAM analysis being investigated by the CA ISO to provide least-cost best-fit information for the IOU procurement process. Such a production simulation study should model all potential renewable resource regions with the appropriate production cost for each renewable technology, in addition to the other resources. This would ensure efficient use of resources from the participants.

7. **Ensure the participation of publicly owned utilities**. Public power involvement is essential for the development of least-cost, least-impact transmission solutions. Aligning renewable resource/transmission development with the self-interests of the large public power entities (especially LADWP and SMUD) remains an important challenge. Coordinated action with the Governor and other state agencies may be necessary to win the cooperation of the municipal utilities. The Imperial Irrigation District is the only public power agency proactively participating in statewide transmission planning efforts.

8. **Provide adequate resources**. While D.04-06-010 establishes that each party in the study group will pay its own costs, provision needs to be made for production simulations not able to be timely performed by the CA ISO, and for assignment of an experienced meeting leader, if such a skill is not available from among the participants. Each transmission owner performs power flow studies of upgrades proposed to its system, but today only the ISO has the capability to perform production cost simulations on each transmission alternative. With its limited budget and staffing, the ISO may need supplemental funding to complete such modeling on a timely basis.

9. **Organize Study Groups around the voluntary commitments of key parties rather than by CPUC order**. It may be most effective to obtain commitments from the senior management of key parties to have their organizations participate in collaborative planning for the development of integrated generation/transmission projects. This may require more time at the beginning of the effort, as each organization evaluates the costs and benefits of participating. But forming the collaboratives as voluntary associations may improve the quality of participation and reduce the time necessary to produce the development plan. CPUC authority to order participation remains an essential backstop. But a joint request from the CPUC, CEC and Governor may be effective in securing voluntary commitments.

Appendix A – SCE Study Alternatives

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. For completeness of the report, the Tehachapi Collaborative Study Group has nonetheless made an attempt to conceptualize such a local area transmission plan and develop corresponding conceptual costs based on previous conceptual studies by assuming the potential Tehachapi local area configuration shown below in Figure A-10. Generic MW values consistent with previous conceptual studies performed were assigned to each of the substation sites in order to "guesstimate" conceptual substation facilities.

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

A total of ten alternatives to upgrade or build new transmission lines and substations were developed by SCE and the CAISO to interconnect the Tehachapi area wind generation resources into the CAISO controlled network. These alternatives included a new transmission line towards the north, extending and connecting (looping) the existing Midway-Vincent No.3 500 kV line into Tehachapi or into Antelope, and all transmission constructed to the south. Following a presentation made at a meeting held on October 27, 2004, the Tehachapi Collaborative Study Group voted to limit further study scope to four of the ten transmission alternatives. The rationale for limiting the study scope was based on input provided by the CAISO indicating that there was no value gained in utilizing the existing Midway-Vincent No.3 500 kV transmission line.

The four alternatives examined share the same Tehachapi local area wind collector facilities discussed in Chapter 2, Section 2.2 and differ slightly in the facilities identified to be necessary to interconnect the wind resource areas. The Tehachapi Interconnection facilities are summarized in the following sections with one-line diagrams provided in Figures A-1 through A-4. Study Results and delivery upgrades are addressed in Section 2 in this Appendix A.

1.1. Description of Common Transmission Facilities in all four Alternatives

1.1.1. New Vincent-Mira Loma 500 kV Transmission Line

The need for a new 500 kV line into the Mira Loma area was identified as part of the SCE CAISO Annual Expansion Program. SCE is currently pursing a plan that involves converting the existing Vincent-Rio Hondo No.1 230 kV transmission line to 500 kV and building a new 500 kV section between Rio Hondo and Mira Loma. The line will bypass the Rio Hondo substation and continue to Mira Loma. Such arrangement will facilitate future development of Rio Hondo 500 kV substation. This new line will provide an added benefit of supporting delivery of Tehachapi area wind generation to the SCE load center. Since the project is needed for load serving purposes, it has been added to the conceptual transmission plans but has not been assigned directly to the addition of Tehachapi area wind generation. It should be noted that if a different 500 kV transmission line is constructed to satisfy load serving requirements, additional costs will be incurred directly assigned to Tehachapi in order to convert the Rio Hondo substation to 500 kV.

1.1.2. Pardee-Pastoria Transmission Line Reconductor

This project is an infrastructure replacement project which was identified in the 2004-2008, 2013 CAISO Controlled SCE Transmission Expansion plan. Since the project is needed for other purposes, it has been added to the conceptual transmission plans but has not been assigned directly to the addition of Tehachapi area wind generation.

1.1.3. Antelope Transmission Project - Segment 1

The PPM Fairmont Wind Project (201 MW) is the first "Tehachapi area" wind generation project in the CAISO queue with completed System Impact and Facilities studies. The results of the System Impact and Facilities studies have identified the need for a new Antelope-Pardee transmission line in order to eliminate thermal overload problems on the existing Antelope-Mesa 230 kV transmission line triggered by the addition of the wind project. The CA ISO planning department has reviewed results of studies and approved interconnection of the Fairmont Wind Project with the condition that the Antelope-Pardee transmission line be designed for 500 kV but initially energized at 230 kV.

1.1.4. Antelope Transmission Project – Segments 2 and 3

Segment 2 consists of a new 500 kV transmission line, initially energized at 230 kV, between Vincent and Antelope. Segment 3 consists a new 500 kV transmission line initially energized at 230 kV between Antelope and the new Tehachapi area Substation 1 (near Cal Cement). Segment 3 also includes certain local Tehachapi area facilities discussed in Chapter 4. It is expected that the CA ISO will approve at some point Segment 2 and Segment 3 to accommodate additional wind generation located north of Antelope in the Cottonwood area and Tehachapi area respectively. New right-of-way (ROW) will be required for both of these segments. As currently proposed, Segment 2 involves widening the existing ROW while Segment 3 requires acquisition of new ROW.

1.1.5. 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.

1.1.6. Antelope-Mesa 230 kV Transmission Line Upgrade between Vincent and Mesa

Upgrades to the Antelope-Mesa 230 kV transmission line will be required to support the large amount of wind generation resources identified by the California Energy Commission. System Impact Studies performed for developers proceeding with the FERC required CA ISO Interconnection Process have identified this transmission line as the choke point for wind generation interconnection in the Tehachapi area. The necessary upgrades involve tear-down and rebuild since the existing facilities cannot support a larger conductor type. The tear-down and rebuild can be sectionalized into three segments: (1) Rio Hondo to Mesa, (2) Vincent to Rio Hondo, and (3) Antelope to Vincent. The section between Rio Hondo and Mesa should be reconstructed as a double-circuit 230 kV transmission line since it is not envisioned to convert Mesa to 500 kV. The section between Vincent and Rio Hondo should be 500 kV construction standard initially energized at 230 kV to avoid waste since there exists the potential for a future Rio Hondo 500 kV substation. Finally, the section between Antelope and Vincent can be reconstructed with either double-circuit 230 kV or single-circuit 500 kV depending on the upgrade alternative selected.

1.1.7. Antelope-Conceptual Substation5 Line Upgrade

Upgrades to a section of the existing Antelope-Magunden No.2 230 kV transmission line will be required to interconnect wind generation resources located in the Cottonwood area. This conceptual study assumed that these upgrades would be in the form of a line reconductor similar to the Pastoria-Pardee Line Reconductor project. Detailed engineering review of tower structures may result in need to tear-down and rebuild thereby increasing costs associated with this line upgrade.

1.1.8. Additional Reactive Resources

A total of 713 MVAR of reactive resources (nine 79.2 MVAR shunt capacitor banks) were added throughout the network in order to restore bus voltages to levels identified prior to adding and dispatching the Tehachapi area wind resources.

1.2. Description of Transmission Facilities not common in all four Alternatives

1.2.1. New Pardee 500 kV Facilities

Alternatives 1, 2 and 10 include new 500 kV substation facilities at Pardee. Pardee is already designed as a 500 kV substation. Request for approval of 500 kV facilities at Pardee will be done, if an alternative which includes 500 kV facilities at Pardee is selected, at the appropriate time.

1.2.2. New Antelope 500 kV Facilities

Alternatives 1 and 2 include new 500 kV substation facilities at Antelope. SCE is pursuing approval of the Antelope 500 kV rating as part of the CPCN Application filed for Segment 1 of the Antelope Transmission Project. Request for approval of 500 kV facilities at Antelope will be done, if an alternative which includes 500 kV facilities at Antelope is selected, at the appropriate time.

1.2.3. Third 500 kV Transmission Line between Antelope and Tehachapi

Alternative 2 includes 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.

1.2.4. Second 500 kV Transmission Line between Antelope and Vincent

Alternatives 2 and 3 include a second 500 kV transmission line between Antelope and Vincent. This line is similar to the 500 kV transmission line identified in Segment 2 of the Antelope Transmission Project.

1.2.5. Antelope-Mesa 230 kV Transmission Line Upgrade between Antelope and Vincent

a. 500 kV Construction

   Since Alternatives 1 and 2 include 500 kV substation facilities at Antelope, it would be rational and cost effective to upgrade the section of Antelope-Mesa 230 kV transmission line between Antelope and Vincent with 500 kV. Such an upgrade would maximize overall system capability.

b. 230 kV Construction

   Since Alternatives 3 and 10 do not include 500 kV substation facilities at Antelope, it would be rational and cost effective to upgrade the section of Antelope-Mesa 230 kV transmission line between Antelope and Vincent with double-circuit 230 kV. Such an upgrade would maximize overall system capability and would be necessary to meet criteria requirements for loss of one or two transmission lines.

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

SCE's Alternatives 1, 3, and 10 include 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 as outlined in the Study Plan discussed in Appendix E.

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 A-1
Alternative 1

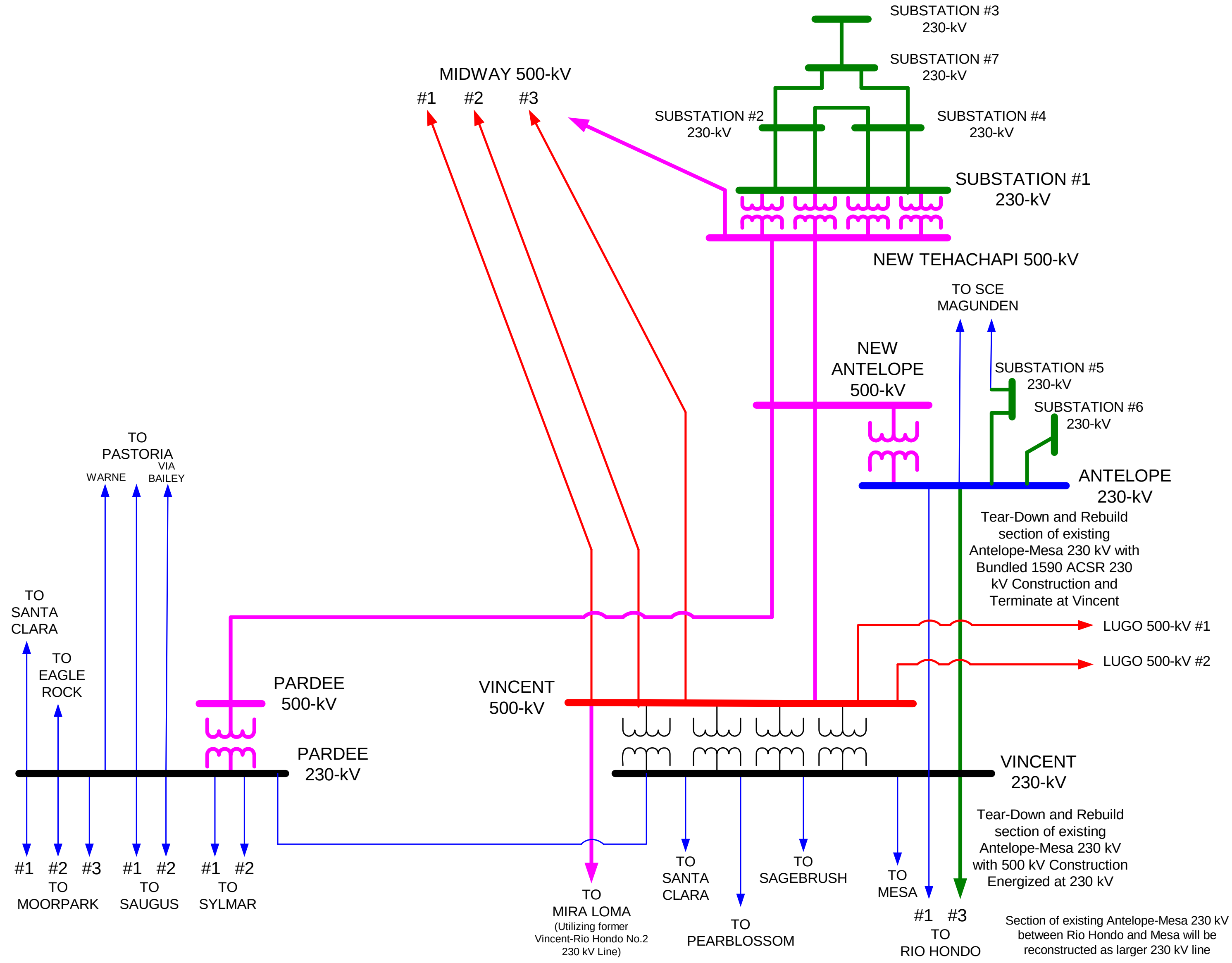


Figure A-2
Alternative 2

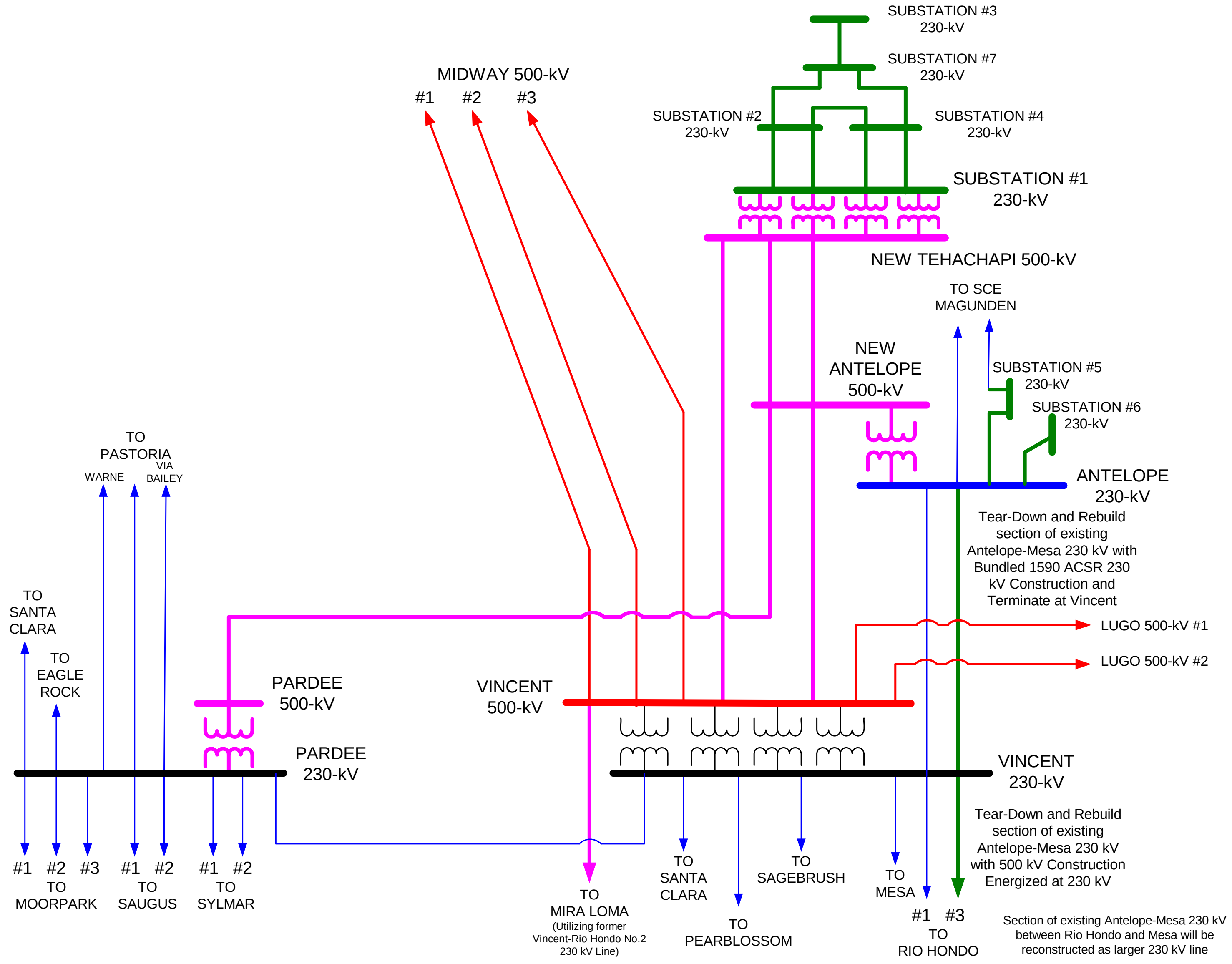


Figure A-3
Alternative 3

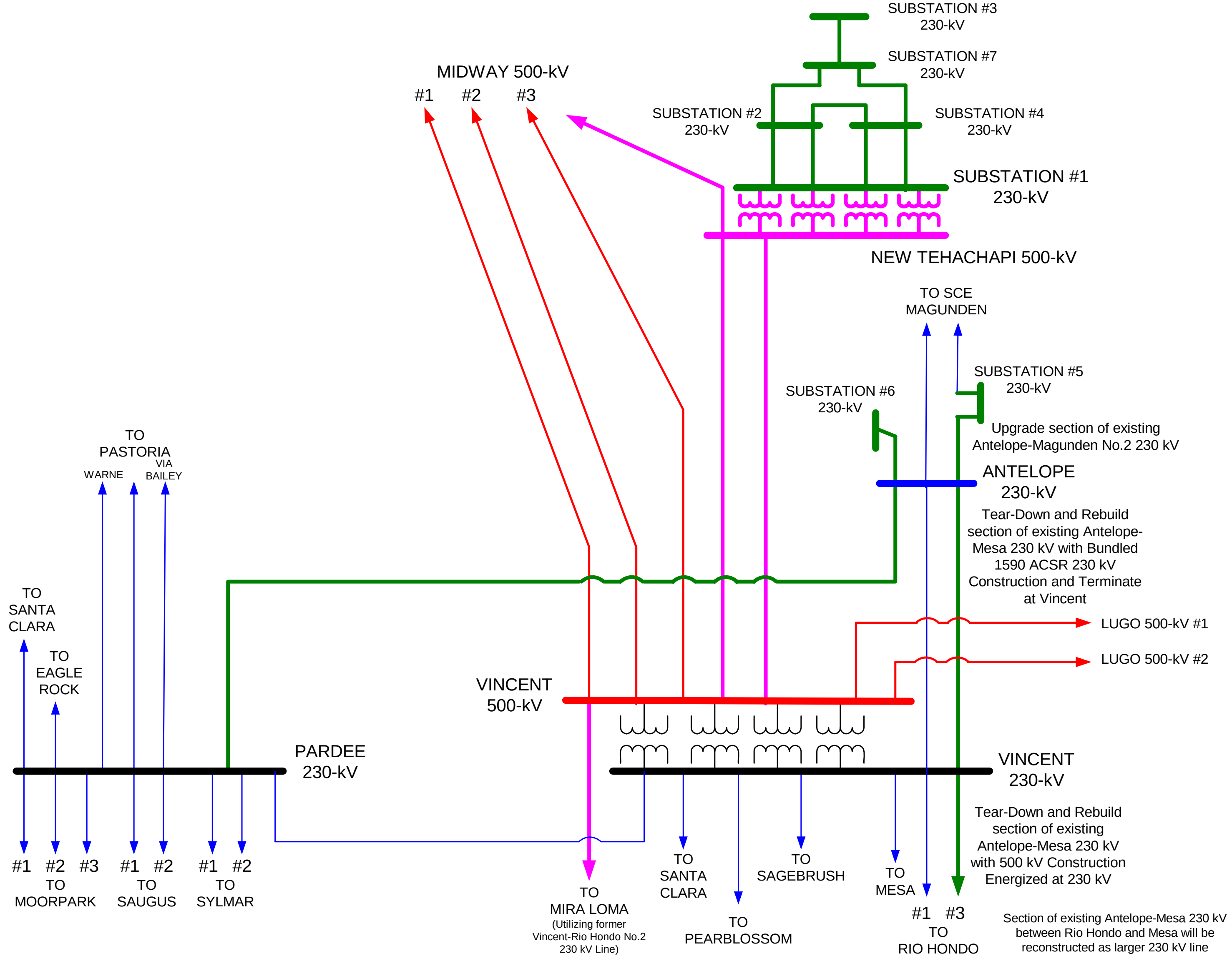
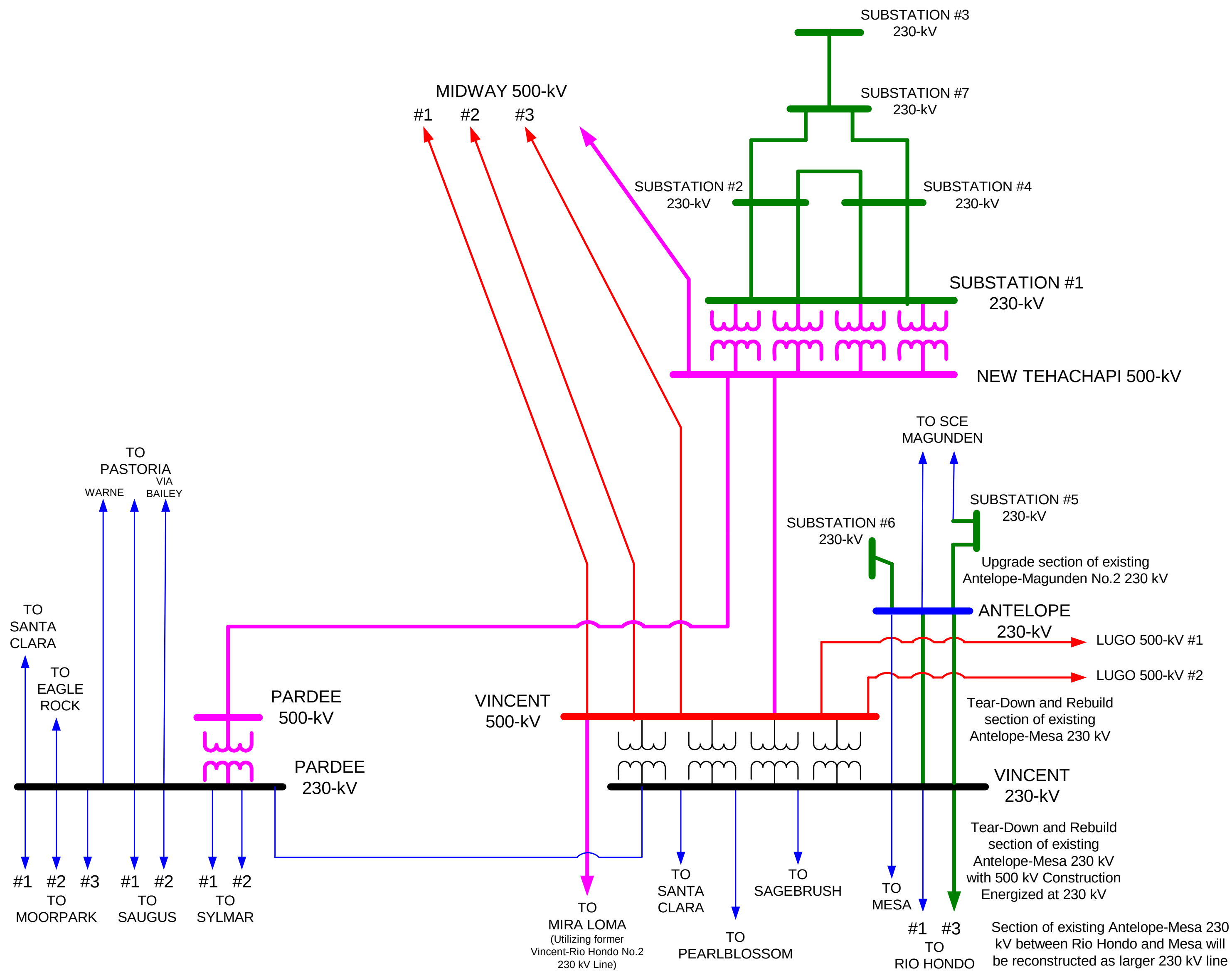


Figure A-4
Alternative 10



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

Conceptual power flow studies were not conducted for simultaneous loss of two transmission lines (N-2). Many of the problems associated with simultaneous loss of two transmission elements can be solved with use of a special protection scheme. Other problems associated with simultaneous loss of two transmission elements cannot be identified with simple conceptual analysis but rather require the detailed system impact studies to be performed. As such, no effort was made in identifying conceptual requirements for loss of two transmission facilities. Additionally, since the studies are conceptual in nature and do not properly identify impacts, the design of special protection schemes cannot be developed and therefore use of such schemes to resolve problems is difficult to determine. As such, detailed studies are necessary as results from these studies form the basis for identifying necessary equipment and engineering design which in turn drives the actual facility costs.

The following sections present the conceptual power flow results for the alternatives identified in Section 1 of this Appendix A.

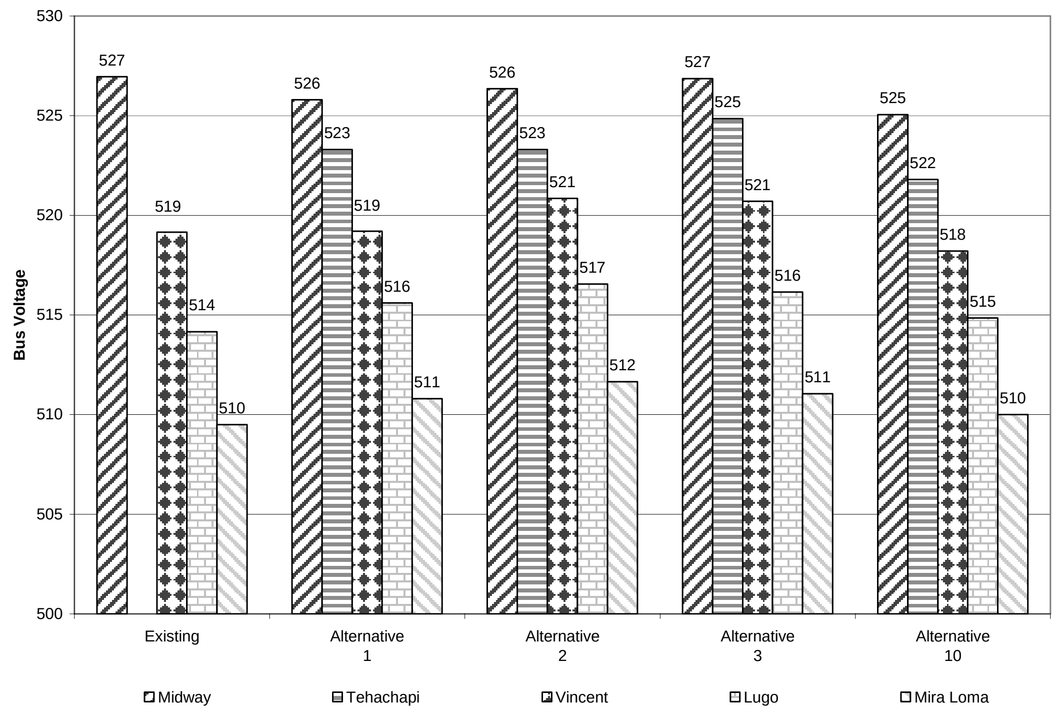
2.1. SCE Transmission System

2.1.1 SCE Conceptual Power Flow Case Summary

2.1.1.1 Heavy Summer Critical Bus Voltages

Critical bus voltages were evaluated in order to properly determine if under heavy summer conditions, the identified network facilities are sufficient to interconnect and deliver Tehachapi area wind generation. These bus voltages are summarized below in Figure A-5.

Figure A-5
Critical Bus Voltages



As can be seen, on a comparative basis to the existing network, the addition of shunt capacitor banks (713 MVAR) was necessary throughout the SCE network to maintain critical 500 kV bus voltages at the existing operating limits. Without installation of these reactive resources, bus voltages at Vincent would not meet the minimum acceptable operating voltage schedule.

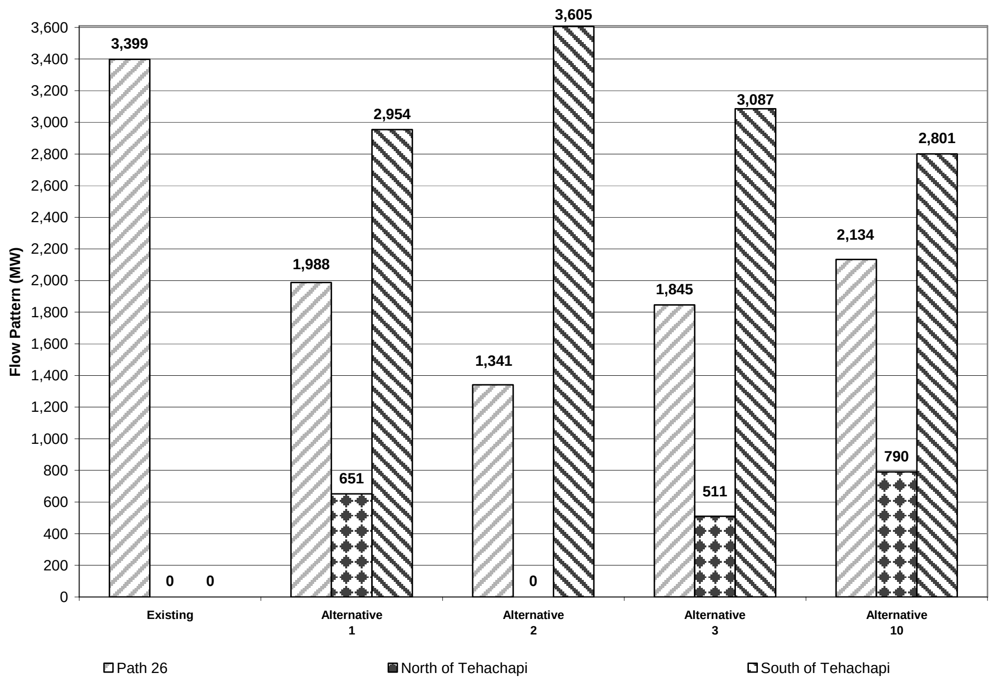
2.1.1.2 Heavy Summer Path 26 and Tehachapi Area Flow Patterns

With the addition of the Tehachapi area wind resource area, the total flow on Path 26 is reduced as wind generation is scheduled to serve PG&E system load. For reporting purposes, the flows on the existing three Midway-Vincent 500 kV lines were considered as Path 26. Flows on new transmission facilities connecting the Tehachapi area to both SCE and PG&E where not considered to be part of Path 26. It should be noted that transmission alternatives that involve a new transmission line which connects the Tehachapi area to both SCE and PG&E will in fact be part of Path 26. Detailed studies in accordance with WECC Procedures for Regional Planning Project Review and Rating Transmission Facilities[23] and the WECC Progress Report

[23] http://www.wecc.biz/documents/library/procedures/planning/NEWRPPR_402_Revised.pdf

Policies and Procedures[24] will therefore be required in order to establish revised Accepted Path Rating and obtain the proper technical approvals. Flow patterns obtained after integrating the Tehachapi wind resource area are summarized below in Figure A-6.

Figure A-6
Path 26 and Tehachapi Flow Patterns

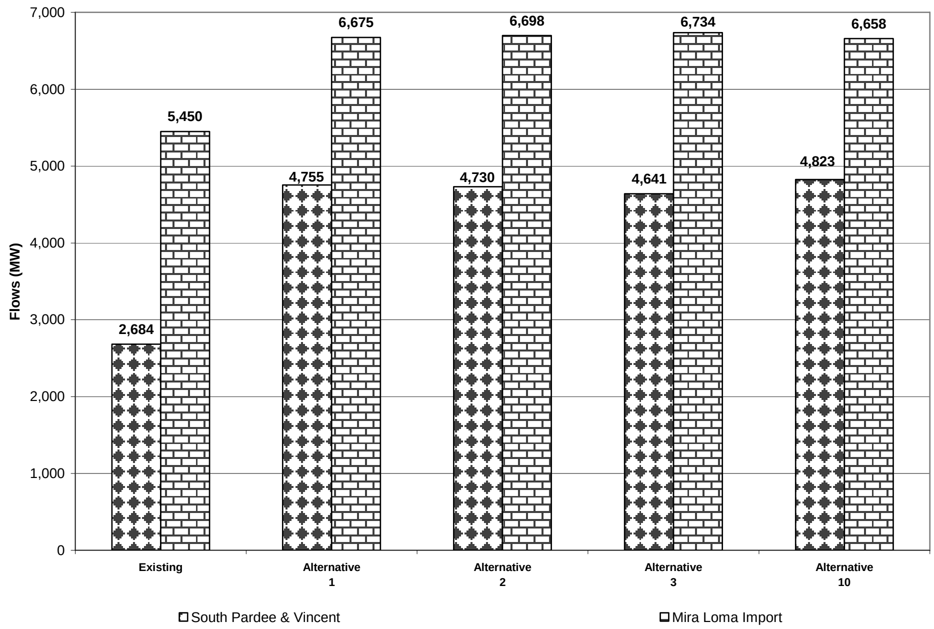


2.1.1.3 Increased Flow South of Lugo, Pardee and Vincent

With the addition of over 4,000 MW of wind generation in the Tehachapi area, additional north-to-south flow was identified since 50% of the Tehachapi renewable resource was scheduled to Arizona, Baja California, and Southern California. Such flows will be captured in terms of increased flow to the Mira Loma area and increased flow south of the Pardee and Vincent substations. The flow patterns obtained after integrating the Tehachapi wind resource area are summarized below in Figure A-7.

[24] http://www.wecc.biz/documents/library/procedures/Progress_Report_Procedures_2002.pdf

Figure A-7
Mira Loma Import and South of Pardee & Vincent Flow Patterns



2.1.1.4 Incremental System Losses

System losses were found to increase with the integration of wind generation resources from the Tehachapi losses. This increase in losses is attributed to displacing generation resources located close to the load centers and transmitting the energy produced from the Tehachapi generation located away from the load centers.

Figure A-8 summarizes the incremental real power losses identified in the four alternatives. As can be seen, the results are not substantially different and therefore line loss reduction is not expected to play a significant role in determining the best economic alternatives. Figure A-9 summarizes the incremental reactive power losses identified in the four alternatives. It should be noted that on average, 45% of the incremental reactive losses was supplied from the addition of the shunt capacitor banks and the remaining 55% of the incremental reactive losses was supplied from existing synchronous generators throughout the system. Detailed system impact studies will be necessary to determine adequacy of transient stability performance and need for dynamic reactive resources. On a conceptual basis, the capacitor banks were assumed to be sufficient. However, need for dynamic support may result in higher cost estimates than those provided.

Figure A-8
Incremental Real Power Losses (MW)

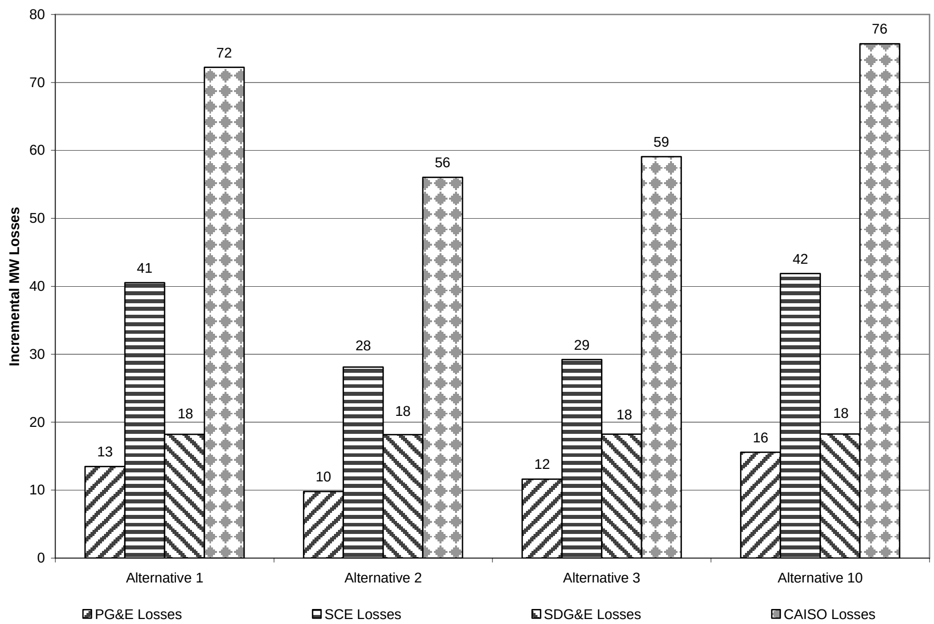


Figure A-9
Incremental Reactive Losses (MVAR)

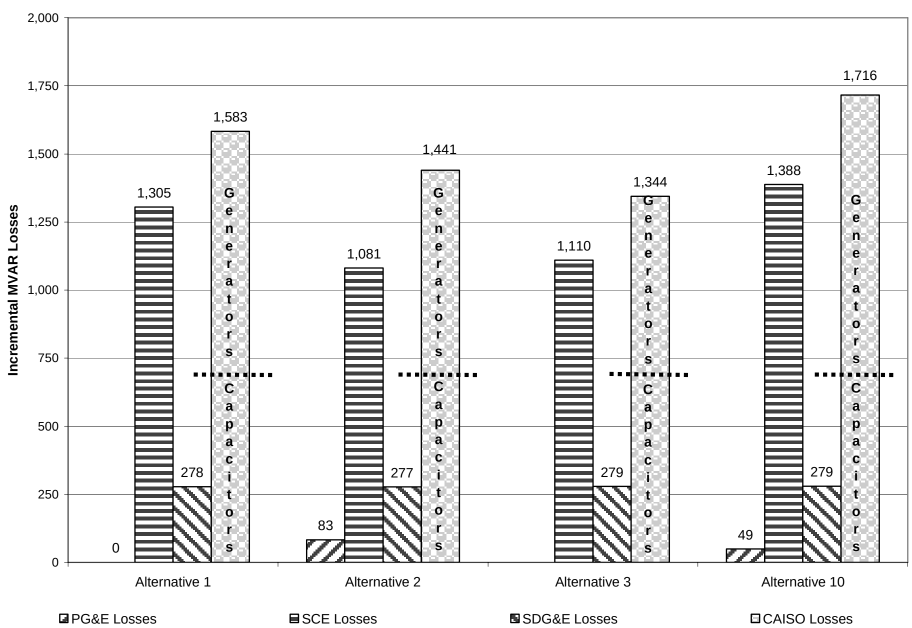
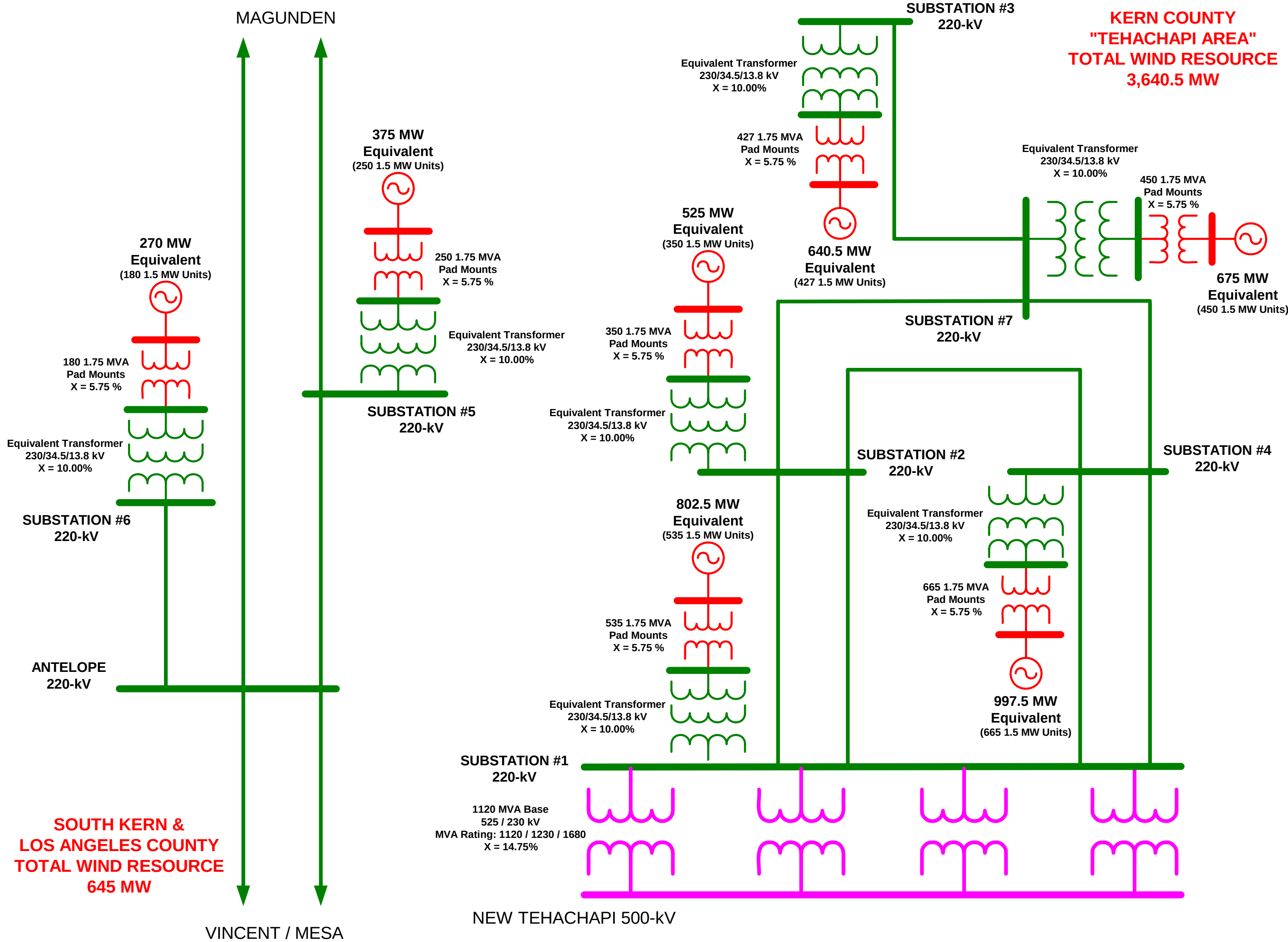


Figure A-10


MAGUNDEN
375 MW
Equivalent
(250 1.5 MW Units)
250 1.75 MVA
Pad Mounts
X = 5.75 %
Equivalent Transformer
230/34.5/13.8 kV
X = 10.00%
SUBSTATION #5
220-kV
270 MW
Equivalent
(180 1.5 MW Units)
180 1.75 MVA
Pad Mounts
X = 5.75 %
Equivalent Transformer
230/34.5/13.8 kV
X = 10.00%
SUBSTATION #6
220-kV
ANTELOPE
220-kV
SOUTH KERN &
LOS ANGELES COUNTY
TOTAL WIND RESOURCE
645 MW
VINCENT / MESA
SUBSTATION #3
220-kV
KERN COUNTY
"TEHACHAPI AREA"
TOTAL WIND RESOURCE
3,640.5 MW
Equivalent Transformer
230/34.5/13.8 kV
X = 10.00%
427 1.75 MVA
Pad Mounts
X = 5.75 %
640.5 MW
Equivalent
(427 1.5 MW Units)
Equivalent Transformer
230/34.5/13.8 kV
X = 10.00%
450 1.75 MVA
Pad Mounts
X = 5.75 %
675 MW
Equivalent
(450 1.5 MW Units)
525 MW
Equivalent
(350 1.5 MW Units)
350 1.75 MVA
Pad Mounts
X = 5.75 %
Equivalent Transformer
230/34.5/13.8 kV
X = 10.00%
SUBSTATION #7
220-kV
SUBSTATION #2
220-kV
SUBSTATION #4
220-kV
802.5 MW
Equivalent
(535 1.5 MW Units)
535 1.75 MVA
Pad Mounts
X = 5.75 %
Equivalent Transformer
230/34.5/13.8 kV
X = 10.00%
Equivalent Transformer
230/34.5/13.8 kV
X = 10.00%
665 1.75 MVA
Pad Mounts
X = 5.75 %
997.5 MW
Equivalent
(665 1.5 MW Units)
SUBSTATION #1
220-kV
1120 MVA Base
525 / 230 kV
MVA Rating: 1120 / 1230 / 1680
X = 14.75%
NEW TEHACHAPI 500-kV

Transmission Facilities Common in all four SCE Alternatives:

- New Vincent-Mira Loma 500 kV Transmission Line
- Pardee-Pastoria Transmission Line Reconductor
- Antelope Transmission Project - Segment 1: New Antelope-Pardee transmission line be designed for 500 kV but initially energized at 230 kV.
- Antelope Transmission Project – Segments 2 and 3: Segment 2 consists of a new 500 kV transmission line, initially energized at 230 kV, between Vincent and Antelope. Segment 3 consists a new 500 kV transmission line initially energized at 230 kV between Antelope and the new Tehachapi area Substation 1 (near Cal Cement). Segment 3 also includes certain local Tehachapi area facilities.
- Second 500 kV Transmission Line between Antelope and Tehachapi
- Antelope-Mesa 230 kV Transmission Line Upgrade between Vincent and Mesa: The tear-down and rebuild can be sectionalized into three segments (1) Rio Hondo to Mesa, (2) Vincent to Rio Hondo, and (3) Antelope to Vincent.
- Antelope-Conceptual Substation 5 Line Upgrade: involving the existing Antelope-Magunden No.2 230 kV transmission line
- Additional Reactive Resources in SCE system

Transmission Facilities not common in all four Alternatives:

- New Pardee 500 kV Facilities associated with Alternatives 1, 2 and 10
- New Antelope 500 kV Facilities associated with Alternatives 1 and 2
- Third 500 kV Transmission Line between Antelope and Tehachapi associated with SCE Alternative 2
- Second 500 kV Transmission Line between Antelope and Vincent associated with SCE Alternatives 2 and 3
- Antelope-Mesa 230 kV Transmission Line Upgrade between Antelope and Vincent. This line would require upgrading to 500 kV if either Alternatives 1 or 2 is selected; and would require upgrading to double circuit 230 kV if SCE Alternatives 3 or 10 is selected.
- New 500 kV Transmission Line from Tehachapi to PG&E: Alternatives 1, 3, and 10 include 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. 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. These PG&E will be discussed in Appendix B

2.2. Alternative 1 Study Results

2.2.1 Base Case Power Flow Results – Alternative 1

Conceptual power flow results indicate that the existing Antelope-Vincent 230 kV transmission line loads up to 107% of normal conductor limit. As a result, upgrade of this transmission line may be required to ensure delivery of wind generation to appropriate load centers.

2.2.2 Single Contingency Power Flow Results – Alternative 1

Conceptual power flow results identified four single contingencies that result in thermal overloads under heavy summer conditions and ten single contingencies that result in thermal overloads under light spring conditions. The contingencies were found to impact five different 230 kV transmission lines. The impacts to the five overloaded lines are summarized as follows:

a) Three outages impact Bailey-Pastoria 230 kV transmission line (T/L) with loss of the Antelope-Tehachapi5 230 kV T/L (section of existing Antelope-Magunden No.2 230 kV) resulting in highest overload of up to 128%. Use of a special protection scheme (SPS), subject to CA ISO and WECC approval, may resolve these problems.

b) Two outages impact existing Antelope-Vincent 230 kV T/L with loss of new Antelope-Vincent No.2 230 kV T/L (upgraded section of existing Antelope-Mesa 230 kV) resulting in highest overload of 190%. Since the overload is significant, use of an SPS is deemed to be inappropriate therefore requiring additional upgrade of this T/L. The upgrade will necessitate tear-down and rebuild of the existing line as the current tower infrastructure is insufficient to support a larger conductor size. It is envisioned that the rebuild be double-circuit tower design.

c) Six outages impact the existing Antelope-Magunden No.1 230 kV T/L with loss of Antelope- Tehachapi5 230 kV T/L resulting in highest overload of 168%. Use of an SPS, subject to CA ISO and WECC approval, may resolve these problems.

d) Six outages impact the existing Pardee-Pastoria-Warne 230 kV T/L with loss of Bailey-Pastoria 230 kV resulting in highest overload of 131% on the Pardee leg. Use of an SPS, subject to CA ISO and WECC approval, may resolve these problems.

e) Outage of the new Vincent-Rio Hondo No.3 230 kV T/L (upgraded section of existing Antelope-Mesa 230 kV) overloads the existing Vincent-Rio Hondo No.1 230 kV T/L up to 122%. Use of an SPS, subject to CA ISO and WECC approval, may resolve these problems.

2.3 Alternative 2 Study Results

2.3.1 Base Case Power Flow Results – Alternative 2

Conceptual power flow results indicate that the existing Antelope-Vincent 230 kV transmission line loads up to 100% of normal conductor limit.

2.3.2 Single Contingency Power Flow Results – Alternative 2

Conceptual power flow results identified three single contingencies that result in thermal overloads under heavy summer conditions and twelve single contingencies that result in thermal overloads under light spring conditions. The contingencies were found to impact six different 230 kV transmission lines. The impacts to the six overloaded lines are summarized as follows:

a) Three outages impact Bailey-Pastoria 230 kV transmission line (T/L) with loss of the Antelope-Tehachapi5 230 kV T/L resulting in highest overload of up to 128%. Use of an SPS, subject to CA ISO and WECC approval, may resolve these problems.

b) Three outages impact existing Antelope-Vincent 230 kV T/L with loss of new Antelope-Vincent No.2 230 kV T/L resulting in highest overload of 154%. Since the overload is significant, use of an SPS is deemed to be inappropriate therefore requiring additional upgrade of this T/L. The upgrade will necessitate tear-down and rebuild of the existing line as the current tower infrastructure is insufficient to support a larger conductor size. It is envisioned that the rebuild be double-circuit tower design.

c) Six outages impact the existing Antelope-Magunden No.1 230 kV T/L with loss of Antelope- Tehachapi5 230 kV T/L resulting in highest overload of 166%. Use of an SPS, subject to CA ISO and WECC approval, may resolve these problems.

d) Six outages impact the existing Pardee-Pastoria-Warne 230 kV T/L with loss of Bailey-Pastoria 230 kV resulting in highest overload of 131% on the Pardee leg. Use of an SPS, subject to CA ISO and WECC approval, may resolve these problems.

e) Outage of the new Vincent-Rio Hondo No.3 230 kV T/L overloads the existing Vincent-Rio Hondo No.1 230 kV T/L up to 122%. Use of an SPS, subject to CA ISO and WECC approval, may resolve these problems.

f) Outage of the Eagle Rock-Sylmar 230 kV T/L overloads the Eagle Rock-Pardee 230 kV T/L up to 122%. Use of an SPS, subject to CA ISO and WECC approval, may resolve these problems.

2.4 Alternative 3 Study Results

2.4.1 Base Case Power Flow Results – Alternative 3

Conceptual power flow results indicate that the existing Antelope-Vincent
230 kV transmission line loads up to 104% of normal conductor limit. As a result, upgrade of this transmission line may be required.

2.4.2 Single Contingency Power Flow Results – Alternative 3

Conceptual power flow results identified one single contingency that result in thermal overloads under heavy summer conditions and eighteen single contingencies that result in thermal overloads under light spring conditions. The contingencies were found to impact six different 230 kV transmission lines. The impacts to the six overloaded lines are summarized as follows:

a) Three outages impact Bailey-Pastoria 230 kV transmission line (T/L) with loss of the Antelope-Tehachapi5 230 kV T/L resulting in highest overload of up to 128%. Use of an SPS, subject to CA ISO and WECC approval, may resolve these problems.

b) Fourteen outages impact existing Antelope-Vincent 230 kV T/L with loss of new Antelope-Vincent No.2 230 kV T/L resulting in highest overload of 187%. Since the overload is significant, use of an SPS is deemed to be inappropriate therefore requiring additional upgrade of this T/L. The upgrade will necessitate tear-down and rebuild of the existing line as the current tower infrastructure is insufficient to support a larger conductor size. It is envisioned that the rebuild be double-circuit tower design.

c) Six outages impact the existing Antelope-Magunden No.1 230 kV T/L with loss of Antelope- Tehachapi5 230 kV T/L resulting in highest overload of 166%. Use of an SPS, subject to CAISO and WECC approval, may resolve these problems.

d) Six outages impact the existing Pardee-Pastoria-Warne 230 kV T/L with loss of Bailey-Pastoria 230 kV resulting in highest overload of 132% on the Pardee leg. Use of an SPS, subject to CAISO and WECC approval, may resolve these problems.

e) Outage of the new Vincent-Rio Hondo No.3 230 kV T/L (upgraded section of existing Antelope-Mesa 230 kV) overloads the existing Vincent-Rio Hondo No.1 230 kV T/L up to 121%. Use of an SPS, subject to CAISO and WECC approval, may resolve these problems.

f) Outage of the Eagle Rock-Sylmar 230 kV T/L overloads the Eagle Rock-Pardee 230 kV T/L up to 123%. Use of an SPS, subject to CAISO and WECC approval, may resolve these problems.

2.5 Alternative 10 Study Results

2.5.1 Base Case Power Flow Results – Alternative 10

Conceptual power flow results indicate that the existing Antelope-Magunden No.1 230 kV transmission line loads up to 109% of normal conductor limit. As a result, upgrade of this transmission line may be required.

2.5.2 Single Contingency Power Flow Results – Alternative 10

Conceptual power flow results identified two single contingencies that result in thermal overloads under heavy summer conditions and sixteen single contingencies that result in thermal overloads under light spring conditions. The contingencies were found to impact six different 230 kV transmission lines and one 500/230 kV transformer bank. The impacts to the six overloaded lines and one transformer bank are summarized as follows:

a) Three outages impact Bailey-Pastoria 230 kV transmission line (T/L) with loss of the Antelope-Tehachapi5 230 kV T/L resulting in highest overload of up to 126%. Use of an SPS, subject to CAISO and WECC approval, may resolve these problems.

b) Three outages impact the existing Antelope-Vincent 230 kV T/L with loss of either Antelope-Vincent No.2 or No.3 230 kV T/L resulting in the highest overload of 109%. It appears that the use of an SPS may not be a suitable solution due to exceeding generation tripping limits under loss of two transmission line contingencies. As a result, the Antelope-Vincent 230 kV T/L should be upgraded to improve overall performance in order to be in compliance with CAISO generation tripping limitations.

c) Twelve outages impact the existing Antelope-Magunden No.1 230 kV T/L with loss of Antelope- Tehachapi5 230 kV T/L resulting in highest overload of 184%. For the same reasons discussed above, it is necessary that the existing Antelope-Magunden No.1 230 kV T/L be upgraded.

d) Four outages impact the existing Pardee-Pastoria-Warne 230 kV T/L with loss of Bailey-Pastoria 230 kV resulting in highest overload of 126% on the Pardee leg. Use of an SPS, subject to CAISO and WECC approval, may resolve these problems.

e) Outage of the new Vincent-Rio Hondo No.3 230 kV T/L (upgraded section of existing Antelope-Mesa 230 kV) overloads the existing Vincent-Rio Hondo No.1 230 kV T/L up to 122%. Use of an SPS, subject to CAISO and WECC approval, may resolve these problems.

f) Outage of the Eagle Rock-Sylmar 230 kV T/L overloads the Eagle Rock-Pardee 230 kV T/L up to 129%. Use of an SPS, subject to CAISO and WECC approval, may resolve these problems.

g) Outage of the Vincent-Tehachapi No.1 500 kV overloads the new Pardee 500/230 kV Transformer Bank in excess of the maximum allowable limits. As a result, a second transformer bank will be necessary to mitigate any such overload.

Appendix B - PG&E Study Alternatives

1. PG&E Alternatives

Under **summer peak** conditions, the import of Tehachapi wind generation to serve the Bay Area loads would schedule power flow in the south-to-north direction (counter to the prevalent flow) on Path 15 and Path 26 and is not expected to cause normal or emergency overloads on the existing PG&E system. Power flow studies show that under summer on-peak operating conditions when prevalent the power transfer is typically from north to south on Path 26, addition of generation south of Midway would tend to decrease power transfer into Southern California. In addition, since La Paloma, Elk Hill, and Sun Rise combined-cycle plants were released for commercial operation in 2003, Path 15 power flow is typically lightly loaded under summer peak conditions. (See Table B-2)

Accordingly, all PG&E alternatives investigated are for mitigating expected **off-peak** transmission problems when the prevalent power transfer is in the south to north direction. PG&E investigated three alternatives to mitigate the impacts of scheduling and delivering 2,000 MW of Tehachapi generation (Alternatives 1, 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 (Table B-1).

1.1 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. Based on the number of overloaded facilities and the magnitude of overload under normal conditions (see Table B-5), this Alternative would expand the times and conditions under which curtailment of generation would be required. It would also reduce operating flexibility. Compliance with FERC Open Access rules, and agreement from the CAISO, among other requirements, would be needed for all three options listed below:

1.1.1 Schedule and Deliver Tehachapi wind generation to PG&E using the existing Path 26 south-to-north transfer capability:

Due to the constraints on Path 15 south-to-north transfer capability, only about 1,300 MW of the existing Path 26 south-to-north rating (3,000 MW) can be transmitted from Southern California to the Bay Area under certain off-peak conditions (see Table B-3). Assuming it were consistent with FERC open access rule, this option would replace the existing 1,300 MW of south-to-north power transfer from Southern California with 1,300 MW of Tehachapi wind generation. Because under this scenario no change in power transfer would result north of Midway, no network upgrade would be needed in the PG&E area. This option could require that some contracts be negotiated or renegotiated, potentially adding new contractual encumbrances. In addition, if the original 1,300 MW (which was displaced by the Tehachapi generation) of south-to-north power transfer from Southern California must be returned to the Pacific Northwest, it would have to take alternative paths in the Western Interconnected System, the impacts of this alternative power flow pattern has not been studied.

Table 3B-1: Preliminary PG&E Area Conceptual Transmission Plan for Importing Tehachapi Generation

Import	PG&E Alternative 1	PG&E Alternative 2	PG&E Alternative 4	PG&E Alternative 5
300 MW	**Network Upgrades:** Not determined. (see discussion below)	Build a 230 kV 300 MW phase-shift switching station at Big Creek. **Other Network Upgrades:** None, does not include SCE cost estimate	N/A	N/A
1100 MW	**Network Upgrades:** Not determined. (see discussion below)	N/A	**Phase A:** Build a new Los Banos – Midway 500 kV line with 65% series comp **Other Network Upgrades:** Upgrade Los Banos – Westley 230 kV line and Los Banos 500/230 kV transformer.	**Phase A:** Build a new Gregg - Tehachapi 500 kV line with 62% series comp and a new Gregg 500 kV Substation with one 500/230 kV bank. **Other Network Upgrades:** Upgrade Los Banos - Westley 230 kV line
1500 MW	**Network Upgrades:** Not determined. (see discussion below)	N/A	**Phase B:** Same as Phase A, except also building a new Tesla – Los Banos 500 kV line. **Other Network Upgrades:** None	**Phase B:** Same as Phase A, except also building a new Tesla - Gregg 500 kV line w/o series comp. **Other Network Upgrades:** None
2000 MW	**Network Upgrades:** Not determined. (see discussion below)	N/A	**Phase C:** Same as Phase B, except also install RAS to trip Tehachapi generation. See Note 1. **Other Network Upgrades:** None. However, if the RAS is not approved, then new transmission facilities would be needed.	**Phase C:** Same as Phase B, except installing 62% series comp on the Tesla – Gregg. **Other Network Upgrades:** None

1.1.2 Displace Midway Area generation

Approximately 3,050 MW of the 3,350 MW of installed generation capacity in the Midway area were assumed on-line in the base case. Most of the 3,350 MW of generation are combine-cycle, oil-recovery plants or existing Qualifying Facilities (QFs). Approximately 2,600 MW of the Midway area generation were connected to the existing Path 15 Remedial Action Scheme (RAS) and therefore participate in generation tripping for a 500 kV double-line outage between Tesla and Midway. This scheme was identified as part of detailed System Impact and Facility Studies for the existing generators at Midway and was put in place as a requirement for the generators to interconnect in the Midway area. The scheme enables the system to maintain public safety and compliance with Applicable Planning Criteria by reducing power flowing on the remaining lines immediately following the identified outages. The remaining 450 MW of generation assumed on-line are either supplying their own load (oil recovery plants) and cannot participate in the RAS or are too small to effectively participate in RAS.

The 5,400 MW of Path 15 south-to-north transfer capability under normal conditions can only be supported with operation of the RAS immediately following the identified outages. If the 2,600 MW of 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 of about 4,100 MW, which is a decrease of 1,300 MW. Due to the reduction on Path 15 transfer capability, approximately 1,300 MW of Tehachapi wind generation could be scheduled in place of the 2,600 MW of Midway area generation. Note the dispatching the Midway generation off-line may not be feasible since the same generators would need to be on-line to support the next day's peak load. Agreement from the CAISO will be necessary.

1.1.3 Connect Tehachapi Wind Turbines To Path 15 RAS

Assuming that FERC open access rules were satisfied, another way of maintaining Path 15's transfer capability of 5,400 MW is to replace the Path 15 RAS provided by the Midway generation with Tehachapi wind generation. Due to the intermittent nature of wind generation, the existing RAS controllers used in the Path 15 RAS could not estimate the available amount of wind generation to trip for the next contingency. A new type of RAS controller and other equipment would be required. In addition, 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 (or shadow generation) to the extent they are electrically close to Midway. Because Tehachapi generation is electrically further way from Path 15 as compared to the Midway generation, it is expected that the Tehachapi wind turbine and its shadow generators would be less effective in relieving overload around Path 15 than that of the existing Midway generation RAS. Therefore, more generation tripping will be necessary to relieve overloads than would otherwise be necessary. As mentioned above, this RAS would need to be approved by WECC, and be in compliance with CAISO Criteria for the use of RAS for mitigation.

1.2 **PG&E Alternative 2**: Big Creek-Fresno Phase-Shifted Tie (Figure B-1)

This Alternative would establish a new interconnection point between PG&E and SCE by building a Big Creek-Fresno 230 kV Phase Shifter Tie to tie together PG&E's Gregg-Helms PSP with SCE's Big Creek-Rector 230 kV lines at a new switching station. This Alternative would enable to import 300 MW of Tehachapi wind generation to the Fresno Area, which is located north of Path 15. Study shows that for 300 MW of power transfer in the PG&E system, additional network upgrade is not needed. This alternative has no impact on the existing Path 15 south-to-north transfer capability and would not need any additional network upgrades at PG&E system. It could also potentially defer the need for the proposed Fresno Long-term Plan Project (a new Gates – Gregg 230 kV double-circuit tower line) by about 8 years. However, SCE's Big Creek system would require additional network upgrades to support the import, the cost of which is not included in this PG&E report (see Appendix C, SCE study). This Alternative would also require contractual arrangements between PG&E and SCE on issues such as inadvertent flow, and agreement between PG&E, SCE and the CAISO governing the dispatch and operation of the existing generators, resolution of any physical limitation of Helms Pump Storage Plant and other operating issues. This alternative will be further discussed in Appendix C.

1.3 **PG&E Alternative 3**: Bakersfield-Magunden Phase-Shifted Tie (—Figure B-1)

The study results show that the Magunden 230 kV Phase-shifted Tie with 300 MW of import could cause normal and emergency overloads under summer off-peak conditions. The Gates – Midway 500 kV line could experience 100.6% normal overload and 106% emergency overload for loss of the Los Banos – Midway 500 kV line (Category "B" contingency). The overloads under normal and Category B emergency condition indicate that this alternative could realize less than 300 MW of transfer capability and would require additional RAS to trip the Tehachapi wind generation or network upgrades.

Due to the low import capability and the need for additional network upgrades, this alternative was removed from further consideration.

1.4 **PG&E Alternative 4**: Tesla-Los Banos-Midway 500 kV Lines (Figure B-2)

This alternative of building a 500 kV line from Tesla to Midway along the existing Pacific AC Intertie (PACI) route could potentially import about 2,000 MW of Tehachapi wind generation to the Bay Area. This alternative could be implemented in three phases.

i. Phase A would build a Los Banos – Midway 500 kV line with 65% series compensation and upgrade transmission facilities between Los Banos and Wesley substations. This addition would allow import of about 1100 MW.

ii. Phase B would in addition to Phase A build a Tesla – Los Banos 500 kV line. This addition would allow a total import of 1500 MW.

iii. Phase C would, in addition to Phase B, also install a Remedial Action Scheme (RAS) to trip about 1,000 MW of Tehachapi generation during contingencies that would allow a **total** import of 2,000 MW.

The increase use of RAS in Phase C must be approved by the WECC and CAISO. A new type of RAS with the accompanying relaying and communications facilities would be required because the existing RAS controller cannot estimate intermittent generation to determine the generators to be tripped for the next contingency. If a RAS cannot be implemented, then new transmission facilities such as a new Tehachapi – Midway 500 kV line could be required.

1.5 **PG&E Alternative 5**: Tesla- Gregg - Tehachapi 500 kV Lines (Figure B-3)

This alternative of building a Tesla – Gregg – Tehachapi 500 kV line could potentially import about 2,000 MW of Tehachapi wind generation to the Fresno Area and the Bay Area. This alternative could be implemented in three phases.

i. Phase A would build a Gregg – Tehachapi 500 kV line with 62% series compensation and a new Gregg 500 Substation. This addition would allow import of about 1,100 MW.

ii. Phase B would in addition to Phase A build a Tesla – Gregg 500 kV line. This addition would allow a total import of 1,500 MW.

iii. Phase C would in addition to Phase B install 62% series compensation on the Tesla – Gregg 500 kV line that would be able to import a total of 2,000 MW.

This alternative would also increase the Fresno Area import capability by about 1,000 MW that would eliminate the need for the Fresno Long Term Plan Project (a new Gates – Gregg 230 kV double-circuit tower line). Contractual arrangements must be worked out between PG&E and SCE to establish a new interconnection point, and to work out issues such as inadvertent flow. Agreement also needs to be established between PG&E, SCE and the CAISO regarding dispatch and use of existing generation. The impact of balancing and integrating the initial 1,100 MW of an intermittent energy such as wind generation on the Fresno area customers and resolution of any physical limitation of Helms Pump Storage Plant would also need to be addressed.

Figure B-1: Alternatives 2 and 3: SCE-PG&E Phase-shifted System Tie

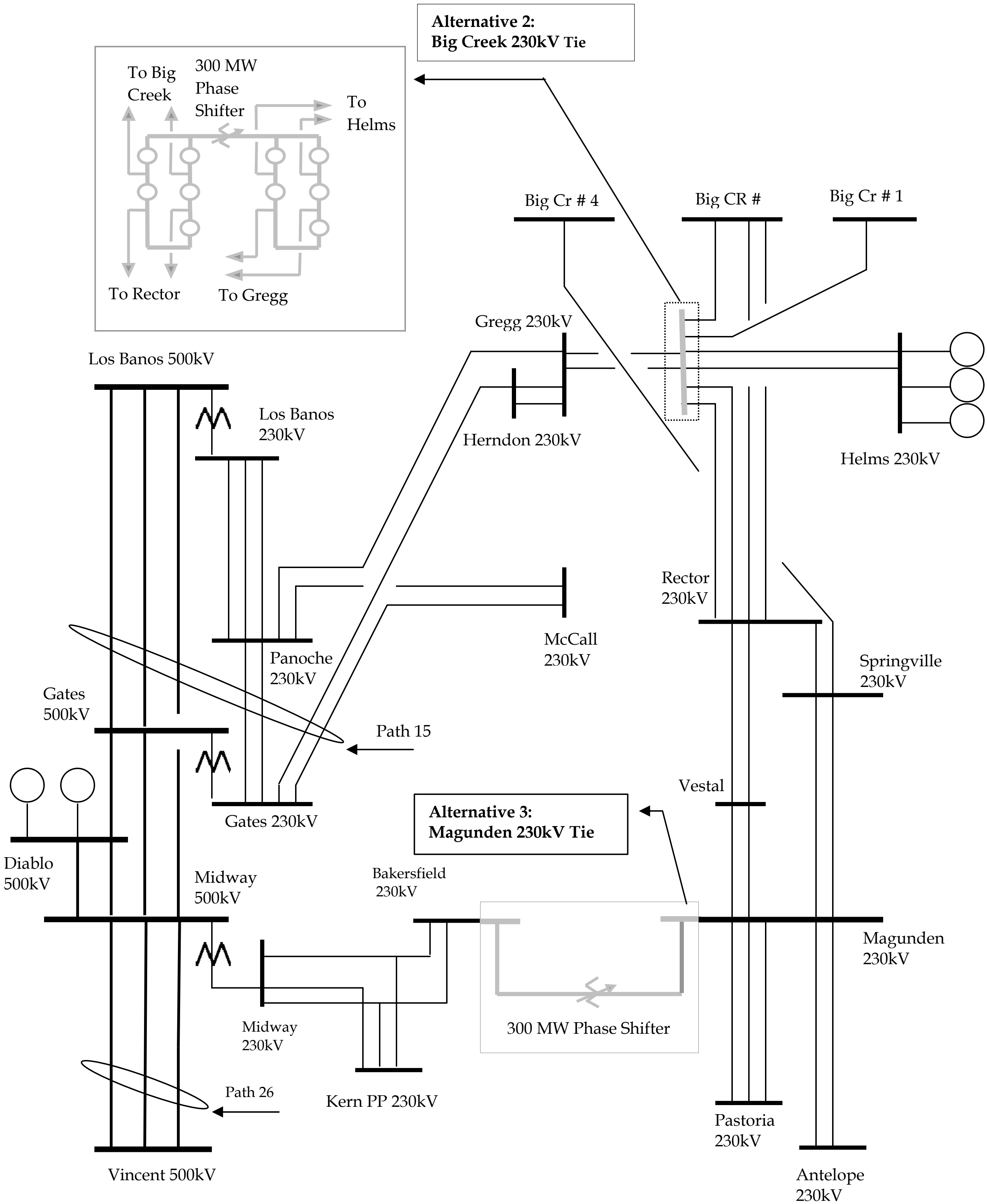


Figure B-3: Alternative 4: Tesla – Los Banos – Midway 500 kV line

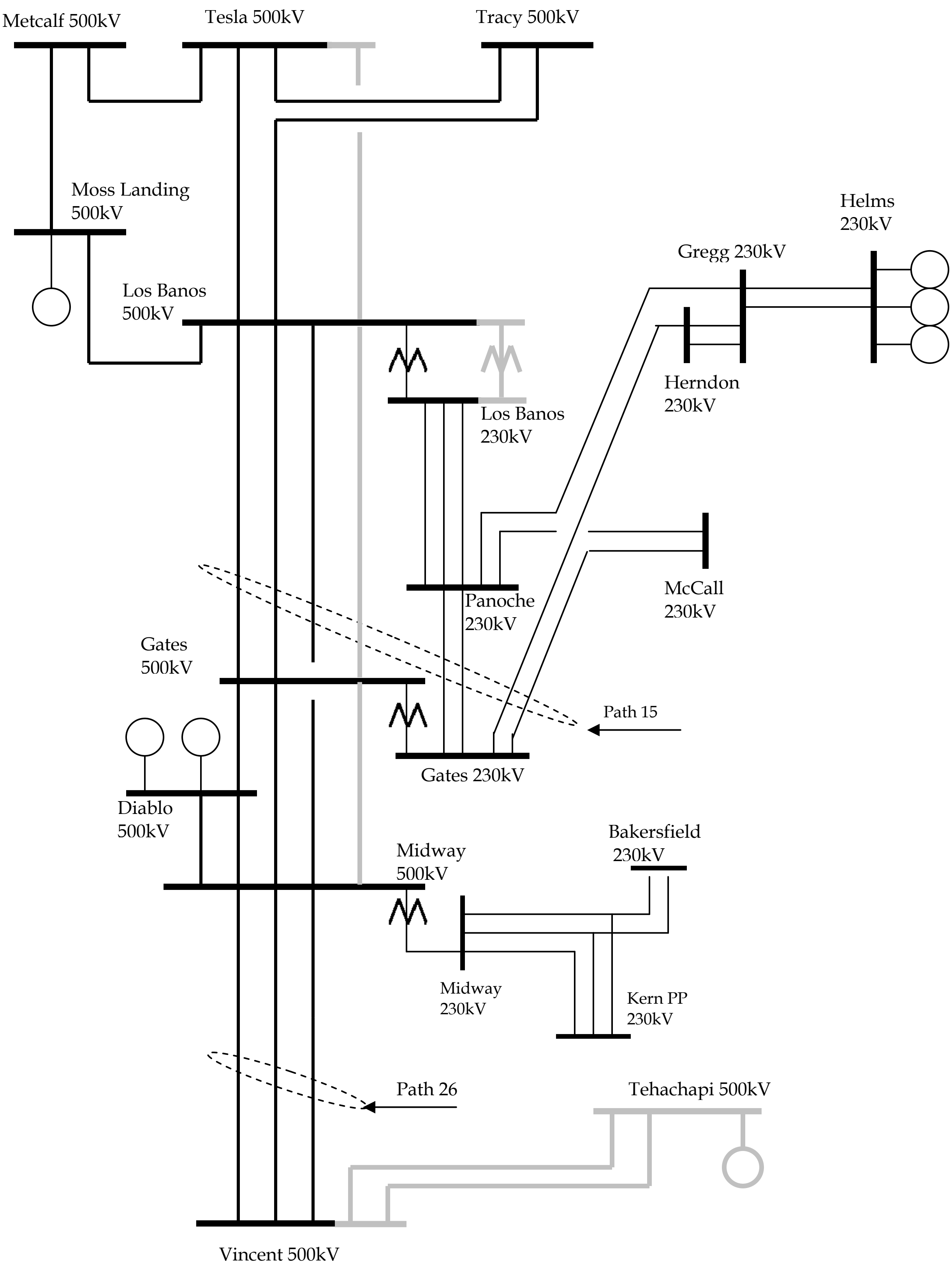
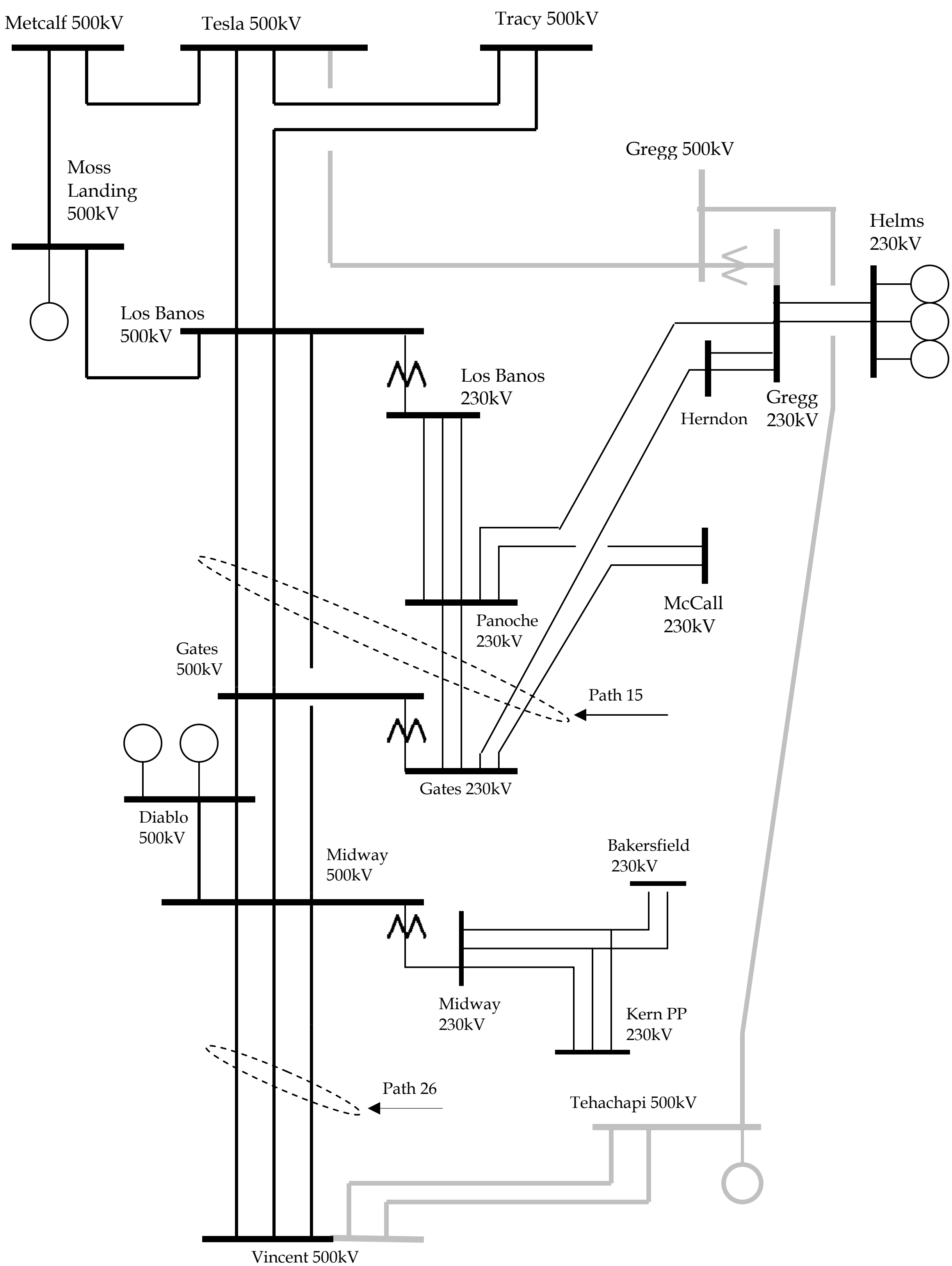


Figure B-4: Alternative 5: Tesla – Gregg – Tehachapi 500 kV line



2. PG&E Power Flow Studies

The SCE and PG&E transmission systems are interconnected by Path 26 via three 500 kV transmission lines: Midway-Vincent No.1; Midway-Vincent No.2; and Midway-Vincent No.3.

Path 26 has a north-to-south WECC Accepted Rating of 3,400 MW and a south-to-north WECC Accepted Rating of 3,000 MW. This path is expected to play an important role in transmitting renewable energy from resources located in the SCE or SDG&E areas (SP15).

PG&E performed power for peak and off-peak conditions under normal (all facilities in service) conditions and for selected single and double 500 kV contingencies.

2.1 Delivering 2,000 MW of Tehachapi Power to PG&E's Midway Substation:

2.1.1 Under Expected Summer Peak Conditions

Southern California historically relies on imports to serve local loads typically under summer peak conditions. Path 26 is one of the major paths for used for importing hydro generation located in the Northwest and typically has heavy north-to-south power flows under summer peak conditions. In the event of imports of Tehachapi generation to serve the Bay Area loads, a counter-flow is created, as a result, Path 26 would experience a south-to-north flow that would result in decreasing the original north-to-south loading on Path 26 Table B-2 shows that for the case studied, power flow on Path 26 decreases from 3,403 MW to 1,416 MW in the north to south direction with increase import of 2,000 MW.

Table B-2: PG&E Area Loads, Generation and Major Path Flow
(2009 Summer Peak Base Cases)

Descriptions	Base Case	Importing 2,000 MW at Midway w/o upgrade
Path 66 Flow (north to south)	4,800	4,518
Path 15 Flow (north to south)	558	-1,411
Path 26 Flow (north to south)	3,403	1,416
PDCI Flow (north to south)	3,094	3,090
PG&E Area Load/Loss	27,480	27,467
PG&E Area Generation	26,039	24,317
Fresno Area Load/Loss	3,088	3,083
Helms Generation*	1,200	1,200

Fresno Transmission Imports	635	629
Imports from Tehachapi Generation	0	2,000
Generation Reduction in the Bay Area	0	1,700

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

2.1.2 Under Expected Off-Peak Conditions

South-to-north power flows on the existing Path 26 typically occur during off-peak hours when SCE and other Southern California entities schedule return-energy to the Northwest, usually as part of contractual arrangements. Due to the south-to-north transfer capability constraints on Path 15, approximately more than 1,300 MW of the existing Path 26 south-to-north rating (3,000 MW) can be transmitted from Southern California to the Bay Area under certain off-peak conditions. The remaining approximately more than 1,600 MW of the Path 26 south-to-north transfer capability were not loaded (see Table B-3). Therefore, this capacity could be used for delivering Tehachapi wind generation to Midway only (that is, not to any areas north of Midway). In addition, the existing Path 26 south-to-north rating could be upgraded to 3,400 MW for delivering 2,000 MW of Tehachapi wind generation to Midway under off-peak conditions. The upgrade could be achieved by implementing a Remedial Action Scheme (RAS) to trip Tehachapi wind turbines for a Midway – Vincent 500 kV double-line outage subject to CAISO criteria for the use of RAS for mitigation. Such RAS must also be approved by the WECC. If such a RAS is not technically feasible after detailed studies when more information on the Tehachapi generators is available, then new transmission lines connecting Tehachapi to the PG&E system would be needed. Table B-3 shows that for the case studied, power flow on Path 26 increases from 1,325 MW to 3,315 MW in the south to north direction with increase import of 2,000 MW.

Table B-3: PG&E Area Loads, Generation and Major Path Flow
(2009 Summer Off-Peak Base Cases)

Descriptions	Base Case	Import 2,000 MW at Midway w/o upgrade
Path 66 Flow (south to north)	3,670	3,526
Path 15 Flow (south to north)	5,399	7,241
Path 26 Flow (south to north)	1,325	3,315
PDCI Flow (south to north)	1,848	1,848
PG&E Area Load/Loss	13,225	13,397
PG&E Area Generation	15,546	13,582

Fresno Area Load/Loss	1,545	1,549
Helms Generation*	-620	-620
Fresno Transmission Imports	2,025	2,029
Imports from Tehachapi Gen	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

2.2 Delivering 2,000 MW of Tehachapi Power into the remaining PG&E system

Path 15 is the major path between the Bay Area and Midway and has a north-to-south WECC Accepted Rating of 3,265 MW and a south-to-north WECC Accepted Rating of 5,400 MW. Path 15 consists of the following three 500 kV and four 230 kV transmission lines between Los Banos and Midway and is schematically illustrated in Figure B-1:

i. Los Banos – Gates #1 500 kV line,
ii. Los Banos – Gates #3 500 kV line,
iii. Los Banos – Midway 500 kV line,
iv. Gates – Gregg 230 kV line,
v. Gates – McCall 230 kV line,
vi. Gates – Panoche #1 230 kV line, and
vii. Gates – Panoche #2 230 kV line.

2.2.1 Under expected Summer Peak Conditions

The prevailing power flow during the summer peak conditions on Path 15 has been predominantly from north to south to supply local load in Southern California via Path 26. Since La Paloma, Elk Hill, and Sun Rise combined-cycle plants were released for commercial operation in 2003 with a total generation of 2126 MW in the Midway Area, Path 15 power flow is typically lightly loaded under summer peak conditions. The import of Tehachapi wind generation to serve the Bay Area loads would schedule power flow in the south-to-north direction (counter to the prevalent flow) on Path 15 and is therefore not expected to cause normal or emergency overloads on the existing PG&E system under summer peak conditions. Conceptual study results are shown below in Table B-4.

Table B-4: Steady State Power Flow Study Results Summary
(2009 Summer Peak Base Case <u>without Contingencies</u>)

	Transmission Facilities	S-N Rating	Base Case	Import 2,000 MW At Midway w/o upgrade

		(Amps)	(Amps)	(%)	(Amps)	(%)
1	Gates - Midway #1 500 kV line	2230	670	30.0	325	14.6
2	Los Banos - Midway 500 kV line	2230	402	18.0	439	19.7
3	Los Banos - Gates #1 500 kV line	2230	203	9.1	505	22.6
4	Gates - Panoche #1 230 kV line	742	51	6.9	176	23.8
5	Gates - Panoche #2 230 kV line	742	51	6.9	176	23.8
6	McCall - Henrietta tap2 230 kV line	825	201	24.4	283	34.2
7	Gates - Henriettatap1 230 kV line	1600	129	8.1	173	10.8
8	Gates - Midway 230 kV line	742	104	14.0	246	33.1
9	Los Banos - Westley 230 kV line	1484	188	12.7	660	44.5
10	Helms - Gregg 230 kV lines	1908	1471	77.1	1473	77.2

2.2.1 Under expected Off-Peak Conditions

Heavy south-to-north flows on Path 15 typically occur during off-peak hours when the Midway Area generators were dispatched to serve the Bay Area loads in addition to transferring return energy from Southern California entities. Therefore, Path 15 does not have spare south-to-north transfer capability for importing additional generation from Midway to the Bay Area under off-peak conditions. Using the generation dispatch pattern in the off-peak base case approved by the CAISO and stakeholders and agreed to in the Study Plan (Appendix E), Path 15 could load up to 5,400 MW of the south-to-north rating. This Path loading level has also been shown in other past studies conducted.

Assuming that the solution to mitigate the one pre-existing overload on the McCall-Henrietta Tap2 230 kV transmission line would also mitigate the increase in loading introduced by scheduling 2,000 MW from Tehachapi, a total of seven facilities will still be loaded in excess of the maximum normal rating under normal (all facilities in service) conditions. These overloads, ranging from 6% to 44% over the rating (or allowable limit), are summarized below in Table B-5. Because the overloads would occur under normal conditions and are large and numerous, network upgrades would likely be needed to support importing Tehachapi wind generation to serve the Bay Area loads under off-peak conditions.

Table B-5: Steady State Power Flow Study Results Summary
(2009 Summer Off-peak Base Case without Contingencies)

	Transmission Facilities	SN Rating	Base Case		Import 2,000 MW at Midway w/o upgrade	
		(Amps)	(Amps)	(%)	(Amps)	(%)

1	Gates - Midway #1 500 kV line	2230	2107.1	94.5	3212	***144.0***[25]
2	Los Banos - Midway 500 kV line	2230	1864.1	83.6	2787	***125.0***
3	Los Banos - Gates #1 500 kV line	2230	1712.9	76.8	2516	***112.8***
4	Los Banos - Gates #3 500 kV line	2230	843.9	37.8	1236	55.4
5	Gates - Panoche #1 230 kV line	742	581.4	78.4	824	***111.0***
6	Gates - Panoche #2 230 kV line	742	581.4	78.4	824	***111.0***
7	McCall - Henrietta tap 2 230 kV line	825	868.3	***105.2***[26]	997	***120.9***
8	Gates - Henrietta tap1 230 kV line	1600	1482.6	92.7	1690	***105.6***
9	Gates - Midway 230 kV line	742	622.1	83.8	799	***107.7***
10	Los Banos - Westley 230 kV line	1484	1101.0	74.2	1480	99.7

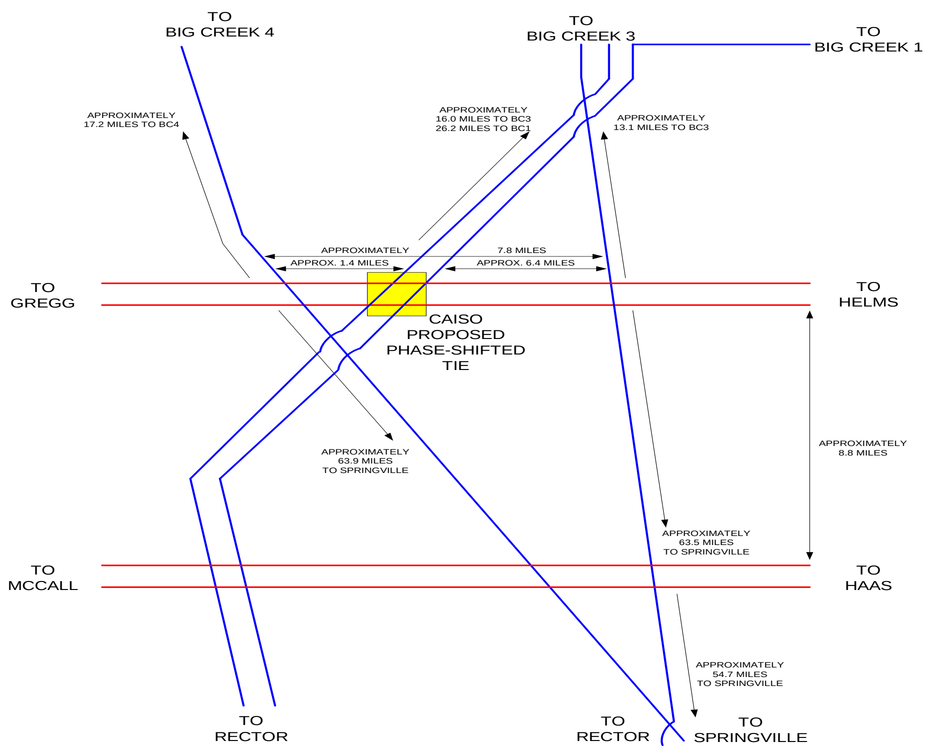
[25] These normal overloads show that the existing systems north of Midway do not have spare capacity for importing additional 2000MW at Midway without network upgrades.
[26] The normal overload on the McCall – Henrietta tap 2 230 kV line was caused by opening the McCall – Midway 115 kV line at Corcoran. PG&E is evaluating alternatives to relieve the overload.

Appendix C - Big Creek-Fresno Phase-Shifted Tie

1. Big Creek-Fresno Phase-Shifted Tie Study Results

During the Evidentiary Hearings held for Phase 6 of Investigation 00-11-001, the CAISO suggested alternatives to the then proposed SCE Conceptual Transmission Plan. These alternatives involved establishing two new SCE-PG&E system ties in the Bakersfield and Fresno areas to assist with delivery of Tehachapi area wind generation resources. The system tie in the Bakersfield area involved constructing a new transmission line to connect the SCE Magunden substation to the PG&E network and installing a phase-shifting transformer to "push" up to 300 MW of power from the Big Creek corridor to the PG&E system. The system tie in the Fresno area involved constructing a new switching station at the crossing of the Gregg-Helms 230 kV (PG&E owned) and Big Creek-Rector 230 kV (SCE owned) transmission lines, as shown below in Figure C-1, and installing a phase-shifting transformer to "push" up to 300 MW of power from the Big Creek corridor to the PG&E system. The Tehachapi Collaborative Study Group examined both of these alternatives and agreed to exclude the SCE-PG&E system tie in the Bakersfield area from the ultimate plan because it was found not to be able to deliver the 300 MW as intended.

Figure C-1
Big Creek-Fresno System Tie



2. SCE Transmission System

2.1 Base Case Power Flow Results

Conceptual power flow results indicate that in order to support this new system-tie, additional system upgrades will be necessary to mitigate thermal overload problems identified. Loading on the section of the existing Big Creek 3-Rector line between Big Creek 3 and the Fresno Tie point was found to exceed maximum allowable thermal limit under base case conditions. To mitigate this overload, reconductoring of this section will be necessary. It should be noted that such reconductoring may necessitate tear-down and rebuild since the existing tower infrastructure is not capable of supporting larger standard aluminum conductor (ACSR) and may not be capable of supporting “new” composite core or steel-supported trapezoidal conductors (ACSS/TW). Detailed engineering review of tower structures will be necessary to determine if such “new” conductor types or ACSS/TW conductors can be supported by the existing tower infrastructure.

2.2 Single Contingency Power Flow Results

In addition to the base case thermal overload problems identified, a total of five single contingency overloads were identified. Prior to the addition of the phase-shifted system tie, only one single contingency resulted in the need to "run-back" or curtail hydro-generation at Big Creek. With the addition of the phase-shifted system tie, the amount of generation currently participating in the "run-back" scheme is insufficient to mitigate the thermal overloads. Therefore, additional means to mitigate thermal overload problems will be required.

2.3 Impact to existing Big Creek Special Protection Scheme

Lastly, under loss of two transmission lines, a special protection scheme (SPS) will need to be designed to transfer trip the phase-shifted system tie and at the same time transfer trip whatever wind generation was integrated with such facility. Such SPS design will probably be much more complicated than the current Pastoria Energy Facility (PEF) SPS making approval of such a scheme highly unlikely. Design of such an SPS cannot be known until results of detailed studies are obtained. The results of the detailed studies will form the basis for engineering the design of the SPS.

2.4 Results of Sensitivity Studies

Sensitivity studies were performed to determine the value, in terms of eliminating other transmission facilities needed to deliver power to the various load centers, of including the phase-shifted system tie into the overall conceptual transmission plan. Based on these studies, the phase-shifted system tie did not eliminate the need to upgrade the existing Antelope-Mesa 230 kV transmission line nor did it eliminate the need for PG&E to increase transfer capability north of Midway beyond 300 MW (see PG&E results). The inclusion of the Bakersfield area phase-shifted system tie together with the Fresno area phase-shifted system tie also did not eliminate need to upgrade existing Antelope-Mesa 230 kV transmission line nor did it eliminate the need for PG&E to increase transfer capability north of Midway beyond 300 MW. As a result, adding this transmission component serves to only increase the total cost of the Conceptual Transmission Plan.

3. PG&E Transmission System

3.1 PG&E power flow study results

This alternative assumes that the 300 MW of power transfer would be under both on-peak (when the expected prevalent power flow between PG&E and

SCE is in the *north to south* direction) and off-peak (when the expected prevalent power flow between PG&E and SCE is in the *south to north* direction) conditions, although the connection would only be needed for off-peak conditions. This assumption was made because it would provide the most straight-forward operating requirements as it would eliminate the need to, for example, change the phase shifter angle daily or seasonally.

This alternative has no impact on the existing Path 15 south-to-north transfer capability and would not need any additional network upgrades at PG&E system. Tripping the phase shifter may be needed under single contingency conditions on-peak. It could also potentially defer the need for the proposed Fresno Long-term Plan Project (a new Gates – Gregg 230 kV double-circuit tower line) by about 8 years. However, SCE's Big Creek system would require additional network upgrades to support the power transfer.

This Alternative would also require contractual arrangements between PG&E and SCE on issues such as inadvertent flow, and agreement between PG&E, SCE and the CAISO governing the dispatch and operation of the existing generators, resolution of any physical limitation of Helms Pump Storage Plant and other operating issues.

It may be possible to transfer more than the 300 MW to PG&E system under off-peak conditions on the PG&E system, however, transfers beyond 300 MW have not been studied by SCE. As such, there may be additional requirements that have not been identified. Under on-peak conditions (when the prevalent power flow is in the north-to-south direction), transfers higher than 300 MW can be possible over the existing Path 26 and Path 15 in a south-to-north direction.

Appendix D – Cost Estimates

CONCEPTUAL TRANSMISSION PLAN – COST ESTIMATES

1. SCE Transmission - Conceptual Cost Estimate

SCE utilized previous conceptual cost estimates for determining the corresponding costs associated with the Tehachapi local area network excluding installation of SVC at Substation 1. These costs are "best-guess" estimates based on limited amount of information. Since substation locations for conceptual substations number 3, 4, and 7 are unknown at this time, the costs are for informational purposes only and most likely will be different as real wind generation developers identify real projects in the area. However, this information costs will not skew selection of most economic alternative since these costs are included into every alternative. For 500 kV transmission lines, SCE revised previous conceptual study estimates to be consistent with recent CPCN Application and assumed all lines south of Tehachapi would cost approximately the same.

Table D-1 summarizes the total cost corresponding to each alternative evaluated. As can be seen, three of the transmission upgrade alternatives evaluated cost approximately the same while one is slightly higher. Table D-2 provides the itemized cost estimates and indicates alternative for which cost applies. Table D-3 provides a summary of potential additional costs associated with delivery upgrades. Note that the costs associated with the Vincent-Mira Loma 500 kV transmission line currently under review in the CAISO Annual Expansion Planning process is not included into these tables. It should be emphasized that if an alternative 500 kV transmission line to the Mira Loma area that does not originate at Vincent is constructed, additional delivery costs will be assigned to the Tehachapi generation since conversion of the Rio Hondo 500 kV substation will be triggered. Based on this information, it is impossible to determine which alternative is more beneficial to the ratepayers.

Table D-1
Conceptual Cost Estimates Comparison for the Various SCE Alternatives

	Direct Assignment Cost ($ million)	Land Rights ($ million)	Delivery Upgrade Cost ($ millions)	Total Cost ($ millions)
Alternative 1	$1,415.2	$57.0	$44.0	$1,516.2
Alternative 2	$1,329.9	$81.3	$44.0	$1,455.2
Alternative 3	$1,380.6	$75.1	$44.0	$1,499.7
Alternative 10	$1,393.7	$57.0	$166.5	$1,617.2

Table D-2
Tehachapi Integration Conceptual SCE Cost Estimates

Transmission Element Description	Part of Alternative(s)	Facilities ($ millions)	Land Rights ($ millions)
Local Tehachapi Facilities (Obtained from Previous SCE Conceptual Studies)	1, 2, 3, 10	$715.0	$10.0
Antelope-Pardee 500 kV T/L **(Segment 1 PEA Filed)**	1, 2, 3, 10	$76.8	$3.5
Antelope-Vincent No.1 500 kV T/L **(Segment 2 PEA Filed)**	1, 2, 3, 10	$36.2	$18.1
Antelope-Vincent No.2 500 kV T/L (Assumes same costs obtained for Segment 2 PEA)	2, 3	$36.2	$18.1
Antelope-Vincent No.3 500 kV T/L (Assumes same costs obtained for Segment 2 PEA)	2	$36.2	$18.1
Antelope-Tehachapi No.1 500 kV T/L	1, 2, 3, 10	$68.2	$4.5
Antelope-Tehachapi No.2 500 kV T/L	1, 2, 3, 10	$68.2	$4.5
Antelope-Tehachapi No.3 500 kV T/L	2	$68.2	$4.5
New Antelope-Vincent No.2 230 kV T/L	1, 2, 3, 10	$34.0	None
New Antelope-Vincent No.3 230 kV T/L	10	$10.0	None
Vincent-Rio Hondo No.3 500 kV T/L (Upgrade section of Antelope-Mesa 230 kV T/L)	1, 2, 3, 10	$74.0	None
Rio Hondo-Mesa 230 kV T/L (Upgrade section of Antelope-Mesa 230 kV T/L)	1, 2, 3, 10	$18.5	None
Antelope 230 kV Substation (Add One Position)	10	$6.0	Minimal
Antelope 500 kV Substation (1 Bank)	1, 2	$37.5	Part of Segment 1
Pardee 500 kV Substation (1 Bank)	1, 2, 10	$37.5	None
Vincent 500 kV Substation (Add One Position)	1, 2, 3, 10	$8.4	None
Vincent 500 kV Substation (Equip 2nd Bay of Breaker-in-a-Half)	2, 3	$4.2	None
Shunt Capacitor Banks (Engineering Review Needed to Verify Feasibility)	1, 2, 3, 10	$10.8	None
Tehachapi to Midway 500 kV (PG&E)	1, 3, 10	$230.1	$16.4

Table D-3
Conceptual Cost Estimates for Potential SCE Delivery Upgrade

Transmission Element Description	Part of Alternative(s)	Facilities ($ millions)	Land Rights ($ millions)
New Antelope-Vincent No.3 230 kV (Add 2nd circuit to upgrade section of Antelope-Mesa 230 kV)	1, 2, 3	$10.0	None
Upgrade Antelope-Vincent 230 kV (Rebuild with double-circuit Towers with one circuit)	1, 2, 3, 10	$34.0	None
Upgrade Antelope-Magunden No.1 (Rebuild No.2 line with double-circuit)	10	$95.0	None
Add 2nd 500/230 kV Pardee Transformer	10	$37.5	None
Big Creek-Fresno Tie Related Upgrade (New Switching Station and Big Creek Corridor Upgrades)	Superfluous Expense	$50.0	Minimal

2. PG&E Transmission - Conceptual Cost Estimate

PG&E's conceptual cost estimates associated with accommodating the Tehachapi generation are based on off-the-shelf, planning level unit costs and for information only. Because PG&E has no up-to-date experience with transmission facility construction south of Midway, cost estimates for transmission lines between Tehachapi area and the Midway area are based on SCE's cost estimates for similar transmission facilities. No engineering or environmental field work has been done; as such, these costs cannot be used as a basis for approval by CAISO or PG&E management, nor can they be used to support a CPCN filing. Nonetheless, they are applied in an "apples to apples" fashion to each of the various alternatives and thus permit an overall comparison of the relative costs of different options.

Table D-4 summarizes the total conceptual cost estimate corresponding to each alternative evaluated by PG&E. Table D-5 provides the breakdown into possible phases for each alternative. As mentioned in Chapters 3 and Appendix B above, PG&E's conceptual cost estimates in Tables D-4 and D-5 do not include the costs of congestion management, RAS or voltage support devices. More detailed information concerning specific generation projects will be needed before any such cost estimates can be determined. In addition, since SCE's Alternatives 1, 3 and 10 also include the Midway-Tehachapi 500 kV line, care should be taken not to double count the Midway-Tehachapi 500 kV line ($246 million including land rights) when these SCE alternatives are combined with PG&E Alternatives 4 and 5.

Table D-4
Conceptual Cost Estimates[27] Comparison for the Various PG&E Alternatives

	Direct Assignment Cost ($ million)	Land Rights ($ million)	Delivery Upgrade Cost ($ millions)	Total Cost ($ millions)
Alternative 1	See SCE cost estimate	N/A	Cannot Estimate	Cannot Estimate
Alternative 2	See SCE cost estimate	< $1	$49	$49
Alternative 4[28]	$230	$53	$681	$964
Alternative 5	$508	$56	$443	$1,007

[27] Cost estimate for PG&E portion of the transmission upgrade only; please see also SCE cost estimate
[28] $246 million (or $230 million + $16 million) for Tehachapi-Midway 500 kV line is also included in SCE cost estimate. The Tehachapi-Midway 500 kV line is needed if new RAS to trip Tehachapi generation is not feasible.

Table D-5
Conceptual PG&E Cost Estimate to Accommodate Tehachapi Generation

Alternative	Transmission Upgrades	Facilities $million[29]	Land Rights $million
1	Status Quo	cannot be determined	N/A
2	Fresno (Big Creek) Switching Station equipment	$49	1
4, Phase A:	Los Banos – Midway 500 kV Line with 65% compensation	$439	$26
4, Phase A	Los Banos-Wesley 230 kV DCTL w/ one circuit	$41	$1
4, Phase A	Los Banos 500/230 kV transformer	$32	N/A[30]
4, Phase B	Tesla – Los Banos 500 kV line	$169	$10
4, Phase C	New RAS to trip Tehachapi generation	Cannot be determined	N/A
4, Phase C	If new RAS CANNOT be used, Midway-Tehachapi 500 kV line	$230	$16
5, Phase A	Gregg-Tehachapi 500 kV line with 62% compensation	$508	$34
5, Phase A	Gregg 500/230 kV transformer	32	N/A
5, Phase A	Los Banos-Wesley 230 kV DCTL w/ one circuit	41	1
5, Phase B	Tesla – Gregg 500 kV line	345	21
5, Phase C	Tesla and Gregg Sub Upgrade	25	N/A

[29] Facility costs include environmental mitigation, if assumed needed.
[30] Assuming that land is available for the new 500/230 kV transformer within the existing Los Banos Substation.

APPENDIX E – 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.

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

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

3. 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.

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

5. CPUC Staff responsibilities were added to the responsibility section.

6. 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.

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

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

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CONTENT

I. 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.

II. 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.

III. Purpose of Tehachapi Conceptual Plan

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.

IV. Objectives

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

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

2. 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

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

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

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

    a. 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

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

4. 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)

5. 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

6. develop phasing and priority of each transmission alternative

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

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

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

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

e. 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)

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

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

7. perform preliminary feasibility analysis for the transmission facilities identified

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

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

   c. 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

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

   e. 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

   f. 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

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

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

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

V. <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

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

2. 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.

3. 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

4. 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 theCAISO 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

5. 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.

VI. <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)

a. 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

b. 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

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

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

d. transmission ratings are as follows:

- Normal Rating = 3950 amps
- Long-Term Emergency Rating = 4540 amps
- Short-Term Emergency Rating = 5330 amps

2. Pastoria-Pardee Transmission Line Reconductor

a. 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.

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

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

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

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

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

- Normal Rating = 1240 amps
- Long-Term Emergency Rating = 1426 amps
- Short-Term Emergency Rating = 1500 amps

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

3. San Joaquin Valley Rector Loop and SVC

a. 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.

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

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

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

- Normal Rating = 1200 amps (wave trap)
- Long-Term Emergency Rating = 1200 amps (wave trap)
- Short-Term Emergency Rating = 1284 amps (wave trap)

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

- Normal Rating = 1200 amps (wave trap)
- Long-Term Emergency Rating = 1200 amps (wave trap)
- Short-Term Emergency Rating = 1284 amps (wave trap)

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

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

1. Revised SCE Conceptual Transmission Plan

a. 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).

b. 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).

c. 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.

d. 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.

e. 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.

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

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

h. Substation Expansion at Pardee and Vincent.

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

    a. New phase-shifted system-tie in the Fresno Area

    b. New phase-shifted system-tie in the Bakersfield Area

c. 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.

d. 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.

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

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

3. Midway-Vincent No.4 via Tehachapi

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

b. 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.

c. 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.

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

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

f. Substation Expansion at Midway and Vincent.

VIII. 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.

1. Revised SCE Conceptual Transmission Plan

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

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

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

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

   e. 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

   f. 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
      34.5/0.545-kV : 5.75 percent based on 1.5 MVA with V_{from} of 34.5 and V_{to} of 0.545

   g. Transformer Ratings
      500/230-kV: 1120 MVA
      230/66-kV : 280 MVA
      230/34.5-kV : 100 MVA
      34.5/0.545 kV : 1.5 MVA

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

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

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

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

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

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

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

e. 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

3. Midway-Vincent No.4 via Tehachapi

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

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

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

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

IX. Assessment Process Outline

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

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

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

3. 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

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

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

    b. 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)

    c. 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

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

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

    b. 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

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

6. 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

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

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

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

X. 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:

1. 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 theCAISO 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.

   a. 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.

b. 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.

c. 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.

2. 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 theCAISO 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

a. 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

b. 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.

c. 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.

XI. 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:

1. Load Related Assumptions

   Loads will be modeled in load flow studies as follows:

   a. 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.

   b. 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.

   c. 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.

   d. 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.

   e. 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.

   f. 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.

2. 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 theCAISO Grid Planning Criteria.

e. All QF generation will be modeled in the base case consistent with theCAISO 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.

3. 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).

4. 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.

5. 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.

6. Other Assumptions

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

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

   c. 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.

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

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

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

XII. 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 CAISO 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 theCAISO 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.

XIII. 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.

XIV. 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	02/16/2005

	report of complete transmission phased development	
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 F – Wind Integration Studies

Installed wind generating capacity has been increasing approximately 35% per year, worldwide, for the past seven years. In Europe, wind power makes up more than 25% of total generating capacity in Denmark and parts of Spain and nearly 20% in Germany. The European Union has adopted a target of obtaining 22% of its electricity from renewables by 2010. As wind penetrations increase, more is being learned about how the grid can be operated to take advantage of wind resources while ensuring system reliability and minimizing costs.

The studies listed here address both the cost of integrating various percentage penetrations of wind power and technical grid operation issues on systems having many different resource mixes and operating characteristics. In the US, the Utility Wind Interest Group (UWIG), the National Renewable Energy Laboratory (NREL) and the Oak Ridge National Laboratory (ORNL) have taken the lead in many of these technical studies. California, Minnesota, the New York ISO and Texas (ERCOT) have and continue to study integration issues on their systems.

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