Development Plan for the
Phased Expansion of

Electric Power Transmission Facilities
in the
Tehachapi Wind Resource Area

Second Report
of the
Tehachapi Collaborative Study Group

California Public Utilities Commission

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The report is printed in 5 volumes or electronic files:

- **Volume 1 contains the Second Report;**
- **Volume 2 contains Study Plan #2 the basis for the Second Report (referred to in the Report as Appendix 1);**
- **Volume 3 contains the PG&E Studies (referred to as Appendix 2);**
- **Volume 4 contains the SCE Studies (referred to as Appendix 3);**
- **Volume 5 contains the CAISO Studies and all remaining Appendices 5, 6 and 7.**

Development Plan for the Phased Expansion of
Transmission in the **Tehachapi Wind Resource Area**
Second Report of the
Tehachapi Collaborative Study Group

The Tehachapi Wind Energy Project
"Transmitting Tehachapi Energy to Consumers"

Second Report
To the California Public Utilities Commission
From the
Tehachapi Collaborative Study Group
April 19, 2006

Executive Summary

Introduction

When completed, the Tehachapi Wind Energy Project will capture large amounts of energy from the wind, transform it into electric energy and transmit this electricity to California consumers. In the next few years, thousands of modern wind turbines clustered in wind "farms" spread over more than one thousand square miles will be built in the Tehachapi region. The Tehachapi Project is expected to provide enough electric energy to satisfy the needs of nearly 2 million California homes. If developed to the extent forecast, it will produce more electrical power than any other generation project in California and supply about 5% of California's total electricity needs.

The infrastructure that comprises the Tehachapi Project consists of three essential components - the wind turbines themselves; power lines and equipment to collect electricity from turbines in the local area; and high voltage transmission facilities to reliably interconnect the wind generation with the existing California electricity grid and distribute this power to California consumers.

Permit applications for the initial transmission components of the Tehachapi Project already have been submitted to the CPUC and environmental reviews of these facilities are now underway. In addition, wind generation projects comprising more than half of the total expected project capacity have been submitted to the California Independent System Operator (CAISO) for interconnection studies. However, these projects require transmission facilities to be constructed to enable the electricity generated to reach consumers. Private investment is expected to provide the capital required for the project, estimated at $8 - $9 billion. Approximately $1 billion of that total represents the estimated cost of transmission facilities needed to connect the Tehachapi Project to the grid. The overall project cannot proceed until the CPUC establishes the mechanism by which the recovery of the $1 billion of transmission investments will be assured.

In Decision 04-06-010 (June 9, 2004), the California Public Utilities Commission (CPUC) requested that the Tehachapi Collaborative Study Group (TCSG) devise a comprehensive plan for the transmission lines, major substations, and other transmission infrastructure needed for the project. The first Preliminary Report from the TCSG was submitted to the Commission in March, 2005.[1] That report identified a number of alternatives for the transmission infrastructure and recommended further study to select the best among them. This second report narrows and refines the alternatives submitted last year and makes further recommendations to complete the planning process and facilitate detailed technical studies, approval and construction of the transmission facilities needed for the Tehachapi Project.

Achieving Tehachapi Transmission Planning Goals

The primary goal of the TCSG is to devise a conceptual transmission plan that would allow the wind generation potential in Tehachapi, currently estimated at 4,500 MW, to reach California consumers.[2] The TCSG has consensus agreement on the transmission facilities to provide access for approximately 3,000 MW, and has identified two main alternatives for providing access for the remaining 1,500 MW.

The TCSG also has the goal of providing its recommendations to the CPUC on a schedule that facilitates permitting and construction of needed facilities by 2010. Prior to the beginning of the TCSG process, Southern California Edison Company's (SCE) expert analysis had identified transmission facilities for initial phases of the Tehachapi plan. In its 2005 report, the TCSG agreed with SCE's recommendations which it referred to as Phases 1 and 2. Construction of these facilities is expected to accommodate about 1,600 MW of Tehachapi generation. Permitting is underway for the first 700 MW (Phase 1) of these facilities.

However, certificates of Public Convenience and Necessity (CPCN) for initial Phase 1 facilities have not yet been issued, and CPCN applications have not been filed for subsequent phases. As discussed below, the TCSG urges the CPUC to accelerate its permitting process in order to achieve the state's renewable energy goals.

Of the expected 4,500 MW of incremental capacity in the Tehachapi WRA, interconnection requests for Tehachapi wind projects totaling approximately 3,600 MW have already been submitted to the CAISO. In light of this, the TCSG believes that this indicates that transmission facilities to connect an additional 4,500 MW of Tehachapi generation are likely to be needed.

The TCSG believes that in developing a transmission plan for Tehachapi area generation, consideration should be given to a plan's potential to provide benefits to the State's transmission network, if possible, in addition to providing full grid access to potential Tehachapi wind generation. As discussed below, facilities being considered may provide network benefits and/or may negatively impact grid

[1] Report of the Tehachapi Collaborative Study Group, March 16, 2005

[2] The California Energy Commission provided the estimate of 4,500 MW of potential wind development in Tehachapi and nearby Antelope Valley, and the TCSG has used that value for planning purposes. As of this report, projects totaling approximately 3,600 MW have been submitted to the ISO for interconnection approval, despite the lack of transmission access at the present time. Some observers believe eventual total wind generation in Tehachapi may be significantly larger than 4,500 MW.

performance. Assessment and quantification of the potential network benefits and potential operational challenges will require additional assistance from the CAISO. In order to properly evaluate remaining alternatives, the TCSG therefore recommends that further Tehachapi transmission analysis be conducted under the auspices of the CAISO. The planning process also should determine which facilities of the final two phases (Phases 3 and 4) should be constructed first.[3]

<u>Connecting the Tehachapi Wind Resource Area (WRA) to the California Grid</u>

The Tehachapi WRA lies at the southern end of the San Joaquin Valley in the mountainous region between Bakersfield and Mohave. Transmission connections between Tehachapi and the existing grid can be made to the west at the Midway substation near Buttonwillow and to the south at the Vincent substation near Lancaster.[4] Three existing transmission lines connect the Midway and Vincent substations, collectively referred to as Path 26.

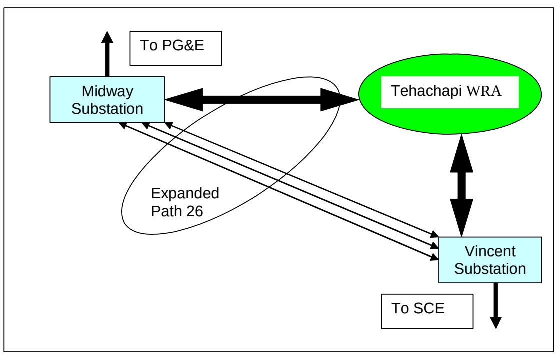

Figure 1 – First alternative – Expanded Path 26 option

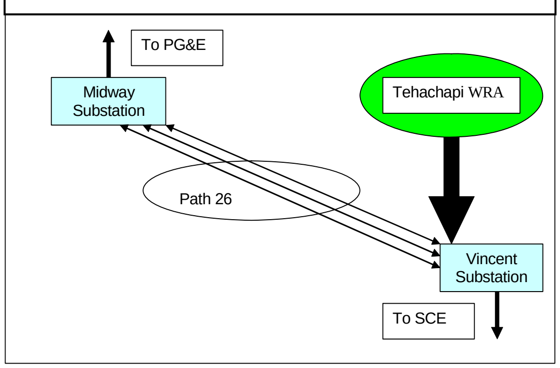

Figure 2 – Second alternative – Gen-tie option

Power lines from Tehachapi can connect at Midway, at Vincent, or at both substations.[5] The TCSG has considered two connection alternatives in detail, as described in Chapter 6. The first alternative connects Tehachapi at both Midway and Vincent as shown in Figure 1. The other alternative connects Tehachapi only at Vincent as shown in Figure 2.

Permit applications have been filed for the first transmission components which will connect Tehachapi to the Vincent substation with one 500 kV line. Two more 500 kV lines are expected to be needed to export 4,500 MW of wind power from the Tehachapi WRA to the existing state grid.[6]

A detailed comparison of the two alternatives is found in Chapter 6. Costs for the two plans are comparable, estimated to be in the neighborhood of $1 billion. A choice between

[3] The phases identified in the 2005 TCSG report were for organizational purposes and did not imply that the Phase 3 facilities should necessarily be constructed prior to those discussed in Phase 4.

[4] This is a simplified description of the transmission connections. Other facilities and connections to the grid have been examined by the TCSG and are described in detail in Chapters 2 and 6.

[5] The two options discussed here appear to be the most likely alternatives among those studied by the TCSG,, but connections to other points may be considered by the ISO. See Chapter 2 for complete description of facilities and connections considered by the TCSG.

[6] For planning purposes, the TCSG assumes that all three of these lines will be operated by the investor owned utilities. However, there are also power lines in the region owned by the Los Angeles Department of Water and Power and by a private company. If substantial amounts of Tehachapi energy were to be transmitted on these lines, a third IOU line from Tehachapi might not be needed.

the two alternatives hinges on benefits of each plan that the TCSG has not yet been able to quantify.

The salient feature of the alternative involving a new Midway – Tehachapi 500 kV line is that it comprises an additional link in Path 26, the major transmission artery connecting Northern and Southern California. The TCSG refers to this alternative as the Expanded Path 26 option. This configuration is expected to be considered a "network facility" which would provide two important benefits to the California grid, namely additional reliability, operating flexibility and additional import capacity into Southern California[7] when Tehachapi generation is low.[8]

The Expanded Path 26 option could complicate grid management, however, since some power from Tehachapi would flow on existing Path 26 lines and use some of the path transfer capacity. This could complicate grid operations as operators must consider these variable flows when scheduling power into Path 26.

The second alternative would provide Tehachapi with access to the grid only at the Vincent substation.[9] In this option, all three of the 500 kV lines necessary to export Tehachapi power would extend south from Tehachapi. Providing access to Tehachapi wind power would be the primary benefit of this alternative. Power lines which serve only to connect generation to the grid are referred to a "gen-ties", and the TCSG calls this plan the "Gen-tie option". The feasibility of constructing a third 500 kV line from the Tehachapi area to Vincent in the Gen-tie option may be complicated, however, due to the rapid urbanization of the Antelope Valley which lies between the Tehachapi and Vincent substations.

The TCSG supports the Commission's February 26, 2006, resolution to immediately pursue further environmental, engineering, cost, operational, regulatory, and other necessary studies that are needed to construct all the transmission facilities included in planning Phases 1, 2 and 3 of the 2005 report.

Resolution of the above issues related to reliability, grid operations, network benefits and costs will require the active assistance of the CAISO. The TCSG therefore recommends the following :

> **Recommendation #1**
> **The TCSG recommends that additional study of all Phase 3 and 4 alternatives discussed herein be conducted expeditiously under the auspices of the CAISO in a forum that is open and collaborative, similar to the TCSG process to date.**

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[7] Additional transmission facilities will be needed to transmit power to the SDG&E system.

[8] A frequent criticism of wind power is that "the wind doesn't blow all the time." A transmission plan that enables additional power transfers during periods of low wind generation would allow the CAISO to manage the variability of wind generation more easily.

[9] This is a simplified description. As described in Chapter 6, SCE's Antelope substation lies between Tehachapi and Vincent. Power exported south from Tehachapi might enter the grid either at Antelope or at Vincent substations.

<u>Financial and Cost Recovery considerations</u>

The Tehachapi Project will require investment of substantial amounts of capital, estimated to be in the neighborhood of $8-$9 billion for the entire project. Transmission facilities in either of the options discussed above will require approximately $1 billion. No debt is expected to be incurred by the state for the Tehachapi Project; all of this capital is expected to come from private sources. In order to attract the required capital for the transmission facilities, however, the mechanism through which the investment will be repaid by electricity consumers must be firmly established.

The TCSG emphasizes that cost recovery issues are of utmost importance and must be resolved in order for the Tehachapi project to proceed, as further discussed in Chapter 7. The TCSG therefore recommends:

> **TCSG Recommendation #2**
> **The TCSG urges the Commission to adopt a decision implementing the provisions of P.U. Code §399.25, by May, 2006, as scheduled in I.05-09-005, and ensure that all utility investments related to construction of Tehachapi transmission facilities will be recovered.**

<u>Streamlining CPUC Transmission siting and permitting process.</u>

In the I.05-09-005 proceeding, the utilities and other Parties have raised issues over the existing CPUC transmission permitting process. In response to these concerns, the CPUC developed preliminary recommendations and conducted a workshop on March 23, 2006 for further comments. The next step would be to implement streamlining measures that would facilitate transmission for renewables.

> **TCSG Recommendation #3**
> **TCSG urges the CPUC to consider and implement recommended streamlining approaches to the existing CPUC transmission permitting process.**

<u>Summary of the TCSG Cost/Benefit Analysis</u>

Economic evaluation of the transmission options is discussed in Chapter 2. Chapter 3 describes the CAISO cost analysis. Cost estimates for each of the facilities considered were obtained from Pacific Gas & Electric and Southern California Edison. The TCSG emphasizes that these estimates are preliminary. Facilities selected for construction will require further study in order to obtain firm estimates which will be conducted as part of the CPCN application process.

The CAISO provided the TCSG with its analysis of the various transmission options using production cost simulation computer modeling. The model dispatches the least cost generation facilities throughout the Western Interconnection (WECC) that are required to meet projected loads, consistent with projected transmission system capabilities. The analysis modeled Tehachapi wind power as a must-take resource similar to Qualifying Facilities, such that all of the incremental 4,500 MW plus the 700 MW of existing Tehachapi power is part of this generation mix.

Each transmission option considered by the TCSG changes the overall Western transmission system and therefore also changes the mix of dispatchable generation facilities chosen by the computer model. The model calculates the annual electricity production cost of the entire WECC for each option, and the difference between the annual production costs for each of the Tehachapi options studied provides a measure of the relative benefits.

For example, if WECC annual production cost for the transmission system with one choice of Tehachapi transmission facilities is $15 billion compared to $15.1 billion for another, the first choice is presumed to have benefits of lower cost relative to the second of $0.1 billion ($100 million) per year. For each alternative under consideration, the revenue requirement associated with the capital costs was calculated and added to the present value of the WECC production costs and operations and maintenance (O & M) costs over 50 years to arrive at an overall economic assessment of the alternative. Each of the major options, together with the costs, is shown in Chapter 2, Table 2.1.

Other facilities considered by the TCSG

As previously reported to the Commission, the TCSG considered a number of other transmission facilities. At the time of that preliminary report, several transmission options in addition to those described above had not been adequately evaluated due to the limited information available. The TCSG now believes it has sufficient information to exclude these options from further consideration as part of the Tehachapi Project.

The transmission lines that carry power north from the Midway substation are known as Path 15. With either of the transmission options described above, power flows on Path 15 are expected to be at the path limit for many hours during the year. That is, Path 15 is expected be "congested" some of the time[10], even though the capacity of Path 15 was recently expanded. The TCSG considered a variety of facilities that would reduce congestion on Path 15 that are expected to occur when the Tehachapi Project is connected to the grid.

As discussed in Chapter 3, the CAISO provided the TCSG with the results of its production simulations for all of the options considered. After weighing the costs of congestion on Path 15 against the cost of facilities that would relieve the congestion,

[10] Predominantly when power flows north of Midway are from South to North (primarily during off-peak hours).

the TCSG concluded that on this basis, these facilities are not cost effective additions to the grid at the present time for the sole purpose of delivering Tehachapi wind energy to Northern California load centers. However, analysis of their network benefits may suggest that they be reconsidered in the future.

Additional transmission facilities in northern California may be desirable for a variety of other economic and/or reliability reasons about which the TCSG has no information. The CAISO will determine all necessary interconnection-related upgrades required in accordance with Federal Energy Regulatory Commission (FERC) interconnection policy.
Another transmission facility examined by the TCSG at considerable length is described in Appendix 5. This facility, referred to by the TCSG as the "Fresno 230 kV Tie", would connect the Pacific Gas & Electric (PG&E) system to the Southern California Edison (SCE) Big Creek lines near Fresno. As described in the report, the Fresno 230 kV Tie facilities would allow a fraction of the electricity generated by the Tehachapi Project to bypass Path 15 and enter the PG&E system near Fresno, thereby reducing congestion on Path 15. As with other facilities in Northern California, the TCSG concluded that the Fresno 230 kV Tie is not a cost effective addition to the grid for the sole purpose of transmitting power from the Tehachapi Project to northern California load centers.

Project Manager for Tehachapi
A project manager should be appointed to expedite implementation of the Tehachapi transmission infrastructure as explained in Section 7.4, below. Accordingly, the TCSG makes the following recommendation.

> **Recommendation # 4**
> **The CPUC should work with the CEC, the legislature and key stakeholders to identify candidates for the position of Tehachapi Power Project manager. The project manager would engage stakeholders to establish a schedule for project implementation and work plan addressing every element of the transmission and generation development. The project manager would report progress to state agencies, stakeholders and the public quarterly.**

Accelerating the Schedule
The March 2005 Report of the TCSG included a conceptual schedule for completing the Tehachapi transmission upgrades by December 2010. The 2005 schedule assumed that the CPCN applications for Phase 1 would be processed and approved by June 2006. It now appears that various delays in the CPCN approval process will cause those applications to be approved no earlier than December 2006. Although the 2005 conceptual schedule was described as "the fastest practicable schedule" for completing the plan by 2010, and time has been lost since, the TCSG believes that it may still possible to meet the 2010 completion goal if all of a number of aggressive

actions to accelerate the process, fully described in chapter 8 and summarized briefly below, are taken.

The TCSG emphasizes the critical importance of completing Segments 1 and 2 of Phase 1 as soon as possible. These segments must be completed before Phase 2 construction can commence. Phase 2 is essential for all projects because they require the additional south-of-Antelope transmission capacity that this phase will provide.

Recommendations:

- Accelerate the CPCN review process for the Tehachapi upgrades by taking all of the specific actions described in Chapter 8;
- Direct the Energy Division, utilities and other TCSG parties to develop a detailed schedule of specific tasks and parties responsible (the "who, what, when") that must be achieved if the larger milestones shown in Chart 8.2 are to be met (moving the schedule back if it is determined in this process that the 2010 completion goal is infeasible);
- Direct the Energy Division to work with SCE to ensure that complete CPCN applications for Phases 2 and 3 be filed as soon as possible;
- Expedite the CPCN approval process for future phases by proposing, on the Commission's own motion, without evidentiary hearings, a finding that Phases 2 and 3 are needed to facilitate the achievement of RPS goals.

Summary of Recommendations

Recommendation #1
The TCSG recommends that additional study of all Phase 3 and 4 alternatives discussed herein be conducted expeditiously under the auspices of the CAISO in a forum that is open and collaborative, similar to the TCSG process to date.

TCSG Recommendation #2
The TCSG urges the Commission to adopt a decision implementing the provisions of P.U. Code §399.25, by May, 2006, as scheduled in I.05-09-005, and ensure that all utility investments related to construction of Tehachapi transmission facilities will be recovered.

Recommendation #3
TCSG urges the CPUC to consider and implement recommended streamlining approaches to the existing CPUC transmission permitting process.

Recommendation # 4
The CPUC should work with the CEC, the legislature and key stakeholders to identify candidates for the position of Tehachapi Power Project manager. The project manager would engage stakeholders to establish a schedule for project implementation and work plan addressing every element of the transmission and generation development. The project manager would report progress to state agencies, stakeholders and the public quarterly.

Recommendation # 5
All aggressive actions to complete the Tehachapi transmission upgrades by December 2010 should be taken now. It is critical to complete Segments 1 and 2 of Phase 1 as soon as possible because they must be completed before Phase 2 construction can commence. Phase 2 is essential for all projects because they require the additional south-of-Antelope transmission capacity that this phase will provide.

CHAPTER 1

INTRODUCTION

Background

On June 9, 2004, as part of Proceeding I.00-11-001, the administrative law judge issued Decision 04-06-010 entitled "Interim Opinion on Transmission Needs in the Tehachapi Wind Resource Area". It called for "a collaborative study group to develop a comprehensive transmission development plan for the phased expansion of the transmission capabilities in the Tehachapi area." The plan was to be incorporated in a report to be submitted on March 9, 2005. The submittal date was later changed to March 16, 2005.

The Tehachapi Collaborative Study Group (TCSG)

The Decision cited above further stipulated that the plan was to be the product of a study group, coordinated by Commission staff, assisted by the CAISO with SCE, PG&E, wind developers and other interested parties "…to participate in the collaborative study process." In compliance with this order, the Tehachapi Collaborative Study Group (TCSG) was formed.

The March 16, 2005 Report

The underlying assumption guiding this stage of the planning was that approximately one half of the output from Tehachapi would flow to PG&E and the other half to SCE.

A second assumption was made that the average capacity added by each of the three 500 kV lines is approximately 1,500 MW. Based on these two principles, the transmission planning departments at PG&E and SCE produced alternatives for delivering 4,000 MW of incremental generation from Tehachapi proper and 500 MW from the adjoining Antelope Valley, with 2,000 MW going to PG&E. The path to PG&E was either from Tehachapi to SCE's Vincent Substation and thence over the existing three 500 kV circuits that comprise Path 26, or over a 500 kV line from Tehachapi to PG&E's Midway Substation or Gregg Substation plus Tehachapi-Vincent-Path 26.

PG&E presented two alternatives: in one, a 500 kV line from Midway to Los Banos Substation (a fourth circuit on Path 15) plus a 500 kV line from Los Banos to Tesla Substation in the Bay Area, the Tehachapi generation to Midway is delivered over Path 26. And in the second, a 500 kV line from Tehachapi to Gregg Substation in the Fresno area to Tesla Substation, the Tehachapi generation is delivered in part directly to Gregg and in part to Midway over Path 26.

SCE presented four alternatives, designated 1, 2, 3 and 10, each with three 500 kV lines out of Tehachapi. Alternative 1 has a line from Tehachapi to Midway and two 500 kV lines from Tehachapi to SCE’s Antelope Substation, north of Vincent; Alternative 2 has all three 500 kV lines to the SCE grid, with two lines to Antelope and one directly to Vincent. Alternatives 3 and 10 are variations on Alternative 1 with internal differences on the SCE system.

In addition, a 230kV tie between the SCE and PG&E networks in the Fresno area was studied. The tie would deliver Tehachapi generation to PG&E from Tehachapi to Antelope and thence over existing 230 kV lines from Antelope to Big Creek Substation with a phase shifted tie from these lines to PG&E’s Helms-Gregg lines. The capacity of the tie would be 300 MW or more, depending on the extent of upgrades to the SCE system. This alternative would supplement Path 26 flow and could deliver generation to PG&E with a minimum of transmission upgrades. It could be a feasible alternative if Tehachapi development did not exceed 2,000 MW.

A phased development of the transmission infrastructure was proposed, consisting of:

Phase 1: Antelope-Pardee, Antelope-Vincent and Tehachapi-Antelope 500 kV lines operated at 230 kV. Deliverability of Tehachapi and Antelope Valley generation is 700 MW.

Phase 2: Upgrade Antelope-Mesa 230 kV line to 500 kV with connection to Vincent Substation, operated at 230kV. Deliverability of Tehachapi and Antelope Valley generation increases to 1,600 MW.

Phase 3a: A second 500 kV line between Tehachapi and Antelope Substations operated at 230 kV. Deliverability of Tehachapi and Antelope Valley generation increases to 2,350 MW.

Phase 3b: 500kV yards are added at Tehachapi, Pardee and in Alternatives 1 and 2 at Antelope Substations and the 500 kV lines previously operated at 230 kV are operated at rated voltage. Deliverability of Tehachapi and Antelope Valley generation increases to 3,300 MW.

Phase 4: A 500 kV line from Tehachapi to Midway and the first of PG&E's alternatives is implemented, or the second PG&E alternative is implemented. Deliverability of Tehachapi and Antelope Valley generation increases to 4,500 MW.

The capital cost of every transmission component was estimated and the cost of the alternatives was calculated. A schedule for implementation of the Tehachapi infrastructure in time to meet the Energy Action Plan 2010 target was prepared.

When all this material had been put together, the study group ran out of time. The information was presented in the report with the conclusion "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."

Start of Second TCSG Study

The recommendation above was implemented by means of letters dated March 30, 2005 from the Director of the Energy Division of the CPUC to PG&E, SCE and the CAISO. The letters requested that the representatives from these agencies to the TCSG continue to work on to the second phase of the study and established a deadline for a second report on March 1, 2006. The request for personnel participation was granted and TCSG members from CEERT, CalWEA, and the wind industry have also stayed on, so that the original team has been maintained virtually intact.

Study Plan # 2

Highlights of the plan, as reproduced in Appendix A, for the second stage of the study include:

- Refinement of power flow studies, particularly for the Fresno Tie project
- PG&E revised its second alternative from Tehachapi-Gregg-Tesla to Tehachapi-Midway-Gregg-Tesla (SCE's Alternative 1 contains Tehachapi-Midway).
- The CAISO committed to doing a production simulation study of the alternatives in which Tehachapi wind would be dispatched in accordance with recorded wind flow patterns for the area and other generation based on economics. Tehachapi generation would flow into the system as determined by network configuration and the non-Tehachapi generation that was dispatched, rather than assigning a set proportion of Tehachapi generation to a given area.

That is, the requirement that 2,000 MW be transmitted to PG&E would no longer hold. In addition, the new 500 kV lines could be loaded up to 3,400 MW, the thermal rating of Edison's 500 kV lines.

- The recommended alternative, or set of alternatives would be selected based on economics: from the capital costs, the utilities' revenue requirements would be calculated, to which would be added the present value over the life of the projects of the O & M costs and, as obtained from the production simulation study, the present value over the life of the projects of the incremental cost over the cost of the alternative, or set of alternatives, whose cost was the least. A spread sheet would be made showing all the cost elements for each of the alternatives, or set of alternatives, and the ranking of the set based on least cost.

CHAPTER 2

PROCESS TO EVALUATE ALTERNATIVES

2.1 Introduction

The power flow studies done by PG&E and SCE have defined a number of alternatives equally capable of delivering the full incremental 4,500 MW of Tehachapi generation to load centers. To choose among them the principal criterion is economics: which alternative or combination of alternatives will do the job for the least cost. Since this cost is on the order of $1 billion, a careful evaluation is justified.

The recommended alternative, or set of alternatives would be selected based on economics: from the capital costs, the utilities' revenue requirements would be calculated, to which would be added the present value over the life of the projects of the O & M costs and, as obtained from the production simulation study, the present value over the life of the projects of the incremental cost over the cost of the alternative, or set of alternatives, whose cost was the least. A spread sheet would be made showing all the cost elements for each of the alternatives, or set of alternatives, and the ranking of the set based on least cost.

2.2 Calculation of Project Cost

There are three components to the cost of each project or alternative or combination of alternatives: the utility's revenue requirement for the construction of the facility, the operation and maintenance costs for the facility over the life of the project and the electric system operating costs over the life of the project. This third component consists of network losses, congestion payments and generation, not including Tehachapi generation, which is assumed to be taken as available (as the wind blows) and is therefore the same for all projects. The present value of the operation and maintenance costs and the present value of the production costs are added to the revenue requirement to obtain the total cost of the project over its economic life. If only economics are taken into consideration, the least-cost project is preferred.

2.3 Elements of Economic Evaluation

Capital Cost: The actual amount paid for engineering, construction, interest during construction. These costs were estimated by the utilities and are given in Appendices 2 and 3. An exception is the cost of the Tehachapi-Midway transmission line, which was estimated by the TCSG Cost Subgroup, whose report is contained in Appendix 8. It should be emphasized that these estimates are preliminary. Facilities selected for construction will require further study in order to obtain firm estimates. The cost of acquisition of rights-of-way is especially uncertain, since routes cannot be finalized until environmental reviews have been completed. Moreover, some routes must pass through regions undergoing rapid urbanization, making future acquisition costs difficult to predict. In addition, the two utilities use different methodologies for making their estimates, making comparison difficult. Nevertheless, the TCSG believes that the capital cost estimates are adequate for the purposes of comparison of alternatives.

To cover the capital cost, the utilities have a "revenue requirement", which is obtained by applying a multiplier to the capital cost to take into account return on capital, taxes, insurance, administration and depreciation. This multiplier was calculated as follows. In the CAISO Board Report of 2/24/05 on the PVD2 project, SCE's "real economic carrying charge for transmission" is 10.43%, which is a value applicable to a capital cost to obtain stream of annual costs. To convert this to a multiplier applicable to a single cost, its present value based on SCE's assumed rate of return of 7.16%[11] and a project life of 50 years was calculated to be 1.41.

The transmission facility is assumed to go on line in 2010, but all costs are calculated for 2005, therefore the present value of the revenue requirement for 2010 is calculated for 2005, based on the 7.16% rate of return and 5 years, which yields a multiplier of 0.708.

Annual operating and maintenance is assumed to be 1% of the capital cost. Its present value is based on a project life of 50 years starting in 2010 and projected to 2005 with a 7.16% discount rate.

The production costs were calculated by the CAISO using a production cost simulation program, described in Chapter 3, below. For the purpose of comparing projects, the incremental costs over the lowest cost project or scenario were used. The present value of the annual incremental cost based on a 50 year project life beginning in 2010 and projected to 2005 with an interest rate of 7.16% was calculated.

2.4 Study Scenarios

The scenarios designated on Table 2.1 below, are a subset of those analyzed in Chapter 3. Each of the scenarios below would accommodate the full Tehachapi projected output. See Figures 2.1 through 2.6 below.

[11] See Note 2 of Table 2.1

Scenario E, Figure 2.1: SCE Alternative 1	500kV lines, two from Tehachapi to Antelope to Vincent, one from Antelope to Pardee, one from Tehachapi to Midway.
Scenario F, Figure 2.2: SCE Alternative 1 with PG&E Alternative 4	500kV lines, two from Tehachapi to Antelope to Vincent, one from Antelope to Pardee, one from Tehachapi to Midway to Los Banos to Tesla.
Scenario G, Figure 2.3: SCE Alternative 2, PG&E Alternative 4	500kV lines, two from Tehachapi to Antelope to Vincent, one from Antelope to Pardee, one from Tehachapi to Vincent, one from Midway to Los Banos to Tesla.
Scenario G-NNM, Figure 2.4: SCE alternative 2	500kV lines, two from Tehachapi to Antelope to Vincent, one from Antelope to Pardee, one from Tehachapi to Vincent.
Scenario I, Figure 2.5: SCE Alternative 1 with PG&E Alternative 5	500kV lines, two from Tehachapi to Antelope to Vincent, one from Antelope to Pardee, one from Tehachapi to Gregg to Tesla.
Scenario J, Figure 2.6: SCE Alternative 2 with PG&E Alternative 6	500kV lines, two from Tehachapi to Antelope to Vincent, one from Antelope to Pardee, one from Tehachapi to Vincent, one from Midway to Gregg to Tesla.

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2.5 Results

The results given in Table 2.1 provide a cost comparison of the transmission alternatives examined to integrate the full incremental 4,500 MW of Tehachapi wind generation. As can be seen, the production cost simulations differ slightly when comparing simulations that take into account the full WECC area with those that consider only the CAISO controlled area. These differences are minimal. Noteworthy is the fact that the projects with the lower production costs (F, G, I, J) have large infrastructure investments which make them more costly overall than the low infrastructure investment projects, E and G-NM. Based on the cost comparison, SCE's Alternative 2 with PG&E's Alternative 1 (shown on Table as Scenario G-NM) was found to be the alternative with the lowest total cost. SCE's Alternative 1 with PG&E's Alternative 1 (shown on Table as Scenario E) was found to be the alternative with the second lowest total cost. The total cost of these two is probably within the accuracy of the calculations and can therefore be considered equal on an economic basis. The remaining alternatives resulted in a total cost increase ranging from $870 million to $1.22 billion as compared to the lowest cost alternative.

TABLE 2.1

COST COMPONENTS OF TRANSMISSION ALTERNATIVES

PRODUCTION COST COMPONENT FOR ALL WECC AREA COMPARED TO CAISO AREA ONLY

COST COMPONENT	MULTIPLIER	CAISO PRODUCTION COST RUN					
		E	F	G	G-NM (10)	I	J
SINGLE LINE DIAGRAM		2.1	2.2	2.3	2.4	2.5	2.6
CAPITAL COST (1)		$1,090	$2,015	$1,863	$938	$2,060	$1,908
REVENUE REQUIREMENT (2)	1.41	$1,538	$2,843	$2,628	$1,323	$2,907	$2,692
PV REVENUE REQUIREMENT (3)	0.708	$1,089	$2,012	$1,860	$937	$2,057	$1,905
ANNUAL O & M	CAPITAL COST *0.01	$11	$20	$19	$9	$21	$19
PV ANNUAL O & M (4)	12.61	$137	$254	$235	$118	$260	$241
INCREMENTAL PRODUCTION COST (5)							
ALL WECC AREA		$8	$8	$3	$16	$13	$0
ISO AREA ONLY		$16	$0	$15	$27	$11	$15
PV INCREMENTAL PRODUCTION COST (6)							
ALL WECC AREA	12.61	$101	$101	$38	$202	$164	$0
ISO AREA ONLY	12.61	$202	$0	$189	$340	$139	$189
TOTAL COST (7)							
ALL WECC AREA		$1,327	$2,366	$2,132	$1,257	$2,481	$2,145
ISO AREA ONLY		$1,428	$2,266	$2,283	$1,395	$2,455	$2,335
DIFFERENCE FROM LOWEST COST (9)							
ALL WECC AREA		$70	$1,110	$876	$0	$1,224	$889
ISO AREA ONLY		$33	$870	$888	$0	$1,060	$939
RANK (8)							
ALL WECC AREA		2	5	3	1	6	4
ISO AREA ONLY		2	3	4	1	6	5

NOTES TO TABLE 2.1

NOTES

1: Construction cost estimated by SCE or PG&E in 2005 M$, includes AFUDC.
2: Construction cost plus taxes, insurance, administration and depreciation (2005 M$) based on
PVD2 CAISO 2/24/05 Board Report: rate of return = 7.16%, "'real economic carrying charge rate for transmission"
= 10.43%. Present value in 2010 of 10.43% at 7.16% discount rate for 50 years is 1.41 per formula shown below.
(((1+0.0716)^50-1)/((1+0.0716)^50*0.0716)*0.1043
3: Present value in 2005 of annual revenue requirement in 2010, discount rate at 7.16% per formula shown below.
1/(1+0.0716)^5
4: Present value in 2005 of annual O & M for 50-year project life
starting in 2010 at 7.16% discount rate, inflation assumed at 2% per year per formula shown below.
(((1+0.0716-0.0200)^50-1)/((1+0.0716-0.200)^50*(0.0716-0.0200)))*(1/(1+0.0716)^5)
5: WECC-wide annual production cost (2005 M$) minus annual production cost of lowest cost alternative (Run J),
6: Present value in 2005 of annual incremental production cost for 50-year project life
starting in 2010 at 7.16% discount rate, inflation assumed at 2% per year per formula shown below.
(((1+0.0716-0.0200)^50-1)/((1+0.0716-0.200)^50*(0.0716-0.0200)))*(1/(1+0.0716)^5)
7: Sum of present value of revenue requirement plus present value of O &M plus present value of incremental
production cost.
8: Cost ranking starting with lowest cost alternative
9: Increase of total cost over total cost of lowest cost alternative.
10. Tehachapi-Midway rated 3400MW.
11. Same as G, except no PG&E upgrade.

CAPITAL COSTS

2005 M$, includes AFUDC

COST COMPONENT	CAPITAL COS
Antelope-Pardee 500kV line	80.3
Antelope-Vincent 500kV line	63.6
Antelope-Tehachapi 500kV line	99.5
Upgrade Antelope to 500kV: one 1000MVA, 500-230kV transformer	37.5
Upgrade Pardee to 500kV: one 1000MVA, 500-230kV transformer	37.5
Upgrade Tehachapi to 500kV: four 1000MVA, 500-230kV transformers	150
Sum of Phase 1 additions at 500kV	468.4
Phase 2: Upgrade Antelope-Mesa line with Antelope-Vincent segment at 500kV	145
Upgrade Vincent Substation: add 500kV transformer bank and terminations and shunt capacitors	62.1
Tehachapi-Vincent 500kV line	163.1
Tehachapi-Midway 500kV line at 3400MVA	315.4
Tesla-Los Banos-Midway 500kV line	924.4
Tesla-Gregg-Midway 500kV line	969.8

CAISO ALTERNATIVE

E1: Phase 1 at 500kV, Phase 2, Upgrade Vincent Substation, Second Antelope-Tehachapi 500kV line, Tehachapi-Midway 500kV line at 3400MVA	1090.4
F: Phase 1 at 500kV, Phase 2, Second Antelope-Tehachapi 500kV line, Tesla-Los Banos-Midway 500kV line, Upgrade Vincent Substation, Tehachapi-Midway 500kV line at 3400MVA	2014.8
G: Phase 1 at 500kV, Phase 2, Second Antelope-Tehachapi 500kV line, Tesla-Los Banos-Midway 500kV line, Upgrade Vincent Substation, Tehachapi-Vincent 500kV line	1862.5
GNNM: Phase 1 at 500kV, Phase 2, Second Antelope-Tehachapi 500kV line, Upgrade Vincent Substation, Tehachapi-Vincent 500kV line	938.1
I: Phase 1 at 500kV, Phase 2, Second Antelope-Tehachapi 500kV line, Tesla-Gregg-Midway 500kV line, Upgrade Vincent Substation, Tehachapi-Midway 500kV line	2060.2
J: Phase 1 at 500kV, Phase 2, Second Antelope-Tehachapi 500kV line, Tehachapi-Vincent 500kV line, Upgrade Vincent Substation, Tesla-Gregg-Midway 500kV line	1907.9

Fig 2.1: Project E
Existing: solid lines
New: dotted lines
PG&E: black
SCE: red

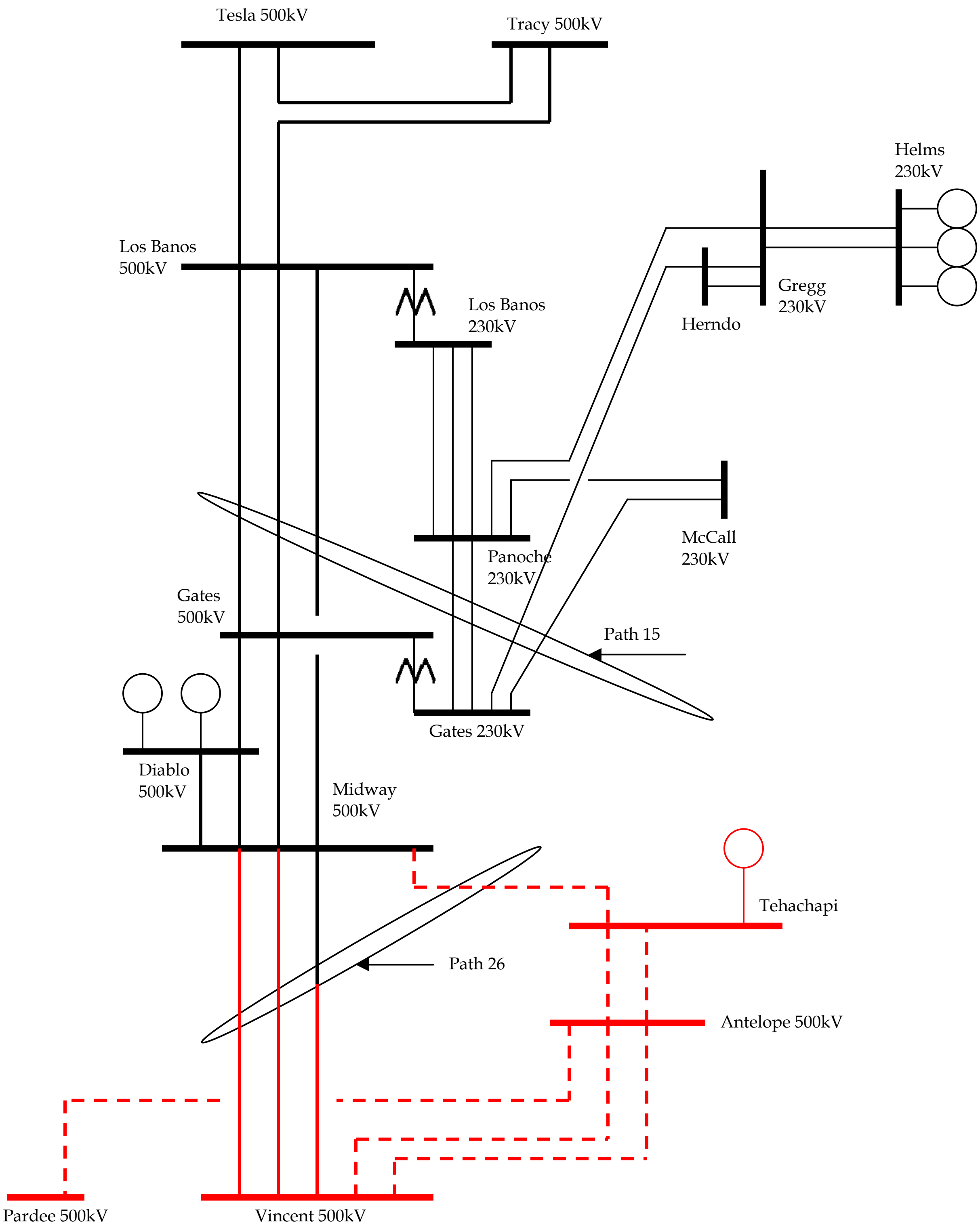


Fig 2.2: Project F

Existing: solid lines

New: dotted lines

PG&E: black

SCE: red

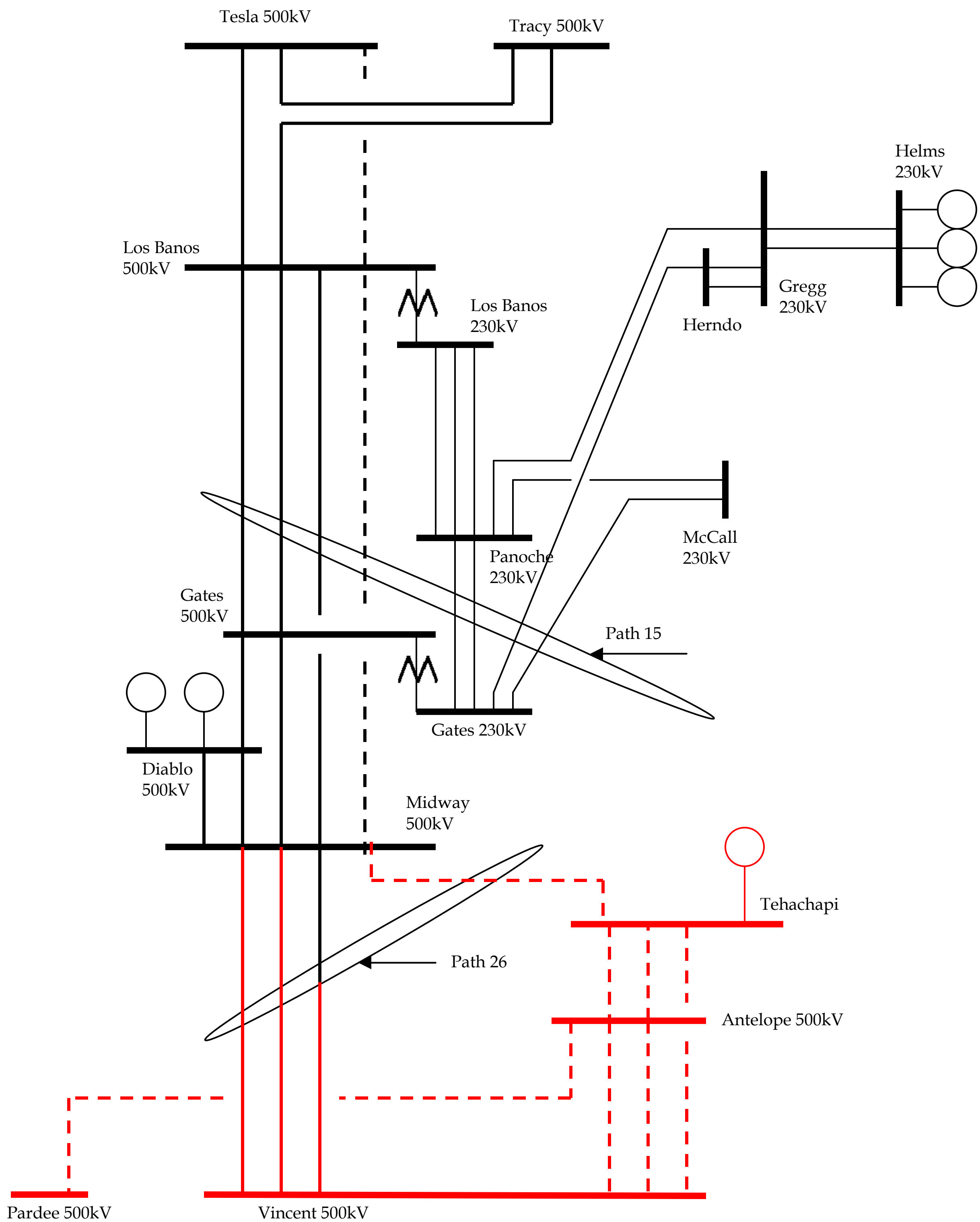


Fig 2.3: Project G
Existing: solid lines
New: dotted lines
PG&E: black
SCE: red

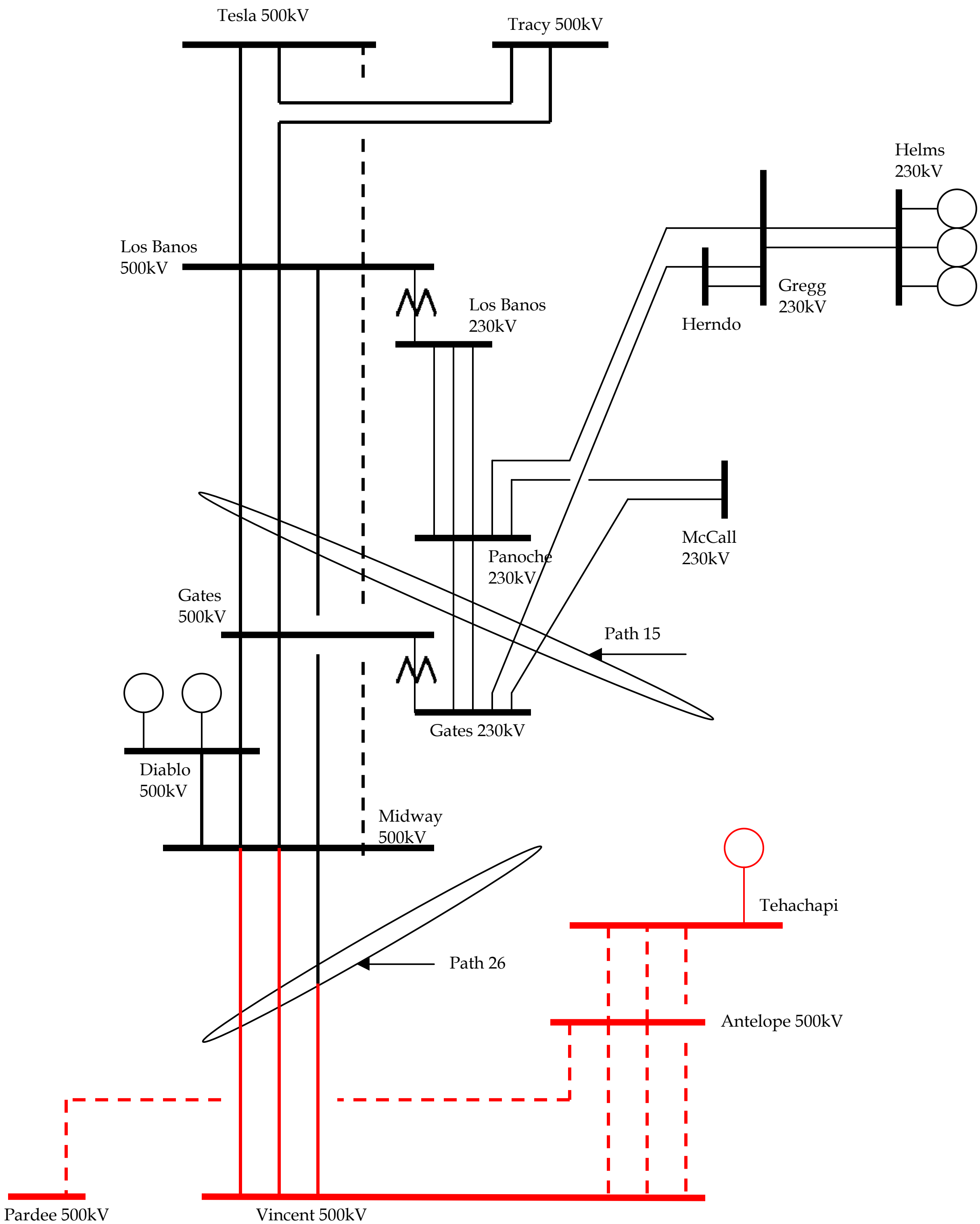


Fig 2.4: Project G-NM

Existing: solid lines
New: dotted lines
PG&E: black
SCE: red

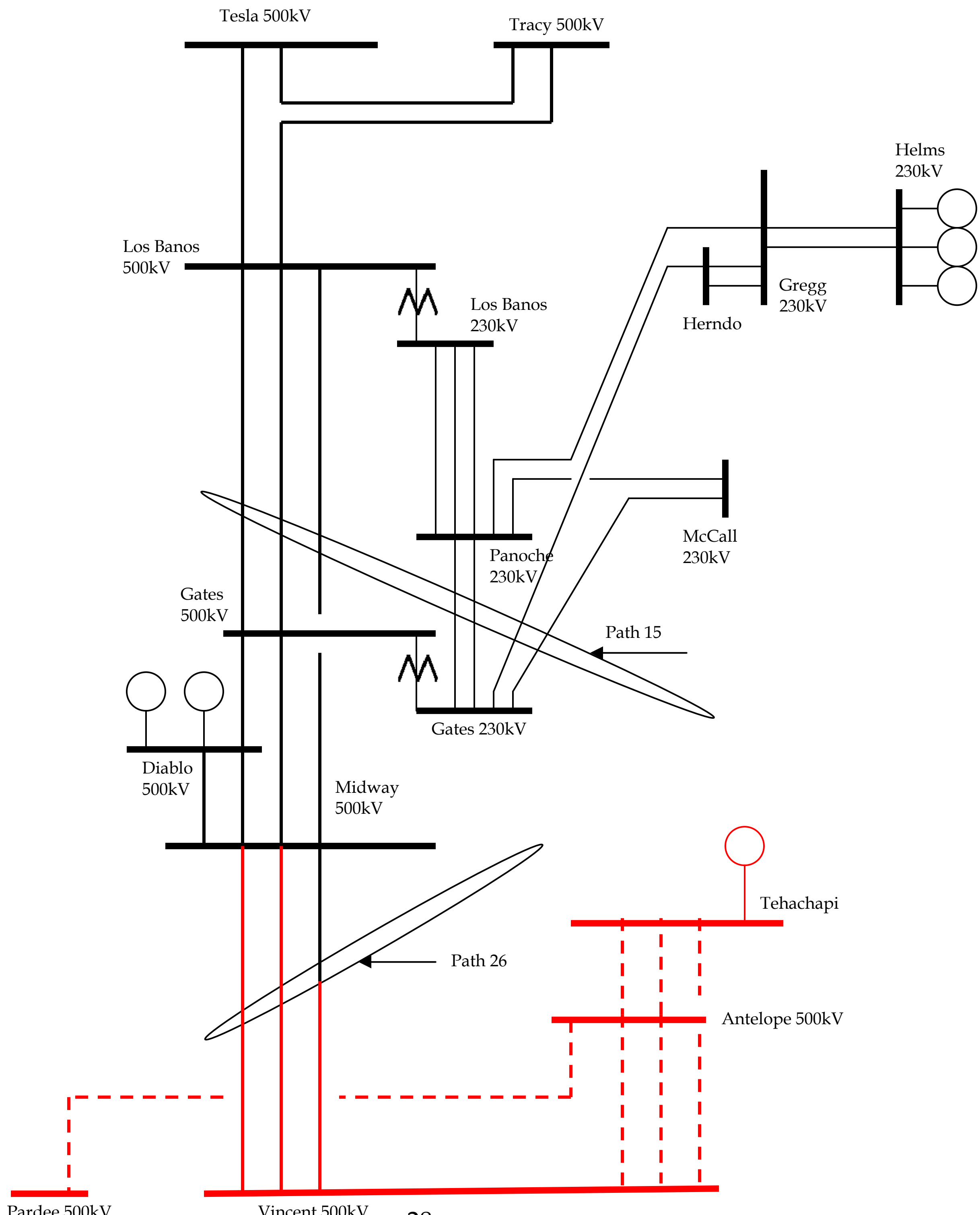


Fig 2.5: Project I
Existing: solid lines
New: dotted lines
PG&E: black
SCE: red

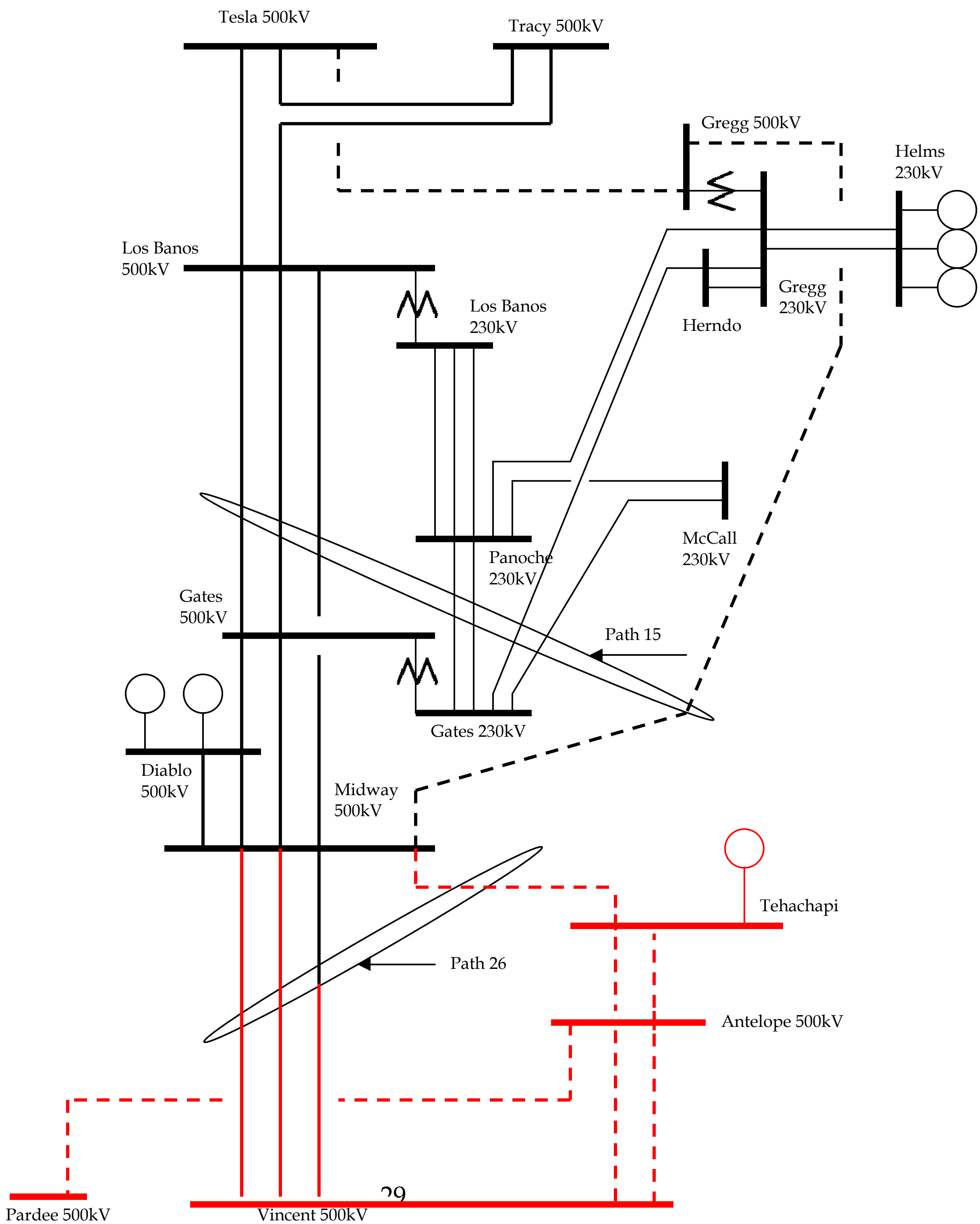
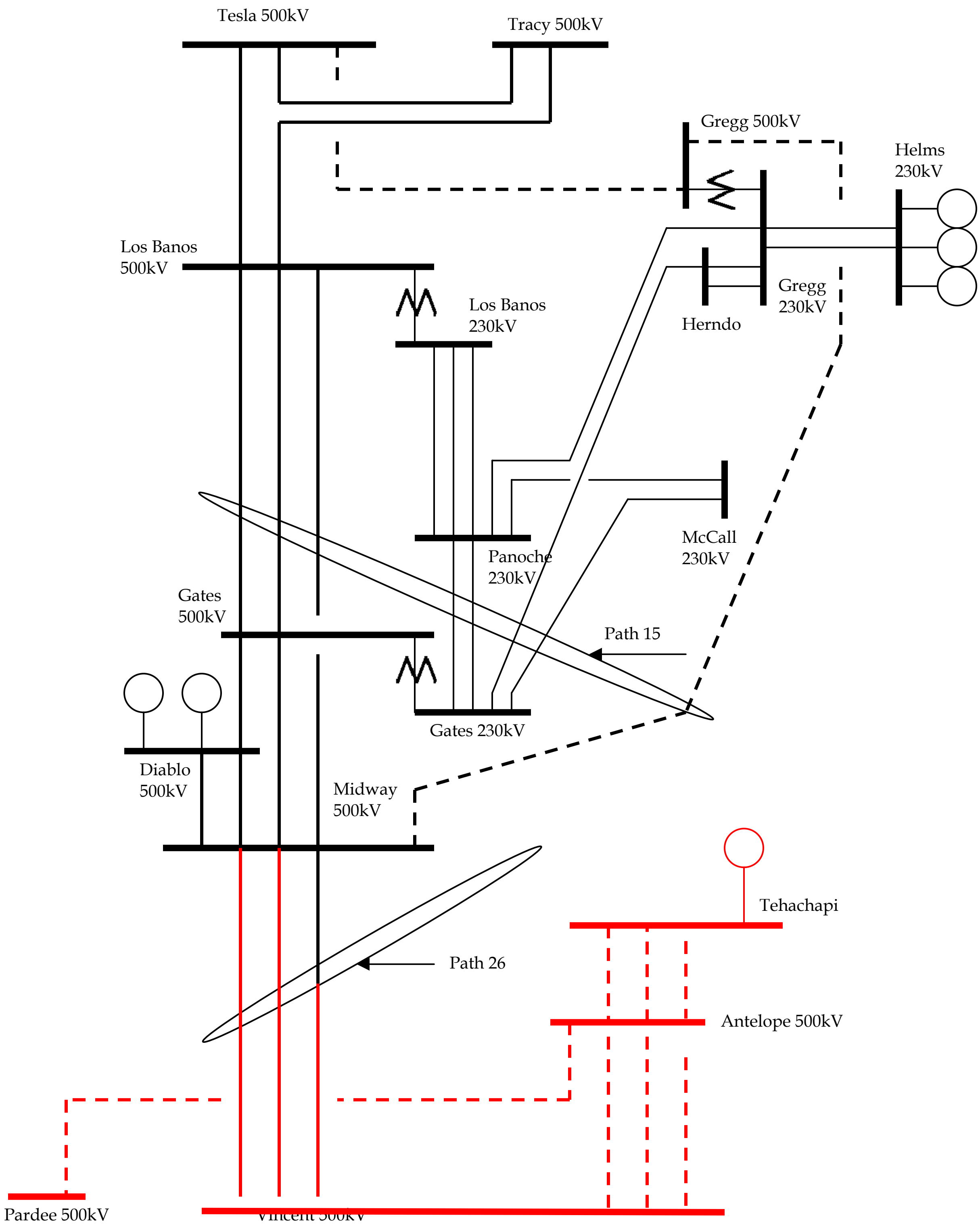


Fig 2.6: Project J

Existing: solid lines
New: dotted lines
PG&E: black
SCE: red



CHAPTER 3

PRODUCTION SIMULATION STUDIES BY CAISO

3.1 Background

As part of the TCSG study plan, the CAISO was requested to perform production cost modeling to determine production costs, congestion costs and system losses associated with the various transmission alternatives. The production cost simulation software provides an economic optimization of generation dispatches to minimize the total hourly production cost for the transmission system that is subject to generation, transmission and operational constraints modeled. The output of the production simulation tool was processed to estimate the comparative production cost, and any loss and congestion savings of each of the alternatives. The purpose of this portion of the study was to help determine any significant differences and provide a relative ranking of the transmission alternatives developed by the TSCG.

Productions cost simulations were performed to determine the annual production costs of the entire WECC system for the various alternatives being considered to incorporate 4,500 MW of incremental wind potential in the Tehachapi area. In addition, the annual results for California participants were determined to provide a California area perspective. The analysis was used to compare differences in the WECC production costs, power losses and congestion hours resulting from the alternative transmission configurations being considered. The analysis did not consider other potential benefits such as reduction in reliability-must-run generation cost, reduction in emission and increased operational flexibility. It should also be noted that potential concerns involved with the intermittency of wind and its potential impacts on system operation such as regulation and reserve are not part of this evaluation.

The 2008 SSG-WI (Seams Steering Group-Western Interconnection) base case developed by SSG-WI Planning Work Group (PWG) and also used in the recent Imperial Valley Study[12] was used as a starting case to maintain consistent assumptions between similar studies. The SSG-WI base case was modified with the CAISO load level to reflect forecasted 2010 conditions. In addition, new transmission projects in southern California

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

that are approved and planned to be online by 2010 were included in the model. The analysis is based on all lines in service and does not consider any contingency or loss of facility conditions. Appendix 4 summarizes the study assumptions used, including the transmission and operational constraints applied in the simulations to optimize system operations.

3.2 Study Scenarios Descriptions

CAISO evaluated the study scenarios provided by the TCSG which are described in the Study Plan #2 of Appendix 1 and based on the Tehachapi transmission alternatives documented in the TCSG March 16, 2005 report. Various levels of incremental Tehachapi wind output from 0 MW, 1,600 MW, 3,300 MW and 4,500 MW were modeled to assess the differences in the annual production costs and were used to help determine a relative ranking of the transmission configurations proposed. Sensitivities to combining PG&E alternatives with SCE alternatives were performed to determine if additional reinforcements on the PG&E system north of Midway would be economic and what optimum combination, if any, could be identified. The analysis also considered a 300 MW, 500 MW and a 600 MW 230 kV phase shifted tie (Phase angle regulator – PAR) in the Fresno area interconnecting SCE's Big Creek 230 kV transmission system with PG&E's Helms 230 kV transmission and was based on thermal analytical analysis discussed in Chapter 4. The Fresno tie was analyzed to see if it could provide any potential incremental benefits with coordinating the Tehachapi wind generation and the existing Helms pumped storage facility. Not all sizes of the Fresno PAR were investigated for the scenarios.

Table 3.1 summarizes the scenarios[13] based on the progressive phases of the conceptual transmission plans and combinations of transmission alternatives developed to accommodate a potential of up to 4,500 MW of incremental wind in the Tehachapi and Antelope Valleys.

Chapter 2 and Appendix 4 provide figures to illustrate the transmission configurations.

[13] Scenario lettering corresponds to Study Scenarios outlined in Chapter 2 and in Study Plan #2.

Table 3.1: Study Scenarios Reviewed

Alternative		Scenario	Description
PG&E	SCE		
0 MW Incremental Tehachapi Area Wind Generation			
SCE Phase 1 Facilities		A	Existing system after completion of SCE's Phase 1 Facilities (Segments 1, 2 & 3: Antelope-Vincent, Antelope-Pardee). Build at 500 kV operate at 230 kV
		B	Scenario A with a Fresno phase shifter (+/- 600 MW capability assumed)
1600 MW Incremental Tehachapi Area Wind Generation			
SCE Phase 1 & 2 Facilities		C	Scenario A with Phase 2 Facility Upgrades (Vincent-Mesa 230 kV, Antelope-Vincent built at 500 kV operate at 230 kV)
		D	Scenario C with Fresno 230 kV tie (Phase shifter, +300, +500, +600 MW, +/-600 MW capabilities)
3300 MW Incremental Tehachapi Area Wind Generation			
4	1	K	500 kV Tesla-Los Banos-Gates-Midway-Tehachapi with 2 Tehachapi-Antelope, Antelope-Vincent, Antelope-Pardee
5 - Phase 1	1	L	500 kV Tesla-Gregg-Tehachapi with 2 Tehachapi-Antelope, Antelope-Vincent, Antelope-Pardee
4	1	M	Tesla-Los Banos-Gates-Midway 500 kV with Fresno 230 kV tie, two 500 kV lines Tehachapi-Antelope
5C	1	N	Tesla-Gregg 500 kV with Fresno 230 kV tie, two 500 kV lines Tehachapi-Antelope
4500 MW Incremental Tehachapi Area Wind Generation, Without Fresno 230 kV Tie **No North of Midway Reinforcements**			
-	1	E	Scenario C with Tehachapi-Midway 500 kV, SCE Phase 1 & 2 Facilities operated at 500 kV
-	2	G-NM	500 kV lines -3 Tehachapi-Antelope, 2 Antelope-Vincent, Antelope-Pardee
4500 MW Incremental Tehachapi Area Wind Generation, Without Fresno 230 kV Tie **With North of Midway Reinforcements**			
4	1	F	500 kV Tesla-Los Banos-Gates-Midway-Tehachapi with 2 Tehachapi-Antelope, Antelope-Vincent, Antelope-Pardee
4	2	G	Scenario F with 500 kV Tehachapi-Midway replaced with 500 kV Tehachapi-Vincent
5 - Phase 1	1	H	500 kV Tesla-Gregg-Tehachapi with 2 Tehachapi-Antelope, Antelope-Vincent, Antelope-Pardee
5	1	I	500 kV Tesla-Gregg-Midway-Tehachapi with 2 Tehachapi-Antelope, Antelope-Vincent, Antelope-Pardee
5	2	J	Scenario F with 500 kV Tehachapi-Midway replaced with 500 kV Tehachapi-Vincent

Additional Sensitivities With 4500 MW Tehachapi Area Wind Generation			
-	2	O	230 kV Fresno Tie with 2 Tehachapi-Antelope, Tehachapi-Vincent, Antelope-Vincent, Antelope-Pardee 500 kV
4	3	P	500 kV Tesla-Los Banos-Gates-Midway-Tehachapi with 2 Tehachapi-Vincent and 230 kV Antelope-Vincent, Antelope-Pardee
5	3		500 kV Tesla-Los Banos-Gates-Midway-Tehachapi with 2 Tehachapi-Vincent and 230 kV Antelope-Vincent, Antelope-Pardee
4	10	Q	500 kV Tesla-Gregg-Midway-Tehachapi, Tehachapi-Vincent, Tehachapi-Pardee
5	10		500 kV Tesla-Gregg-Midway-Tehachapi, Tehachapi-Vincent, Tehachapi-Pardee

3.3 Local Area Transmission Interfaces

There are two major transmission pathways in the vicinity of the Tehachapi area that may be impacted by integrating a large amount of new resources into the 500 kV bulk power system. The Path 15 and Path 26 interfaces measure the power flows north and south of the PG&E's Midway area. Path 15 measures power flow north of Midway through the Los Banos area and Path 26 the flow imported or exported south of the Midway area. Path 26 is comprised of the three 500 kV lines between PG&E's Midway Substation and SCE's Vincent Substation and currently forms the only existing transmission link between both PG&E and SCE, but also northern and southern California. The SCE alternatives developed would inject over 4000 MW of Tehachapi wind into the Vincent area at the southern end of the existing Path 26 lines under SCE Alternative 2 or into the middle of the Path 26 if the 500 kV system is reinforced from Midway through the Tehachapi area to the Vincent area as provided by SCE Alternatives 1, 3 or 10. PG&E alternatives would provide reinforcement across Path 15.

RESULTS

3.4 Annual Production Costs

The simulations of hourly production runs optimized the system with sufficient generation resources to meet hourly demand and transmission losses subject to transmission and operational constraints for the conditions studied. Monitored transmission lines and interfaces were found congested for various time periods for all the scenarios studied.

Table 3.2 provides a summary of the annual results comparing each of the study scenarios based on the entire WECC system. While there may be some inefficiencies of system operation as shown occurring by the number of congestion hours of Path 15, Path 26, or the entire WECC system, the resulting annual production cost for the WECC system demonstrates the overall efficiency and impact on system operation of the alternative transmission configurations. Additional details of the results and annual flow duration curves for select scenarios studied are provided in Appendix 4.

The annual benefits of reinforcing Path 26 and/or Path 15 can be seen by the reduction in congestion of those interfaces paths and the resulting incremental cost difference between the alternatives.

Table 3.2 – Summary of WECC Results

Alternative							
PG&E	**SCE**	**Scenario**	**WECC Transmission Losses (TWH)**	**WECC System Congestion (Hrs)**	**Path 26 Congestion (Hrs)**	**Path 15 Congestion (Hrs)**	**WECC Annual Production Cost (M$)**
0 MW Tehachapi Area Incremental Wind Generation							
SCE Phase 1 Facilities		A	34.751	147375	350	1403	15690
		B(+/-600[1]	34.644	147968	284	1282	15692
		B(+300)[1]	34.673	152720	269	1253	15686
1600 MW Tehachapi Area Incremental Wind Generation							
SCE Phase 1 & 2 Facilities		C	34.825	145671	397	1546	15422
		D(+/-600)[1]	34.717	145646	335	1421	15429
		D(+600)[1]	34.705	148719	317	1338	15433
		D(+500)[1]	34.737	149077	299	1357	15431
		D(+300)[1]	34.705	151500	347	1410	15418
3300 MW Tehachapi Area Incremental Wind Generation							

4	1	K	34.647	143115	176	1	15135
5 - Phase 1	1	L	34.469	143808	41	110	15143
4	1	M(+/-600)[1]	34.450	144546	446	1505	15134
5C	1	N(+/-600)[1]	34.502	146426	1904	0	15120
4500 MW Tehachapi Area Incremental Wind Generation, Without Fresno 230 kV Tie **No North of Midway Reinforcements**							
-	1	E	34.782	144227	2	2573	14934
-	2	G-NM	34.762	144276	803	1986	14942
4500 MW Tehachapi Area Incremental Wind Generation, Without Fresno 230 kV Tie **With North of Midway Reinforcements**							
4	1	F	34.719	142507	757	0	14934
4	2	G	34.737	145563	2691	0	14929
5 - Phase 1	1	H	34.486	142914	85	0	14961
5	1	I	34.491	143246	137	0	14938
5	2	J	34.553	146198	2577	0	14926
Additional Sensitivities With **4500 MW Tehachapi Area Wind Generation**							
-	2	O(+/-600)[1]	34.601	144944	695	1722	14948
-	2	O(+300)[1]	34.615	150878	2391	0	14931
4	3	P	34.778	143092	953	0	14940
5	3		34.580	144188	911	0	14938
4	10	Q	34.751	142764	879	0	14940
5	10		34.533	143301	821	0	14937

Notes:

1) Fresno PAR +/- 600 MW, +600 MW, +500 MW or +300 MW SCE to PGE direction.
2) New Midway-Tehachapi line rating 3421 MVA.

Table 3.3 provides a summary of the annual cost difference results comparing the WECC system with the California Participants[14] for each of the study scenarios. The incremental annual cost differences are referenced from the lowest annual cost result within each of the 0 MW, 1600 MW, 3300 MW and 4500 MW Incremental Tehachapi output levels. As an example within the 1600 MW Incremental Tehachapi output level, Scenario D(+300 MW)

[14] California Participants Annual results are the sum of PG&E, SCE and SD&E annual results. Includes all generation (including IPPs) modeled within PG&E, SCE and SDG&E

is used as the reference with the lowest annual production cost and Scenario D(+600 MW) would result in $15 million higher annual operating costs for the WECC system. Similarly, within the 4500 MW Incremental Tehachapi output level, Scenario J (SCE Alternative 2 with PG&E Alternative 5) is used as the reference with the lowest annual production cost and Scenario E (SCE Alternative 1) results in $8 million higher annual operating costs for the WECC system. A similar comparison of Scenario J and E based on the CAISO Participant results shows only a $1 million annual savings

Table 3.3 – Comparison of Incremental Annual Cost Differences

Alternative			**WECC**		**California Participants[3]**	
PG&E	**SCE**	**Scenario**	**Annual Production Cost (M$)**	**Cost Difference[2] (M$)**	**Annual Cost (M$)**	**Cost Difference[2] (M$)**
0 MW Incremental Tehachapi Area Wind Generation						
SCE Phase 1 Facilities		A	15690	4	4271	11
		B(+/-600[1]	15692	6	4260	**0**
		B(+300)[1]	15686	**0**	4263	3
1600 MW Incremental Tehachapi Area Wind Generation						
SCE Phase 1 & 2 Facilities		C	15422	3	4108	11
		D(+/-600)[1]	15429	11	4103	5
		D(+600)[1]	15433	15	4108	11
		D(+500)[1]	15431	13	4106	8
		D(+300)[1]	15418	**0**	4097	**0**
3300 MW Incremental Tehachapi Area Wind Generation						
4	1	K	15135	15	3923	6
5 - Phase 1	1	L	15143	23	3917	**0**
4	1	M(+/-600)[1]	15134	14	3937	20
5C	1	N(+/-600)[1]	15120	**0**	3921	4
4500 MW Incremental Tehachapi Area Wind Generation, Without Fresno 230 kV Tie **No North of Midway Reinforcements**						
-	1	E	14934	8	3818	16
-	2	G-NM	14942	16	3829	27

4500 MW Incremental Tehachapi Area Wind Generation, Without Fresno 230 kV Tie With North of Midway Reinforcements						
4	1	F	14934	8	3802	**0**
4	2	G	14929	3	3817	15
5 – Phase 1	1	H	14961	35	3817	15
5	1	I	14938	13	3813	11
5	2	J	14926	**0**	3817	15
Additional Sensitivities With 4500 MW Incremental Tehachapi Area Wind Generation						
-	2	O(+/-600)[1]	14948	22	3816	12
-	2	O(+300)[1]	14931	5	3813	11
4	3	P	14940	14	3801	-1
5	3		14938	12	3806	4
4	10	Q	14940	14	3811	9
5	10		14937	11	3813	11

Notes:

1) Fresno PAR +/- 600 MW, +600 MW, +500 MW or 300 MW SCE to PGE direction.
2) Cost difference reference is based on the lowest annual cost within of each of the 0 MW, 1600 MW, 3300 MW and 4500 MW Tehachapi output levels.
3) California Participants Annual results are the sum of PG&E, SCE and SD&E annual results. Includes all generation (including IPPs) modeled within PG&E, SCE and SDG&E
4) New Midway-Tehachapi 500 kV line normal rating of 3950 Amps assumed.

For the conditions studied and assumptions used, these results do not show significant cost benefits and result in differences of less than 1% in annual savings between the alternative transmission configurations. The WECC annual savings are within about 0.25% difference and California Participant results are within a 0.7% difference for the alternatives to incorporate 4,500 MW of Incremental Tehachapi wind. Differences between the WECC and California Participant results are due to internal California congestion that may be overshadowed when considering the overall WECC system optimization compared with the results within the California area only.

3.5 With and Without North of Midway Reinforcement

To incorporate the expected Tehachapi full output to be developed, SCE Alternative 1 (Scenario E – without reinforcements north of Midway) shows about $ 8 million to $11 million lower annual savings compared to SCE Alternative 2 (Scenario G-NM, without reinforcements north of Midway). The incremental annual savings resulting from reinforcing north of Midway with the PG&E Alternative 4 or 5 in combination with the SCE Alternatives 1 or 2 are summarized in the Table 3.4.

Table 3.4 - North of Midway Reinforcement Annual Savings

4500 MW Incremental Tehachapi Wind Output

Alternative		Incremental Annual Saving (M$)	
PG&E	SCE	WECC	California Participant
4	1	0	16
5	1	-4	5
4	2	13	12
5	2	16	12

3.6 Helms Pumped Storage Coordination with Tehachapi Wind

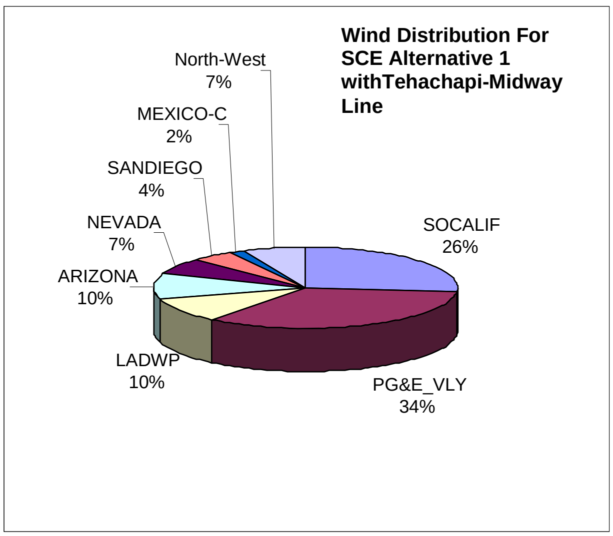
The production cost simulations did not demonstrate any difference in the operation of the Helms pumped storage facility with or without a Fresno 230 kV tie model. This is a result of how the pump storage facility schedules are determined. Schedules developed are based on the load level within a region and estimated generating and pumping thresholds for the facility. The schedule of the pumped storage facilities cannot be coordinated with the assumed hourly wind profile without a significant effort and would result in a fixed scheduled that would be separate from the optimization of the system resources. Therefore this was not investigated further under this study.

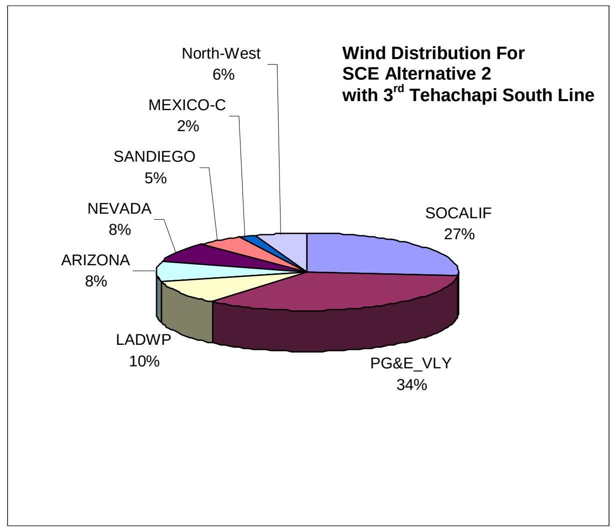
3.7 Fresno 230 kV Tie Operation

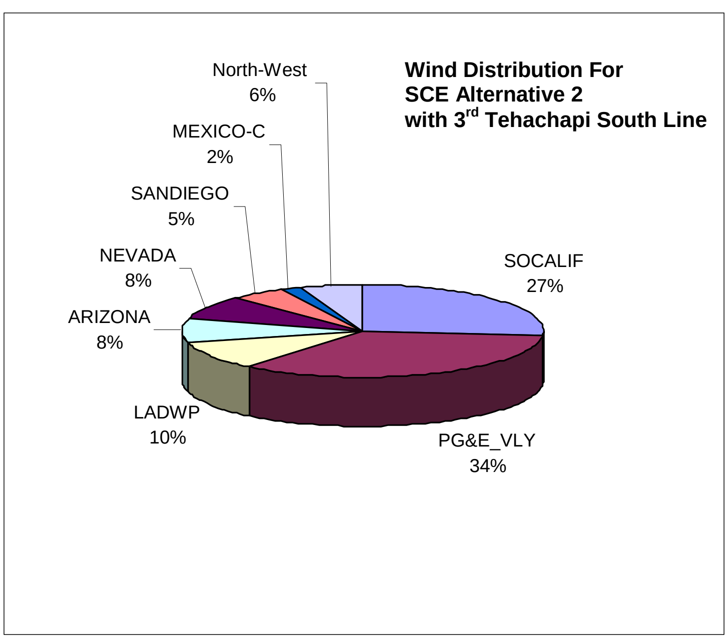
The Fresno phased-shift tie modeled in this analysis assumed a capability up to +/-600 MW and with an angle range of +/-45 degrees. Simulations found the tie frequently changed schedule and angle from hour to hour and suggested that control of the facility may require constant intervention by operators. It was also found that a 300 MW tie resulted in lower system operational costs than no tie or higher rated ties of 500 MW or 600 MW and is influenced by the available Midway and Bay area generation for hourly dispatch with the Tehachapi wind.

3.8 Distribution of Tehachapi Wind

The Tehachapi wind was modeled as an hourly resource that must be taken if available and would be used to displace high cost inefficient generation on the system. Although there is a general assumption that the Tehachapi power would be equally split between PG&E and SCE the production simulation program will dispatch the system with wind for the most efficient low cost WECC system operation. The following figures compare the annual energy distribution with and without Tehachapi wind to illustrate the potential recipients of the power based on SCE Alternative 1 and SCE Alternative 2. There is no significant difference in the annual energy distribution between the two alternatives.







It is important to note that subsequent to completion of this production cost analysis, it was determined through thermal analytical studies discussed in Appendix 7, that Path 26 thermal transfer capability in the north to south direction may be less than the 4000 MW assumed for SCE Alternatives 1, 3 or 10 that include a new 500 kV Midway-Tehachapi-Vincent path that would parallel the existing Path 26. Based on the incremental differences between the alternatives, it is not expected that there would be any significant change in the results and savings would be within the ranges shown. Additional detailed thermal, voltage and stability studies would be required to determine the actual Path 26 transfer capability.

These production cost study results alone do not provide an adequate basis for making investment decisions. These production cost simulation study results, the results of the power flow and stability studies, and the cost of implementing the individual projects will all influence the choice of upgrade ultimately selected (see Chapter 2). It is also important to note that this production cost simulation study was developed solely for comparing transmission alternatives required to incorporate a large amount of wind resources in the Tehachapi area and should not interpreted as a determination of wind as a preferred renewable resource.

CHAPTER 4: POWER FLOW STUDIES AND FACILITY COST STUDIES

The evaluation described in Chapter 2 shows that the upgrades studied for north of Midway (including the 230 kV tie to transmit power to PG&E in the Fresno Area) would not be economic for the sole purpose of transferring Tehachapi generation to load centers in Northern California at this time. The material in Section 4.1 describes the studies done by PG&E, on which this conclusion is based.

4.1 PG&E Transmission 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 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. Even in those instances when it may be necessary for the CAISO to increase the power transfer into Southern California by an amount equal to this expected decrease, it would only bring the north to south power transfer at Midway back to the original amount, resulting in a net change of zero MW on Path 26. 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 2-1, Appendix 2.)

Accordingly, all PG&E alternatives investigated for North of Midway are for mitigating expected off-peak transmission problems when the prevalent power transfer is in the south to north direction (see Tables 2-2 and 2-3, Appendix 2). In the Study completed for the TCSG Report filed on March 16, 2005 PG&E had investigated three alternatives in addition to the status quo (Alternative 1) to mitigate the impacts of scheduling and delivering 2,000 MW of Tehachapi generation (Alternatives 4 and 5) and two alternatives to mitigate the impact of scheduling and delivering 300 MW of Tehachapi area renewable generation (Alternatives 2 and 3) to PG&E. Alternative 3 to deliver 300 MW to PG&E was subsequently dropped because it could not provide the intended 300 MW of transfer capability. In this study PG&E performed further investigation on

Alternatives 1, 2, 4 and 5. In addition, Alternative 2 was expanded to investigate the impact of scheduling and delivering 300 MW, 600 MW and 1,200 MW of Tehachapi area renewable generation. (See Appendix 2 for further discussion on Alternatives 1, 2, 4 and 5.)

PG&E's conceptual transmission alternatives are listed below (see Tables 4.1.1 and 4.1.2). 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 2. Note that the PG&E alternatives include placeholders only for 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 before the plan of service can be determined.

Table 4.1.1 Summary of Conceptual Transmission Plan and Planning Level Cost Estimates [15] for PG&E Alternative 2 [16] (see Figure 4.1.2)

Cumulative Import Level	**Plan "A" (100% at Switching Station #1)**	**Plan "B" (50% at Switching Station #1 and 50% at Switching Station #2)**
300 MW	Build Switching Station #1 with a 300 MVA phase shifter **Other Reinforcement in PG&E Area:** • Upgrade Borden-Gregg 230kV line (peak) **Conceptual Cost Estimate: $85 million**.	N/A
600 MW	Same as 300MW import level, except with one 600MVA phase shifter and building a new 230kV line between Switching Station #1 and Gregg. **Other Reinforcement in PG&E Area:** • Upgrade Borden-Gregg 230 kV line (peak) • Upgrade Storey 1 – Gregg 230kV line (peak) **Conceptual Cost Estimate: $222 million**	Build Switching Station #1 and #2 with a 300 MVA phase shifter at each station. **Other Reinforcement in PG&E Area:** • Upgrade Hass-McCall and Balch-McCall 230 kV lines (peak & off-peak) • Upgrade Borden-Gregg 230kV line (peak) **Conceptual Cost Estimate: $179 million**
1200MW (Peak)	**Not feasible** (Due to the maximum phase angle range of +/-45 degree)	**Not feasible** (Due to the maximum phase angle range of +/-45 degree)

[15] These planning-level cost estimates are preliminary, unit cost-based estimates and do not reflect project-specific engineering, environmental mitigation requirements, or permit, land acquisition, and legal costs and assumes all over-head line construction. All estimates include 30% contingency and are subject to change based on final engineering and design as well as the requirements of any CPUC or other required permit processes.

[16] The cost estimates are for PG&E's portion of the Alternative only and include the UPC(s) for controlling power flows from SCE to PG&E

Table 4.1.1 Summary of Conceptual Transmission Plan and Planning Level Cost Estimates [15] for PG&E Alternative 2 [16] (see Figure 4.1.2)

Cumulative Import Level	**Plan "A" (100% at Switching Station #1)**	**Plan "B" (50% at Switching Station #1 and 50% at Switching Station #2)**
1200MW (Off-peak) [17]	Same as 600 MW import level, except with two 600MVA phase shifters. **Other Reinforcement in PG&E Area:** • Install 450 MVAR of voltage support. • Restrict the import level to Helms operation at 600 MW or more of pumping. **Conceptual Cost Estimate: $326 million**	Same as 600 MW import level, except with a 600 MVA phase shifter at each station. **Other Reinforcement in PG&E Area:** • Upgrade Hass-McCall and Balch-McCall 230 kV lines. • Restrict the import level to Helms operation at 600 MW or more of pumping. **Conceptual Cost Estimate: $380 million**

[17] The import capability would depend upon the Helms pumping operation. This alternative could support 1200 MW of import only under the off-peak conditions with at least two Helms units in pumping operation.

Table 4.1.2 Summary of Conceptual Transmission Plan and Planning Level Cost Estimates[1] for PG&E Alternatives 1, 4 and 5

Cumulative Import Level	**PG&E Alternative 1 (See 4.1.1)**	**PG&E Alternative 4 (See Figure 4.1.3)**	**PG&E Alternative 5 (See Figure 4.1.4)**
500MW	**Network upgrade not determined (see discussion on above)** **Conceptual Cost Estimate: Not determined**	**Phase 4A**: Build a new Los Banos-Midway 500kV line operated at 230kV. **Other Reinforcements in PG&E Area:** None **Conceptual Cost Estimate: $533 million**	**Phase 5A:** Build a new Gregg-Midway 500kV line operated at 230kV. **Other Reinforcements in PG&E Area:** None **Conceptual Cost Estimate: $406 million**
1100MW	**Network upgrade not determined (see discussion on above)** **Conceptual Cost Estimate: Not determined**	**Phase 4B:** Same as 4A, except also reconnecting the new line to 500kV and installing 65% series compensation. **Other Reinforcements in PG&E Area:** Upgrade Los Banos – Westley 230 kV line and Los Banos 500/230 kV bank **Conceptual Cost Estimate: $137 million**	**Phase 5B:** Same as 5A, except also building Gregg 500kV Substation with a 500/230kV, 1122/1350 MVA bank and reconnecting the new line. **Other Reinforcements in PG&E Area:** None **Conceptual Cost Estimate: $76 million**

2000MW	**Network upgrade not determined (see discussion on above)** **Conceptual Cost Estimate: Not determined**	**Phase 4C:** Same as 4B, except, also building Tesla – Los Banos 500 kV line. **Other Reinforcements in PG&E Area:** Install additional RAS **Note:** This Phase would increase the OTC from 5000 MW to 7000 MW. However, it may ***not*** be feasible to increase Path 15 Rating to 7,400 MW from the existing Rating of 5,400 MW[18] **Conceptual Cost Estimate: $254 million**	**Phase 5C:** Same as 5B, except also installing series comp on Gregg -Midway line (31%), and Tesla-Gregg line (62%). **Other Reinforcements in PG&E Area:** None **Conceptual Cost Estimate: $451 million**

4.1.1 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. Power flow study to date shows overloads, ranging from 3% to 48% over the ratings (or allowable limit) of eight transmission facilities under normal (all facilities in service) operating conditions (see Table 2-3, Appendix 2). As a result, this alternative would expand the times and conditions under which curtailment of generation would be required. 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.

If existing generation in areas around Midway Substation is curtailed to allow transfer of Tehachapi power, Path 15 south to north transfer capability will have to be reduced. This is because the existing Path 15 south-to-north transfer capability under normal conditions can only be supported with operation of the Remedial Action Scheme (RAS) immediately following identified outages. If Midway area generation that is connected to the existing RAS were dispatched off-line or kept at minimum generating levels (assuming that the FERC open

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

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[19].

Connecting Tehachapi generation to the RAS to support Path 15 is neither effective nor is it practical even assuming installation of a new type of RAS controller and other equipment so it can predict the amount of wind generation available to trip if the outage occurs. For wind turbines to be part of generation RAS to replace the Midway generation RAS, the new RAS controller would need to ensure that sufficient generation was available to trip regardless of the wind output. At this time, no solution has been identified that will not in turn require tripping a higher amount of load commensurate with the increased amount of generation tripped to keep the net amount of net generation to be tripped within the allowable limit. The need for facility upgrades can be triggered by transient stability and post-transient voltage study results or the determination that the use of special protection systems is ineffective, violates criteria or otherwise could not be utilized.

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

4.1.2 PG&E Alternative 2: Fresno 230 kV Phase-Shifted Tie:

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

Plan A (PG&E_Alt-2A):
Establish one 230 kV tie between PG&E and SCE. Build Switching Station #1 at the crossing of PG&E’s Helms – Gregg 230 kV lines and SCE’s Big Creek – Rector 230 kV lines. Install one phase shifter or power flow controller to control the tie line flow

[19] Curtailing all Midway area generation that can be curtailed (about 2,600 MW) would reduce Path 15 south to north transfer capability from 5,000 MW to about 3,600 MW. This would enable Path 26 to load to about 2,700 MW.

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

4.1.3 PG&E Alternative 4: Tesla – Los Banos - Midway 500 kV line

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

Phase A (PG&E_Alt-4A): Build a new Los Banos – Midway 500kV line operated at 230 kV.

Phase B (PG&E_Alt-4B): Same as 4A, except, re-connecting the new Los Banos – Midway line to 500kV bus and installing 65% series compensation.

Phase C (PG&E_Alt-4C): Same as 4B, except, also building a new Tesla - Los Banos 500kV line without series compensation.

4.1.4 PG&E Alternative 5: Tesla –Gregg – Midway 500 kV line

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

Phase A (PG&E_Alt-5A): Build a new Gregg - Midway 500kV line operated at 230 kV.

Phase B (PG&E_Alt-5B): Same as 5A, except also building a Gregg 500 kV Substation with a 500/230 kV transformer bank and re-connecting the new Gregg - Midway 500kV line.

Phase C (PG&E_Alt-5C): Same as 5B, except also building a new Tesla - Gregg 500kV line with 62% series compensation and installing 31% series compensation on the Gregg – Midway 500 kV line.

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.

Figure 4.1.1 - PG&E Existing System

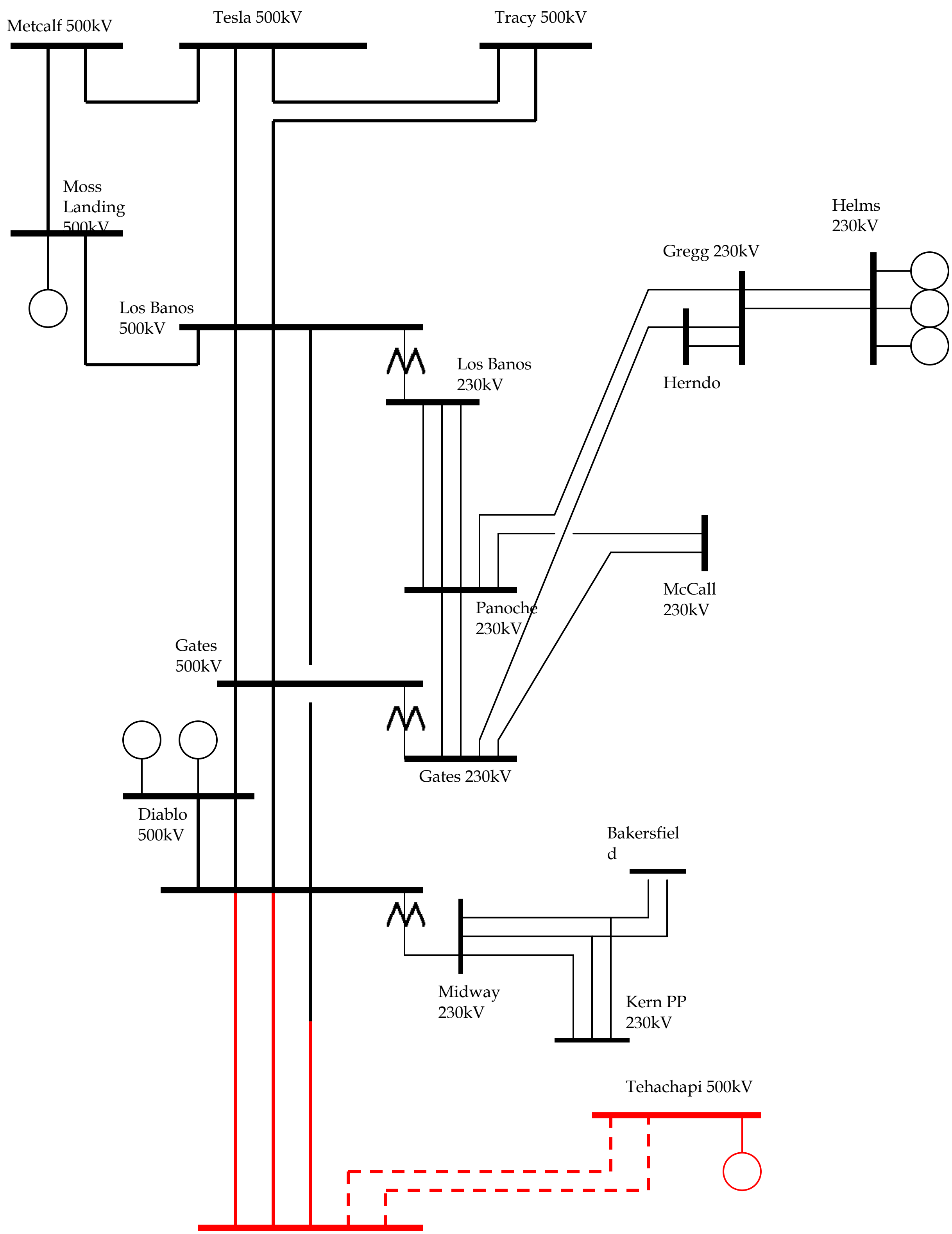


Figure 4.1.2 - PG&E Alternative 2: Fresno 230 kV Tie

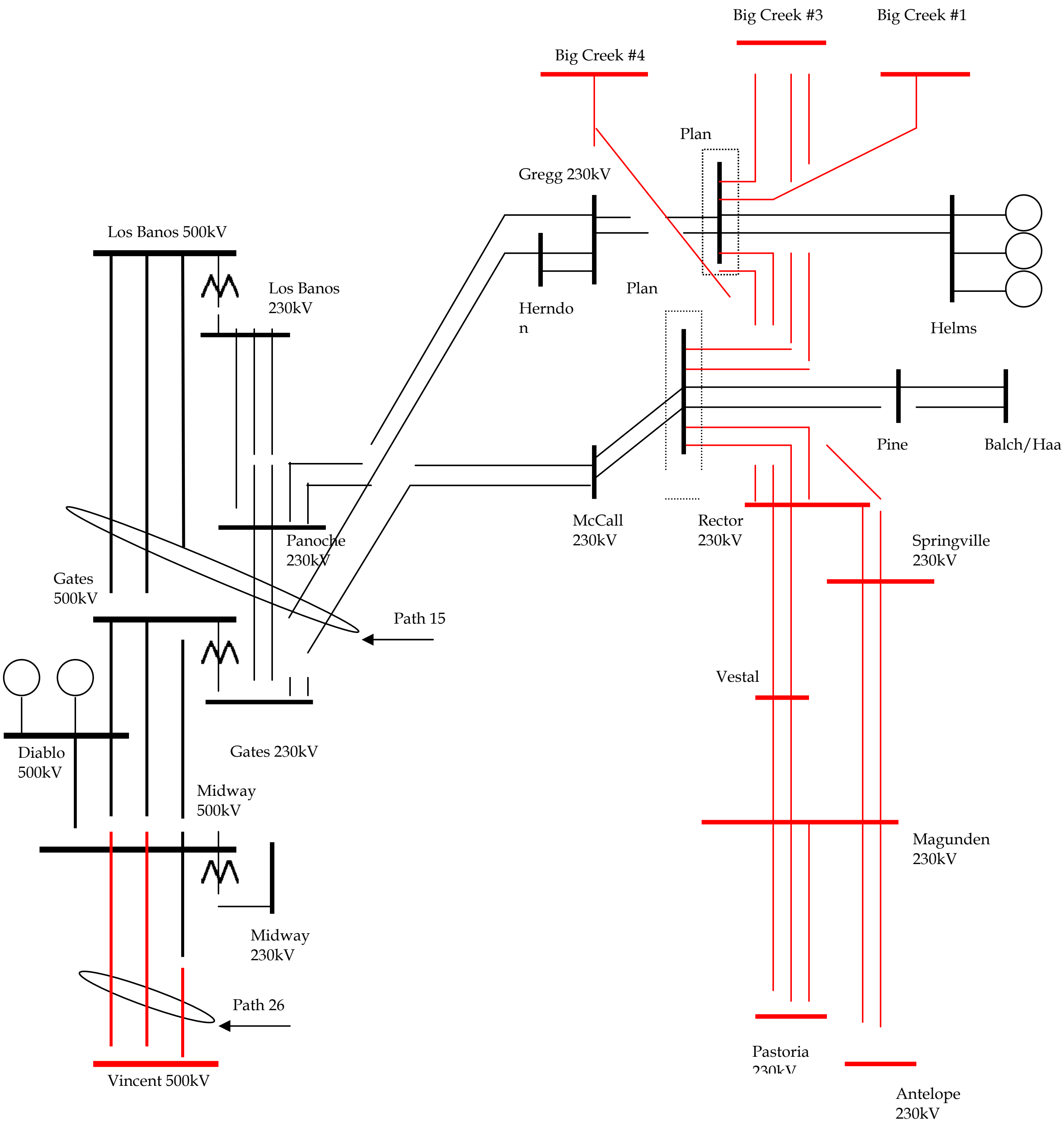


Figure 4.1.3 - PG&E Alternative 4: Tesla – Los Banos – Midway 500 kV line

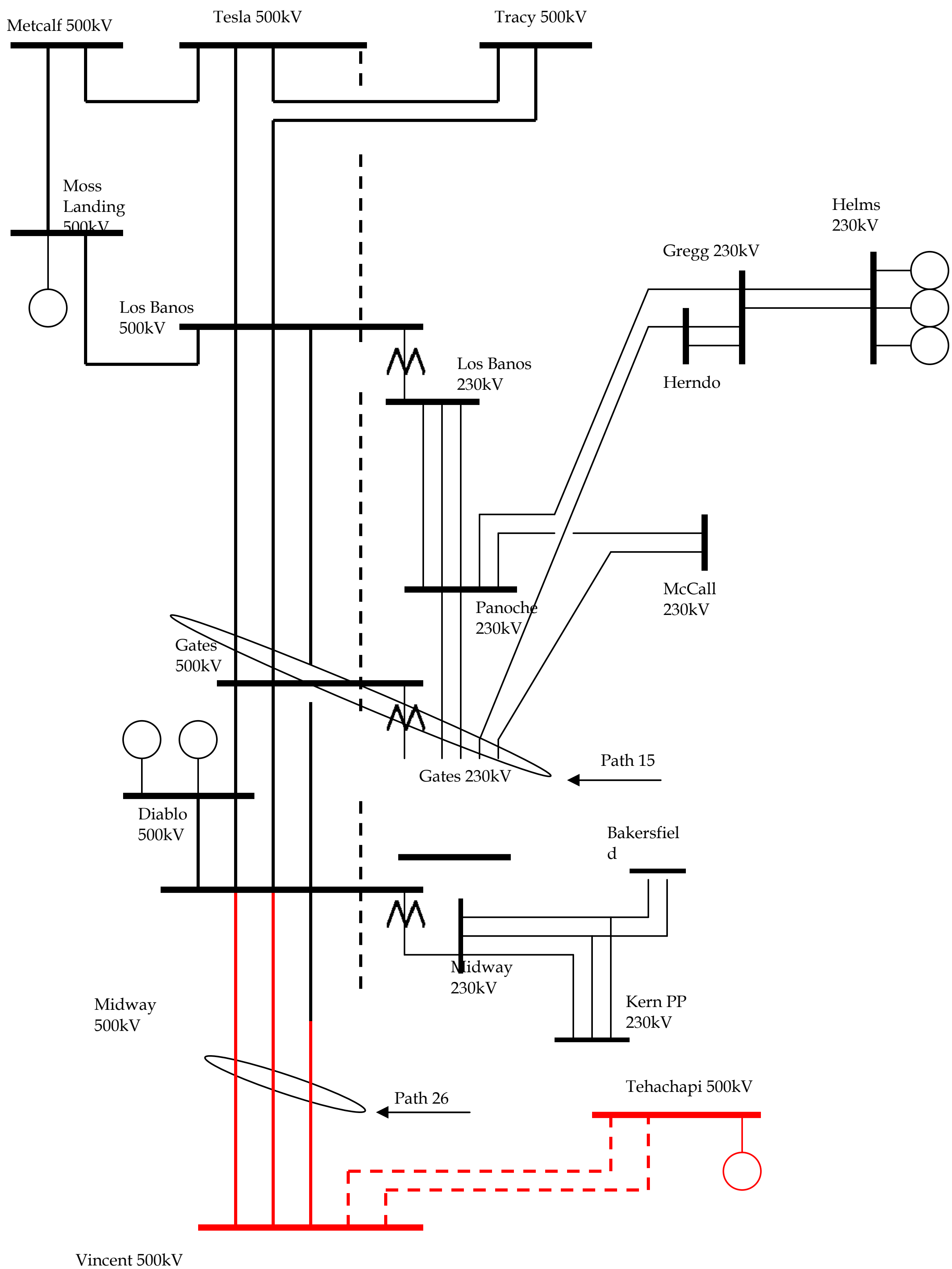
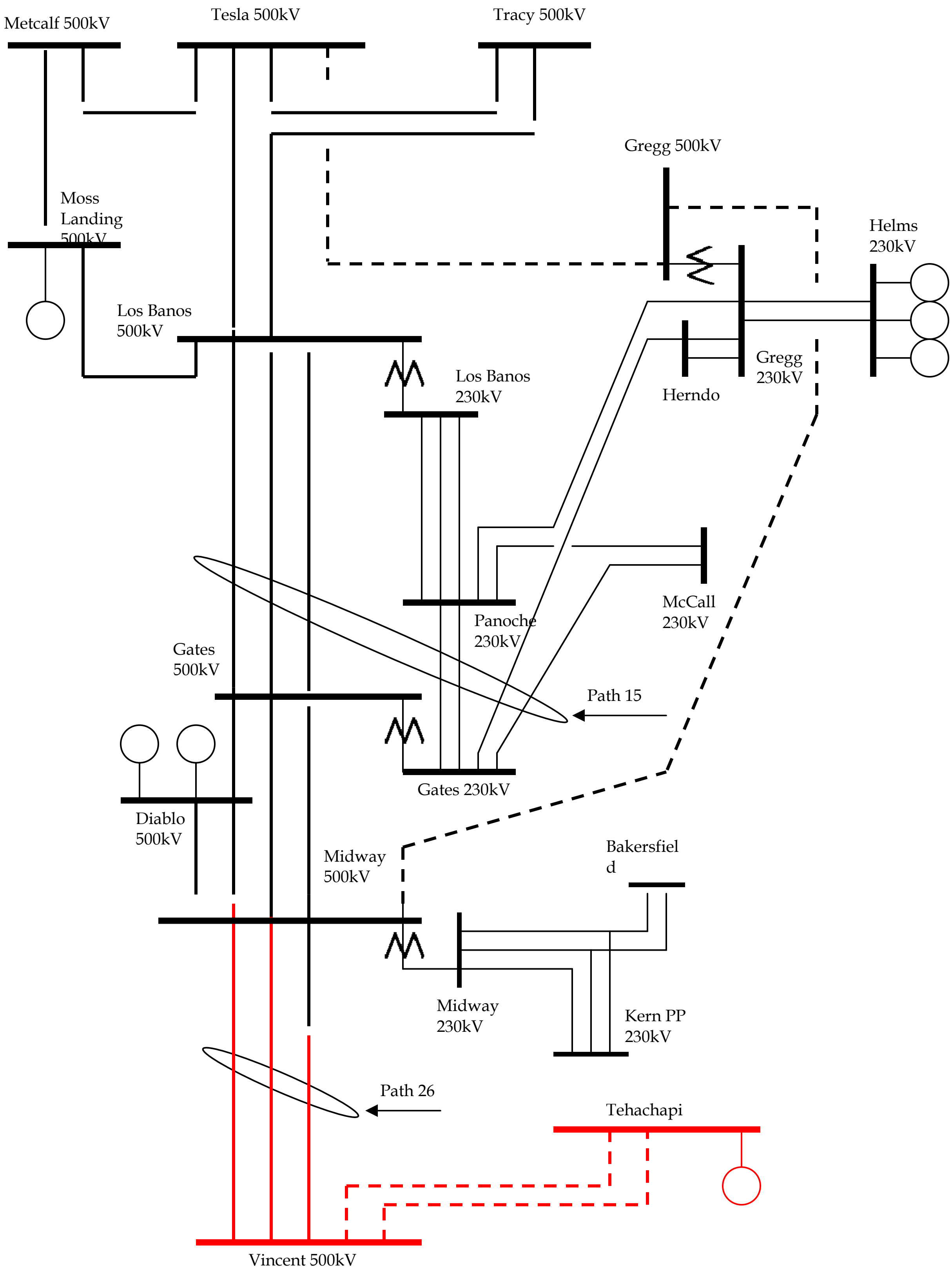


Figure 4.1.4 - PG&E Alternative 5: Tesla – Gregg – Midway 500 kV line



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4.2 Southern California Edison Studies

SCE Transmission Alternatives

Under summer peak conditions, scheduling the Tehachapi wind generation to serve the Los Angeles Basin Area loads would result in power flow in the north-to-south direction adding to the total south of Vincent and south of Lugo flow (Path 26, imports from southern Nevada Area, and SCE Northern Area). Such flows are expected to cause normal or emergency overloads on the existing SCE Bulk Power system. Scheduling power north to PG&E to serve the Bay Area loads would result in decreasing power flow on Path 26 (counter to the prevalent flow). It should be noted that such a "scheduling" reduction on Path 26 may not actually result in a real-time reduction on Path 26 since the CAISO could reschedule additional power on Path 26 thereby effectively transmitting all of the Tehachapi wind generation to the south.

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, and all generation resources in the SCE Northern area are anticipated to be dispatched to serve SCE load, the addition of generation resources located in Tehachapi would increase power transfer into the Los Angeles Basin Area. Accordingly, all SCE alternatives investigated options for integrating Tehachapi wind generation into the existing system and for increasing the power transfers south of the SCE Antelope and Vincent substations.

In the study completed for the TCSG Report filed on March 16, 2005 SCE had investigated two fundamental alternatives for integrating Tehachapi wind generation into the existing system. The first alternative involved constructing all facilities south from Tehachapi to SCE's Antelope and Vincent substations. The second alternative involved constructing facilities both to SCE and to PG&E. The conceptual transmission plans were developed with the assumption that 2,000 MW of Tehachapi wind generation would be scheduled to SCE and an additional 2,000 MW would be scheduled to PG&E. In addition, SCE evaluated alternatives that delivered power from the SCE San Joaquin Valley via the Big Creek Corridor to the PG&E Fresno Area via the Gregg-Helms 230 kV transmission lines. As part of this study, SCE performed detailed parametric studies to further investigate a potential phase-shifted system tie with an intended purpose of delivering up to 1,200 MW from the SCE San Joaquin Valley to the PG&E Fresno Area utilizing phase-shift technology. This alternative has been subsequently dropped due to significant operational issues and significant cost associated with the alternative (see Appendix 3 for further discussion on the Big Creek-Fresno System Tie alternative).

SCE's conceptual transmission alternatives derived under heavy summer load conditions are listed below in Table 4.2.1. SCE is in the process of formalizing the complete project description for Phase 2, which will be the subject of a CPCN filing with the Commission as required per CPUC Resolution E-3969. Based on recent generation interconnection studies underway, the integration plan involves conversion of the existing Mesa Substation to 500 kV instead of utilizing the Rio Hondo substation as previously conceptualized. As a result, cost estimates for Phase 2 are conceptual and do not include estimates for converting the Mesa substation to 500 kV. SCE will provide complete cost estimates and a detail scope of work as part of the CPCN application. It should also be noted that no shunt voltage support devices were included into the Summary because no voltage stability studies, which are required for this determination, have been conducted. Further studies will be needed to explore opportunities to adjust each of the elements of the conceptual transmission alternative before the final plan of service can be determined. With the recent submittal of interconnection requests for additional wind generation projects in the area made to the CAISO, SCE anticipates finalizing the exact plan of service as part of the detailed Feasibility, System Impact, and Facilities Studies. Results of these more detailed studies will provide sufficient information to identify triggering thresholds for phasing of transmission facilities and may identify the need for additional facility upgrades not addressed in these conceptual studies. The need for such facility upgrades can be triggered by transient stability and post-transient voltage study results or the determination that the use of special protection systems is ineffective, violates criteria or otherwise could not be utilized.

Table 4.2.1 Summary of Conceptual Transmission Plan and Planning Level Cost Estimates[20] for SCE

Cummlative Generation	Alternative 1	Alternative 2
700 MW	Antelope Transmission Project • Antelope-Pardee 500kV line (energized at 230 kV) • Antelope-Vincent 500kV line (energized at 230 kV) • Antelope-Tehachapi 500kV line (energized at 230 kV) **Conceptual Cost Estimate: $243.4 million**	Same Alternative 1
1,600 MW	Tehachapi Transmission Plan Phase 2 • New Substation #5 230 kV Substation[21] • Antelope-Substation#5 230 kV (double-circuit) • Antelope-Mesa Corridor Upgrade (500 kV) ($145 M) • Mesa Substation Conversion to 500 kV ($150 M) • Vincent-Mira Loma 500 kV[22] **Conceptual Cost Estimate: $ 349 million**	Same Alternative 1
3,000 MW	Tehachapi Transmission Plan Phase 3 • Second Antelope-Substation#5 230 kV (double-circuit) • Second Antelope-Tehachapi 500kV line ($99.5) • Increase Antelope Operating Voltage to 500 kV • Increase Pardee Operating Voltage to 500 kV • Increase Tehachapi Operating Voltage to 500 kV **Conceptual Cost Estimate: $341 million**	Same Alternative 1
4,500 MW	Tehachapi Transmission Plan Phase 4A • Midway-Tehachapi 500kV line • Expand Midway Substation • Increase Tehachapi 500 kV Capability **Conceptual Cost Estimate: $390.4 million**	Tehachapi Transmission Plan Phase 4B • Vincent-Tehachapi 500kV line • Increase Tehachapi 500 kV Capability **nceptual Cost Estimate: $238.1 million**

[20] These planning-level cost estimates are preliminary, unit cost-based estimates and do not reflect project-specific engineering, environmental mitigation requirements, or permit, land acquisition, and legal costs and assumes all over-head line construction. All estimates include a 30% contingency and are subject to change based on final engineering and design as well as the requirements of any CPUC or other required permit process.

[21] A wind developer with a 300 MW project is evaluating permitting this substation as part of their wind project through Kern County. Considering only this first project and assuming a temporary operating solution is approved, the PTC could allow a portion of the first project to be in service outside of Phase 2. If it is later determined that the substation permitting should be undertaken by SCE, or the wind developer does not permit an adequate substation site as part of the wind project sufficient to accommodate all other wind projects requesting interconnection, or a temporary operating solution is not authorized, SCE will undertake the permitting of this substation with timelines consistent to those of Phase 2 or Phase 3.

[22] Cost for the Mira Loma-Vincent 500 kV transmission line not assigned to Tehachapi.

Antelope Transmission Project

Figure 4.2.1 Tehachapi Conceptual Transmission Plan Phase 1

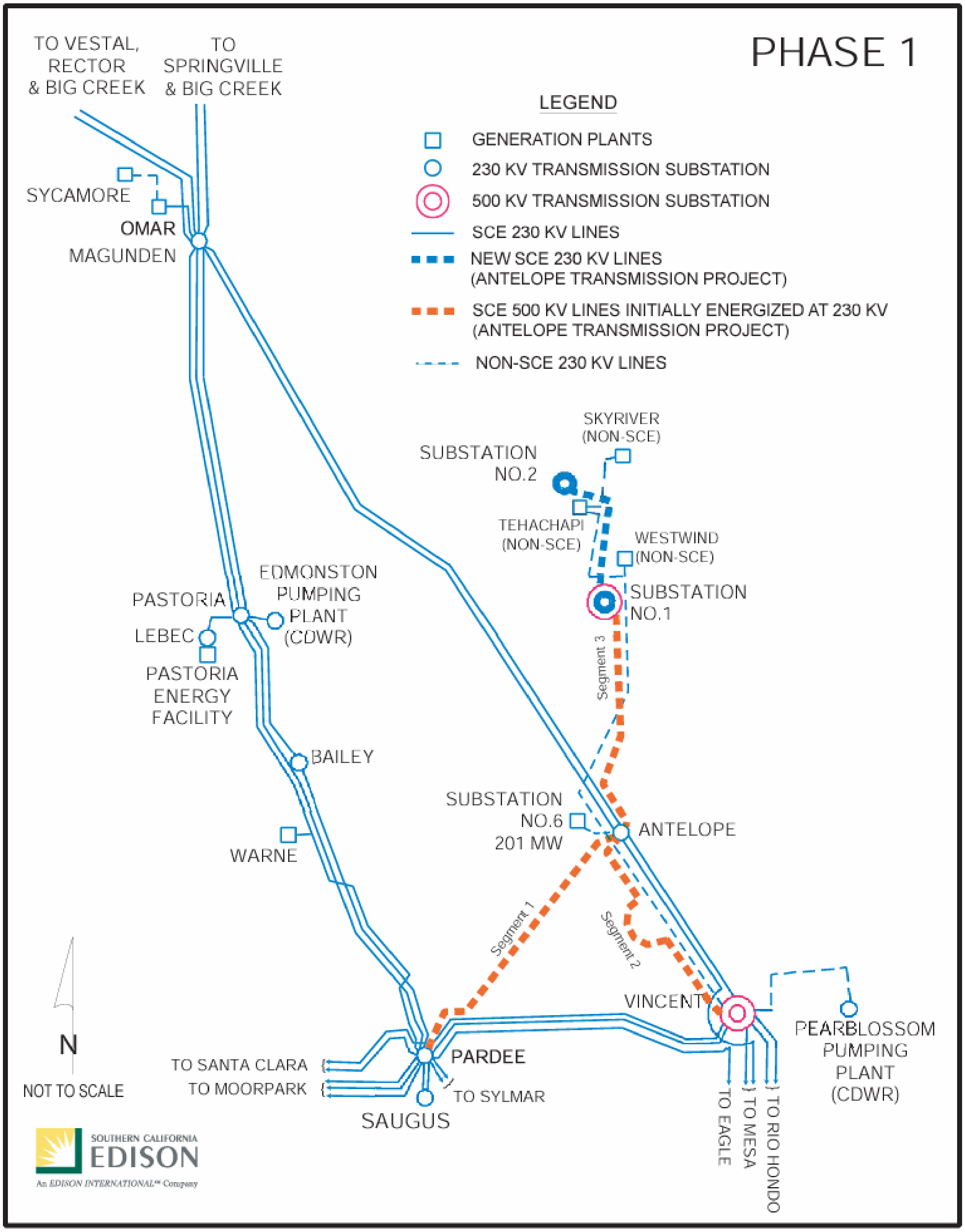


Figure 4.2.2 Tehachapi Conceptual Transmission Plan Phase 2

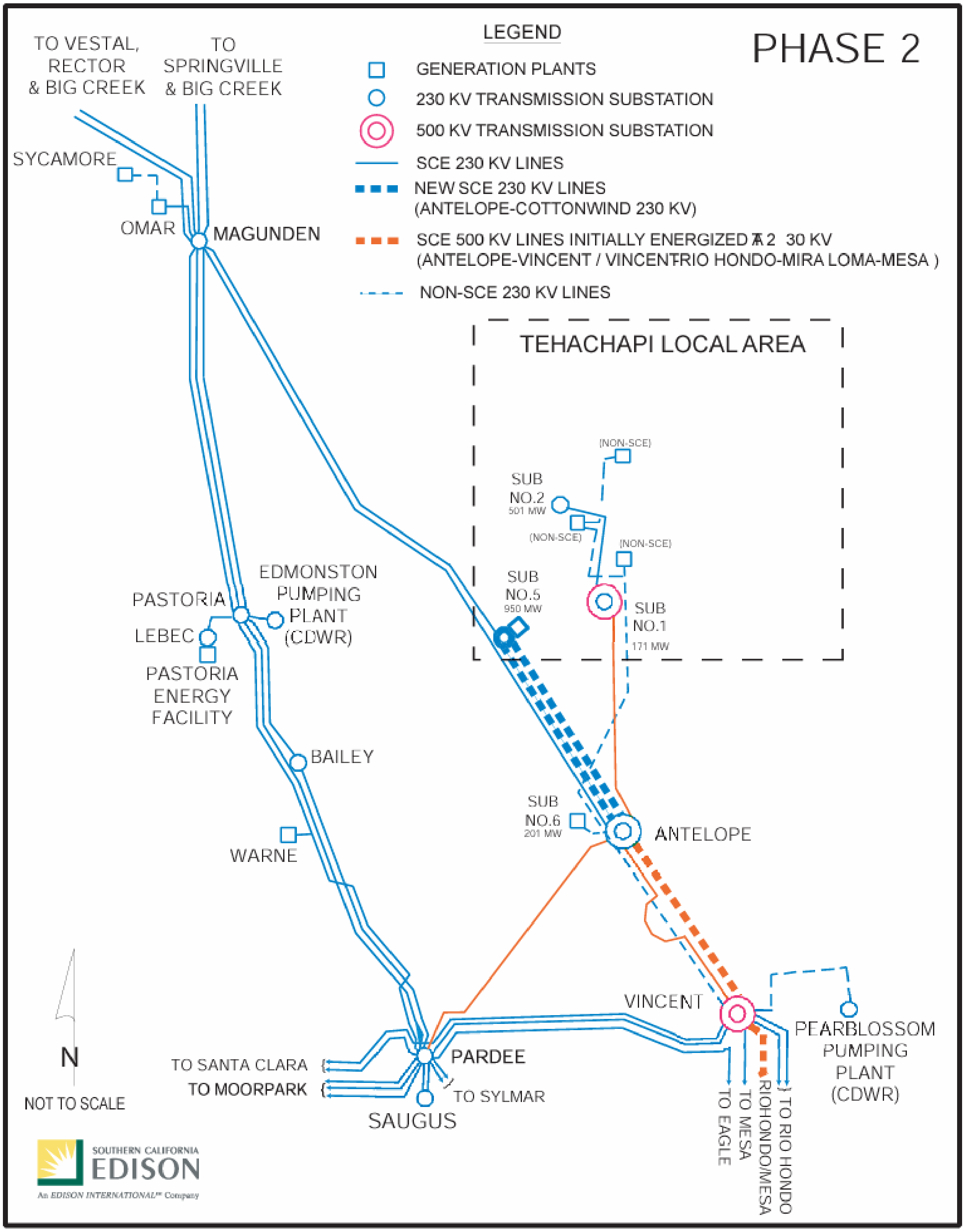


Figure 4.2.3 Tehachapi Conceptual Transmission Plan Phase 3

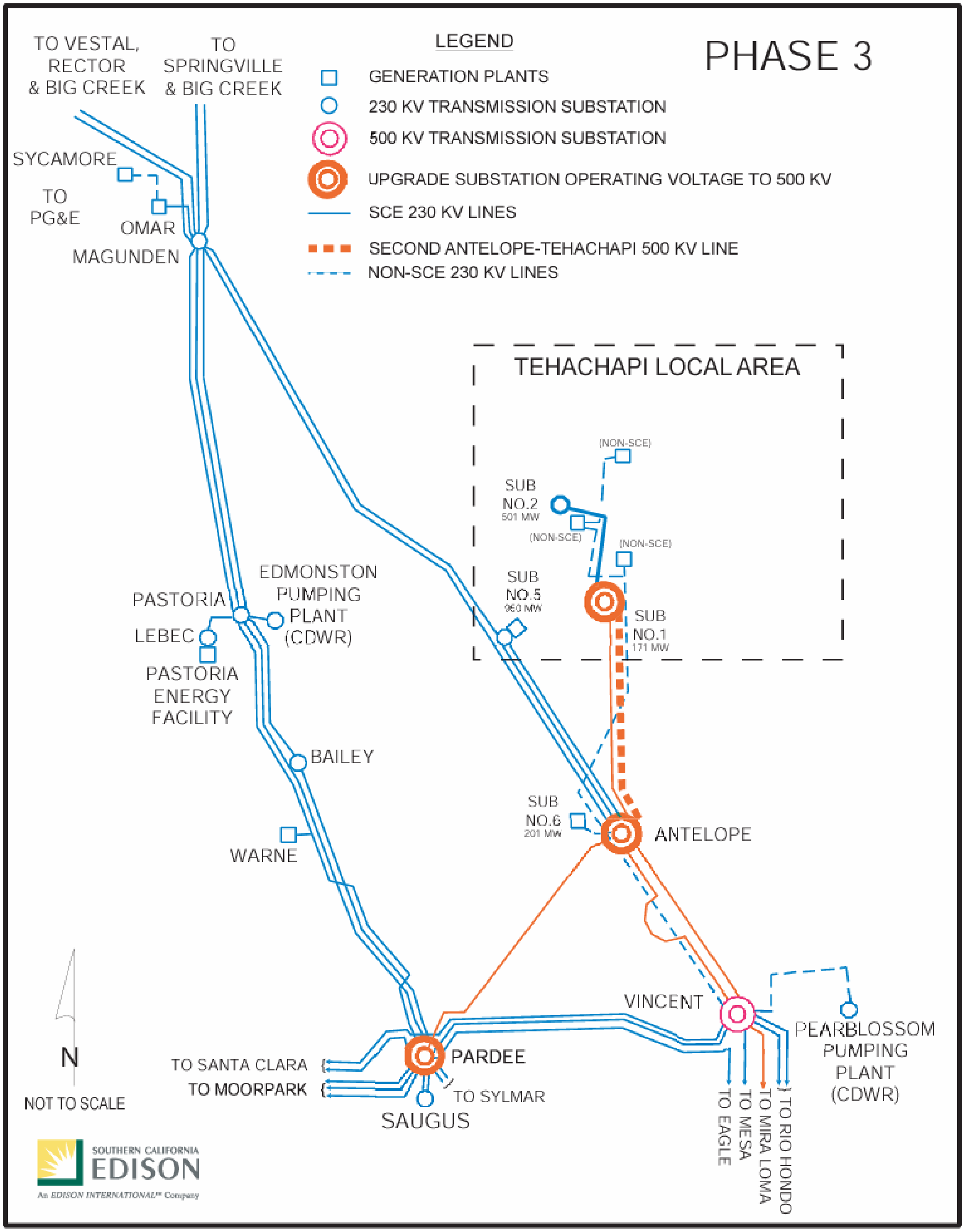


Figure 4.2.4 Midway-Tehachapi 500 kV Transmission Line

Tehachapi Conceptual Transmission Plan Phase 4

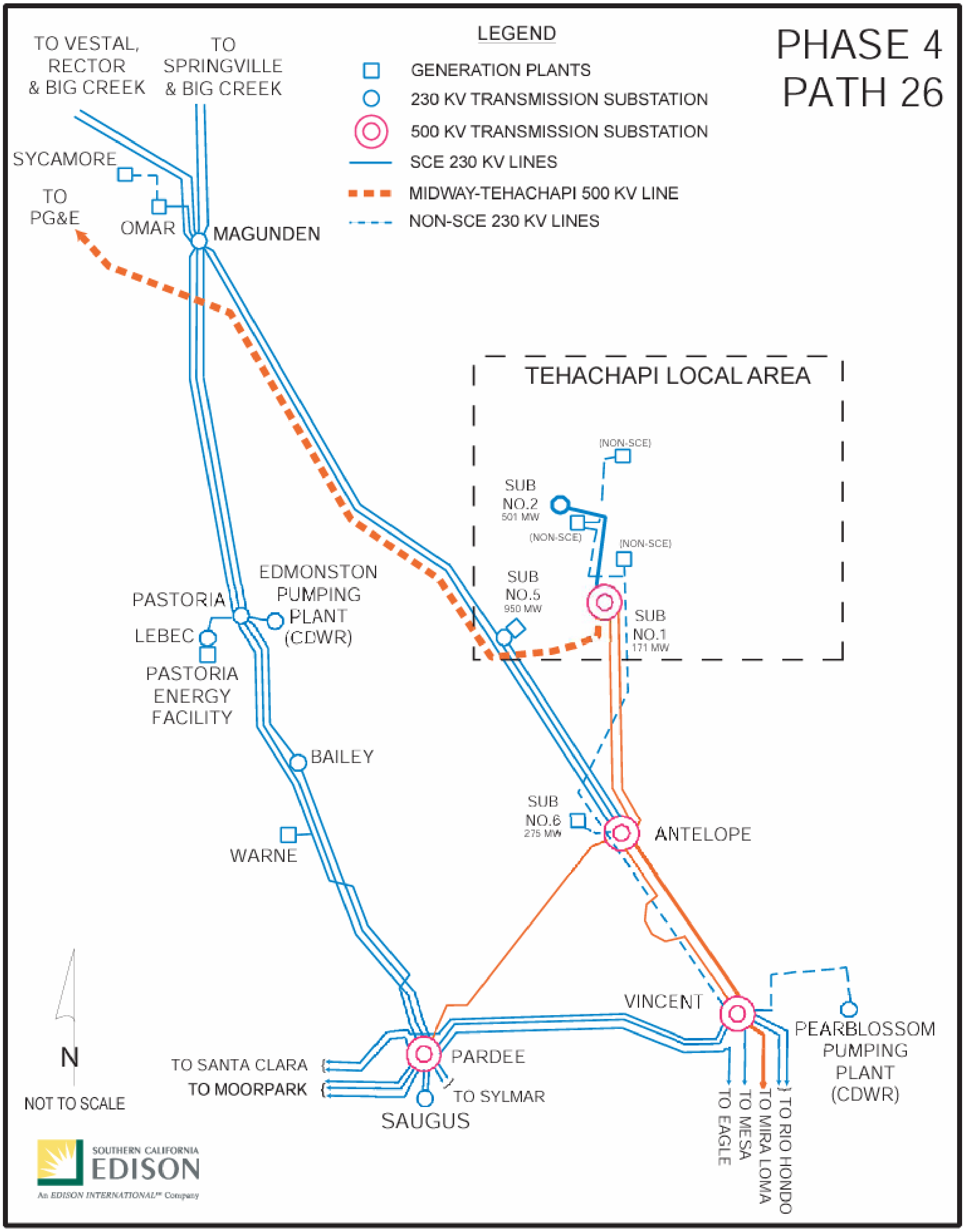
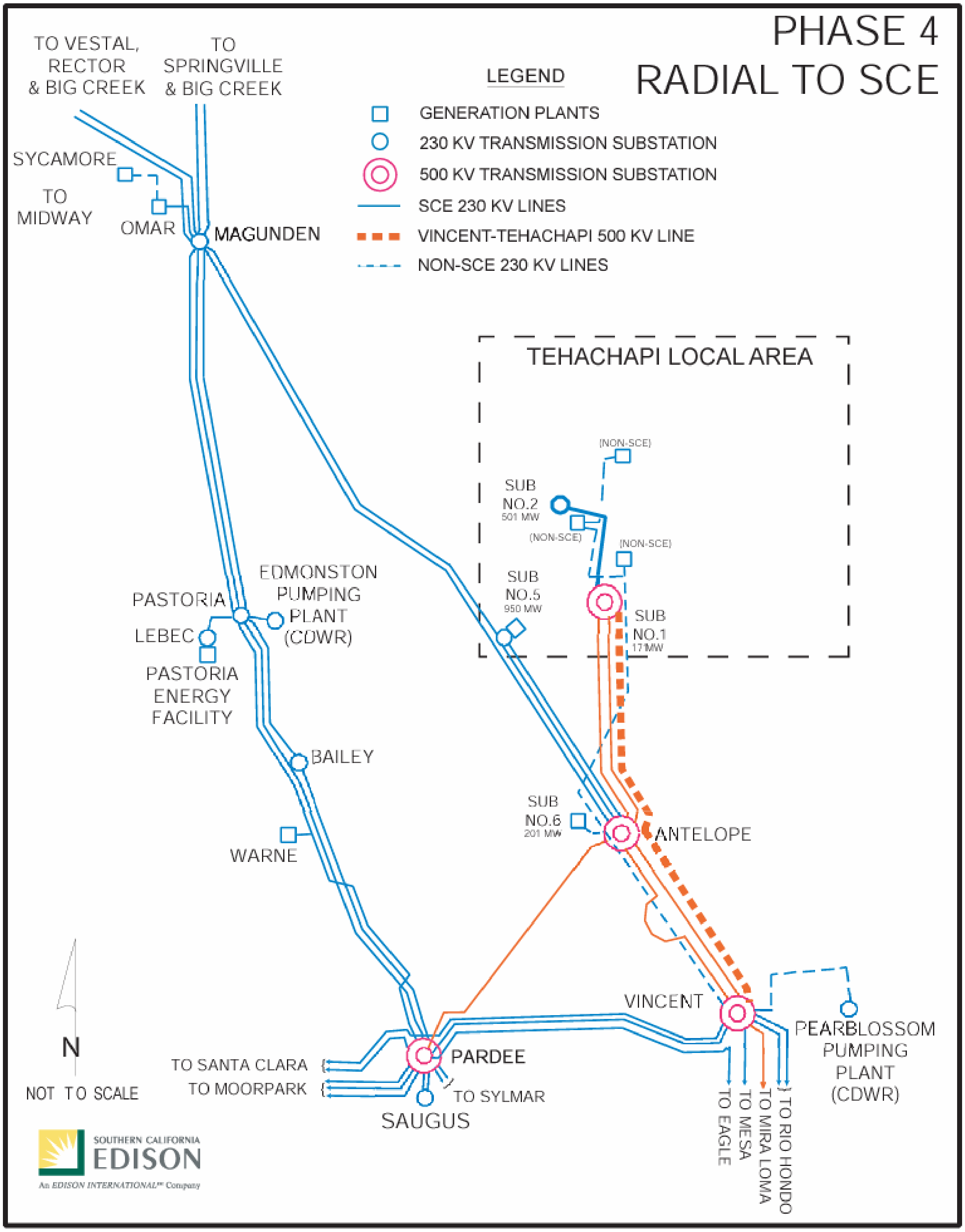


Figure 4.2.5 Vincent-Tehachapi 500 kV Transmission Line

Tehachapi Conceptual Transmission Plan Phase 4



Chapter 5

Operations Analysis of 5,200 MW of Wind Generation in the Tehachapi Area

5.1 Introduction and Background

The California ISO (CAISO) has significant operating experience with managing the impact of over 2,200 MW of wind generation in our control area. The CAISO control area is one of the largest in the Western Interconnection and it covers approximately 70% of the State of California. The advantage of a large control area is that 2,200 MW of wind generation is still only 4% of the total generation resources in this area. The other advantage is the wind generation is spread throughout the state in five different geographic areas with different weather patterns and different power production patterns. When one area has increasing energy production, one of the other areas may have decreasing production and the result is a smoother and more manageable energy production pattern. Tehachapi and San Gorgonio are the two largest wind generation areas today and their energy production has the largest impact on CAISO Grid Operations.

Currently the Tehachapi area has 740 MW of installed wind generation capacity. The plan is to add more 4500 MW of generation in this area in a series of phases. Although the transmission expansion plan is focused on the additional amount of generation, the operational impact must look at the impact from the total amount of generation in this area.

Table 5.1: Planned Capacity Additions

	Installation of Additional MW	Cumulative Additional MW Capacity	Total Generation MW Capacity
Phase 1	700	700	1,440 MWs
Phase 2	900 MW	1,600 MW	2,300 MWs
Phase 3	1,700 MW	3,300 MW	4,000 MWs
Phase 4	1,200 MW	4,500 MW	5,200 MWs

The exact timing for all the new generation construction in these phases is not firm but the goal is to complete all of these generation additions by 2010 for the utilities to meet their RPS goals. The addition of 4,500 MW of new wind generation over the next 5 years in the Tehachapi area will have significant impact on both the transmission system and the real-time operation of the California power grid.

5.2 Market Issues

There are market issues that need to be solved for the consumers in the State to receive the maximum benefit from the use of renewable resources. Wind generation energy must be accurately forecasted and scheduled in the Day-Ahead market. Accurately forecasted wind energy should displace the most expensive energy that would normally be produced by fossil fueled generators. Accurate Day-Ahead energy production forecasts are essential for unit commitment decisions and optimum procurement of ancillary services.

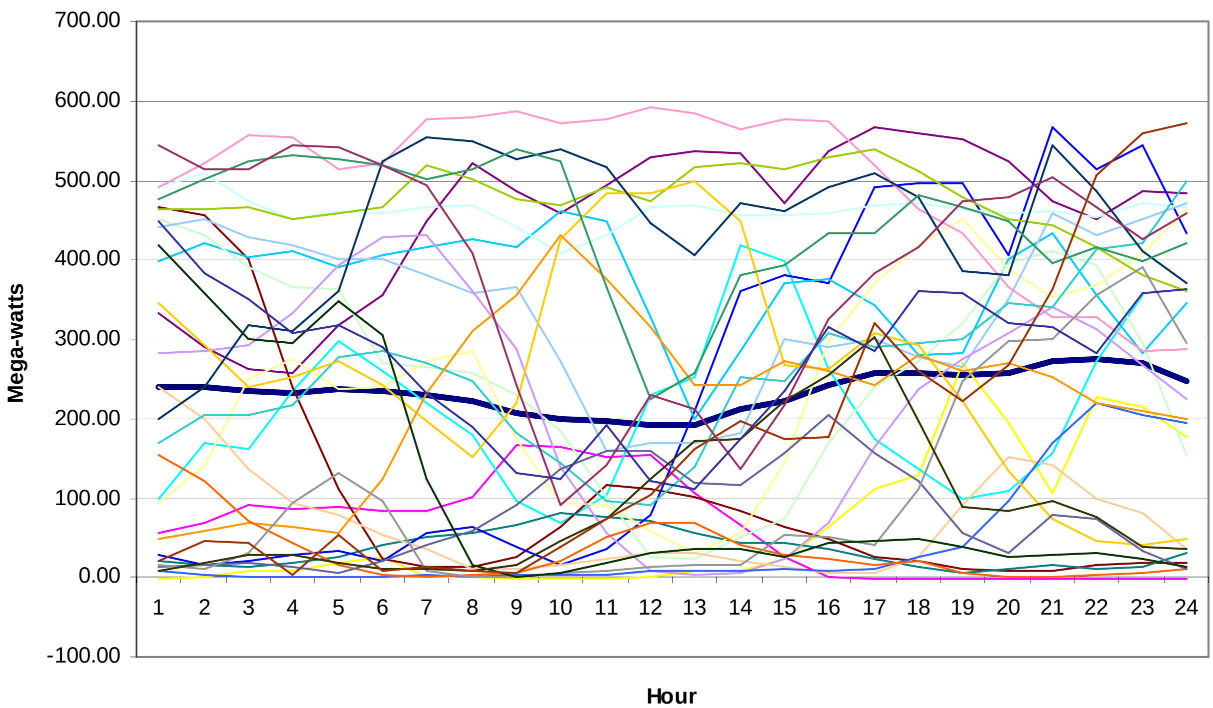


Figure 5.1 - Daily Wind Generation Energy Production inTehachapi for April 2005

Figure 5.1 shows the hourly wind generation energy production in Tehachapi for April 2005. Although the average production is approximately 200 Megawatts, the hourly pattern for any specific day shows how extremely variable the energy production is on any specific day. This picture illustrates the difficulty of forecasting the daily and hourly power production for this area. The January through April period is probably one of the more difficult sets of months to accurately forecast daily energy production due to the variability of the weather patterns. The summer weather patterns for the Tehachapi area are more predictable and the energy production forecasts are more accurate.

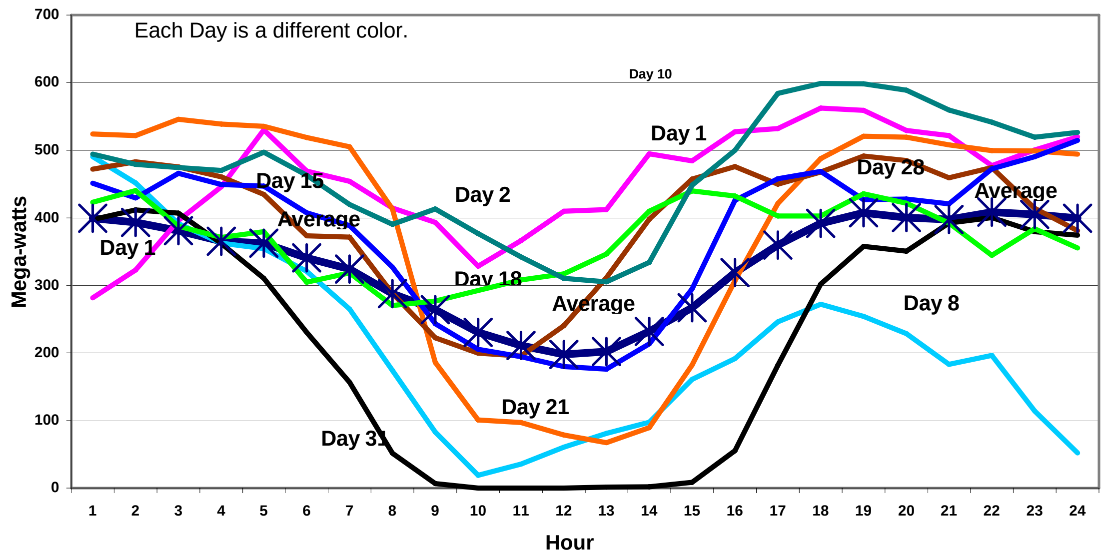


Figure 5.2 – Daily Wind Generation Production in Tehachapi for May 2005

Figure 5.2 shows the hourly production for the existing 740 MWs of wind generation in Tehachapi for May 2005. The average production has increased to approximately 300 Megawatts and the hourly energy production patterns exhibit more of the typical summer energy production patterns for this area.

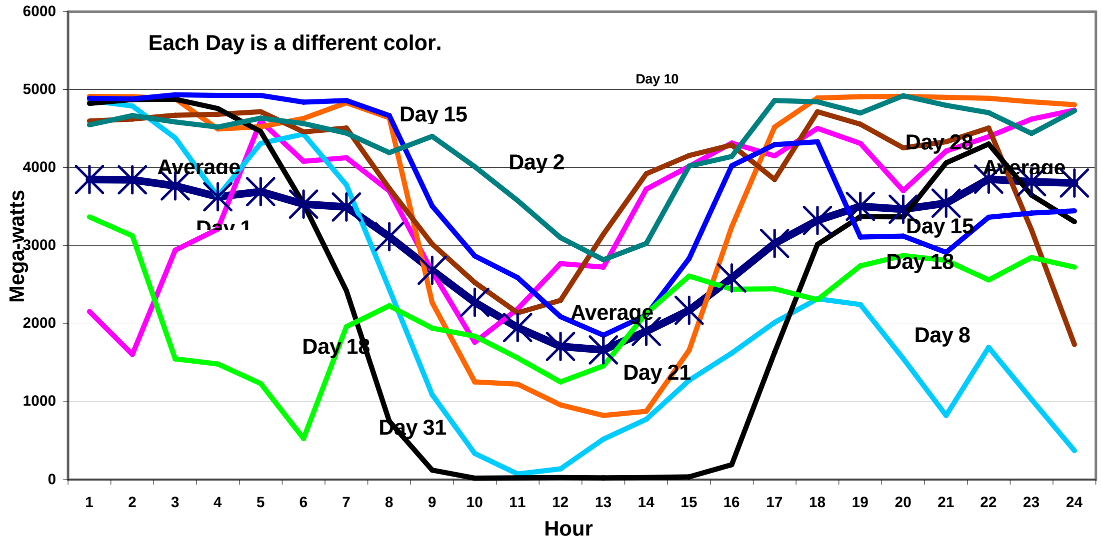


Figure 5.3 – Model of the Predicted Daily Wind Generation Production for Tehachapi with 5200 Megawatts of Installed Wind Generation Capacity

Figure 5.3 shows what the typical daily energy production could look like for a high production month like May when the amount of wind generation capacity has been increased to a total of 5200 Megawatts. The average production has increased to approximately 3000 Megawatts. The major operational concern will be the large daily energy ramps, both up and down, that could exceed 1800 Megawatts in an hour. These large ramps will require new ramp forecasting tools and new strategies to insure reliable operation of the grid.

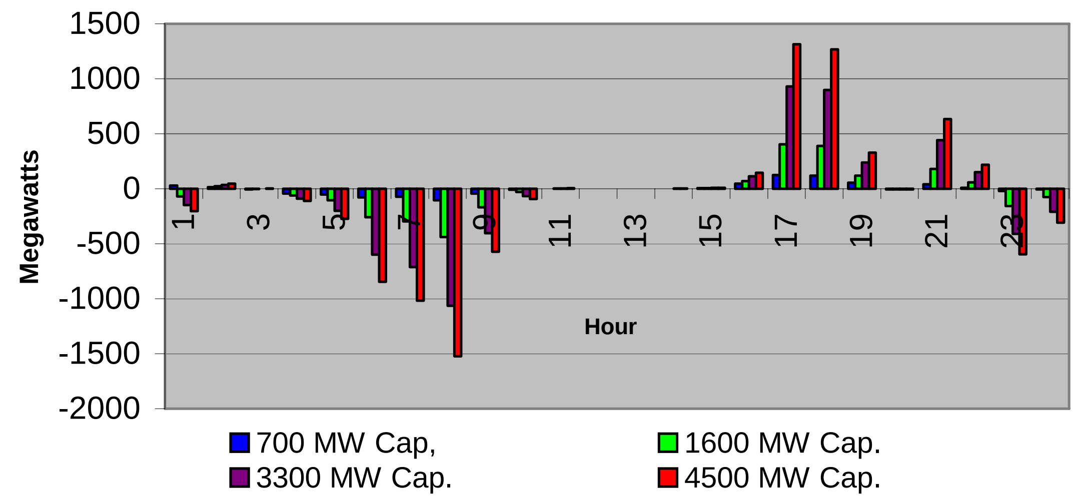


Figure 5.4 – Hour Ramps as new Generation in Added in Tehachapi

Figure 5.4 shows some of the expected energy ramps with up to 4500 Megawatts of generation capacity. With 5200 Megawatts of generation capacity, the energy ramps can be as high as 1800 to 2000 Megawatts in an hour. Unfortunately the large ramps down between 6 AM and 9 AM are the opposite of the morning ramp up of loads. From a Control Area Operators perspective, they will have to ramp up as much as 2000 to 3000 Megawatts in an hour to rebalance the system and control frequency.

Scheduling of the Tehachapi energy production in the Day-Ahead market will also help to mitigate transmission congestion issues and insure there are feasible schedules for delivery of the energy to the load centers. The new CAISO market system is expected to be operational by November 2007. Under the new market rules, the Tehachapi energy will have to be scheduled as a source and the load area (sink) will have to be identified for the energy schedules. This information will be used to verify that sufficient transmission capacity is available for the delivery of the energy. Transmission congestion issues will be resolved in the Day-Ahead market with feasible schedules for all generators in the control area.

In addition, accurate energy production forecasts will be needed five hours ahead of the real-time operating hour for the CAISO to send the correct dispatch notices to quick start units that may be required to replace wind generation energy. Ideally the forecasted hourly wind generation energy production will be scheduled in the Day-Ahead and Hour-Ahead energy markets. The CAISO is working with the CEC and their consultants to develop improved wind generation energy forecasting methodologies that can improve the scheduling of energy from these wind generation resources.

5.3 Operational Issues

The operational issues that must be addressed to accommodate this large amount of new wind generation in the Tehachapi area are:

1. Low Voltage Ride-Through (LVRT) Capability
2. Reactive Power supply and voltage control
3. Supervisory Control and Data Acquisition (SCADA) Capability
4. Impact on Regulation Resources
5. Load Following –Supplemental Energy Dispatch
6. Ramps and Ramp Rates
7. Frequency Response Issues
8. Operating Reserves
9. Energy Production Fit with Daily Load Pattern
10. Capacity factor for meeting summer peak loads

1. Low Voltage Ride-Through (LVRT) Capability

The WECC LVRT Standard requires wind generating plants to remain in-service during 3-phase faults with normal clearing times (4-9 cycles or 0.15 sec) and single line to ground faults with delayed clearing, and subsequent post-fault recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. (Minimum voltage of 0.15 per unit as measured on the high side of the wind generating plant step up transformer)

All new wind generation built in the Tehachapi area should have a Low Voltage Ride Through Capability that meets the WECC planning standards. The existing 740 MWs of generation in the Tehachapi area does not have this capability and it is probably not practical to retrofit these existing units to bring them into compliance with the new standard. The net result is there will be some risk of a loss of 740 MWs of generation due to a three-phase fault in the Tehachapi, Antelope, or Vincent areas. 740 MWs is still below the CAISO's MSSC (Most Severe Single Contingency event), which is typically the loss of 1100 MW unit. As long as all the new generation built in the Tehachapi area meets the WECC LVRT standard, the loss of ALL the generation (4500 MWs) in the Tehachapi area should be a very low probability event.

2. Reactive Power Supply and Voltage Control

The CAISO standard is that a wind generating plant shall operate with a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as specified in the LGIA (Large Generator Interconnection Agreement) in order to maintain a specified voltage schedule, if the Interconnection System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The key requirement is the ability to control the generation facilities to meet the required voltage schedule at the interconnection point.

3. Supervisory Control and Data Acquisition (SCADA) Capability

The CAISO needs real-time (4 second) SCADA data from the wind generation facilities and from metrological data associated with this facility. The detailed specification for the SCADA data and metrological data will be the same or similar to the current requirements for the CAISO's PIRP (Participating Intermittent Resources Program) and these requirements are published on the CAISO Web site.

4. Impact on Regulation Resources

Regulation Resources are used to automatically rebalance the system on a minute-to-minute basis within a specified tolerance band. The tolerance band for the CAISO is approximately plus and minus 110 MWs. The Automatic Generation Control (AGC) system sends control signals every 4 seconds to the generating units on regulation to increase or decrease generation to match the changes in system load and changes in other generating units. The CAISO typically procures between 600 MWs and 800 MWS of regulation per hour.

The currently 740 MWs of installed capacity in Tehachapi does not make a noticeable impact on the CAISO procurement and use of regulation resources. The minute-to-minute changes in the Tehachapi Wind Generation energy production are well within the control capability of the CAISO systems.

Increased generation capacity to Phase 2 – 1,600 MW; Phase 3 – 3,300 MW and Phase 4 – 4500 MWs is expected to have an impact on the amount of regulation resources required. Certainly Phase 3 and 4 will have an impact. Studies are still in progress to determine the magnitude of these impacts and these results should be available by summer 2006.

5. Load Following –Supplemental Energy Dispatch

Load following or Supplemental Energy Dispatches are used to rebalance the system every 5 minutes. The CAISO market based systems do an automatic supplemental energy dispatch every 5 minutes to follow increases/decreases in load and generation. These supplemental energy dispatches are often several hundred megawatts per hour. Generators typically have block hourly schedules or Preferred Operating Point (POP). Load however can vary by hundreds of megawatts in an hour so the supplemental energy dispatches are used to increment or decrement the generator schedules to make their energy production match the changes in system load. The Supplemental Dispatches change the real-time market-clearing price.

As can be seen in Figure 5.1 above, the Tehachapi energy production can vary from minimum to maximum or from maximum to minimum within a couple of hours. The existing 740 MW of Tehachapi wind generation can result in 50 to 250 MW of Supplement Energy Dispatch per hours during periods of major changes.

As the amount of wind generation increases in Tehachapi in Phases 1, 2, 3, and 4, there will be major increases in the amount of Supplemental Energy Dispatches. Figure 5.4 illustrates the size of the increases such as 200, 400, 500, 1,000 and even 1,500 MW per hour of supplemental energy dispatches, both increases and decreases[23]. Figure 5.4 also shows that the Tehachapi wind generation typically has major decreases in energy production morning load pickup period (6 AM to 10 AM). This will require the CAISO to send dispatch notices to other generation resources to either INC of DEC 2,000 to 3,000 MW of supplemental energy during some of these periods. The INC notices increase generation to make up for the decrease in wind generation energy production during the morning load pickup. The opposite situation will be true in the evening hours as the temperature sensitive load (air conditioning) is dropping off at the same time as the wind generation is increasing.

To successfully integrate the planned increase in Tehachapi wind generation, the CAISO will need many generating units to increase and decrease their supplemental energy bids. This will provide the flexibility needed to move the production of many units to keep the system in balance and meet frequency and control performance standards.

6. Ramps and Ramp Rates

A serious issue with the large amount of wind generation in the Tehachapi area is the hourly energy ramps, both positive and negative. To successfully integrate this large amount of generation into the control area will require a ramp-forecasting tool. This type of forecasting tool is different from the market energy-forecasting tool as its objective is to forecast the hourly energy ramps for the next day. This will enable the operator to get the system set up to handle the large ramps. The ISO will also need a real-time metrological forecasting tool that enables the operator to see large weather fronts that are approaching the Tehachapi area that will drive these large energy production ramps. The CAISO will work with the state agencies, the IOU's and the wind generation developers in the Tehachapi area to determine the best ramp-forecasting tool that would benefit all parties. Such a tool would assist the CAISO to integrate this much wind generation into daily operations.

7. Frequency Response Issues

[23] Figure 5.2 is based upon preliminary analysis and scale-up of historic data. Further investigation of new technology and its impacts is required.

The WECC[24] has decided to move ahead with a new Frequency Response Standard for the Western Interconnection. The WECC is considering adoption of the recommendations of the FRR[25] task force as published in their White Paper. The FRR standard will be written by the WECC MORC[26] Work Group and the goal is to have it reviewed and approved by the NERC[27] Board of Directors by the end of 2006.

The major issue for the CAISO is that the wind generators do not have a governor or any frequency response capability. Therefore, the ISO will have to have many other units on line that can provide the frequency response that will be required by the new WECC Standard in 2007.

8. Operating Reserves

The amount of operating reserves the CAISO procures today is not driven by the amount of wind generation. However, with the concentration 4,500 MW in the Tehachapi area, this may change.

If this generation is carried on two transmission lines, and it is producing at its maximum capability, the ISO would have to plan for the loss of as much as 2,300 MW of generation due to the loss of one line. This could become the ISO's MSSC[28]. A remedial action scheme may be required to trip wind generation in the event of a transmission line outage.

The CAISO's operating reserve requirement could increase by as much as 1,000 MW. This may not be a serious operating problem, as this would most likely occur at night and not during peak hours. Reserves would probably be available but added procurement would t increase costs.

9. Energy Production Fit with Daily Load Pattern

The wind generation energy production pattern for the Tehachapi area tends not to fit the daily load pattern and have a minimum amount of energy production across the afternoon peak load periods in the hot summer days. Morning load ramps tend to coincide with wind generation ramp-downs. The ideal solution is to have a large energy storage capability such as a new pumped storage system or other types of energy storage that can be used to shift the off-peak energy production to delivery during peak load periods. Unfortunately current energy storage technology is still too expensive to provide this capability and unless we have a national or state tax credit

[24] Western Electricity Coordination Council
[25] Frequency Response Reserve
[26] Minimum Operation Reliability Criteria
[27] North American Electric Reliability Council
[28]

plan for storage investments, it will be hard to finance investments in storage technology.

10. Potential Over-Generation Conditions

An issue that Operations encounters today with the current fleet of wind generation is the fact that the wind generation often peaks at night when the system is at minimum load. During off-peak hours in April, May and June, the ISO can experience over generation conditions when off-peak hydro generation levels are high due to heavy runoff and off-peak wind generation is high. Additional wind generation will increase the frequency and magnitude of over generation conditions.

11. Capacity Factor for Meeting Summer Peak Loads

The CAISO is calculating the actual capacity factor the Tehachapi wind generation for the past three years based upon the CPUC's formula for calculating the capacity factor. [29]

12. Additional Issues

The following list of actions is currently being studied by the CAISO in conjunction with the Intermittency Analysis Project at the CEC. Significant results are expected by December 2006.

1. Determine the best methodology for calculating the amount of regulation and load following resources that are needed on a month-to-month basis.
2. Determine the attributes required for new generation that can complement the production characteristics of wind generation and other renewable resources. Every type of generator has some type of limitation so we should determine the best mix of future generation types that meets operational requirements and energy reliability at reasonable cost.
3. Develop new concepts for automatic generation control and dispatch of controllable loads to assist with mitigating the impact of the variability of wind generation energy production.
4. Explore changes in interconnection scheduling protocols, policies and procedures to remove one of the barriers to moving wind generation energy between control areas.
5. Wind generators currently cannot increase energy output in response to frequency dips during system disturbances. What should be done to ensure the operator can meet interconnect performance standards.

[29] *[Cite to this document: This information should be available later by March 2006.]*

6. There are over-generation problems during light load periods. What can be done to increase the flexibility for reducing power output from all generation resources, including wind generation, during minimum load periods?
7. Explore the feasibility of using energy storage technology to shift off-peak energy production to delivery during peak load periods.
8. Improve wind energy forecasting tools and weather forecasting.
9. Develop procedures and protocols with wind generators for controlling large ramps up and down during periods of high wind variability such as major storms.

Chapter 6

Recommended Facilities for Each Phase of Development

Since its first report to the CPUC, the TCSG has continued to examine various potential transmission lines to reliably connect the Tehachapi WRA to the California grid. This chapter summarizes the TCSG findings, describes the current status of the Tehachapi plan and recommends actions to complete the plan.

6.1 Key Considerations for Connecting Tehachapi to the Grid

The northern and southern sections of California's electricity grid currently are connected by three high voltage transmission lines known collectively as Path 26. The northern terminus of Path 26 is PG&E's Midway substation at the southern end of Path 15. SCE's Vincent substation, which connects to several lines feeding southern California, is the southern terminus of Path 26. The Tehachapi WRA lies east of Path 26, as shown in Figure 6.1, and connections from Tehachapi to the grid can be made either to Northern or Southern California or to both regions.

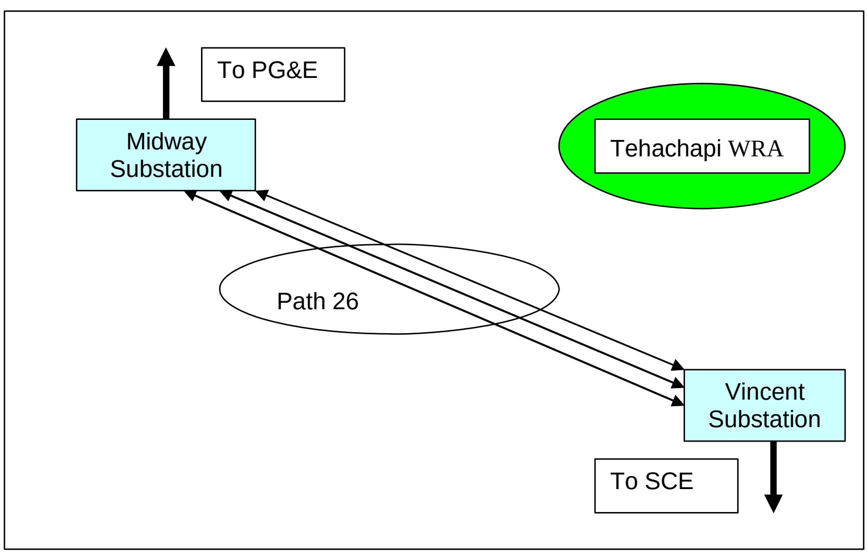


Figure 6.1

Based on the direction of the CPUC in D.04-06-010, the TCSG uses 4,500 MW as the total projected output in the Tehachapi WRA[30]. As of the date of this report, Tehachapi wind projects totaling about 3,600 MW have submitted interconnection requests to the CAISO for processing. The ultimate eventual generation capacity from Tehachapi is unknown, of course, and may be more or less than the assumed 4,500 MW. Nevertheless, the TCSG continues to believe that 4,500 MW remains the appropriate planning target.

TCSG identified three 500 kV connections as being needed to reliably export Tehachapi generation to the grid. An alternative approach of connecting Tehachapi with only two high-capacity 500 kV lines is reported in Section 6.8 below. [31]

Prior to the inception of the TCSG, SCE had developed a conceptual transmission plan that included one 500 kV connection between Tehachapi and Southern California via the SCE Vincent substation.[32] This SCE plan became the basis for TCSG Phases 1 & 2 as described in its earlier report. An updated description of Phase 1 and 2 facilities is included below.

Since issuing its March 16, 2005 report, the primary effort of the TCSG has been to examine feasible connections for the second and third 500 kV lines connecting Tehachapi to the grid. The overriding issue has been whether or not to connect to both Northern and Southern California. While the TCSG has roughly estimated the costs of this option, it could not fully evaluate the benefits to the state's electricity network or the impact of the options on grid operations. The TCSG therefore does not now have a consensus recommendation for whether the second and third major Tehachapi connections should include a new 500 kV line from Tehachapi to Midway, and if so, whether that line should be built before or after a second 500 kV line connection from Tehachapi to Southern California.

The California Independent System Operator (CAISO) has developed a Transmission Economic Assessment Methodology (TEAM) which is used to evaluate the costs and benefits of transmission proposals. The TEAM analyzes how proposed facilities affect physical flows and market prices (i.e., reliable operation of the grid, congestion relief, access to new (lower cost) generation). In addition, CAISO grid operations experts can evaluate the impacts of new transmission options on grid management. The TCSG therefore recommends that

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[30] As described in Chapter 1, the 4,500 MW was initially made up of approximately 4,000 MW develop in the Tehachapi region proper and 500 MW in the Antelope Valley region. As of the date of this report, projects totaling approximately 1,300 MW have requested interconnection to the CAISO Grid in the Antelope Valley region. There is also 740 MWof existing wind generation connected to the SCE grid over either SCE 66 kV lines or over the privately owned Sagebrush line.

[31] There is also a possibility that power lines in the region owned by the Los Angeles Department of Water and Power and by a private corporation could be utilized to export some Tehachapi generation. If so, these lines might serve as the third connection between Tehachapi and the EHV grid.

[32] SCE Renewable Conceptual Transmission Plan, filed August 29, 2003.

further development of the Tehachapi conceptual transmission plan be conducted under the auspices of the CAISO.

6.2 Phase 1: First 500 kV Connection to Southern California

Phase 1 development consists of three segments, with all facilities to be built by SCE:

Segment 1, the "Antelope to Pardee Transmission Project," consists of a new 25.6 mile, 500 kV transmission line connecting the Antelope and Pardee substations. This line would initially be operated at 220 kV.

Segment 2, the "Antelope to Vincent Transmission Project," includes the construction of a new 21.5 mile, 500 kV transmission line to connect SCE's existing Antelope Substation, located in Lancaster, with SCE's existing Vincent Substation located near Acton. This line would be built on new right-of-way to be acquired over private land between the two existing substations, both in Los Angeles County. This line would be initially operated at 220 kV.

Segment 3, the "Antelope to Tehachapi Transmission Project," includes four elements:

- A new 26.1 mile, 500 kV transmission line to connect SCE's Antelope Substation with a new Tehachapi Substation One to be located near Cal Cement. This line would be initially operated at 220 kV.
- A new 500/220/66 kV substation (Tehachapi Substation One).
- A new 220/66 kV substation (Tehachapi Substation Two) near Monolith.
- A new 9.4 mile, 220 kV transmission line to connect Substation One with Substation Two.

SCE refers to Segments 1-3 collectively as the Antelope Transmission Project. It submitted separate CPCN applications for Segment 1 (A.04-12-007) and for Segments 2 & 3 (A.04-12-008) on December 9, 2004, and filed an amended application for Segments 2 & 3 on September 30, 2005.

The total wind generation able to be exported with Phase 1 upgrades is 700 MW. These upgrades are shown in Figure 6.2.

The environmental documents for Segment 1 (Antelope-Pardee) are scheduled to be released for public review by August 30, 2006. The CPUC could thus act to approve Segment 1 in October 2006.

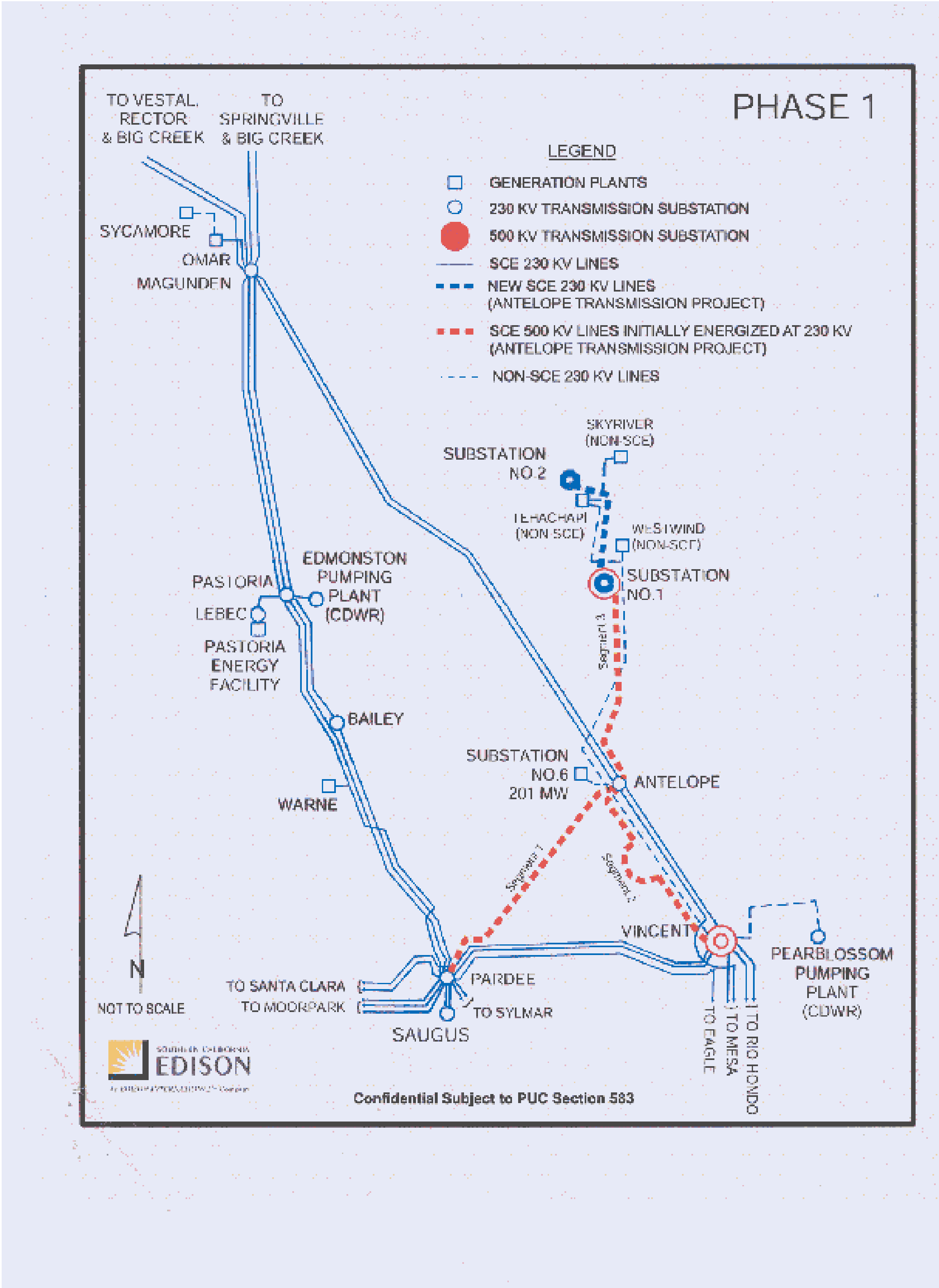
PHASE 1
LEGEND
GENERATION PLANTS
230 KV TRANSMISSION SUBSTATION
500 KV TRANSMISSION SUBSTATION
SCE 230 KV LINES
NEW SCE 230 KV LINES (ANTELOPE TRANSMISSION PROJECT)
SCE 500 KV LINES INITIALLY ENERGIZED AT 230 KV (ANTELOPE TRANSMISSION PROJECT)
NON-SCE 230 KV LINES
TO VESTAL, RECTOR & BIG CREEK
TO SPRINGVILLE & BIG CREEK
SYCAMORE
OMAR
MAGUNDEN
SKYRIVER (NON-SCE)
SUBSTATION NO.2
TEHACHAPI (NON SCE)
WESTWIND (NON-SCE)
SUBSTATION NO.1
EDMONSTON PUMPING PLANT (CDWR)
PASTORIA
LEBEC
PASTORIA ENERGY FACILITY
BAILEY
SUBSTATION NO.6 201 MW
ANTELOPE
WARNE
VINCENT
PEARBLOSSOM PUMPING PLANT (CDWR)
N
NOT TO SCALE
TO SANTA CLARA
TO MOORPARK
PARDEE
TO SYLMAR
SAUGUS
TO EAGLE
TO MESA
TO RIO HONDO
EDISON
Confidential Subject to PUC Section 583

Figure 6.2. Phase 1 Upgrades

In March 2006, the CPUC hired its environmental consultant to review the environmental studies conducted by SCE for Segments 2 & 3. The CPUC expects to have draft environmental documents for these segments available for public review by December 2006. The CPUC is expected to rule on Segments 2 & 3 in mid-2007.

6.3 Phase 2A: Antelope to Substation No. 5

The intent to construct new transmission evidenced by the Phase 1 CPCN filings made it possible for wind generation companies to advance their projects in the region. Since those filings, more than 1,100 MW of wind projects have entered the CAISO queue requesting interconnection to Substation No. 5. A developer proposing the first 300 MW of the total is evaluating permitting Substation No. 5. Assuming a temporary operating solution is approved, a Permit to Construct (PTC) could potentially allow a portion of the project to be in service before construction of additional network facilities is complete.

The remainder of the generation resources connecting at Substation No. 5 may require construction of at least one new 18.6 mile, double circuit 230 kV transmission line from the Antelope Substation to the new 230 kV Substation No. 5. This transmission line and new 230 kV Substation No. 5 were identified as part of Phase 2 development facilities in the TCSG March 2005 report. It is the TCSG's understanding is that the construction of these facilities may be permitted as a Permit to Construct (PTC), while the new lines might require a CPCN. Facilities to be located north of Antelope/Vincent may be permitted separately from the facilities to be located south of Antelope/Vincent.

6.4 Phase 2B: Network Upgrades of the SCE System

The second phase of Tehachapi transmission development consists of network upgrades of the SCE system needed to enable power to flow from the Antelope-Vincent substation area to Southern California load centers. In the TCSG March 2005 report, these were identified collectively as the Antelope-Mesa upgrades. Part of the cost of these upgrades may be in common or shared with SCE's planned Vincent-Mira Loma 500 kV transmission line (T/L) project. These upgrades will increase cumulative Tehachapi export capacity to 1,600 MW. The major components of these upgrades include:

- Tear down and rebuild the Antelope-Mesa and Antelope-Vincent 230 kV T/L between Antelope and Vincent with a second new 500 kV T/L. (The first new Antelope-Vincent 500 kV T/L is to be built in Phase 1, Segment 2).

- Tear down and rebuild the section of the existing Antelope-Mesa 230 kV T/L between Vincent and Rio Hondo with a third Vincent-Rio Hondo 500 kV T/L, initially operated at 230 kV.
- Tear down and rebuild the section of the existing Antelope-Mesa 230 kV T/L between Rio Hondo and Mesa with a second Rio Hondo-Mesa 230 kV T/L.

CPUC Resolution E-3969 (February 16, 2006) ordered SCE to perform the studies necessary for the preparation of PEAs and the filing of CPCNs by the end of 2006 for these Antelope-Mesa upgrades and for the Antelope-Tehachapi Substation 5 230 kV transmission line.

Phase 2 upgrades are shown on Figure 6.3 below.

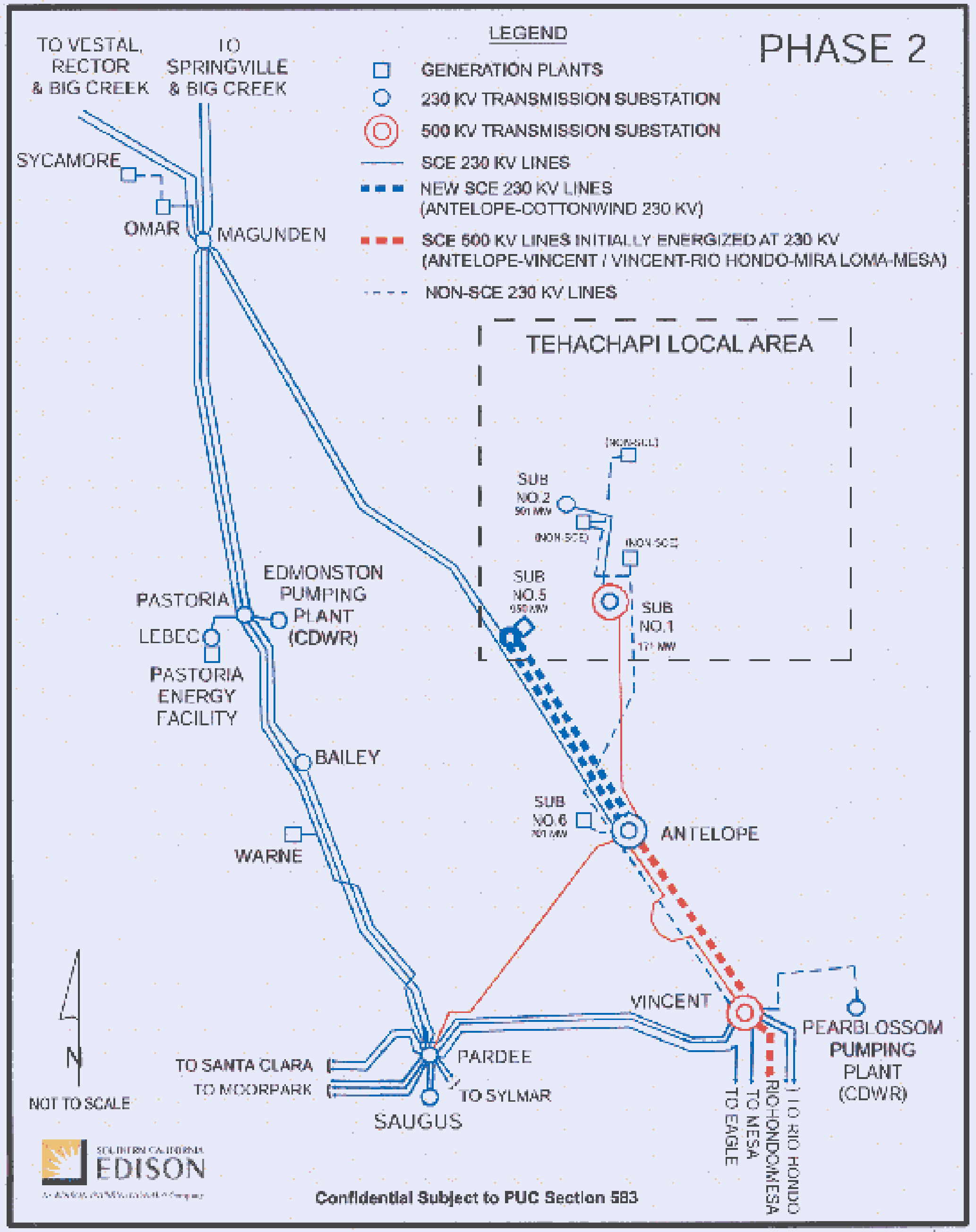
PHASE 2
LEGEND
GENERATION PLANTS
230 KV TRANSMISSION SUBSTATION
500 KV TRANSMISSION SUBSTATION
SCE 230 KV LINES
NEW SCE 230 KV LINES
(ANTELOPE-COTTONWIND 230 KV)
SCE 500 KV LINES INITIALLY ENERGIZED AT 230 KV
(ANTELOPE-VINCENT / VINCENT-RIO HONDO-MIRA LOMA-MESA)
NON-SCE 230 KV LINES
TO VESTAL, RECTOR & BIG CREEK
TO SPRINGVILLE & BIG CREEK
SYCAMORE
OMAR
MAGUNDEN
TEHACHAPI LOCAL AREA
SUB NO.2
(NON-SCE)
(NON-SCE)
SUB NO.5
SUB NO.1
EDMONSTON PUMPING PLANT (CDWR)
PASTORIA
LEBEC
PASTORIA ENERGY FACILITY
BAILEY
SUB NO.6
ANTELOPE
WARNE
VINCENT
PEARBLOSSOM PUMPING PLANT (CDWR)
PARDEE
TO SANTA CLARA
TO MOORPARK
TO SYLMAR
SAUGUS
TO EAGLE
TO MESA
RIOHONDO/MESA
TO RIO HONDO
N
NOT TO SCALE
SOUTHERN CALIFORNIA EDISON
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Figure 6.3. Phase 2 Upgrades

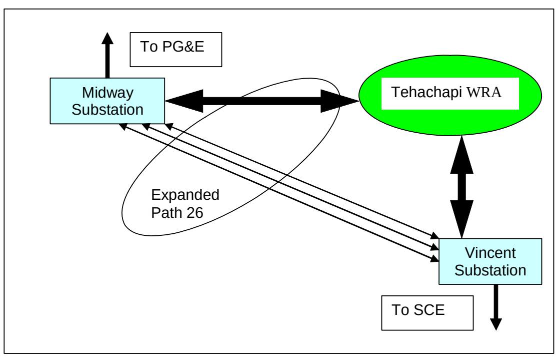
6.5 Alternatives for the Second and Third Tehachapi Connections

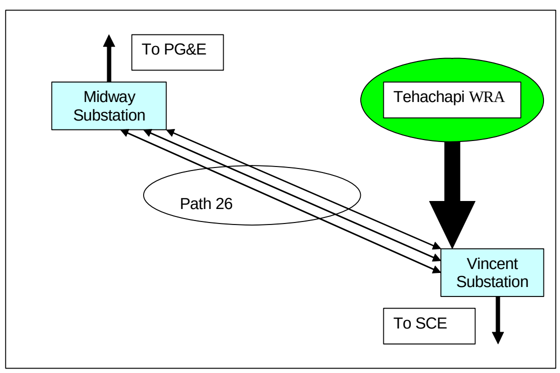
Following the Phase 2 network upgrades, two additional 500 kV connections will be needed, one in each of Phase 3 and Phase 4. These lines could be configured as two lines from Tehachapi to the south/SCE system; or alternatively, as one line to the north/PG&E system and one line to the south.

In the first TCSG report to the CPUC, Phase 3 consisted of a second 500 kV transmission line connecting Tehachapi with the Southern California grid. Phase 4 of that plan considered a connection to Northern California. It must be emphasized that the phase numbering was for identification purposes only and was not meant to imply that construction of the phases occur in the numbered order.

A connection between Tehachapi and Northern California, together with one or more connections to Southern California, would constitute an additional link in Path 26, the major transmission artery connecting Northern and Southern California. The TCSG refers to this alternative (Figure 6.4 below) as the Expanded Path 26 option. This configuration is expected to be considered a "network facility" which would provide two important benefits to the California grid, namely additional reliability, operating flexibility and additional import capacity into Southern California[33] when Tehachapi generation is low.[34]

Figure 6.4. Expanded Path 26 Option Figure 6.5. Gen-tie Option





33 Additional transmission facilities will be needed to transmit power to the SDG&E system.
34 A frequent criticism of wind power is that "the wind doesn't blow all the time." A transmission plan that enables additional power transfers during periods of low wind generation would allow the CAISO to manage the variability of wind generation more easily.

The Gen-Tie Option (see Figure 6.5) would provide Tehachapi with access to the grid only at substations in Southern California.[35] In this option, all three of the 500 kV lines necessary to export Tehachapi power would extend south from Tehachapi. Providing access to Tehachapi wind power would be the primary benefit of this alternative. Power lines which serve only to connect generation to the grid are referred to as generation tie lines or "gen-ties", and the TCSG calls this the Gen-tie option. The feasibility of constructing a third 500 kV line from the Tehachapi area to Vincent in the Gen-tie option may be complicated, however, due to the rapid urbanization of the Antelope Valley which lies between the Tehachapi and Vincent substations.

The Expanded Path 26 option could complicate grid management, however, since some power from Tehachapi would flow on existing Path 26 lines and use some of the path transfer capacity. This could complicate grid operations as operators must consider these variable flows when scheduling power into Path 26. Under the Gen-tie option, management of Path 26 flows would be simpler. Further study of these alternatives from a grid operations standpoint will be required. The TCSG does not have the data to conduct these studies.

The results of production cost simulations comparing the two alternatives are discussed in Chapter 3. Costs for the two configurations appear comparable, estimated to be in the neighborhood of $1 billion. A choice between the two alternatives hinges on benefits of each that the TCSG has not yet been able to quantify.

Issues related to reliability, grid operations and network benefits are beyond the expertise of the TCSG. Resolving these issues will require both more active assistance from the CAISO and more active involvement of the CPUC. The TCSG therefore makes the following recommendation:

> Recommendation #1
> The TCSG recommends that additional study of Phases 3 and 4 be conducted expeditiously under the auspices of the CAISO in a forum that is open and collaborative, similar to the TCSG process to date.

To resolve which facilities should be built in Phase 3, CPUC Resolution E-3969 orders SCE to submit a recommendation by 12/31/06, for preferred and alternate routes for three options: Tehachapi Substation One to Midway Substation; Tehachapi Substation One to Vincent Substation; or other alternative.

[35] SCE's Antelope substation lies between Tehachapi and Vincent. Power exported south from Tehachapi might enter the grid either at Antelope or at Vincent substations.

Together with the CAISO analysis of the Expanded Path 26 option (Tehachapi-Midway) and the Gen-Tie option (Tehachapi-Vincent), this will determine which facilities should be built first.[36]

The component facilities of Phase 3 and Phase 4, regardless of which is built first, are described in the following sections.

6.6 Phase 3: Second 500 kV Connection to the Grid

Phase 3 will bring cumulative Tehachapi export capacity to 3,300 MW. As noted above, the numbering of phases 3 and 4 is not intended to indicate development or construction priority.

Phase 3 upgrades, as presented on Figure 6.6, shows the Antelope-Tehachapi #2 500 kV line added to Phase 1 and Phase 2 upgrades. In its first report, the TCSG contemplated that the second southern line would connect to the grid through the Vincent substation. Given the Phase 2 upgrades of the SCE system south of Antelope, the TCSG now believes that a second 500 kV line will be required only between Tehachapi and the SCE Antelope substation.

In Phase 3, all of the 500 kV facilities built in Phases 1 and 2 but energized initially at 230 kV will then be operated at 500 kV. This will entail the conversion of the Antelope, Pardee, Tehachapi and Vincent substations to 500 kV. More specifically, this will require adding one 500 kV transformer bank to the Antelope Substation, and to the Pardee Substation; adding three 500 kV transformer banks to the Tehachapi Substation One; and adding and equipping a breaker-and-a-half 500 kV bay at the Vincent 500 kV Substation.

Operating the Tehachapi transmission facilities at 500 kV will also require additional reactive support equipment throughout the SCE service territory.

CPUC Resolution E-3969 orders SCE to immediately pursue further environmental, engineering and other studies necessary to support approval of all the transmission facilities included in planning Phases 1, 2 and 3 of the 2005 report. The Resolution states further that the CPUC will order the preparation of a PEA and the filing of a CPCN for the preferred second 500 kV connection from Tehachapi to the EHV grid by 12/31/07. The TCSG recommends that the Commission direct its Energy Division to work with SCE to ensure that complete CPCN applications for Phases 2 and 3 are filed as soon as possible.

[36] The CAISO may identify other connection alternatives and/or other network upgrades necessary to accommodate the very significant amount of Tehachapi energy as well.

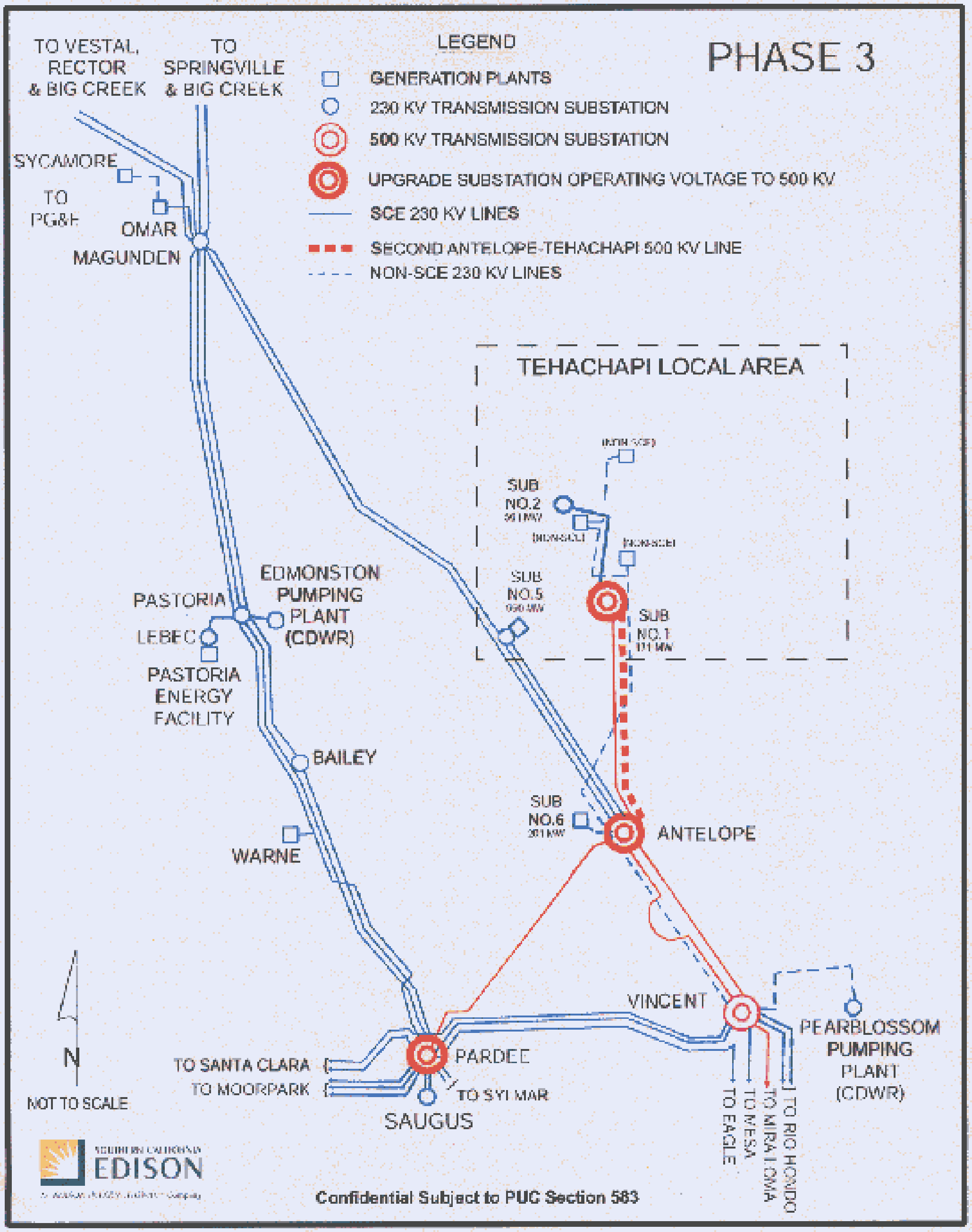

PHASE 3
LEGEND
GENERATION PLANTS
230 KV TRANSMISSION SUBSTATION
500 KV TRANSMISSION SUBSTATION
UPGRADE SUBSTATION OPERATING VOLTAGE TO 500 KV
SCE 230 KV LINES
SECOND ANTELOPE-TEHACHAPI 500 KV LINE
NON-SCE 230 KV LINES
TO VESTAL, RECTOR & BIG CREEK
TO SPRINGVILLE & BIG CREEK
SYCAMORE
TO PG&E
OMAR
MAGUNDEN
TEHACHAPI LOCAL AREA
SUB NO.2
SUB NO.5
SUB NO.1
EDMONSTON PUMPING PLANT (CDWR)
PASTORIA
LEBEC
PASTORIA ENERGY FACILITY
BAILEY
SUB NO.6
ANTELOPE
WARNE
VINCENT
PEARBLOSSOM PUMPING PLANT (CDWR)
N
NOT TO SCALE
TO SANTA CLARA
TO MOORPARK
PARDEE
TO SYLMAR
SAUGUS
TO EAGLE
TO MESA
TO MIRA LOMA
TO RIO HONDO
EDISON
Confidential Subject to PUC Section 583

Figure 6.6. Phase 3 Upgrades

6.7 Phase 4: Possible Third 500 kV Connection to the Grid

Phase 4 adds a third 500 kV connection between Tehachapi and the EHV grid. This would increase the cumulative export capacity to 4,500 MW. As noted, the numbering of phases 3 and 4 is not intended to indicate development or construction priority. Further study will identify the least cost interconnection configuration, and determine the need for three lines.

Phase 4 can be configured in either of two alternative ways:

- as an expansion of Path 26, with a new 500 kV line from Tehachapi Substation One to the PG&E Midway Substation. This configuration is shown on Figure 6.7 below. The TCSG calls this the Expanded Path 26 option.
- with a third 500 kV line from Tehachapi Substation One to the SCE Vincent Substation. Figure 6.8 diagrams this configuration, which is labeled, "Radial to SCE." The TCSG refers to this as the Gen-Tie option.

In the latter case, all three 500 kV lines would connect Tehachapi generation to the SCE system; there would be no direct connection to the PG&E system/Northern California.

The TCSG anticipates that the CAISO studies necessary to identify the relative grid impacts and costs/benefits of these two alternative configurations will be completed later in 2006. Given that 3,600 MW of wind projects have already applied for interconnection in the Tehachapi region, environmental studies and permitting for Phase 4 should begin immediately after the choice of routing for the third 500 kV connection is made.

6.8 4,000 MW from Tehachapi Over Two Circuits

The possibility of using only two not three circuits emerged after studies of three lines were well under way. Although few collaborators could support the alternative at this late date the CPUC Energy Division staff, due to potential substantial capital cost savings, urges the CAISO to assess the two-circuit alternative within its further study of Phases 3 and 4.

In the July 14, 2004 Tehachapi Study Plan, and results as presented in the 2005 report, all transmission alternatives to interconnect Tehachapi generation assumed conventional capacity (well under 2000 MW) for each of three 500 kV circuits. However, it has since been learned that for its Phase 1 segments the thermal limit of SCE's standard design 500kV circuit is 3400MW. Staff's initial analysis indicates that only two such circuits could potentially deliver 4,000 MW from Tehachapi Substation 1 to the existing network and that a single circuit may suffice under emergency conditions. System performance for specific contingencies must still be assessed, and there could be problems with voltage support and possibly stability under the N-1 condition. The CAISO should identify the problems, formulate measures to mitigate them, and compare the cost of mitigation to the cost of the third circuit to Antelope or to Midway.

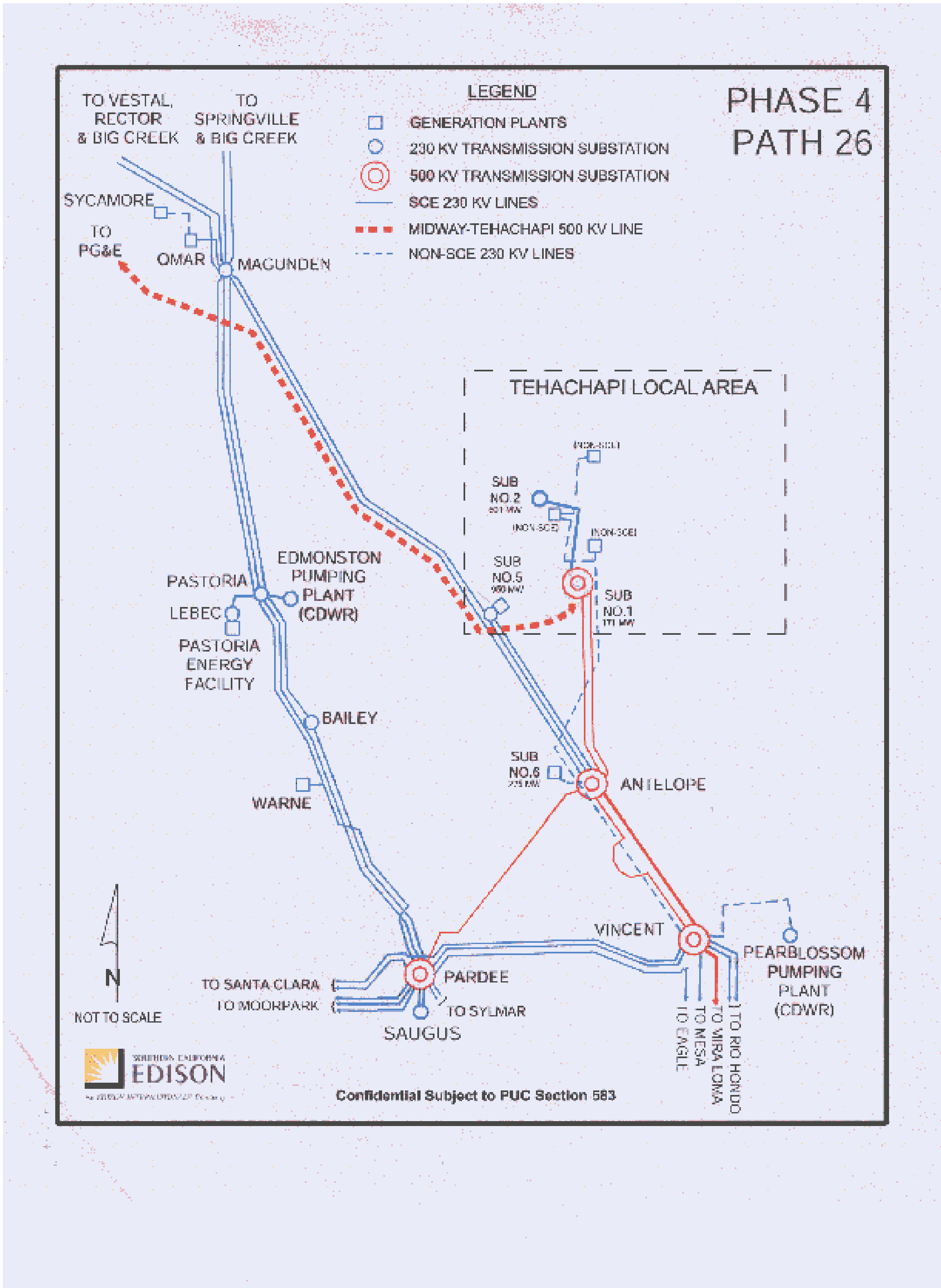


Figure 6.7. Phase 4 Upgrades, Expanded Path 26

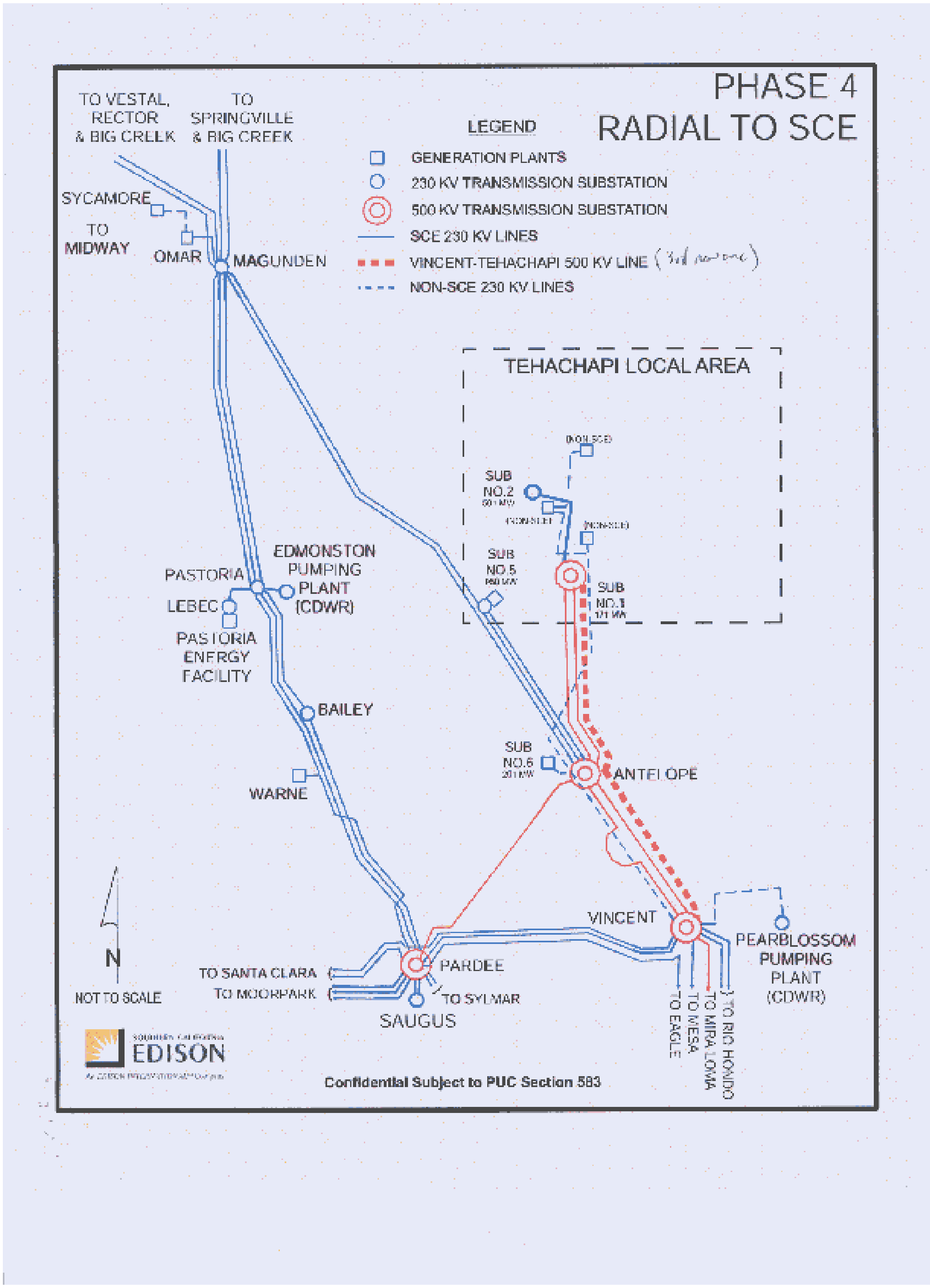


Figure 6.8. Phase 4 Upgrades, Gen-Tie Option

CHAPTER 7

POLICY AND IMPLEMENTATION ISSUES

Cost Recovery Issues

This chapter explains the necessity of using the P.U. Code Section 399.25 backstop provisions regardless of the type of transmission upgrade. It also explains the uniqueness of the Tehachapi transmission project: there is at present no pre-construction assurance of cost recovery for construction costs. Finally, it explains that the cost-recovery backstop provided by Section 399.25 is necessary to solve the problem.

7.1 The Uniqueness of Tehachapi: Why Advance Assurance of Cost Recovery is Required

The Tehachapi transmission project differs from most major transmission projects because of its relationship to the interconnected generating units. This difference affects the principles and process by which cost recovery certainty is obtained for Tehachapi's sponsor.

In the customary situation, a major transmission upgrade is constructed to accommodate a known, large generating plant. In this case, the generating facility can plan and pay for an appropriately sized interconnection facility with the in-service dates of each facility coinciding. In addition, traditional generation facilities can be located in areas that minimize the need for transmission facility upgrades.

The Tehachapi project, in contrast, is spawned by the anticipated construction of a large number of small wind generation projects to support the state's RPS mandate. These projects must be located in the relatively remote area where the renewable resource exists. Constructing interconnection facilities to support each project as it materializes would lead to numerous gen-tie facilities from Tehachapi to Antelope and other low-voltage facilities that would have to be replaced with higher-voltage facilities later -- an environmentally and economically irresponsible approach. Yet, no single wind project can bid a project that includes the cost of an upgrade that will efficiently accommodate the other projects in the resource area. This is due in part to the long lead time required for large transmission projects; developers cannot reliably price power from a project that cannot be built for several years due to lack of transmission capacity.[37]

The solution for the Tehachapi WRA is for the utility to plan, finance and construct transmission facilities that are sized to accommodate the expected wind generation projects. This, in turn, requires the utility to be assured of cost recovery in the absence of firm generator commitments to utilize 100% of the upgrade capacity.

7.2 The Source of Assurance of Cost Recovery: P.U. Code Section 399.25

California utilities will not begin construction without assurance of cost recovery. Section 399.25 authorizes the PUC to offer that assurance, if the costs are prudent.

Such assurances must be made whether the upgrade is "network" or "non-network." For a **network upgrade**, built before interconnection agreements, FERC will protect the utility from disallowance due to insufficient demand, if certain criteria are met.[38] This protection does not translate into advance assurance of cost recovery. Pursuant to customary FERC practice, the utility may not seek cost recovery until construction is complete. For this reason, in its recent Resolution E-3969, the CPUC has provided backstop cost recovery assurances for Tehachapi planning and permitting costs for various but not all elements of the recommended plan contained in this report.. This same assurance will be necessary for construction costs, at the time that the CPUC approves each CPCN application. This assurance is truly backstop, since a facility's network status, and FERC's announced protection from disallowance in the event of excess capacity, will translate into cost recovery through FERC-jurisdictional transmission rates. However, there remains a possibility

[37] A developer will not place its equipment order without knowing the in-operation date. Absent placement of equipment orders, equipment prices -- which can be affected by currency exchange rates, primary resource costs, and turbine supply/demand issues -- are unpredictable. Compounding the problem is uncertainty in future federal tax benefits. On the other side of the table, the purchasing utility is unlikely to sign a bid whose price is uncertain. For the same reasons, it is difficult for developers to sign interconnection agreements.

[38] With respect to interconnection-related network upgrades, the TCSG expects that utilities can be encouraged to exercise their discretion to provide up-front funding if FERC provides early assurances of cost recovery, including 100% recovery for abandoned plant. FERC has already indicated its willingness to work with California utilities in this regard. See *Southern California Edison Company*, 112 FERC ¶ 61,014 (2005) at para. 61. The TCSG hopes FERC would grant similar relief to all California utilities proposing to make similar investments in network upgrades needed to help facilitate the development of renewable resources.

that FERC's view of what should have been built will differ from the Commission's; the backstop is also necessary to cover these potential instances.

For a **non-network upgrade**, the cost cannot be expected to be recovered in FERC-jurisdictional transmission rates.[39] In this non-network context, Section 399.25 provides the only path to cost recovery assurance; all planning and construction costs will be recovered from retail ratepayers and/or from generators on a pro-rata basis after each generator comes on line.

The details of how these cost recovery provisions should be implemented are being addressed in I.05-09-005, where the parties have submitted briefs and reply briefs and a final decision is expected in May 2006.

7.3 Cost Recovery Recommendations

A. The Commission should issue a final decision on cost recovery policy according to the schedule set forth in I.05-09-005, resulting in a final decision by May 2006. That decision should be applied to the Tehachapi case based on these principles:

a.) The individual generator would be responsible for construction of an individual gen-tie from its project site to a designated new substation(s) identified in this plan whose function is to be a collection point for shared transfer of multiple projects to the common grid. Presumably the generator would recover this cost in the price it charged for the project's energy output. The recovery risk for the cost of this gen-tie is solely on the generator.

b.) For transmission projects that are needed for reliability or to promote economic efficiency within the meaning of the CAISO Tariff, but are also needed to facilitate achievement of RPS goals, "all feasible [CPUC] actions" should include, at a minimum: (1) supporting Participating Transmission Owner (PTO) requests for CAISO approval for addition of the project to the CAISO-controlled grid; (2) supporting utility requests for the recovery of the prudently-incurred costs of such projects within FERC-jurisdictional rates; and (3) allowing

[39] SCE petitioned FERC to allow the multiple-generator Tehachapi "trunk line" to be rolled into rates, but its petition was rejected on the basis of SCE's and the ISO's assertion that the upgrade would be devoid of network benefits; for FERC to have enabled roll-in, network benefits are required under the FERC's precedents.

recovery in retail rates of the costs of any such projects that are not approved for inclusion in FERC rates.

c.) For projects that are not needed for reliability or to promote economic efficiency within the meaning of the CAISO Tariff, and therefore would not be needed but for the interconnection of new generation, but *are* "network upgrades" for which a utility may be willing to exercise its discretion to provide up-front funding under federal interconnection policy, the Commission's actions should include: (1) supporting utility requests to FERC for early cost recovery assurances, including exceptions to abandoned plant policy, as well as reasonable arguments that the facilities in question are "network facilities" rather than "direct assignment facilities" or "gen-ties"; (2) after the facilities are placed in service, supporting utility requests for the recovery of prudently-incurred costs within FERC jurisdictional rates; and (3) allowing recovery in retail rates of any such costs that are not approved for inclusion in FERC rates.

d.) Finally, for high-voltage, bulk transfer generation-tie lines serving multiple RPS generators that are not needed but for the interconnection of new renewable generation and also do not qualify as network facilities, the Commission should allow full recovery of prudently-incurred costs. These costs would be recovered in retail rates and/or from generators. For the Tehachapi plan, the utility would exercise the option to fund and construct such facilities built in advance of generation. The exact locations/sizes/construction timing of these collection points would be determined as individual generation projects matured.

B. The Commission should provide cost recovery assurances for planning and permitting costs to all elements related to integration of Tehachapi WRA generation.

While this chapter has focused on providing cost recovery assurance for utilities, the TCSG points out that an essential purpose of this assurance is also to provide reasonable regulatory certainty to generators as to what costs they will be responsible for before committing to a fixed-price bid and securing financing for a project Therefore, the TCSG further recommends the following:

C. The Commission should provide generators with reasonable certainty concerning the transmission costs they will be responsible for before the generator is required to make a binding price bid. The CPUC should require the utility to develop a estimate of the pro-rated facilities charge it will assess to generators interconnecting to the authorized facilities before construction of the transmission facilities commences.[40] Various solutions may be possible. For example: any costs exceeding this amount could be recoverable through the ratepayer backstop;[41] or, the generator could be allowed to adjust its PPA according to actual costs.

7.4 Existing CPUC Transmission Permitting Process

The CPUC reviews regulated utility transmission projects under the present requirements of PUC Section 1001 and 1002, General Order 131-D, Rule 17.1 and the CPUC Decision 89905 Appendix B Information and Criteria List (Criteria List) for the Proponent's Environmental Assessment (PEA) filings. In addition, to the requirements and practices of the proceeding process, the CPUC, as Lead Agency, must comply with the CEQA process. Further, if the project has not been determined to be exempt, the CPUC ED staff must also conduct a contract process for an environmental consultant under the requirements of state contracting and General Order 163A.

Processing Non-Exempt 131-D PTC and CPCN Projects

The CPUC transmission review for a Permit to Construct (PTC) or a Certificate of Public Convenience Necessity (CPCN) is generally conducted in the following steps with the ALJ general proceeding and the CEQA process in somewhat parallel tracks:

CEQA Process

1. Application and PEA is filed with the CPUC.

2. If the project is not 131-D or CEQA exempt, a contract process must be initiated for an environmental consultant. Completing the contract process takes 3 to 4 months and has taken place either before or after the filing of the application. It requires the completion of the contract request process, advertisement of the Request for Qualifications (RFQ) for at least 4 weeks; review of the Statement of Qualifications (SOQs); consultant interviews; completion of evaluations; contract package preparation; and Department of General Services (DGS) approval.

[40] That charge will be a component of the standard interconnection agreement that the parties file at FERC.

[41] Potentially charging ratepayers for a share of costs may be particularly appropriate when the upgrade provides system benefits (though short of what is required to achieve "network" status) or when the upgrade is expected eventually to become part of a larger network configuration.

3. Contractor and the CPUC Project Manager (PM) review the application using the PEA Information and Criteria List and generally do 1 to 2 rounds of PEA deficiency reviews with the first required in 30 days per GO 131-D and CEQA Guideline15101.

4. After the application is deemed complete, a determination must be made on whether an Environmental Impact Report (EIR) or Mitigated Negative Declaration/Negative Declaration (MND/ND) is necessary. This is usually based on the conclusions of a consultant prepared initial study that utilizes the PEA information.

5. Environmental Document Preparation for EIR or MND

Draft Environmental Impact Report (DEIR) Major Tasks

- DEIR preparation involves site visits; incorporating and supplementing, as necessary, PEA information; clarifying the project description; developing and screening alternatives; consulting with applicable agencies; conducting public scoping meetings; preparing of any scoping report; working with applicant on data requests; preparing a draft mitigation and monitoring report; completing any required biological or cultural surveys if not done by the applicant or can be done prior to construction; and preparing and reviewing administrative draft documents. Public review of the DEIR is normally 45 days.

- Workshops are conducted during the public review period. ALJ may hold public participation hearings (PPHs) in this same time frame which is separate from the CEQA public meeting requirements.

- The EIR is finalized after draft review. The Energy Division (ED) PM works with consultants to complete responses to comments on DEIR. Per the Permit Streamlining Act, CEQA 21151.5, and Rule 17.1, the final EIR must be completed and certified within a year after the application is deemed complete.

Draft Mitigated Negative Declaration (DMND) Tasks

- Utilizing and supplementing PEA information, the consultant prepares the initial study and draft MND. This usually requires site visits, agency consultations, data requests with the applicant, and ED review of the administrative draft MND.

- In coordination with the consultant and legal the PM discusses the proposed mitigation measures with the applicant to reach agreement for publishing a MND; otherwise an EIR would be required without applicant agreement on mitigation measures.

- Draft MND is released for a 30 day public review period. Scoping meetings and agency consultations may be scheduled during this time period.
- The consultant in coordination with the ED PM prepares the response to comments and finalizes the MND. Per the Permit Streamlining Act, CEQA 21151.5, and Rule 17.1, a final MND must be completed and adopted within 180 days of deeming the application complete.

ALJ Proceeding Process

1. After the application and PEA is filed in the docket office, the ALJ has generally started the proceeding process during the above discussed EIR or MND preparation activities. The ALJ conducts a prehearing conference and prepares a scoping memo outlining the issues and schedule for testimony, briefs, and possible hearings. The EIR or MND process and schedule is included in the memo. Certain issues including need may be bifurcated and proceed ahead of the final EIR/MND completion.

2. The ALJ may conclude all proceeding activities prior to or at the time the EIR or MND is finalized by the ED; or the ALJ may continue the proceeding process focusing on routing issues after the EIR or MND has been finalized by the ED.

3. At the conclusion of the proceedings, the ALJ will prepare the proposed decision that involves certification of the EIR or the adoption of the MND and the decision.

4. The Commission votes on the proposed decision.

5. The Notice of Determination must be sent to the State Clearinghouse (SCH) within 5 days of the effective date of a final Commission decision approving a project in order to preserve the CEQA statute of limitations of 30 days for filing a civil challenge. If the five days is missed an entity has 180 days to challenge [CEQA Guidelines 15094 (g) 15112(c)].

6. After the CPUC decision process is completed and the project is approved, the ED staff and the consultant prepare a mitigation monitoring compliance and reporting program (MMCRP). Throughout the construction period, the consultant and ED staff coordinate with the applicant on the implementation of mitigation measures and monitoring construction activities. The ED staff works with the consultant on notices to proceed for construction and any necessary variances.

Processing Exempt 131-D Projects

GO 131-D III (B) (1) allows exemptions from PTC or CPCN requirements. The process is generally as follows:

1. The utility must file a notice/advice letter for the exemption not less than 30 days before the date when construction is intended to begin per 131-D. If no protests are filed, the utility may proceed with construction 45 days after first publication of the notice.

2. Within 20 days after the notice is mailed or published, an individual can object to the exemption.

3. The utility has five business days upon receipt of the protest to respond. Construction can't commence until the Executive Director has issued an Executive Resolution.

4. Within 30 days of the utility's response, the Executive Director must issue an Executive Resolution on whether the utility must file a PTC or the protest is dismissed for the lack of a valid reason. Also, the Executive Director must state the reasons for granting or denying the protest.

7.5 Policy Issues Associated With The Existing CPUC Permitting Process and Streamlining

In the I.05-09-005 proceeding, the utilities and other interested parties have raised issues regarding the existing CPUC transmission permitting process. As part of the proceeding, parties were directed by Commissioner Grueneich to file comments identifying the top six issues that the CPUC should address in 2006 and in 2007. Parties filed comments on November 15, 2005. A subsequent workshop was held on December 6, 2005. One of the top six priority items identified by the parties in the briefings and at the workshop was streamlining the siting and permitting process for transmission. The parties identified the following issues in their November briefings and at the December workshop:

- CPUC consultants should not duplicate applicant's environmental analysis.
- CPUC should focus only on the requirements of CEQA.
- EMF policy should not be relitigated in every proceeding.
- CPUC needs to follow the required time frames for handling protests to 131-D exempt projects.
- Utility should be able to use an existing environmental document in lieu of a PEA where applicable.
- CPUC should avoid time consuming EIRs when a mitigated negative declaration would be appropriate with up-front negotiated mitigation measures.

- CPUC needs to start contract process prior to application filing to avoid review delays.
- CPUC needs to fully utilize PEA for preparing a MND or EIR and not duplicate efforts.
- CPUC should consider ways to consolidate NEPA/CEQA reviews.
- There needs to be more up front collaboration and cooperation.
- CPUC needs to adopt internal procedures to ensure compliance with Permit Streamlining Act and 131-D timeframes.
- CPUC should consider general changes in process to streamline and expedite the CPCN/PTC approval process.
- CPUC should consider separating the approval of a transmission corridor from the approval of the detailed siting and engineering of the transmission towers within the corridor.

The CPUC Energy Division has also found that the process has not always gone as smoothly and expeditiously as possible. There are numerous reasons for this situation including the following:

- The existing mandated state contract process takes 3 to 4 months, and is often not initiated prior to the application filing. This tends to extend out the time for PEA deficiency review and consultant preparation of the EIR or MND documentation.
- The contract process was not conducted in a reasonable amount of time.
- At the time of filing, the PEA has numerous deficiencies.
- In a joint EIR/EIS (environmental Impact statement), the memorandum of understanding (MOU) agreement was not done up front in a timely manner which allows co-lead agency issues to go unresolved for long periods of time.
- At the time of filing, up-front strategic planning was not done for handling and resolving known issues between ED and their consultant and, if applicable, with co-lead agency.
- The applicant is not timely with responses to PEA deficiencies or data requests as required by ED staff and consultant to maintain schedule.
- The ED staff and/or consultant do not adhere to the agreed upon schedule or there was not an up front commitment to a schedule by all parties.
- There was higher than anticipated public and agency controversy which in turn required more meetings, more alternative analysis, more required documentation on impacts and mitigation, and a longer proceeding with hearings, briefings, etc.

- Ed staff, their consultant, and/or the applicant did not anticipate issues that later seriously impacted the schedule.
- The ALJ proceeding schedule is longer for any number of reasons.

In light of the above proceeding comments and the identified issues with the existing permitting process, the CPUC Energy Division CEQA Unit staff prepared a memo to Commissioner Grueneich's office responding to the parties' comments and provided preliminary recommendations on streamlining the transmission permitting process.

At the direction of Commissioner Grueneich, Energy Division staff then scheduled a workshop for March 23, 2006 to further discuss permitting issues and to allow comments on the Energy Division staff's preliminary recommendations on streamlining the permit process. Prior to the workshop, staff's recommendations and their detailed responses to parties' 11/15/05 briefs and 12/6/05 workshop comments were sent to the parties for their review and comment. Energy Division staff's preliminary recommendations specifically included the following for exempt and non- exempt transmission projects:

1. **<u>Exempt Projects Under 131-D III (B) (1), Rule 17.1 and/or CEQA</u>**

Applicant needs to provide specific information for ED to quickly determine exempt projects by providing adequate justifications and clearly identifying the appropriate exemption. In addition, applicant needs to strictly adhere to exemption language to avoid protest and lengthy resolution of issues or the possible decision that a MND or EIR is required by the CPUC. ED staff must adhere to CPUC time frames for handling protests and preparing resolutions.

2. **<u>Processing Steps for Non-exempt Projects</u>**

<u>Pre-Filing Steps</u>

<u>CPUC/ED Staff</u>

1. At 6 months before utility filing, ED staff/Contracts Office/DGS initiates and completes contract process within 3 months.
2. At 3 months before filing the PEA, ED staff along with the consultant awarded contract, review the administrative draft of the PEA and provides and completes input to the utility within 2 months of filing.

<u>Utility/Applicant</u>

1. Utility develops specific project based on the procurement process.
2. Notifies ED staff within 6 months of filing of the project.

3. Conducts open houses and consultations with the public and agencies to discuss and assess any issues.
4. At not later than 6 months before filing, the utility should be making a concerted effort to resolve any issues (public, agencies, and others) or have strategic plan for doing so prior to filing or early on after filing.
5. At ED contract completion or at 3 months before filing, the utility develops an administrative draft PEA or equivalent information that fully adheres to 131-D and the PEA Information and Criteria List and addresses all issues to the maximum extent possible.
6. Utility works with ED staff on their administrative draft PEA input.

Application Filed and Deemed Complete

CPUC/ED Staff

1. Assuming PEA has been revised with all ED input, the application and PEA can be deemed compete within 30 days of filing.
2. Within 30 days of deeming the application complete, ED must decide whether to prepare ND or EIR. Utilizing the PEA and any supplemental information, ED prepares an initial study to make this determination; or decides that an EIR is clearly required and does not formally prepare an initial study.
3. If MND initially determined, ED and consultant works with the utility to develop project modifications/or mitigation measures that would allow for the public release of a MND instead of an EIR.
4. If an EIR is determined in 1 above, ED and consultant must immediately address unresolved issues internally and/or in concert with the applicant. For any unresolved issues, a strategic approach for resolution needs to be developed in writing and agreed to by all applicable parties including the applicant.
5. In accordance with the Permit Streamlining Act, a schedule for the MND or EIR completion must be developed at the early stages of deeming the application complete. It must be adhered to by all parties including ED, its consultants, applicant, and any other agency if a joint document.

Utility

1. Utility files PEA as revised by ED input after 6 months of project notification.
2. Utility works with ED and its consultant on project modifications and/or mitigation measures that will allow for a MND.
3. Utility responds expeditiously to any data requests submitted by CPUC ED staff and its consultants during the preparation of EIR or MND.

ALJ

1. After 30 days from filing the application, the ALJ should schedule a prehearing conference to address issues and schedule for the proceeding and the CEQA process.
2. A scoping memo outlining the issues and schedule should be prepared as soon as possible after the prehearing conference.

3. The ALJ should consider scheduling parts of the proceeding prior to the environmental document being finalized by ED staff and consultant.
4. ALJ should prepare the proposed decision as soon as possible after the environmental document is finalized by ED staff and consultant.

OTHER CONSIDERATIONS FOR STREAMLINING THE PROCESS POSSIBLY REQUIRING CHANGES TO REQUIREMENTS AND PROCEDURES

In addition to activating the above procedural steps in the near term, there are other overall considerations for streamlining the process.

Contract Process

1. Consider going back to the use of On-Call consultants by utility service areas and some other geographic delineation. Need to work with legal and Contracts Office.
2. ED could re-evaluate the "Round Robin" format of contracting. ED could develop a pool of consultants that could be utilize throughout the state, This format along with the one above will require Contracts Office and Legal Division support and input to successfully implement at the CPUC.

Personnel Issues

1. In addition to fully utilizing existing staff, management needs to support hiring additional staff at a sufficient level to make a 100% commitment to a more efficient streamline process.
2. CEQA Unit needs consistent legal support for exemption determinations, contract questions, and assisting in issue resolutions and developing a successful approach to legal questions on CEQA as ED is conducting the MND or EIR process.
3. CEQA Unit should be trained in the proper use of project management methods (scope, schedule, quality control), such as anticipating impacts that could affect the schedule and resolving them before they happen.

On March 23, 2006 the workshop was held to further discuss the permitting process and to comment on staff's preliminary recommendations. There were over 25 participants. A number of comments were presented on the existing process and on the staff' s recommendations including a project management approach to the Tehachapi development. The Energy Division is presently preparing a workshop report that will be finalized by mid April 2006. This report will present all the workshop comments and provide for next steps in implementing streamlining measures.

7.6 A Project Management Approach to Tehachapi Development

The TCSG joins the parties in I.05-09-005 in recommending that the CPUC implement the proposals in section 7.5 above to streamline and shorten CPUC permit approval processes. But streamlining the state's current approach to renewable energy and transmission development is inadequate to the opportunity at hand.

The need to build new generation in the state, the Loading Order adopted by the Commission, and the Energy Action Plan goal of having renewables supply 20% of our electricity by the end of 2010 combine to give Tehachapi development special urgency. Wind energy is less expensive than gas-fired generation, and every year of delay in Tehachapi development imposes real economic costs on California ratepayers. With 3,600 MW of projects already in the CAISO queue, wind companies have demonstrated the ability to meet the full build-out target for Tehachapi development on a schedule to meet the EAP 2010 goal. Streamlining the current permit application and approval process is essential, but by itself is unlikely to bring the necessary transmission into service in time. The current approach puts the CPUC in a largely reactive posture, at a time when proactive CPUC leadership is called for.

D.04-06-010 outlines an agenda of developing transmission in advance of interconnection requests.[42] With this decision, the Commission demonstrated its understanding that a business-as-usual approach to transmission development would not meet the goals indicated in state law and adopted, in concert with the CEC and the Governor, as its own policies. Adopting a project management approach to Tehachapi transmission development would better enable the Commission to follow through on the vision outlined in D.04-06-010.

In this approach, the CPUC would act as the project manager for the development of all Tehachapi transmission facilities. It would establish a detailed work plan and milestone schedule for all phases of the proposed development, and act to ensure achievement of the milestones.

If feasible, the schedule should be geared to a December 31, 2010 in-service date for the transmission facilities necessary to export 4,500 MW of wind generation from the Tehachapi region. The schedule and accompanying work plan would identify interim milestones and the supporting tasks necessary to complete each phase of the development in the optimum sequence.

[42] Interim Opinion on Transmission Needs in the Tehachapi Wind Resource Area, June 9, 2004, in I.00-11-001.

The schedule and work plan will thus clarify exactly when the Commission must order the IOUs to complete studies and file applications; and the dates by which the Commission itself must approve applications. It will also identify other Commission actions, including coordinating procurement activities with the transmission development schedule, and providing cost recovery assurances. As discussed in sections 7.1 through 7.3 above, ensuring cost recovery at least cost to ratepayers may advise working with the CAISO to amend provisions of its tariff, and to establish cost recovery in transmission rates through a coordinated Section 205 Federal Power Act filing at FERC.

Members of the TCSG are prepared to assist the Commission in establishing such a milestone schedule and work plan to guide Tehachapi transmission development.

Organizing Tehachapi transmission development as one integrated project to be completed in phases over four years may make a Programmatic EIR the most effective permitting vehicle. Determining whether or not to develop a P-EIR for the inter-related phases of Tehachapi development should be one of the first tasks of the work plan.

7.6.1 CPUC Project Manager

This approach requires the Commission to appoint a project manager to lead this effort. The project manager will have responsibility for ensuring that all elements of the transmission development are completed on schedule. S/he will:

- coordinate the development of the milestone schedule and project work plan;
- monitor progress on each element of the schedule;
- anticipate problems and delays;
- work with CPUC staff and consultants, IOU staff, and state, federal and local agency staff to solve all problems necessary to keep the overall development on schedule;
- establish a stakeholder working group to assist in solving problems;
- ensure that the Commission is informed and prepared to take action, by issuing orders or otherwise, necessary to meet schedule milestones.

To this end, the project manager must have the authority to mobilize the full resources of the Commission, without regard to departmental boundaries.

7.6.2 CEQA Considerations of the Project Management Approach

CEQA does not preclude the CPUC from being the lead agency in charge of a Tehachapi EIR while also being the project proponent. Government entities commonly serve as lead agency on infrastructure projects that they intend to fund, build, own and/or operate. The key proviso in such cases is that the agency (i.e., the CPUC) prepare the EIR before making the decision to proceed with the project. The dual role of project proponent and lead agency also requires that CEQA provisions be scrupulously observed.

In sum, a project management approach gives the Commission powerful new tools with which to lead transmission development. It will enable the Commission to know the status of every major component of the overall project at all times, and so to anticipate problems and delays.

7.6.3 The Tehachapi Power Project

Building 4,500 MW of new generation at Tehachapi and the transmission to access it is the largest power project undertaken in California since Diablo Canyon. The TCSG believes that it is appropriate to consider the combined $10 billion generation and transmission development as one integrated project. Expediting its completion meets important state economic development, fuel diversity, rate stabilization, environmental and climate goals.

The wind generating plants, which represent the great bulk of the investment required, are expected to be built by private companies. Publicly owned utilities and private entities over which the CPUC has no jurisdiction may supply some of the transmission needed to export Tehachapi generation. POUs are also expected to purchase significant quantities of Tehachapi generation.

Getting the Tehachapi Power Project built at least cost and on the Energy Action Plan schedule will thus require coordinating the activities of a range of power purchasers, wind generating companies and their bankers and suppliers, transmission owners, the CAISO, the CPUC, and local, state and federal permitting agencies. Appointing a project manager invested with the mandate to get the project built can help ensure timely completion of the project.

The TCSG accordingly recommends that the CPUC work with the CEC, the legislature and key stakeholders to identify candidates for the position of Tehachapi Power Project manager. Candidates should have experience overseeing large scale infrastructure projects. The project manager would engage stakeholders to establish a milestone schedule and work plan addressing every element of the generation and transmission development. The small staff necessary to support this project manager role could be drawn from the CPUC, CEC IOUs and/or other stakeholders. The project manager would report progress to state agencies, stakeholders and the public quarterly.

CHAPTER 8

CONCEPTUAL SCHEDULE FOR COMPLETING TEHACHAPI PLAN & NECESSARY RELATED ACTIONS

8.1 Updated Conceptual Schedule

The March 2005 Report of the TCSG included a conceptual schedule for completing the Tehachapi transmission upgrades by December 2010. Chart 8.1 updates this schedule based on what has actually occurred since that report was issued, and shows that the March 2005 timeline for completion has now slipped to 2011. Chart 8.2 presents a revised schedule that would now be required to complete the plan by 2010.

The 2005 schedule assumed that the CPCN applications for Phase 1 would be processed and approved by June 2006. It now appears that various delays in the CPCN approval process will cause those applications to be approved no earlier than December 2006. Although the 2005 conceptual schedule was described as "the fastest practicable schedule" for completing the plan by 2010, and time has been lost since, the TCSG believes that it may still be possible to meet the 2010 completion goal if <u>all</u> of a number of aggressive actions to accelerate the process, as described in this chapter, are taken.

The TCSG emphasizes the critical importance of completing Segments 1 and 2 of Phase 1 as soon as possible. These segments must be completed before Phase 2 construction can commence. Phase 2 is essential for all projects because they require the additional south-of-Antelope transmission capacity that this phase will provide. Without Phases 1 and 2, the contributions from the potential Tehachapi wind generations to help meet the RPS mandated state goal is severely hindered.

Completing the goal by 2010, as shown in Chart 8.2, is very ambitious when compared to the timelines that are normally expected for major transmission projects. Accelerating the process is, however, necessary to preserve the opportunity for the Tehachapi region to meet its promise, as stated in Finding of Fact 3 of D. 04-06-010, to provide "a significant portion of the goals for renewable energy development in California." If the state is to reach its ambitious RPS goal of 20% renewable generation by 2010 with wind generated from Tehachapi, the time and process required to permit and build major new transmission facilities to access Tehachapi wind must be streamlined.

In addition to providing the infrastructure necessary to meet the state's RPS goals, accelerating the schedule is important also because the schedule will affect developers' ability to obtain temporary interconnections to enable their projects to come on line (with some curtailment) before the planned transmission facilities are operational. This is because the CAISO may approve a temporary interconnection on a case by case basis only if the permanent facilities are "planned." The filing and processing of a CPCN (or PTC) provides clear evidence of those plans.

The balance of this chapter describes the actions that are necessary to accelerate every phase in order to complete construction by 2010, and the additional particular actions that are necessary in specific phases. In summary, we recommend that the Commission take the following actions:

Recommendations:

- Accelerate the CPCN review process for the Tehachapi upgrades by taking all of the specific actions described in this chapter;

- Direct the Energy Division, utilities and other TCSG parties to develop a detailed schedule of specific tasks and parties responsible (the "who, what, when") that must be achieved if the larger milestones shown in Figure 8.2 are to be met (moving the schedule back if it is determined in this process that the 2010 completion goal is infeasible);

- Direct the Energy Division to work with SCE to ensure that complete CPCN applications for Phases 2 and 3 be filed as soon as possible;

- Expedite the CPCN approval process for future phases by proposing, on the Commission's own motion, without evidentiary hearings, a finding that Phases 2 and 3 are needed to facilitate the achievement of RPS goals.

In addition, as discussed in Chapter 7, the TCSG recommends that the Commission identify a Tehachapi project manager who would be responsible for ensuring that all of these recommendations are carried out in a timely fashion, in order to maximize the opportunity to complete the upgrades by 2010.

8.2 Actions Necessary in Every Phase to Complete Construction By 2010

To complete the Tehachapi plan by 2010, the Commission will need to complete the CPUC review and approval process for each application within twelve months or less in most cases. Although this same recommendation was made in the March 2005 TCSG report (Section 6.3.1), the process for each segment of Phase 1 will have taken at least two years, a significant source of delay in the overall plan. To accomplish review of CPCN applications within 12 months, each of the three phases of the Commission's approval process: consulting contracting, preparation of the CEQA document, and preparation of the Commission's Proposed Decision requires significant reform. These issues are being discussed and addressed presently as part of I.05-09-005 as outlined above in Chapter 7. The TCSG believes that, to create the possibility of completing the Tehachapi plan by 2010, it will be necessary for the CPUC to implement a number of those reforms in the processing of the Tehachapi CPCN applications, including the following:

- Acquire additional CPUC staff capabilities in the CEQA Unit and direct the utilities to acquire additional staffing capabilities as necessary to meet the milestones in the 2010 schedule;

- Consultants should be in place for each phase of the Tehachapi development plan three months before the CPCN application is filed. For phases 2 and 3, if the CPUC clarifies that the applications are due by the end of December 2006, this would be September 30, 2006;

- The Energy Division, the utility and the CPUC's consultant should conduct pre-filing meetings to (a) determine the appropriate scope for the application (limiting the scope to what is required under CEQA), (b) enable the utility to anticipate and address all issues in its application, and (c) ensure that all necessary data is supplied in the application. The consultant should conduct its independent review in parallel with the utility's preparation of the application;

- The application should be deemed complete within a week of its filing (given the pre-filing communication and coordination, which should result in a complete application);

- Direct the consultants to expedite review of the application to meet adopted milestones for the project phase;

- Direct the assigned ALJ to quickly establish in a scoping memo an expedited calendar of activities (briefs, testimony, hearings, etc.) to ensure that the final EIR is certified within one year of an application being deemed complete as required under CEQA; and

- Direct the ALJ to adopt the findings of the Energy Division's review without further litigation of EMF, routing, and other issues that were addressed in the review process.

Additional actions that the CPUC can take to expedite the schedule are:

- Re-conceive the application process as a collaborative endeavor between the Commission and the utility, given the state's interest in meeting the RPS goals;

- Anticipate the permits that will be required by other agencies and closely coordinate with those agencies to minimize post-CPUC permitting delays (see discussion in subsection 8.3);

- Direct SCE to plan for construction, e.g., arrange for equipment, in anticipation of receiving all necessary permits so that construction can begin immediately after those permits are granted.

- Ensure that adequate staffing is in place to handle protests to projects that are exempted from CPCN or PTC requirements, and ensure that the CPUC Executive Director's Resolution is issued within 30 days as required. Late protests should automatically be deemed denied.

8.3 Post-CPUC Permitting -- Resource Agency and Local Permitting

In addition to meeting CPUC permit requirements, utilities proposing to construct Tehachapi transmission facilities must also obtain all required federal and state resource agency permits as well as local (ministerial) permits. The specific permits required will depend on the exact routing and design of each project, and cannot be known with certainty until detailed routing, environmental, and engineering studies are completed (and, where required, after the CPUC has selected the approved route). Such permits and approvals may include those issued under the federal and state Endangered Species Acts (U.S.F.W.S. and California Department of Fish and Game), the Clean Water Act (U.S. Army Corps of Engineers), the Porter-Cologne Water Quality Control Act

(California Regional Water Quality Control Boards), regulations governing use of federally managed lands (e.g., Forest Service, BLM), or local land use regulations. (Although the CPUC preempts all discretionary local authority over the Tehachapi transmission projects, ministerial permits such as encroachment permits may be required.)

In order to minimize the timeline impact of the non-CPUC permitting, the CPUC must closely coordinate with all applicable responsible agencies throughout its project approval process. Where impacts to federal jurisdictional resources are significant enough to trigger full NEPA review, the Commission should consider preparation of a joint EIR/EIS in order to minimize post-CPCN delays. Even where no major issues exist, obtaining resource agency and local permits can be time-consuming in light of limited agency staffing, applicable procedural requirements, and other factors. In selecting the approved routes for Tehachapi transmission projects, the Commission should (1) strive to minimize impacts to jurisdictional resources, (2) closely coordinate with other responsible agencies, and (3) expedite its own processes. These steps will help reduce the time needed to obtain non-CPUC permits, and leave the utilities with adequate time to do so.

8.4 Specific Actions That Must Be Taken to Accelerate Particular Phases

Phase 1. Construction of Segments 1, 2 and 3 could occur within the same 18-month time period, provided human and material resources are available and CPCN applications have been approved.

Expediting Phase 1 is urgent because load-serving requirements will prevent the commencement of construction for Phase 2 until Segments 1 and 2 of Phase 1 are completed.

Phase 2A (Antelope-Substation 5). There are over 1,100 MW currently in the CAISO queue at Substation 5. A 300 MW project is advancing through the permitting process with Kern County and several other projects will soon follow. There is an opportunity presently for a temporary interconnection at Tehachapi Substation 5 that would enable the development of the first project in the queue (with some delivery constraints) in advance of construction of Antelope-Substation 5. CAISO's approval of a temporary interconnection would be contingent on the approval of (or exemption from) a CPCN or PTC for the Antelope-Sub 5 upgrade and the level of facilities required for such a temporary interconnection. The CPUC can help realize this opportunity by exempting Antelope-Substation 5 from a CPCN and instead require a less complex and time-consuming permit-to-construct (PTC) (or provide an exemption from both). A PTC would be reasonable if this upgrade can take place within the existing transmission corridor and does not involve any new route or alternative routing. The schedule assumes that the Commission exempts the upgrade from a CPCN and instead requires a PTC.

Quickly approving and constructing the Antelope-Substation 5 upgrade could also be important because once it is completed, along with Segments 1 and 2 of Phase 1, it may be possible to temporarily interconnect some of the other projects in the queue in advance of the completion of Phase 1: Segment 3 and Phase 2. If so, development of these projects, including local permitting, could commence as soon as the CAISO approved the temporary interconnection, which would be conditioned upon the completion of transmission facilities for Antelope-Sub 5 and for Segments 1 and 2 of Phase 1.

The feasibility of bringing on line some amount of capacity in advance of the completion of Phases 1 and 2 requires additional consideration by all parties. For example, the logistics of completing upgrades that require transmission to be taken out of service may limit the level or the timeframe that temporary interconnection may be feasible. Considering the possibility of temporary interconnections is important, however, given the time that will be required to complete Phases 1 and 2.

Phase 2B (Antelope-Mesa). SCE is planning to submit applications for Phase 2B and Phase 3 by spring and summer of 2007, respectively. The Energy Division should work with SCE to ensure that complete CPCN applications for Phases 2 and 3 are filed no later than these dates (and earlier if possible). The Commission should be prepared to immediately begin processing those applications so that they may be approved by December 2007 (Phase 3) and June 2008 (Phase 2, which has forest land complications). It will speed the process if the Commission makes a need finding prior to or early in the CPCN process on its own initiative, rather than requiring the utility to prove need. This is discussed further in subsection 8.4.

Phase 2B would be located, in part, on land subject to the jurisdiction of the United States Forest Service (USFS), Angeles National Forest, which complicates the review process and requires a joint EIR/EIS. In order to begin construction of Phase 2B as soon as Segments 1 and 2 are completed, therefore, it will also be necessary for SCE and the CPUC to work with the Forest Service in advance of the Phase 2B CPCN filing to ensure that the application review process can be completed within the 18-month timeframe shown in the timeline. As indicated in the December 12, 2005, Assigned Commissioner's Ruling in A.04-12-007, we have learned in the CPCN application process for Phase 1: Segment 1 that early coordination is essential to avoid delays.

Phase 3. As stated above, the Energy Division should work with SCE to ensure that a complete CPCN application for Phase 3 is filed no later than summer 2007, and the Commission should adopt a need finding on its own initiative, no later than the initial stages of the CPCN application process. Phase 1: Segment 3 environmental work should be used to the extent applicable.

8.5 Proactive Finding of Need for Phases 2 and 3

The Commission can speed the CPCN approval process for future phases by proposing, on its own motion, a finding that Phases 2 and 3 are needed to facilitate the achievement of RPS goals. The Commission can propose such a statement either (1) in I. 05-09-005, after a review of this report and an opportunity for comments, or (2) in the CPCN dockets for Phases 2 and 3, shortly after the filing of those applications. The Commission also should anticipate taking this action with regard to Phase 4 at the appropriate time.

Adopting a need statement on the Commission's own initiative before or early in the CPCN approval process is necessary and appropriate for the following reasons:

1. A Need Statement for Phases 2 and 3 Follows the Process Used for Phase I in D. 04-06-010.

In D. 04-06-010, the Commission found that the "magnitude and concentration" of Tehachapi wind resources, as identified in the CEC's Renewable Resources Report,[43] justified a finding that the first phase of Tehachapi transmission upgrades was needed to facilitate achievement of RPS goals.[44] The Commission noted that this need determination was "separate and severable" from the need finding that would be made in individual CPCN proceedings for specific transmission projects.[45] That individual need determination would examine alternatives to the proposed project, as required under G.O. 131-D, and would examine whether the specific project was likely to further RPS goals based on the results of the RPS process to date. The Scoping Memo for Edison's CPCN application for Segment 1 of Phase I re-affirmed this more limited scope of the need determination in individual CPCN proceedings.[46] In other words, the individual CPCN proceedings for the Phase 1 segments will determine whether additional transmission

[43] "Renewable Resources Development Report," CEC Publication Number 500-03-080F, November 2003. In this study, the CEC estimated that the Tehachapi area contains the largest wind resource in California, with undeveloped potential of about 14,000 gigawatt-hours per year, representing the single largest cost-competitive renewable resource potential in the state. The CEC's two scenarios for the state to achieve 20% renewable generation by 2010 both assume 4,060 MW of new wind generation would be installed in the Tehachapis, and would supply 40% of the renewable generation needed to meet the RPS goals.

[44] D.04-06-010, *mimeo*., p. 44 and Conclusion of Law 11.

[45] *Id.*, p. 16 - 17.

[46] *See* A. 04-12-007, "Scoping Memo And Ruling Of Assigned Commissioner" (June 7, 2005), at 5.

access to the Tehachapi region is needed based on whether or not it aids in meeting RPS goals. The remaining focus of the individual CPCN cases will be to assure that the specific proposed projects are the best projects among the alternatives and will continue to further RPS goals.

At this time, the TCSG believes that Phases 2 and 3 of the Tehachapi transmission plan also would benefit from an advance Commission finding that they are needed to achieve RPS goals. The TCSG has reached a consensus on the Phase 2 and 3 facilities that should be built to provide access to 3,300 MW of new wind generation in the region—an amount of transmission less than would be required by the Tehachapi wind generation projects already in the CAISO interconnection queue.

2. Substantial evidence of the need for Phases 2 and 3 exists now.

There are numerous indications that wind projects under development in the Tehachapi region will substantially fill the Phase 2 and 3 capacity:

- As of March 17, 2006, the CAISO's interconnection queue included 3,583 MW of wind projects in the Tehachapi region. These projects are listed on Figure 8.3. As shown on the Figure, these projects expect to be on-line by 2010. These queue positions exceed the combined carrying capacity of Phases 1, 2 and 3, estimated to be 3,300 MW. Developers who take queue positions must make significant financial commitments to interconnection studies, indicating that the projects in the queue are likely to be "real" projects.

- Developers have responded strongly and positively to the initial plans for transmission development. While Tehachapi developers have many potential projects in their portfolios, they generally do not make substantial financial commitments for a particular project until they are confident that the necessary transmission capacity will be built. The pent-up demand for Tehachapi transmission has recently been demonstrated by (a) the three additional wind projects totaling 860 MW that entered the queue at Substation 5 within 18 months of an interconnection request being filed by an initial 250 MW project at that location, and (b) the 10 Tehachapi wind projects totaling 2,882 MWs that entered the queue in the year since SCE filed its Phase 1 CPCN applications in December of 2004. This strong response shows that, as developers gain confidence that the necessary transmission capacity will be built, they will enter the interconnection queue. It is reasonable to expect that most if not all of these projects will show up sooner or later on IOUs' (or other retail sellers' or municipal utilities') short-lists and under signed contracts.

- In the initial 2003 and 2004 RPS solicitations, SCE and SDG&E have signed RPS contracts for 500 MW of Tehachapi wind generation. Additional Tehachapi wind projects are expected to be short-listed in the

> IOUs' 2005 RPS solicitations, the results of which will be known in the next several months. Thus, it is now clear that the 700 MW of capacity in Phase I will be fully utilized.

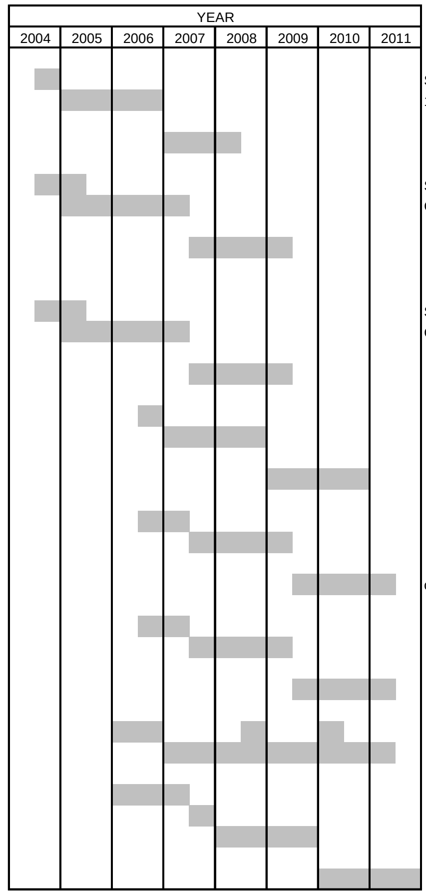
Today, it is apparent that the Phase 1 capacity will be fully utilized for RPS-eligible generation, and developers clearly are pursuing enough new wind generation in the Tehachapi region to more than fill the capacity of Phases 2 and 3. Accordingly, the Commission should find that these next phases are needed to achieve RPS goals. Such a finding would allow the CPCN proceedings for Phases 2 and 3 to focus on the environmental impacts and specific alternative routes for these projects.

The Commission should avoid reading the "necessary" language of Section 399.25(a) as requiring certainty. It is unreasonable for the Commission to expect projects to have executed power purchase contracts and signed interconnection agreements early in the transmission facility permitting stage. The Commission should be looking for an array of evidence which, taken as a whole, demonstrates that, without the transmission facility, achievement of the state's RPS goals would be unlikely to occur. The Commission must be prepared to make a judgment that there is reasonable assurance that the resource area will be developed if transmission capacity is provided, and that substantial progress toward that end has occurred and is continuing. Based on the evidence presented above, the TCSG believes that the Commission should reach the judgment that Phases 2 and 3 are needed for the state to reach its RPS goals.

FIG. 8.1 SCHEDULE TO 2011

CHART 8.1
TEHACHAPI CONCEPTUAL DEVELOPMENT SCHEDULE
ACCELERATED TO COMPLETE PLAN BY 2011

PROJECT PHASE	CUMULATIVE CAPACITY MW	PROJECT ELEMENT	TASK	NOTES
1	700	ANTELOPE-PARDEE	CPCN APPLICATION	SCE filed 12/04
		500kV LINE	CPCN APPROVAL	12/12/05 ACR says December 2006
		Segment 1	POST-CPUC PERMITTING	
			ROW ACQ & CONSTRUCT	
1		ANTELOPE-VINCENT &	CPCN APPLICATION	SCE filed 12/04; supplement 9/05
		ANTELOPE-TEHACHAPI	CPCN APPROVAL	CPUC currently aiming for 2007 Q2
		500KV LINES	POST-CPUC PERMITTING	
		Segments 2&3	ROW ACQ & CONSTRUCT	
1		TEHACHAPI SUBSTATIONS	CPCN APPLICATION	SCE filed 12/04; supplement 9/05
		& 230KV LINES	CPCN APPROVAL	CPUC currently aiming for 2007 Q2
		Segment 3	POST-CPUC PERMITTING	
			ROW ACQ & CONSTRUCT	
2A		ANTELOPE-SUBSTATION 5	CPCN APPLICATION	
			CPCN APPROVAL	
			POST-CPUC PERMITTING	
			ROW ACQ & CONSTRUCT	
2B	1600	UPGRADE ANTELOPE-	CPCN APPLICATION	
		MESA 230KV	CPCN APPROVAL	
			POST-CPUC PERMITTING	
			ROW ACQ & CONSTRUCT	can't start until Ph1/Segs 1&2 complete
3A	2350	TEHACHAPI-ANTELOPE	CPCN APPLICATION	
		500KV LINE	CPCN APPROVAL	
			POST-CPUC PERMITTING	
			ROW ACQ & CONSTRUCT	
3B	3300	INCREASE OPERATING	TRANSM PLANNING STUDIES	
		VOLTAGE TO 500KV	CONSTRUCT	
4	4500	ISO-APPROVED	TRANSM PLANNING STUDIES	
		ALTERNATIVE TBD	CPCN APPLICATION	
			CPCN APPROVAL	
			POST-CPUC PERMITTING	
			ROW ACQ & CONSTRUCT	

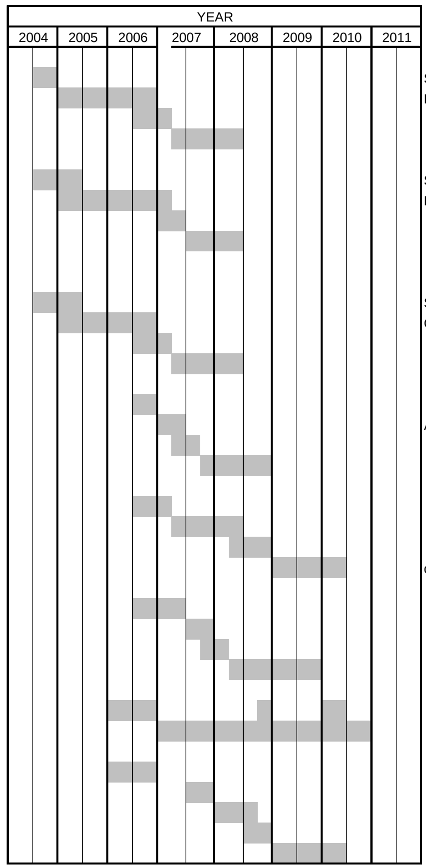


NOTE: TEHACHAPI AREA COLLECTOR LOOP WILL BE DEVELOPED AS REAL PROJECTS MATERIALIZE

FIG. 8.2 SCHEDULE TO 2010

CHART 8.2
TEHACHAPI CONCEPTUAL DEVELOPMENT SCHEDULE
ACCELERATED TO COMPLETE PLAN BY 2010

PROJECT PHASE	CUMULATIVE CAPACITY MW	PROJECT ELEMENT	TASK	NOTES
1	700	ANTELOPE-PARDEE	CPCN APPLICATION	SCE filed 12/04
		500kV LINE	CPCN APPROVAL	Possible approval by Oct 2006
		Segment 1	POST-CPUC PERMITTING	
			ROW ACQ & CONSTRUCT	
1		ANTELOPE-VINCENT &	CPCN APPLICATION	SCE filed 12/04; supplement 9/05
		ANTELOPE-TEHACHAPI	CPCN APPROVAL	By March 2007
		500KV LINES	POST-CPUC PERMITTING	
		Segments 2&3	ROW ACQ & CONSTRUCT	
1		TEHACHAPI SUBSTATIONS	CPCN APPLICATION	SCE filed 12/04; supplement 9/05
		& 230KV LINES	CPCN APPROVAL	CPUC currently aiming for 2007 Q2
		Segment 3	POST-CPUC PERMITTING	
			ROW ACQ & CONSTRUCT	
2A		ANTELOPE-SUBSTATION 5	CPCN APPLICATION	
			CPCN APPROVAL	Assumes exemption from CPCN
			POST-CPUC PERMITTING	
			ROW ACQ & CONSTRUCT	
2B	1600	UPGRADE ANTELOPE-	CPCN APPLICATION	
		MESA 230KV	CPCN APPROVAL	
			POST-CPUC PERMITTING	
			ROW ACQ & CONSTRUCT	can't start until Ph1/Segs 1&2 complete
3A	2350	TEHACHAPI-ANTELOPE	CPCN APPLICATION	
		500KV LINE	CPCN APPROVAL	
			POST-CPUC PERMITTING	
			ROW ACQ & CONSTRUCT	
3B	3300	INCREASE OPERATING	TRANSM PLANNING STUDIES	
		VOLTAGE TO 500KV	CONSTRUCT	
4	4500	ISO-APPROVED	TRANSM PLANNING STUDIES	
		ALTERNATIVE TBD	CPCN APPLICATION	
			CPCN APPROVAL	
			POST-CPUC PERMITTING	
			ROW ACQ & CONSTRUCT	



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

FIG. 8.3 CAISO Queue March 17, 2006

Chart 7.3. Tehachapi Region Active Wind Projects in the CAISO Generation Queue as of March 17, 2006

Request Status			Max MW	Location		Point of Interconnection	On-line Date	
Queue Position	Interconnection Request Receive Date	Queue Date	Summer	County	Utility	Station or Transmission Line	Proposed On-line Date	Current On-line Date
18	4/15/2003	4/15/2003	**200**	Los Angeles	SCE	Antelope	12/31/2005	12/12/2007
20	8/19/2003	9/4/2003	**300**	Kern	SCE	Antelope	12/31/2006	12/31/2008
31	4/12/2004	5/11/2004	**201**	Kern	SCE	Monolith Substation	12/31/2007	12/31/2009
34	7/19/2004	7/19/2004	**300**	Kern	SCE	Monolith Substation	7/1/2007	12/31/2009
73	6/6/2005	6/27/2005	**250**	Kern	SCE	Antelope	12/31/2007	12/31/2008
77	8/19/2005	8/22/2005	**300**	Kern	SCE/PGE	TBD Bakersfield	11/15/2007	11/15/2007
79	5/24/2005	9/7/2005	**51**	Kern	SCE	Proposed New Dutchwind Sub	6/1/2006	12/15/2009
84	11/22/2005	121/1/2005	**400**	Kern	SCE	Cottonwind Substation	12/31/2009	12/31/2009
85	12/28/2005	12/28/2005	**120**	Kern	SCE	Segment 3 230 Collector Loop Tehachapi	9/30/2007	9/30/2007
93	2/22/2006	2/22/2006	**51**	Kern	SCE	Segment 3 of Antelope Transmission Project	3/31/2010	3/31/2010
94	2/24/2006	2/24/2006	**220**	Kern	SCE	Tehachapi Conceptual Station 1	12/31/2008	12/31/2008
95	3/1/2006	3/1/2006	**180**	Kern	SCE	Tehachapi Conceptual Station 2	12/31/2008	12/31/2008
96	3/1/2006	3/1/2006	**550**	Kern	SCE	Tehachapi Conceptual Station 1	12/31/2009	12/31/2009
97	3/1/2006	3/1/2006	**600**	Kern	SCE	Tehachapi Conceptual Station 1	12/31/2009	12/31/2009
98	3/9/2006	3/9/2006	**160**	Kern	SCE	Tehachapi Conceptual Station 5	12/31/2009	12/31/2009
Total			**3,883**					