CALIFORNIA ENERGY COMMISSION

UPGRADING CALIFORNIA'S ELECTRIC TRANSMISSION SYSTEM: ISSUES AND ACTIONS

STAFF REPORT

Prepared in Support of the *Electricity and Natural Gas Report* under the Integrated Energy Policy Report Proceeding (02-IEP-01)

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EXECUTIVE SUMMARY

This report assesses the major issues facing the upgrading of California's electric transmission system, as required under Public Resources Code (PRC) section 25303(a)(3), which requires the California Energy Commission (Energy Commission), as part of the Integrated Energy Policy Report (IEPR), to assess the availability, reliability, and efficiency of the western regional and California transmission systems. The report supports the August 2003 Staff Draft ***Electricity and Natural Gas Assessment Report*** (Publication No. 100-03-014D).

California is crisscrossed by 31,720 miles of bulk transmission lines, along with their supporting towers and substations. The transmission system links power generation resources with customer loads in a complex electrical network that must balance supply and demand on a moment-by-moment basis. An efficient and robust transmission system not only helps deliver the lowest-cost generation to consumers, but also facilitates markets to stimulate competitive behavior, pools resources for ancillary services, and provides emergency support in the event of unit outages or natural disasters. California's transmission system must deliver these benefits in a manner that maximizes their value while minimizing negative environmental and other impacts, both now and in the future as the system is upgraded to respond to changes in generation (amount and location) as well as changes in load patterns.

Some of the existing problems facing the transmission system include congestion on major paths (which prevents optimal economic operation of the system) and constraints in major load centers such as San Francisco and San Diego which affect both the economic and reliable operation of the system. While transmission upgrades may provide a solution (alone or in combination with generation and demand-side management options), the transmission planning and permitting processes have not provided an effective mechanism for bringing forward needed projects (both from an economic and reliability standpoint) that are in the state's best interests and for getting them permitted and built. The initiation of the 2003 IEPR process and the joint Energy Commission/California Public Utilities Commission (CPUC)/California Power Authority Energy Action Plan process is intended to address these issues. The expansion of the transmission system must also take into account the state's aggressive approach to accelerating the development of renewable generation via its Renewable Portfolio Standard (RPS) program.

For this IEPR cycle, staff considered four projects for further analysis in the IEPR 2004 Update that are representative of the type, size, and function of the current and future transmission system: (1) a major interstate project proposed for economic reasons (Devers-Palo Verde 2); (2) a major intrastate, inter-utility project proposed to address local reliability needs (Valley-Rainbow); (3) an intra-utility project proposed to address local reliability needs (Jefferson-Martin); and (4) an intra-utility project proposed to address existing and likely future RPS needs (Tehachapi). These projects are of immediate concern to staff because they will (or do) require a Certificate of Public Convenience and Necessity (CPCN) from the CPUC, and they have either been denied a CPCN based on a CPUC assessment of costs and benefits, or their ability to obtain a CPCN is not yet certain. It is extremely important to the citizens of California that the state has the most accurate and comprehensive assessments available to underpin decisions to permit or deny construction of planned transmission projects. Staff believes that one or more of these projects will benefit from a comprehensive analysis during the 2004 IEPR Update process. Staff also believes that there is a critical need for innovation in the analytical methodologies that are used for evaluating the costs and benefits of transmission projects. Current analytical methodologies used in project permitting typically employ short-term analytical horizons, economic valuation methodologies that do not recognize strategic benefits, present worth valuations that discount long-term project benefits, and utilization of average conditions.

Staff recommends that the collaborative transmission work identified in the Energy Action Plan to determine the statewide need for bulk transmission projects be held during the 2004 and future IEPR updates for the purpose of assessing and comparing costs and benefits, and assessing alternatives and timing issues for projects subject to CPCN approval. As identified in the Energy Action Plan (EAP), the proceedings are intended to build on the California Independent System Operator (CA ISO) annual transmission plan and evaluate transmission, generation and demand-side alternatives to help reinvigorate the state's transmission permitting process and assure expansion of the grid is made on a timely basis and state objectives are evaluated in determining transmission investments that best meet the needs of California.

Results from these proceedings would be carried forward into the IEPR Update report to the Governor and Legislature, and for use in the CPUC and other transmission permitting processes. With respect to the overall structure and content of this collaborative effort, staff recommends that the process be on the order of six to ten months in duration, depending on the complexity of issues addressed, and should represent a melding of the administrative processes used for past Electricity Reports and generation siting cases. Staff proposes that all IEPR Update transmission proceedings be handled by a Commission oversight committee and that a multi-disciplinary team of Energy Commission technical staff function as an arm of the Committee in collaboration with the CA ISO and CPUC staff.

This approach brings together the best expertise available in state service and industry to address the issues related to the need for transmission projects. The utilities will be an essential source of information and analyses on the individual projects and their costs and benefits, as well as alternatives considered in the planning process. The collection of expertise from state service will cover the areas of demand and price forecasting, transmission system assessment, supply options, project alternatives, financial impacts, and environmental benefits and costs, thereby providing an extremely broad scope of independent review.

This transmission work during the IEPR Update will be integrated with other IEPR electricity analyses and policy work, use appropriate IEPR assumptions for demand and price forecasting and supply options, and consider broader strategic benefits than the current process.

Some of the factors that should be considered in these proceedings include:

- Incorporating a low-probability, high-impact event in the analysis;
- Incorporating strategic value of transmission such as:
  - Expanded access to regional markets;
  - Enhancement of grid reliability;
  - Insurance against major contingencies;
  - Regional fuel diversity with bi-directional access;
  - Use of longer term (more than five to ten years) planning horizon;
- Alternative economic approaches to evaluation of project costs and benefits; and
- Better understanding of the costs and benefits of generation and demand-side management (DSM) as alternatives to transmission.

The state has the opportunity within the IEPR process to provide a thorough approach coordinated with other electricity policy work in analyzing the benefits of transmission projects. Collaboration among the Energy Commission, CPUC, CA ISO, and utilities will be vital to successfully implement this process.

Staff also recommends that the Energy Commission hold a workshop toward the end of the 2003 IEPR process to identify transmission projects parties believe should be evaluated in the 2004 Update, and address information and data needs for those transmission projects.

Furthermore, staff recommends the following action as a result of the Joint Energy Commission and League of Women Voters efforts. This action would be pursued during the 2004 IEPR Update. Staff would identify the most effective and efficient methods to implement public participation in the context of the IEPR process and the EAP and ensure community impacts associated with transmission expansion are appropriately considered in the IEPR process and the CA ISO transmission planning process.

CHAPTER 1: INTRODUCTION

PURPOSE

This comprehensive look at issues facing California's electric transmission system was prepared in response to two directives. The first is Senate Bill 1389 (SB 1389) (Chap. 568, Stat. of 2002), which amends PRC section 25300 *et seq.* to require the California Energy Commission to prepare an integrated energy policy report (IEPR) on or before November 1, 2003, and every two years thereafter. PRC section 25302(a) specifically directs the preparation of three subsidiary volumes to the IEPR, including one on electricity and natural gas markets. To that end, this report supports the August 2003 Staff Draft ***Electricity and Natural Gas Assessment Report*** (Publication No. 100-03-014D), by responding to PRC section 25303(a)(3), which states the following:

> The commission shall conduct electricity and natural gas forecasting and assessment activities to meet the requirements of paragraph (1) of subdivision (a) of Section 25302, including, but not limited to, all of the following:
>
> > (3) … Assessment of the availability, reliability, and efficiency of the electricity and natural gas infrastructure and systems including, but not limited to, …western regional and California electricity and transmission system capacity and use.

This report draws upon the transmission-related material in several other staff reports, including the following:

- ***Preliminary Electricity and Natural Gas Infrastructure Assumptions***, February 2003, Publication No. 100-03-004SD.
- ***Electricity Infrastructure Assessment***, May 2003, Publication No. 100-03-007F.
- ***2003 Environmental Performance Report***, August 2003, Publication No. 100-03-010.

All four of the staff reports mentioned above can be found on the Energy Commission website at the following address:

http://www.energy.ca.gov/energypolicy/documents/index.html

The second directive is included in the EAP adopted by the California Consumer Power and Conservation Financing Authority (California Power Authority), Energy Commission, and CPUC on April 18, April 30, and May 8, 2003, respectively. Section IV of the EAP states the following:

> Reliable and reasonably priced electricity and natural gas, as well as increasing electricity from renewable resources, are dependent on a well-maintained and sufficient transmission and distribution system. The state will reinvigorate its

planning, permitting, and funding processes to assure that necessary improvements and expansions to the distribution system and the bulk electricity grid are made on a timely basis.

Specifically, the plan includes the following action:

1. The agencies will collaborate, in partnership with other state, local, and non-governmental agencies with energy responsibilities, in the California Energy Commission's integrated energy planning process to determine the statewide need for particular bulk transmission projects. This collaboration will build upon the California Independent System Operator's annual transmission plan and evaluate transmission, generation, and demand side alternatives. It is intended to ensure that state objectives are evaluated and balanced in determining transmission investments that best meet the needs of California electricity users.

REPORT OVERVIEW

This report begins by describing California's electric transmission system from a physical perspective, as well as from the standpoint of its governance and operation. It then describes the major issues affecting the efficient and appropriate use and expansion of the existing system. It describes the results of staff's analysis on four proposed transmission projects that could provide benefits to California. The report also covers the status of other major projects in various stages of permitting and construction, as well as a perspective on how the transmission system of the future may develop in response to accelerated development of renewable generation resources; transmission research and development plans; and regional activities. It concludes by describing actions that have been, or are being, taken to address planning and permitting issues, followed by staff's recommendations.

CHAPTER 2: GENERAL DESCRIPTION OF CALIFORNIA'S TRANSMISSION SYSTEM (PHYSICAL, OPERATIONS, AND SECURITY)

PHYSICAL SYSTEM

Owners and Miles of Lines

California has a total of 31,721 miles of transmission lines. This includes all lines with voltages of 69 kilovolts (kV) and above that have a bulk transmission function (i.e., they carry electrical energy from where it is generated to the distribution system, other load centers, or a neighboring control area). **Table 2-1** shows the number of circuit miles of transmission owned by each of the three California investor-owned utilities (IOUs): Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E). It also shows the total owned by California's municipal utilities[1] as well as by the federal Western Area Power Administration (Western). (The Los Angeles Department of Water and Power (LADWP) owns a total of 3,519 miles of the municipal total of 5,224 miles.)

Table 2-1
California Transmission Line Ownership
(Source: California Energy Commission)

Transmission Line Ownership in California	Circuit Miles	% of state total
PG&E	18,491	58.3
SCE	5,129	16.2
SDG&E	1,906	6.0
Municipal utilities	5,224	16.4
Federal (Western)	971	3.1
Total In-state Line Mileage	31,721	100

Environmental Characteristics of Transmission Lines

Impacts

A detailed description of the environmental impacts from electric transmission lines is contained in the Energy Commission staff ***2003 Environmental Performance Report*** (Publication No.100-03-010). This report describes the biological and land use compatibility impacts from transmission lines in detail. A brief summary is presented below.

In terms of biological impacts, California's 31,721 miles of electric transmission lines and right-of-ways (ROW) can contribute to habitat loss, fragmentation, and degradation. Based on a ROW width of 200 feet, this results in 758,100 acres of land affected by transmission lines (about 0.8 percent of California's total acreage). Transmission lines can also cause bird mortality from bird strikes and electrocution. They can also cause wildfires: between 1996 and 2002, the number of wildfires from lines ranged from 181 per year to 284 per year. The biological impacts from new transmission to improve system reliability and link new generation resources to the grid may need to be mitigated to reduce the risks of increasing impacts to wildlife and habitats.

The ***2003 Environmental Performance Report*** states the following regarding transmission projects over which the Energy Commission has jurisdiction[2]: "New transmission line, natural gas pipeline, or water supply pipeline right-of-ways for new power plants under Commission jurisdiction should, where possible, avoid federal or state wildlife refuges or preserves, public or private habitat mitigation banks, or other similar protected areas (unless they are within an approved utility corridor) because that perpetuates impacts to species which need protection from further habitat loss." (p. 77)

With respect to land use compatibility, local and regional land use and development planning efforts seldom designate sites or corridors for energy facilities such as power plants and transmission lines, and energy facility proponents are seldom involved in these long-range efforts.

Possible Strategic Environmental Benefits

One of the interests to public policy makers is the environmental performance of the electricity industry and systems in California. As California's demand for electricity grows, competition for air offsets and water resources becomes more problematic. Under some circumstances, expansion of the high-voltage transmission system can help reduce overall electricity system impacts by allowing certain benefits which could include the following:

- Avoidance of local air emissions otherwise caused by local generation;
- Local air offsets needed for generation become available for other new industries with higher economic value to the local area; and

- Avoidance of impacts to the local water and natural gas supplies otherwise required for local generation.

Major Transmission Paths and Their Purposes

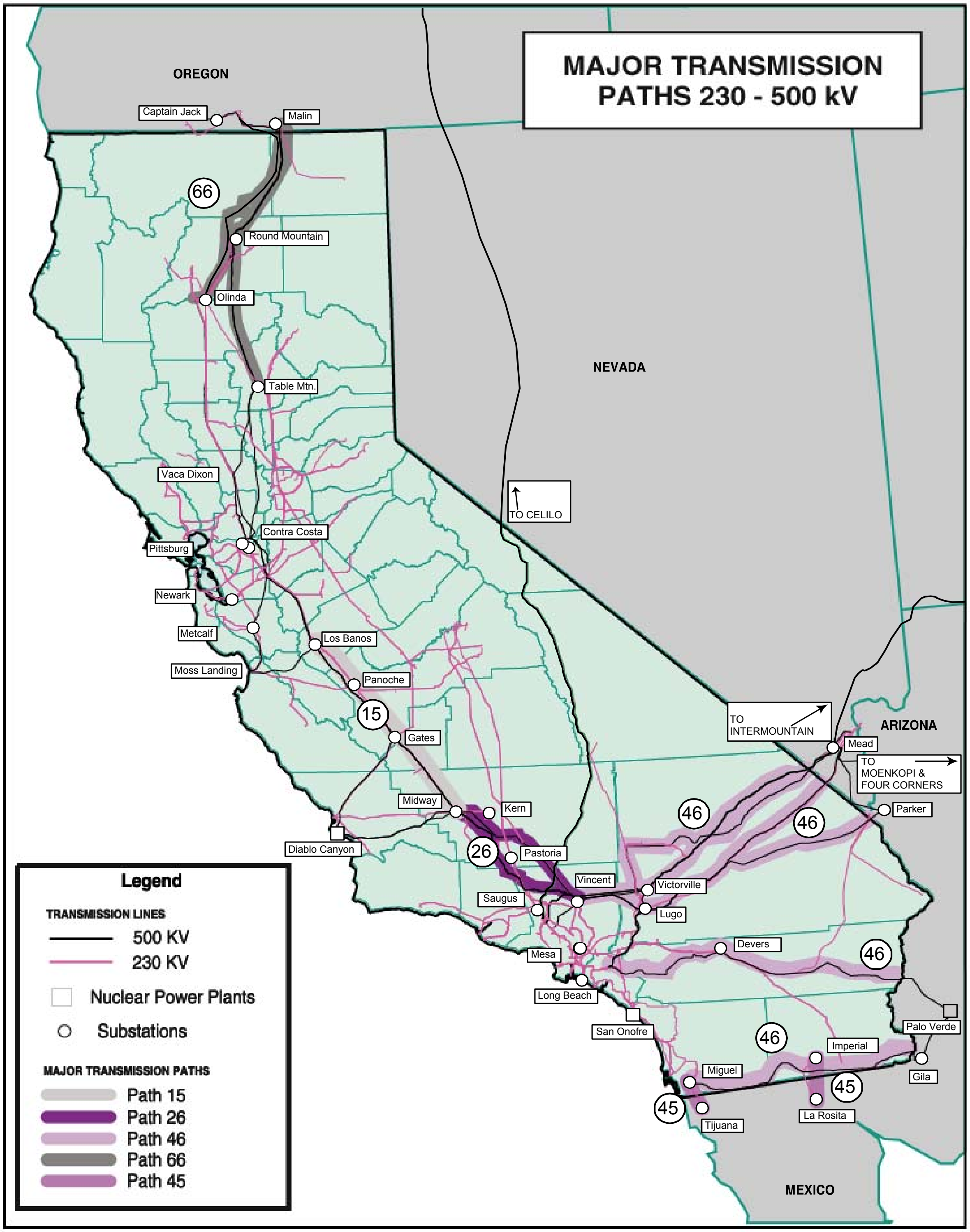
Most of California's electric transmission system was originally built to connect generating facilities to major load centers in the Los Angeles, San Francisco, and Sacramento areas. Thermal generating facilities, such as large gas-fired and nuclear plants, have been built near the coast or in nearby valleys generally close to the load centers, thereby requiring relatively short transmission lines. Hydroelectric facilities in the Sierra Nevada have typically been some of the most remote sources of generation in the state. Each of the state's investor-owned utilities (PG&E, SCE, and SDG&E) designed, built, and operated its own system to meet the needs of its customers.

Until the mid-1960s, the three IOUs operated their transmission systems as islands, with only a few small ties between utilities. As California's dependence on oil and gas generation increased, and licensing of large generating stations was increasingly difficult, the IOUs began planning and building higher-voltage, long lines to neighboring states. The 500 kV transmission lines were built primarily for importing hydroelectric power from the Pacific Northwest and thermal generation from the Southwest. While these transmission lines provided access to less costly out-of-state power, they also provided the additional benefit of emergency interconnection support among the state's utilities to avoid potential wide-scale power disruptions. The 1965 East Coast blackout that affected almost 30 million people and prompted the creation of the North American Electric Reliability Council (NERC) highlighted the need to strengthen ties between utilities as a means of promoting a more reliable interconnected system. Between 1968 and 1974, California utilities built or participated in the construction of about 3,700 miles of 500 kV lines to access remote generation. Since the 1980s only two additional 500 kV projects have been built to access out-of-state resources, and both of these projects were initiated by California municipal utilities.

While interstate connections have not been built, intrastate transmission upgrades have been made to serve new load, reduce local congestion pockets and improve overall efficiency.

California's current bulk intrastate and interstate transmission system is shown in **Figure 2-1**. The map highlights the paths that are most heavily utilized and whose expansion may thus provide significant benefits. The map also shows major substations and the three operating nuclear power plants owned (in whole or in part) by California's IOUs (two in-state and one out-of-state.)

Figure 2-1
California's Major 230 kV and 500 kV Transmission Paths



Source: California Energy Commission

Major Intrastate Connections

The two major intrastate transmission paths are Path 15 and Path 26. Path 15 is a major part of the Pacific AC Intertie (PACI) between the PG&E Los Banos and Midway substations, consisting of 230 and 500 kV lines. It was built to facilitate seasonal exchanges between California and the Pacific Northwest, as well as to reinforce the ability to transmit power between Northern and Southern California. Path 26 is part of a group of 500 kV lines located immediately south of Path 15 which connects the PG&E Midway substation with the SCE Vincent substation near Palmdale, north of the Los Angeles Basin.

Major Interstate Connections

Mexico. Path 45 connects the Comisión Federal de Electricidad's (CFE's) 230 kV lines in northern Mexico with San Diego and the Imperial Valley.

Southwest. Path 46, often referred to as "West of the Colorado River" (WOR), is part of a group of 230 and 500 kV lines that interconnect Southern Nevada and Arizona to Southern California. It imports power to the San Diego and Los Angeles areas from large out-of-state coal and nuclear plants that are either owned or co-owned by California utilities.

Northwest. Path 66, also known as the California-Oregon Interface (COI), consists of two 500 kV lines between the Malin substation in Oregon and the Round Mountain substation in California (the PACI), and a 500 kV line between the Captain Jack substation in Oregon and the Olinda substation in California (known as the California Oregon Transmission Project, COTP).

Paths 15, 26, 45, and 46 are discussed in more detail in Chapter 4.

Local Reliability Areas

The CA ISO has generally defined a local reliability area (LRA) as an electrically defined area characterized by both insufficient generation to support effective competitive electricity markets within the area and by limited transmission capacity to import electricity from outside the area. The effect of this combination of conditions is to increase the susceptibility of the local area to reliability problems and to the exercise of market power by certain local generators. To alleviate these problems, the CA ISO has required certain generators within LRAs to sign reliability must-run (RMR) contracts that require them to operate their facilities during periods designated by the CA ISO at specific contracted prices. Frequently these RMR generators are older facilities with higher air pollutant emission rates.

The two largest LRAs in California are the San Francisco Peninsula and the San Diego area. For more information on these two areas, see the Chapter 3 section entitled "Reliability Problem Areas." In addition, the August 2003 staff report entitled ***Public Interest Energy***

Strategies Report (Publication No. 100-03-012D) provides a more detailed look at the efforts undertaken by various local groups in San Francisco and San Diego to work toward solving their regions' problems.

System Changes Likely to Occur in the Next 10 Years

Appendix B of the February 11, 2003 Staff Draft Report entitled ***Preliminary Electricity and Natural Gas Infrastructure Assumptions*** includes a comprehensive description of each of PG&E's, SDG&E's, and SCE's planned transmission projects for the next several years. The information presented was based on each utility's 2002 transmission expansion plan submitted to the CA ISO, as well as each utility's latest (as of February 3, 2003) monthly status report submitted to the CPUC in response to AB 970 requirements.

The majority of the more than 100 planned projects are relatively small in nature, designed to improve local reliability within each utility's service area rather than improve the efficiency and/or reliability of the bulk transmission system. Staff focused its analysis of the infrastructure assumptions on the major projects which will affect bulk power exchanges, and/or that require a CPCN from the CPUC. Staff identified seven projects which are expected in the next ten years and used these project assumptions (projected on-line date and magnitude of capacity increase) in its market simulation runs. The current status of four of these projects (Path 15 upgrade, Path 26 upgrade, Path 45 upgrade, and Miguel-Mission and Imperial Valley substation upgrades) is discussed more fully in Chapter 3. The other three (Path 46 upgrade from Palo Verde to Devers, a new Jefferson-Martin line, and a new Valley-Rainbow line) were considered by staff for further analysis in the IEPR 2004 Update. See Chapter 4 for more information on these three projects.

For an update on the status of all 100-plus projects, see Appendix C of the August 2003 Staff Draft ***Electricity and Natural Gas Assessment Report***.

Since staff's initial infrastructure analysis in February 2003, it has learned of an additional project being put forth by SDG&E in its Long-Term Resource Plan filed within the CPUC's Resource Procurement Proceeding on April 15, 2003 (R.01-10-024). SDG&E proposes a two-phase transmission expansion plan that would strengthen the 500 kV "backbone" system, allowing additional imports into the Southern California grid from Arizona, Mexico, and Southern Nevada. For this expansion to provide local reliability benefits in addition to anticipated statewide reliability and economic benefits, it needs to tie into SDG&E's service area. The proposed expansion includes the Valley-Rainbow upgrade (renamed the Near-Term Interconnection Project) assumed for 2008 and an additional Long-Term Interconnection Project consisting of a 160-mile, 500 kV line from the (new) Rainbow substation to the existing Imperial Valley substation assumed for 2012. However, given the uncertainty of the Valley-Rainbow project going forward (discussed further in Chapter 4), and the dependence of the Long-Term Project on the Short-Term Project, staff does not believe that the Long-Term Project should be considered likely at this time.

Staff is not aware of any other bulk transmission projects beyond a ten-year timeframe. However, the Energy Commission staff recognizes that longer-term strategic planning may provide risk avoidance of unforeseen extreme events, as well as access to developing markets through the most cost-effective transmission expansion projects. Staff has initiated a joint effort with the CA ISO that is intended to ensure that long-term planning and strategic benefits are included in the CA ISO transmission planning process and IEPR process (see Chapter 6 for more detail.)

SYSTEM OPERATIONS

As described in the CA ISO's ***2003 California ISO Controlled Grid Study – Final Study Plan Version 2.2***, the CA ISO is charged with maintaining the reliability of the CA ISO-controlled grid. The CA ISO-controlled grid consists of the transmission facilities and rights turned over to the CA ISO by PG&E, SCE, SDG&E, the City of Vernon, the City of Anaheim, the City of Azusa, the City of Banning, and the City of Riverside. The CA ISO controls all of the transmission lines owned by PG&E, SCE, and SDG&E (a total of 25,526 miles; see **Table 2-1**). The five cities have entitlements to parts of the Pacific DC Intertie (PDCI), the Intermountain Power Project DC Line, and the WOR system.

The state has three other control areas which provide similar functions. LADWP, the Sacramento Municipal Utility District (SMUD), and the Imperial Irrigation District (IID) have chosen to serve their own customers, but they must coordinate with the CA ISO and other western control areas.

SYSTEM SECURITY

The CA ISO controlled grid is designed to meet the NERC/Western Electric Coordinating Council (WECC) Planning Standards. While controlled loss of generation, load or system separation is permitted in extreme circumstances, their uncontrolled loss is not permitted. An analysis of extreme events such as the loss of an entire substation or power plant is also performed to assess their risks and consequences. A consequence of cascading outages throughout the WECC as occurred during the two western system power outages of July and August 1996 is no longer acceptable. Given the risk of terrorism, the possibility of an extreme contingency is likely to be higher so the need for preparedness plans may be more justifiable. The CA ISO selects about five to ten extreme contingencies to evaluate every year as part of their Controlled Grid Study. This study focuses on where and when the system is most vulnerable. With the heightened risk of terrorism, the CA ISO is considering giving this part of the performance criteria more attention.

It is likely that under most conditions a coordinated terrorist attack on multiple targets, either simultaneously or in rapid succession, would be necessary to cause a significant disruption to California's electricity grid. This is due to the fact that there is considerable redundancy in

California's electricity system as it is designed to accommodate at least two failures of vulnerable components at the same time. A recent example of California's electricity system resilience was demonstrated on the evening of March 21, 2003. On that day, a 500/230 kV transformer at SCE's Vincent substation exploded due to mechanical failure. Ultimately, due to the ensuing fire and protective relaying, the three 500 kV lines that connect Vincent to Midway were taken out of service, severing the critical Path 26 tie which links Northern and Southern California. Two 500 kV lines from Vincent to Lugo and eight 230 kV lines out of Vincent were also taken out of service. While the events of March 21 presented a real world contingency event far more severe than what is traditionally planned for, the only load that had to be curtailed by operators as a result of the disturbance was 300 MW of Department of Water Resources pumping load. However, the impact of the event would likely have been much larger and more widespread had it occurred during a peak demand period. Timing is a critical factor relative to the extent of potential impact from such an extreme event.

Utility preparedness in light of an extreme event is directly related to years of experience responding to power outages caused by bad weather, earthquakes or accidental incidents. The utilities typically have an inventory of spare equipment, access to spare equipment databases from which to acquire additional hardware and mutual assistance agreement with neighboring utilities. This type of preparedness and cooperation can serve to effectively mitigate an extreme event.

CHAPTER 3: IN-STATE PHYSICAL AND OPERATIONAL TRANSMISSION SYSTEM PROBLEMS AND PLANNED SOLUTIONS

TRANSMISSION CONGESTION

Description

Transmission congestion occurs when the amount of power that can be transferred over a line or path is limited by the operating limit of the line or path. For example, congestion limits the amount of relatively low-cost electricity that can be imported into California, or between major load centers in California. As a result, more expensive in-state or local generation sources are required to operate to meet load. There are four major paths that have experienced varying degrees of congestion, as described below.

Path 15 (Los Banos to Gates)

Background and Project Description

Path 15 is a major part of the PACI between the Los Banos and Midway substations which was built to facilitate seasonal exchanges between California and the Pacific Northwest as well as to reinforce the ability to transmit power between Northern and Southern California. Path 15 is a constrained path between the Los Banos and Gates substations because it contains only two 500 kV transmission lines and several lower voltage lines. However, north of Los Banos and south of Gates, the PACI consists of three 500 kV transmission lines.

Historically, Path 15 has played a major role in the seasonal exchanges that take place between Northern and Southern California, and California and the Pacific Northwest. The majority of thermal generation in California is located in Southern California, with additional thermal generation also located in the desert Southwest. The majority of the hydroelectric facilities meanwhile are located in Northern California and the Pacific Northwest. Historical seasonal exchanges and resultant power flows over Path 15, however, have often been limited by the operating capacity of Path 15. While there have been occasions when the path has been constrained in a north-to-south direction, it is the south-to-north transfers that have resulted in the majority of the constraints. This is because the majority of the generation capacity is south of Path 15. Path 15 is constrained to a lower transfer limit than the rest of the PACI in Northern California because there are just two 500 kV transmission lines in this area. The addition of a third 500 kV transmission line between Los Banos and Gates would help to alleviate this constraint on power flows.

This Path 15 upgrade can also be viewed as the cornerstone of a broader vision for a robust transmission system in California. The CA ISO has begun to develop a vision of an improved 500 kV backbone transmission system for the state. The Path 15 bottleneck has been identified as one of the highest priority projects of this backbone system. The benefits of a robust transmission system are increased competition among suppliers and, presumably, lower prices for critical services. An improved backbone transmission system without bottlenecks will also help to ensure that the potential for suppliers to exercise market power is lessened.

Utility engineers have noted that Path 15 overloads have occurred more often over the past few years and have resulted in significant operational issues with regard to the operation of the CA ISO system. The CA ISO reported 227 instances of Path 15 overloads in the south-to-north direction between January 1998 and January 2001. Of these, 51 overloads exceeded 10 minutes in duration resulting in the CA ISO paying a sanction for violating Western Systems Coordinating Council operating criteria. On January 17 and 18, 2001, the CA ISO was forced to invoke 500 MW and 1000 MW, respectively, of rotating blackouts in Northern California to relieve overloading on Path 15. In addition, during the same timeframe, the CA ISO had to issue a number of Stage 2 emergencies during which non-firm load was interrupted in Northern California as a result of the need to reduce the loading on Path 15. The CA ISO believes that a Path 15 expansion, if in place at the time, would have helped to alleviate these constraints on the system, allowing greater transfer of power south-to-north to meet critical needs.

The Path 15 upgrade is an important solution to a backbone system bottleneck, which will have benefits to nearly everyone affected by California's electricity market. From a qualitative perspective, one would expect the expansion to provide increased competition, reduced price variation, north-to-south, and reduced opportunities for the exercise of market power and resulting price spikes.

Studies conducted by the CA ISO during the past two years clearly show that Path 15 constraints impede competitive market function and impose additional costs to loads in Northern California. There are two major problems, one is congestion cost, south-to-north, and the second is market power.

Congestion on Path 15, most common in summer months, but also an issue at other times of the year, limits the amount of relatively low cost electricity exports from Southern California to Northern California and requires more expensive generation resources to operate in Northern California to meet load. The magnitude of these costs is strongly associated with seasonal factors, e.g., summer peak loads, the number of hours Path 15 is constrained, the availability of hydroelectric power to Northern California and other factors. As an example, under drought conditions in Northern California the "congestion costs" associated with limited Path 15 transfers are higher because system operators must run more expensive gas-fired generation in Northern California to meet load. The price differentials between Northern California, north of Path 15 (NP15) and Southern California, south of Path 15 (SP15) shown in the table below, 1998-2000, include both congestion costs and costs associated with the exercise of market power. Congestion costs alone, due to the need to operate less efficient generation NP15, do not add significantly to the price differentials between the two zones, amounting to less than a 10 percent difference, even under conditions of low hydroelectric power availability. The rest of the differential is attributable to market power.

The congestion on Path 15 increased over the period from 1998 to 2000 as loads increased (see **Table 3-1**). In 1998, Path 15 was sufficiently congested to split the California market into separate pricing zones (i.e., NP15 and SP15) for 150 hours when loads were above average annual levels.[3] This congestion rose to 333 hours in 1999, and then more than doubled again to 868 hours in 2000. This congestion led to substantially higher prices on average in the NP15 market. In 1998, NP15 prices were 52 percent higher during these hours than SP15 prices. In other words, the NP15 price might have fallen as much as 52 percent if power could have been imported over Path 15. In 1999, this difference rose to 203 percent. The difference shrunk in 2000 to 34 percent, but only because the average NP15 price was so close to the price cap of $250 per megawatt-hour (MWh) set in August 2000. This cap constrained NP15 prices from rising even higher relative to SP15 prices. The cap also limited the number of hours for which the prices could diverge, so that 868 hours actually underestimates the number of hours when Path 15 was congested in 2000.

Table 3-1
California Market Price Divergence, 1998 to 2000

		Average $/MWh When Split		
	No. of Hrs Split*	NP15	SP15	Percent Difference
1998	150	54.86	36.18	52 percent
1999	333	116.64	38.56	203 percent
2000	868	235.69	175.78	34 percent
* Number of hours that NP15 and SP15 real time market prices diverged when loads were greater than the annual average.				

Source: California Energy Commission

The second related and significant problem is that by limiting south-to-north transfers, Path 15 constraints enhance the ability of suppliers north of Path 15 to exercise market power in a way that increases costs to end users in the north. This occurs because pivotal suppliers are able to set prices above their marginal costs because of resource limitations to competition in NP15 areas. In both cases removal of Path 15 constraints would reduce these conditions and costs to Northern California end users.

In the CA ISO market power study several variables were considered. The most critical variables affecting market power costs were availability of hydroelectric power and the addition of new generation projects. Assuming a middle range estimate of new generation additions, the market power mitigation benefits from a Path 15 expansion ranged from $305 million/year under drought hydroelectric conditions to $104 million/year under average hydroelectric conditions. The CA ISO applied a plus and minus 25 percent adjustment factor to those estimates to broaden the range and account for errors. Based on these estimates the CA ISO believes the proposed Path 15 upgrade would easily pay for itself in one drought year and three normal rainfall years and would, in fact, pay for itself in four normal rainfall years, even under the most pessimistic scenario.

The Path 15 upgrade also provides an important insurance policy against expensive supply shortages (blackouts) in Northern California. The cost of blackouts is generally accepted to be in the range of $10,000 to $25,000 per MWh.[4] Thus, the 500 megawatts (MW) and 1,000 MW rotating blackouts in January of 2001 were costing California $5 to $12.5 million and $10-$25 million dollars, respectively, per hour. Based on these costs, the Path 15 expansion does not need to prevent many blackout hours before justifying its $300 million price tag. Increasing the electricity available to Northern California over Path 15 by 1,500 MW provides cost effective insurance against blackouts.

The Path 15 upgrade also provides insurance against both natural gas shortages and the vagaries of the natural gas market. The blackouts in January of 2001 showed the importance and impact of natural gas markets and supplies on electricity availability in Northern California. Due to supply shortages, natural gas prices had spiked to more than 20 times their normal levels, increasing the cost of producing electricity and making it profitable for some electricity generators to stop producing electricity and instead sell their natural gas. The vulnerability of the electricity supply system to the natural gas market was at least partially responsible for the rolling blackouts. Increasing the import capability of Path 15 will increase Northern California's supply flexibility and access to power generated in the Southwest and the coal-fueled power plants in that region.

Current Status

Formal CPUC proceedings on Path 15 closed in the fall of 2002. In March 2003, the presiding Administrative Law Judge (ALJ) for the Path 15 case submitted a proposed decision recommending that the Commission reject PG&E's request for a CPCN. The draft decision argued that, among other things, the proposed Path 15 expansion would not provide sufficient congestion benefits, market power mitigation or reliability benefits to justify the upgrade based on its anticipated $300 million cost. The presiding CPUC Commissioner on the case, Commissioner Lynch, also submitted a proposed decision recommending that the CPUC grant a CPCN for the upgrade. President Peevey, the new CPUC President, proposed yet a third decision for the CPUC to consider. President Peevey proposed that the CPUC honor PG&E's request to withdraw its application for a CPCN, a request PG&E had made earlier, but which had been rejected. He also recommended that the CPUC find that PG&E could perform the expansion upgrades it proposed as part of the joint PG&E, Western, Trans-Elect agreement, without a CPCN. Finally, President Peevey's proposed decision recommended that environmental assessments for Path 15 previously performed by Western should be accepted by the CPUC.

On May 22, 2003 the CPUC found that the Path 15 upgrade should go forward based on the recommendations contained in President Peevey's proposed decision. The decision limited further involvement by the CPUC in the Path 15 expansion case, except in the event that PG&E increases the costs of its upgrade obligations.

Staff learned from Western at the June 10, 2003 IEPR Electricity Infrastructure Assessment Workshop that approximately two-thirds of the ROW has been acquired. A contractor has been selected to construct the upgrade. Construction will begin when all of the ROW has been acquired, which is expected by the end of summer 2003. The project is expected to be on line on or before December 2004.

Path 26 (Midway to Vincent)

Background and Project Description

Path 26 is part of a group of high-voltage power lines located immediately south of Path 15, which transfer electricity between Northern and Southern California. Path 26 consists of three 500 kV lines that run south from the PG&E Midway substation in Kern County, to the SCE Vincent substation near Palmdale north of the Los Angeles Basin.

Until recently, Path 26 had a bi-directional rating of 3,000 MW. Over the past few years, the path has experienced substantial congestion in the north-to-south direction. This is primarily due to the generation additions in the southern San Joaquin Valley, which connect to the Midway substation at the north end of Path 26. This congestion is expected to increase if a significant amount of new generation development occurs north of Path 26.

Path 26 and Path 15 limit the transfer of electricity between Northern and Southern California. While the Path 26 3,000 MW rating was lower than the Path 15 rating of 3,900 MW, Path 15 actually creates the more significant constraint. This is because of the amount of generation located north and south of both paths and the generation projects that connect to the Midway substation at the north end of Path 26. For example, in a south-to-north direction, 3,000 MW of power coming from the south over Path 26 combined with 1,000 MW of power from the southern San Joaquin Valley or Diablo Canyon entering at Midway or Gates will overload Path 15. This has been a fairly common occurrence limiting economic opportunities north of Path 15. With power flowing in a north-to-south direction, it has been less common to have enough power coming from the north and combining with power entering at Midway or Gates to exceed the 3,000 MW limit of Path 26. However, this is becoming a more common occurrence and is beginning to have economic implications similar to the Path 15 congestion.

Not only is Path 15 congestion more common, but the congestion on Path 15 has different implications from that of Path 26. The limit on Path 15 can lead to supply adequacy problems in Northern California in addition to a lost economic benefit of lower electricity prices. The limit on Path 26 primarily limits Southern California's access to relatively inexpensive hydroelectric resources in the north.

Path 26 limits the north-to-south imports that are typically economic transactions occurring when there has been average or above average rainfall and hydroelectric power is readily available. However, since supply adequacy is not an issue in Southern California (with the exception of the San Diego area) the Path 26 expansion is not needed for supply adequacy and is less critical than the Path 15 expansion.

In response to the need for increased north-to-south transfer capability on Path 26, the CA ISO has requested that the WECC increase the north-to-south rating on Path 26 from 3,000 MW to 3,400 MW. This would be in the north-to-south direction through the use of a Special Protection System (SPS), also referred to as a Remedial Action Scheme (RAS). The 3,400 MW level was determined through short-term planning studies that were completed by the CA ISO as part of a stakeholder process in 2001. The CA ISO has also identified a potential long-term project, which would include replacing equipment and possibly require some reconductoring, increasing the bi-directional north-to-south transfer capability of Path 26 to 4,000 MW. Overall project costs for the short-term and long-term upgrades are shown in **Table 3-2**.

Table 3-2
Path 26 Project Costs

	3,400 MW Case (Short-Term)	**4,000 MW Case (Long-Term)**
PG&E (includes reconductoring in 4000 MW case)	$100,000	$108.5 million
SCE	$2 million	$34 million
Total	$2.1 million	$142.5 million

Current Status

As part of the coordinated transmission planning process, the CA ISO has to satisfy WECC study requirements in order to receive a rating increase for Path 26. This requirement is the western systems coordination portion of the CA ISO coordinated transmission planning process.

The WECC Project Rating Review (PRR) process has three phases that are intended to address planned new facilities. These apply to new additions and upgrades or re-rates of existing facilities that are of regional significance and that require coordination.

Phase 1 is notification to WECC of a project and is initiated by the project participants when the project is reported in the WECC Significant Additions Report or when a formal letter of notification is provided to the Planning Coordination Committee and its Technical Studies Subcommittee .

Phase 2 encompasses an open forum review of the project's plan of service with interested non-project participants, called a Project Review Group. During this phase, the simultaneous transfer capability effects and the impacts of the project on neighboring transmission systems are assessed. Phase 2 is completed when the Review Group Phase 2 Rating Report is accepted by the PCC.

Phase 3, the last part of the PRR process, is a monitoring phase during operation where major changes in assumptions and conditions are evaluated to assure the "Accepted Rating" is maintained. Phase 3 is completed after the project has been placed into service and has maintained its "Accepted Rating" for a reasonable period.

For the short term upgrade of Path 26, the studies provided by the CA ISO to the WECC, through the PRR process, originally demonstrated that the proposed increase from 3,000 MW to 3,400 MW, north-to-south was feasible. The new path rating would eliminate between 31 and 50 percent of historical congestion.

Due to an explosion and fire at SCE's Vincent transformer bank 2AA on March 21, 2003, the current transfer capability of Path 26 is 2,500 MW. Because the installation of a fourth transformer at Vincent had already been planned for July 1, 2003, the fourth transformer will now serve as a functional equivalent for transformer bank 2AA, thereby allowing a return to a path rating of 3,000 MW once it becomes operational. The RAS upgrades at Midway are being made independent of the transformer installation, and according to PG&E should be operational by November 2003. On May 20, 2003, the CA ISO completed a WECC Review Group Rating Report addressing all Review Group comments and achieving an Accepted Rating of 3,400 MW in the north-to-south direction for Path 26, thus completing Phase 2 of the PRR process. On July 17, 2003 the WECC confirmed that the Path 26 rating is 3,400 MW in the north-to-south direction, while the existing accepted rating in the south-to-north direction remains unchanged at 3,000 MW. However, the 3,400 MW north-to-south maximum flow will not be achieved physically until the replacement transformer bank becomes operational, which is currently estimated to occur on September 11, 2003.

The PRR review of the long-term study plan will address the need for increasing the Path 26 north-to-south rating to 4,000 MW due to a future up-rate of Path 15 and additional generation developments at Midway that are proposed to be on-line in 2003 and beyond. The long-term plan would eliminate will up to 77 percent of historical congestion. The PRR review is expected to commence now that the review of the short-term plan has been completed. In order to achieve a 4,000 MW transfer capability for Path 26, equipment at the Midway and Vincent substations would need to be replaced and, if necessary, the PG&E segment (approximately the northern one-third) of the Midway-Vincent 500 kV line would be reconductored.

Staff believes that the Path 26 short and long-term proposals are consistent with the state's goals of mitigation of market power, stabilization of electricity prices and removal of the RMR designations. Based on studies by the CA ISO, the consequences of delaying the Path 26 upgrade could result in lost opportunities for significant savings.

CA ISO studies indicate that investments of as little as $2 million in the Path 26 short-term upgrade project increasing the rating of Path 26 from 3,000 MW to 3,400 MW could reduce congestion costs, that have historically been as high as $94 million annually, by 31 to 50 percent. Investments of $142 million in the long-term upgrade could reduce these annual congestion costs by 77 percent.

While the long-term Path 26 upgrade to 4,000 MW is in the early planning stage, staff believes that the impending certification and construction of a Path 15 upgrade will increase the importance and benefits to be realized from this long term project.

Path 46 (West of the Colorado River to Southern California)

Background and Project Description

The WECC Path 46 is part of a group of high-voltage power lines that interconnect southern Nevada and Arizona to Southern California (see **Figure 2-1**). Path 46 is commonly referred to as WOR. Due to the number of lines that make up Path 46 and their locations, Path 46 is typically divided into a northern and southern system as indicated in **Table 3-3** below. **Figure 2-1** shows the general locations of the Path 46 500 kV lines.

Table 3-3
Path 46 Components

Northern System	
Eldorado – Lugo	500 kV
Eldorado – Lugo	230 kV lines 1 & 2
Mohave – Lugo	500 kV
Julian Hinds – Mirage	230 kV
McCullough – Victorville	500 kV lines 1 & 2
Hoover – Victorville	287 kV
Marketplace – Adelanto	500 kV

Southern System	
North Gila – Imperial Valley	500 kV
Palo Verde – Devers	500 kV
El Centro – Imperial Valley	230 kV
Ramon – Mirage	230 kV
Coachella – Devers	230 kV

Generally speaking, the southern system of Path 46 imports power to the San Diego and Los Angeles markets and is considered fully loaded most of the time. The northern system is less loaded than the southern and imports power to the Los Angeles market and from there to regions north of Path 15. The total Path 46 system has a maximum capability of 10,118 MW. The entitlements or ownership rights on the transmission lines that make up Path 46 are shared by the following utilities:

- SCE, 42 percent
- SDG&E, 12 percent
- LADWP, 33 percent
- Cities of Anaheim, Burbank, Glendale and Pasadena, 9 percent
- California Department of Water & Power (DWR), 2 percent
- IID, 2 percent

Path 46 provides electricity to Southern California from two out-of-state sources. The first is from power plants either owned or co-owned by California utilities. These include coal-fired power plants at Mojave and Navajo and the nuclear power plant at Palo Verde, which provide a continuous flow of electricity into Southern California. The second is from power plants not owned by California utilities that furnish electricity via spot market purchases on an as-needed basis. These spot market purchases are most prevalent during peak demand periods and occasionally cause congestion on Path 46 into Southern California.

Generation project proponents have identified more than 23,000 MW of new generation that could be operating by the year 2008 in Arizona/Nevada. Looking forward, an upgrade of Path 46 would be justified on reliability grounds if new generation additions proposed for operation in Southern California were insufficient in meeting forecasted demand due to the cancellation or postponement of a number of the merchant plants. An upgrade of Path 46 would be justified on economic grounds if increased access between Southern California and Arizona/Nevada would create a more competitive market and lead to lower power prices within the region. This additional 23,000 MW of generation would not necessarily be available to California as existing constraints limit increased transfers during peak periods over Path 46.

Current Status

See the Chapter 5 section entitled "STEP Sub-regional Planning Organization."

Path 45 (California-Mexico Border)

Background and Project Description

Path 45 connects Northern Mexico with San Diego and the Imperial Valley and enables power transfers between Northern Mexico and Southern California. Path 45 consists of two 230 kV transmission interconnections, one between SDG&E's Miguel substation and Tijuana, the second between the Imperial Valley substation and the La Rosita substation near Mexicali. The Miguel to Tijuana 230 kV interconnection is rated at 796 MW; the rating of the Imperial to La Rosita interconnection is 408 MW. Until recently the Path had a maximum rating of 408 MW, which would allow for the loss of the 796 MW Tijuana-Miguel 230 kV line without overloading the La-Rosita Imperial Valley line. The total path rating was recently changed to 800 MW as a result of upgrades to the Imperial Valley to Rosita interconnection. This rating is seasonally and directionally dependent. The summer south-to-north rating is 408 MW and the winter rating is 800 MW. Until recently the north-to-south rating had not been changed.

There are two issues of interest related to Path 45, the level of generation available to San Diego from the Mexican Boarder area and the capability of Path 45 (as well as transmission paths in northern Mexico) to reliably move power from that area to San Diego.

New generation totaling 1,660 MW has been completed in Northern Mexico near Mexicali and was ready for operation in June 2003; 1,070 MW of this capacity is intended for export to the U.S. and the remaining 590 MW will be available to Mexico. The 1,070 MW will connect through Path 45 to the Imperial Valley substation, but not all of it will be available to the San Diego area until upgrades at the substation are completed. Increasing transfers into the San Diego area will also require reinforcement of the Miguel-Mission transmission line, an upgrade which the CPUC has found needed for economic purposes and is currently moving through an expedited CPCN permitting process.

On May 2, 2003, a U.S. District Court found that the environmental assessment associated with the presidential permit issued by the US Department of Energy (DOE) and the ROW grant issued by the Bureau of Land Management allowing for the cross-border transmission lines had not adequately addressed air and water quality impacts. On July 8, 2003 the judge provided for the continued operation of both new plants while giving the US DOE until May 15, 2004 to demonstrate why the court should not set aside the presidential permit.

Current Status

Path 45 connects Northern Mexico with San Diego and the Imperial Valley. Approximately 1,660 MW of new generation has been completed in Northern Mexico near Mexicali and was ready for operation in June 2003. About 1,070 MW of this capacity is intended for export to the U.S.; the remaining 590 MW will be available to Mexico (CFE).[5] The 1070 MW will connect through Path 45 to the Imperial Valley substation.

On May 2, 2003, a U.S. District Court found that the environmental assessment associated with the presidential permit issued by the US DOE and the ROW grant issued by the Bureau of Land Management allowing for the cross-border transmission lines had not adequately addressed air and water quality impacts. On July 8, 2003 the judge provided for the continued operation of both new plants while giving the US DOE until May 15, 2004 to demonstrate why the court should not set aside the presidential permit.

On July 17, 2003, SDG&E received a letter of confirmation from the WECC that Path 45 between CFE and the CA ISO has achieved an Accepted Rating of 800 MW in the northbound flow direction. The Accepted Rating of 408 MW in the southbound flow direction remained unchanged.

Miguel-Mission Status

The Miguel-Mission transmission expansion has been proposed to increase transfers between Northern Mexico and SDG&E. SDG&E filed an application for a CPCN to build a new 230 kV transmission line between its Miguel and Mission substations in 2001. The stated purpose of the project was to reduce congestion problems and improve transfer capability between new resources scheduled for operation in Northern Mexico and San Diego. The CPUC held initial hearings on the project in 2001 but did not take further action until early this year. The Miguel-Mission expansion has been supported by SDG&E, the CA ISO, generation developers in Northern Mexico (the Border Generation Group), and the Office of Ratepayer Advocates (ORA). To expedite the Miguel-Mission permitting process the CPUC allowed SDG&E to file its CPCN through a General Order 131-D process, as most of the information requirements of a CPCN proceeding had already been met.

Miguel-Mission is considered as an economic project by the CPUC and must be found to provide economic benefits to SDG&E rate payers over and above its costs. SDG&E studies found that the project could increase benefits for SDG&E rate payers by an average of $7 million a year over a seven year period. In finding that the project is needed, the CPUC found that the benefits of the project would be between $3 and $7 million a year for SDG&E ratepayers and between $10 and 43 million a year for CA ISO ratepayers. SDG&E filed only limited project cost information, estimating costs of $29.4 million. Because of limited cost information and uncertainties concerning cost allocation between SDG&E and generation developers, the CPUC capped the cost of the project at $54 million.

RELIABILITY PROBLEM AREAS

As introduced in the Chapter 2 section entitled "Local Reliability Areas," the two most significant local reliability problem areas in California are the San Francisco Peninsula and the San Diego area. These are described in further detail below.

Greater Bay Area and San Francisco Peninsula

The Greater Bay Area is the electric load center of Northern California and includes the counties of San Francisco, San Mateo, Santa Clara, Contra Costa and Alameda and represents about half of the electricity demand in PG&E's service territory. Over the next few years PG&E plans to spend between $300 and $900 million upgrading the transmission network in the Greater Bay Area. These upgrades provide voltage support and improve the system's ability to move power within the region so that the approximately 10,000 MW of Bay Area electricity load can be served without violating reliability criteria. The next step will be to increase the amount of power that can be brought in as both a hedge against power plant delays and to help serve growing loads.

PG&E splits the Greater Bay Area into several study areas which include the San Francisco Peninsula sub-area, the South Bay sub-area, and the East Bay sub-area. Both the San Francisco Peninsula and the South Bay sub-areas are dependent on imports from other areas to serve loads while the East Bay sub-area exports power. Power plant development in the Bay Area has slowed considerably in the past two years with the construction of some permitted projects on hold and others delayed in permitting. These delays, along with uncertainty about the continued operations of existing power plants, have created uncertainty in electricity supplies in the Greater Bay Area and have spurred the need for increased import capability.

The forecasted peak electricity load in the Greater Bay Area has changed significantly since 2000. In 2000 the peak load for the Bay Area was expected to reach 12,000 MW by 2012. The new forecast that has been revised to adjust for the economic downturn that has particularly affected the San Jose area; it has the Bay Area electricity demand reaching 12,000 MW in 2018.

Overall, the Greater Bay Area will require improvements to its electricity infrastructure over the next decade in order to meet reliability criteria and reliably serve loads or it could be subject to significant power outages. Some of the necessary infrastructure improvements are in the permitting process while others have either been identified in planning process or are under study. Once the proper solutions are identified the state needs to insure that the proper entities follow through with the implementation.

The Greater Bay Area is electrically framed in the North by the Contra Costa substation, in the East by the Tesla substation and in the South by the Metcalf substation. Each of these substations feed power into the Bay Area over a 230 kV and 115 kV network. The major transmission hubs in the Bay Area include the Moraga and Sobrante substations in the East Bay, the centrally located Newark substation, the Metcalf substation in the South Bay and the Ravenswood substation feeding the San Francisco Peninsula. The San Francisco Peninsula and the South Bay are the areas of biggest concern in the Bay Area. The San Francisco Peninsula sub-area is vulnerable because of the radial transmission feeds and a lack of internal generation. The South Bay is vulnerable again because of a lack of generation but also because of the significant loads served by two substations (Newark and Metcalf) and an internal 115 kV system.

The San Francisco Peninsula sub-area has had significant electric outages and could have more in the future. In 1998 operator error during restoration of a substation following maintenance caused the entire city, including the airport and financial markets, to be without power for most of a business day. This type of outage highlights the vulnerability of San Francisco to blackouts.

The San Francisco Peninsula sub-area is a significant California load with limited transmission and generation resources. The current PG&E forecast for 2005 is for peak loads of approximately 1,230 MW for the San Francisco Peninsula sub-area (950 MW for San Francisco and an additional 280 MW for San Mateo County north of the San Mateo substation), based on a one-in-ten-year forecast. The electricity to serve these loads is currently provided by six transmission lines and three power plants. Because of limited supply options, which include the aging and unreliable Potrero and Hunters Point Power plants, and imports from transmission lines in a single corridor, there are significant risks for future outages.

The forecasted total local generation in year 2005 is 618 MW (363 MW from the Potrero Power Plant (PPP), 215 MW from the Hunters Point Power Plant (HPPP) and 20 MW from the United Golden Gate Cogeneration Plant) (see **Table 3-4**).

Table 3-4
San Francisco Peninsula Generation

Plant	**Unit**	**Size (MW)**	Fuel Type	**In-Service Date**	**Operating Restrictions**
Potrero	3	207	Natural Gas	1965	Bay Area NOx restrictions
	4	52	Distillate	1976	877 hours/year
	5	52	Distillate	1976	877 hours/year
	6	52	Distillate	1976	877 hours/year
Hunters Point	1	52	Distillate	1976	877 hours/year
	2*	0	None	1948	(107 MVAR)
	3*	0	None	1949	(107 MVAR)
	4	163	Natural Gas	1958	Bay Area NOx restrictions
United Cogen	1	20	Natural Gas	1986	None

* Hunters Point units 2 and 3 are now operating as synchronous condensers.

The existing generation in San Francisco is highly vulnerable. The HPPP will be shut down as soon as it can be done without compromising reliability according to an agreement between the City and County of San Francisco (CCSF) and PG&E. The combustion turbines at PPP (Units 4, 5 and 6) and HPPP (Unit 1) emit air pollution at a high rate and thus are restricted in operation to only 877 hours per year (or about ten percent of the year) each due to air district permits. The PPP and HPPP units are old and exhibit frequent outages. The units at these plants are unreliable enough that the CA ISO generally assumes that two units from these plants will be unavailable at any given time. The largest and most critical generating unit on the peninsula is PPP Unit 3 (a steam thermal generating unit) which began operating in 1965 and is significantly beyond the expected 30-year life of a power plant of this type. The HPPP Unit 4 is 45 years old and unless further modifications are made to reduce its rate of pollution will not be allowed to operate after 2005.

The lack of reliability of the generators makes performing routine maintenance on both the generators and transmission facilities difficult. Maintenance generally requires at least a partial shut down of the generator or transmission facility; thus with extremely thin margins the window for maintenance is very small. If delays or problems occur and the facilities are not available for either the summer or the winter peak, the risk of blackouts significantly increases.

Approximately one-third of the power needed for the San Francisco Peninsula sub-area is served by power delivered at the San Mateo substation from 230kV transmission lines connecting the Tesla, Newark, and Ravenswood substations. Another one-third of the San Francisco Peninsula sub-area demand is met through power delivered to San Mateo substation via two 230 kV lines crossing San Francisco Bay. Power then flows northward from the San Mateo substation along the Peninsula to Martin substation through a combination of one 230 kV transmission line, five 115 kV lines, and one 60 kV line.

San Diego

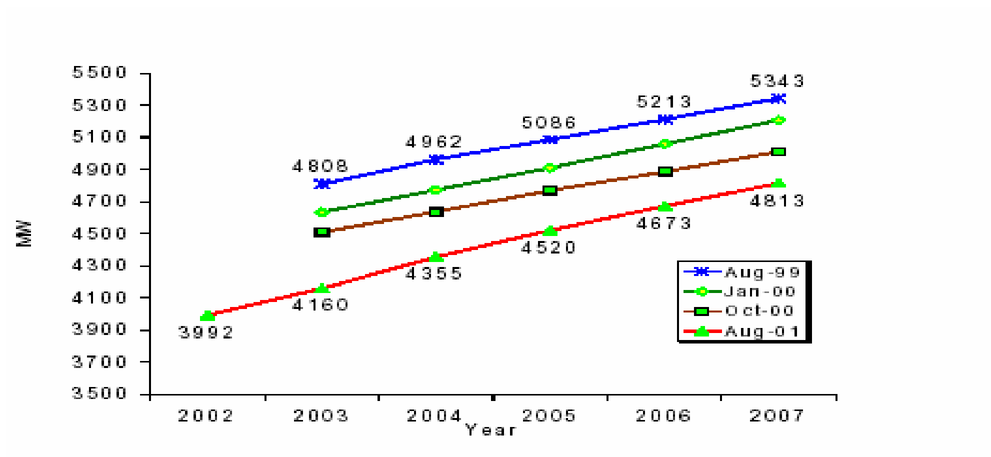
The SDG&E area experienced severe reliability problems in 2000 and early 2001. Outages occurred frequently and electricity prices increased because of a lack of adequate supplies, changes in the operation of electricity markets, and market power problems. High electricity prices, in turn, helped to stimulate conservation and electricity demand dropped significantly through early 2002. Electricity prices have since moderated; demand has begun to rebound and is expected to continue to increase in coming years. While reliability and price problems have not recurred recently, both the CA ISO and SDG&E anticipate future problems unless steps are taken to address structural and market related issues underlying these problems.

SDG&E's reliability problems have resulted, in large part, from the characteristics of the San Diego electricity system. SDG&E is classified by the CA ISO as an LRA and as an RMR area. As an LRA, San Diego is characterized by limited "in-basin" generation and by limited transmission access to generation resources outside of the area. This makes the area extremely vulnerable to disruptions of internal generation supplies and of transmission facilities supplying imports from outside of the San Diego area. Because of limited generation resources, SDG&E's electricity markets also lack sufficient competitiveness to prevent the exercise of market power by key generators under certain peak loading conditions. To mitigate potential market power abuses, the CA ISO requires key generators to sign RMR contracts that require them to operate at specific price levels during times specified by the CA ISO.

The central problem this combination of characteristics creates for SDG&E and CA ISO planners, as well as state and federal regulators, is to ensure that SDG&E has sufficient generation and transmission resources to meet future load requirements, maintain system reliability, and ensure competitively priced electricity for SDG&E customers.

SDG&E 2001 load forecasts reflect several interesting trends. First, SDG&E's 2001 forecast shows substantial declines from its 1999 and 2000 forecasts. SDG&E's 1999 forecast for 2007 shows a peak load of 5,343 MW, compared to a peak load of 4,813 MW in 2007, based on its most recent 2001 forecast. This represents a forecasted peak load reduction for 2007 of 430 MW (**Figure 3-1**).[6] **Figure 3-1** also shows that the slopes of the demand curves, on a comparative basis, are similar. This suggests that certain conservation measures implemented in 2000 may have had a persistent effect in lowering the base forecast, but did not alter the growth curve from that base.

Figure 3-1
SDG&E Load Forecasts



Second, SDG&E's 2001 load forecast, as illustrated in **Table 3-5**, shows steady, substantial growth in demand in the area from its conservation driven lows in early 2000 and 2001 through 2010.[7] The SDG&E forecast is consistent with the 2001 Energy Commission forecast for the same time period, especially the forecast assuming moderate persistence of conservation efforts over time. It is also interesting to note that SDG&E's forecast shows roughly a 14 percent increase over the 2005-2010 forecast period, which is reasonably consistent with Energy Commission projections of 12 and 13 percent over the period, depending on whether conservation measures are assumed to persist at a moderate or low level (Energy Commission Hi forecast). The Energy Commission forecast incorporated three levels of conservation based on assumed levels of conservation achieved during 2000-2001.

- A low demand forecast that assumed high levels of conservation
- A most likely (ML) demand scenario based on medium persistence of conservation levels achieved in 2000 and 2001
- A high (Hi) demand scenario that assumes a lower level of persistence of conservation measures.

At that rate, SDG&E has the highest growth of any utility in the state.[8]

Table 3-5
San Diego Load Forecast (2005-2010)

	2005	2006	2007	2008	2009	2010	Percent Growth ('05-'10)
SDG&E 2001 forecast	4520	4673	4790	4910	5032	5158	14
Energy Commission (ML) forecast	4256	4382	4530	4620	4706	4784	12
Energy Commission (Hi) forecast	4339	4456	4618	4721	4820	4911	13

Energy Commission demand forecast numbers are from the ***California Energy Outlook*, *2001*** Staff Proposed California Energy Demand, 2001-2012 Forecast, Attachment A, October 12, 2001 Committee Workshop.

SDG&E used its 2001 forecast for planning purposes for both its proposed Valley – Rainbow transmission project and its 2002 Grid Planning and Expansion Study. Because of concerns raised by the ORA in the Valley-Rainbow case about the validity of SDG&E's 2001 forecast, Energy Commission staff assessed SDG&E's forecast against its own one-in-ten year heavy summer peak for the SDG&E area for the 2005-2010 time period.

Another important factor concerning San Diego is the capacity and status of new generation facilities that are scheduled to come on line within the next several months to three years. While anticipated new facilities could enhance San Diego supplies by as much as 2000 MW, if all goes well, there are a number of factors that create uncertainties about their status and ability to help meet San Diego load and reliability needs.

There is 2,348 MW of in-basin generation in the San Diego area available to SDG&E. This includes 1,635 MW of gas fired, base load generation at the Encina and South Bay facilities; 215 MW of combustion turbines; 220 MW of peaking facilities and 175 MW of cogeneration (see **Table 3-6**). The 1,600 MW at Encina and South Bay are relatively older, inefficient, and only marginally competitive facilities compared to new generation coming on line elsewhere at this time. Also, all but 220 MW of 1,635 MW of Encina and South Bay generation are classified by the CA ISO as RMR units and must perform as directed by CA ISO contracts. The 147 MW of CalPeak facilities identified in **Table 3-6** are contracted by the DWR to enhance SDG&E's ability to meet peak load conditions.

Table 3-6
San Diego In-Basin Generating Capacity

Generator	Basin Gen Capacity		
	Summer MW	**Winter MW**	**RMR units**
Encina (Cabrillo I)	945	945	1-5
South Bay (Duke)	689	689	1,2,3
Cabrillo CTs	200	216	
Duke CTs	15	15	
CalPeak Peakers	147	147	
Larkspur Peakers	92	92	
Ramco Peakers	84	84	
QF/Cogen	175	175	
Total	**2,348**	**2,364**	

Duke Energy placed its South Bay unit 4 (221 MW) in cold storage in early 2003 until further notice. This move reduces in-basin generation from the projected 2,348 MW to 2,147 MW. Duke's rationale for this step was the inability of South Bay Unit 4 to compete effectively, especially in the face of anticipated new power plants such Otay Mesa and Sempra Palomar. An additional consideration in choosing to retire South Bay Unit 4 may be that the unit was not selected by the CA ISO for an RMR contract for the 2003 period. In addition, the CA ISO San Diego RMR study indicates that 174 MW of qualifying facilities (QFs) owned by the Navy are expected to be shut down in 2003 and will not be available for RMR contracts.[9]

Three large, new generation projects totaling over 2,200 MW of gas-fired generation could be available to San Diego in the 2005-2006 time frame. These include 1,000 MW of the 1,500 MW of new generation located near Mexicali in Northern Mexico and scheduled for commercial operation by mid 2003; the 510 MW Calpine Otay Mesa Power plant located in Southern San Diego County; and the 546 MW Sempra Palomar project. These facilities could provide SDG&E needed new generation to accommodate additional in-basin retirements, plus provide additional reserve margins.

There is a question, however, of the availability of this capacity to the SDG&E area in the event of an outage of the Southwest Power Link (SWPL) line between the Imperial Valley and Miguel substations. In the Valley-Rainbow case, both SDG&E and the CA ISO argued that in the event of an outage on SWPL the two major Mexican 230 kV lines connecting the Tijuana and La Rosita substations in Northern Mexico would be unable to move power from the new facilities to where it is most needed at Miguel in San Diego.

Also, the on-line date for Otay Mesa is uncertain due to project changes. Calpine is discussing these delays with DWR and the on-line date remains unknown at this time.

With a peak load of about 4,500 MW, San Diego must rely on imports from outside the San Diego area to meet the major portion of its peaking requirements. These requirements are supplied by two major transmission paths, Path 44 and the SWPL. Path 44 consists of five 230 kV transmission lines, connects San Diego with the San Onofre Nuclear Generating Station (SONGS) and is San Diego's only major connection with the CA ISO grid. The five lines have a transfer capability of approximately 2,200 MW. The second connection is the 500 kV SWPL which connects San Diego to generation resources in Arizona via the North Gila and Imperial Valley substations. SWPL has a non-simultaneous import capability of about 1,000 MW. With all lines in service (Path 44 and SWPL) SDG&E had a simultaneous import capability of some 2,800 MW in 2002. In addition to Path 44 and SWPL, SDG&E is connected to Northern Mexico via Path 45. Path 45 has a path rating of 408 MW south-to-north, during summer peak conditions and 800 MW south-to-north during winter peak conditions. SDG&E identified the need for the Valley-Rainbow project in 1999 and the project was filed at the CPUC for CPCN review by SDG&E in 2001 to help solve future reliability problems in the San Diego area (see Valley-Rainbow, Chapter 4).

A Miguel-Mission transmission expansion is currently in the CPUC permitting process and will increase transfers between Northern Mexico and SDG&E. The stated purpose of the project is to reduce congestion problems and improve transfer capability between new resources scheduled for operation in Northern Mexico and San Diego. To expedite the Mission-Miguel permitting process the CPUC allowed SDG&E to file its CPCN through a General Order 131-D, as most of the information requirements of a CPCN proceeding had already been met.

TRANSMISSION IMPROVEMENTS TO RESPOND TO THE RENEWABLE PORTFOLIO STANDARD

In September 2002, Governor Davis signed SB 1078 (Chap. 516, Stat. of 2002) and SB 1038 (Chap. 515, Stat. of 2002) to increase California's use of renewable energy resources. SB 1078 created the RPS Program under which the state will increase its electrical generation from renewable sources by at least one percent annually until renewables comprise 20 percent of total IOU procurement by the end of 2017.[10] If a transmission facility is a necessary part of a renewables project approved pursuant to the RPS process, it creates a prima facie finding that the network will facilitate achievement of the renewable power goals established in SB 1078.

SB 1038 requires the Energy Commission to prepare a comprehensive renewables resources development plan that describes the renewable resources in California and the costs of developing and connecting these resources into the transmission and distribution system. SB 1038 also requires the CPUC to use the Energy Commission's renewables resources development plan as the basis for developing a comprehensive transmission plan for renewable electricity generation facilities. The transmission plan, which is to be completed by December 1, 2003, is to provide for the rational, orderly, cost-effective expansion of transmission necessary to facilitate development of renewable generation.

On July 1, 2003, the Energy Commission forwarded to the CPUC, the CA ISO, and stakeholders its preliminary renewable resource assessment as the initial step in the development of the transmission plan for renewables. On July 7, 2003, the CA ISO hosted a stakeholder meeting to facilitate development by the utilities of study plans to assess the additional transmission facilities that would be required to accommodate the resources identified by the Energy Commission. By August 29, 2003, the utilities are expected to have identified a set of transmission system upgrades related to renewable resource development that appear most likely to be required, based on the geographic location and magnitude of resource development projected by the Energy Commission and to describe what steps should be taken to plan for them. These plans could include assessment of major environmental issues, land acquisition, and the filing of applications for CPCNs.

In November 2000, the CPUC initiated proceeding I.00-11-001 to identify and take actions necessary to reduce or remove constraints on the state's existing electrical transmission and distribution system, per AB 970 (Chap. 329, Stat. of 2000). In Phase 6 of that proceeding, it was determined that the transmission system in the Tehachapi area would need to be expanded to accommodate new wind generation in the area. To address the feasibility of upgrading or expanding the transmission system in the Tehachapi area, SCE solicited input and interest in participating in a conceptual study group to aid the CPUC with their investigation.

SCE performed and completed a Phase 1 conceptual study to aid developers' understanding of the extent transmission facilities are required to accommodate up to 2,500 MW of proposed wind generation. This study focused on the development of three to four new 230 kV transmission lines from Tehachapi to SCE's Vincent and Pardee substations and three to four new 230/66 kV substations serving up to ten 66 kV lines each.

The Phase 2 conceptual study was undertaken in September 2002 by SCE and eight wind developers to further determine the 230 kV facilities needed in the Tehachapi area to accommodate the new wind generation identified in Phase 1. The Phase 2 study also identified and described requirements for potential sites for the 230/66 kV substations previously identified in the initial study.

The results from both conceptual studies were provided to the CPUC for Phase 6 of the AB 970 proceeding, on the Tehachapi Transmission Project. Evidentiary hearings for this proceeding were held by the CPUC in June 2003. SCE plans to conduct detailed environmental studies for the Tehachapi Transmission Project in 2003, and file an application for a CPCN around February 1, 2004.

NEAR-TERM RESEARCH AND DEVELOPMENT AS A SOLUTION TO SYSTEM PROBLEMS

Public Interest Energy Research

In 1996, California adopted legislation establishing a public benefit surcharge that would insure the continued funding of energy-related public interest research and development (R&D) during the transition to a more competitive environment.[11]

The California Energy Commission was given the responsibility to administer a Public Interest Energy Research (PIER) program and conduct public interest energy R&D that seeks to improve the quality of life for California citizens by developing environmentally sound, safe, reliable, and affordable electricity services and products. The PIER program has six legislatively defined subject areas. One of these subject areas is the Energy System Integration (ESI) program area which is responsible for transmission R&D to improve the efficiency, reliability and adequacy of the California grid.

Transmission R&D – Improving the Operation of the Existing Grid

From the earliest years of the research program, it was recognized that the transmission infrastructure was aging and the prospect of building new transmission lines faced obstacles. Initially, PIER research partners were primarily utilities and private sector companies. Reliability concerns focused on developing new tools and materials that would reduce outages and expand the capability of the existing infrastructure to transfer power.

R&D Addresses Improved Grid Management

Seeking to expand partnering opportunities and leverage limited transmission research funds to address critical transmission problems in the state, PIER entered into a three year intergovernmental agreement with Lawrence Berkeley National Laboratory (LBNL) as the program administrator for the Consortium for Electric Reliability Technology Solutions (CERTS) to research and develop tools and systems that will provide real-time information on transmission system conditions. This agreement has allowed the Energy Commission to leverage approximately $10 million dollars in DOE funds, to date, for research in California at the CA ISO to provide tools that support system operations and improve grid reliability.

As PIER began this partnership, the critical nature of California's energy crisis was beginning to unfold. Struggling to keep the lights on, system operators were focused on congestion and crisis management. Adding to the system operators' problems were the increasing volumes of data they had to process as a result of the growth of both the transmission network and the number of power transactions. CERTS research specifically considered these issues and has provided important new approaches to help solve these problems.

When grid operators manage electricity operations there are two problems they must address. First, they must maintain system voltages and frequency within acceptable boundaries. If the voltage drops too far, the entire power system can collapse. Next they must plan and be prepared to take action should unexpected events take place, such as the loss of one or more transmission lines or generators. Before restructuring, this was done by individual utilities that owned and controlled both transmission and generation. After restructuring, the CA ISO was suddenly faced with the challenge of managing a statewide transmission network with multiple market participants moving power to and through California from all over the West. As a result, system operators are struggling with data overload which impacts their ability to identify, assess, and analyze corrective actions necessary to avoid system problems.

Two CERTS research projects are addressing and helping the CA ISO deal with these problems today. First is a voltage management tool that presents real-time information on system conditions in readily understood graphic-visuals. This tool reduces the time needed to initiate corrective action from 30-60 minutes to less than 5 minutes. This tool is installed at the CA ISO and is being used by their system operators to maintain system reliability. The second research project is focused on a post-disturbance analysis that is based on synchronized phasor measurements. This tool will reduce the risk of blackouts in the state by helping system operators diagnose and prevent them from happening in the future. The CA ISO staff is actively involved in the development of this tool and has confirmed its usefulness following installation of prototypes in their control room.

Illustration of R&D to Improve System Efficiency

Moving out of the dispatch center, critical PIER research is also looking to address the physical limits of the existing grid and for ways, in the short-term, to improve the efficiency and performance of the most congested transmission pathways in the state. Path 15 is one of the most important and congested transmission corridors in California. PIER-ESI has partnered with The Valley Group to install sensors on transmission structures in this area to monitor conductor tension and net radiation temperature. The data is transmitted via radio to the utility's control center. Real time ratings of the lines are calculated and displayed to operators. At the conclusion of this project, results showed:

- The installed system showed high reliability;
- Software has been operating at PG&E's control center since November 2001;
- Data analysis indicates that significantly higher ratings could be used for Path 15 during peak load times; and
- PG&E is planning operational use of the sensors on a trial basis after establishing joint procedures with CA ISO.

PIER is evaluating what research is necessary to help facilitate development of the joint utility and CA ISO procedures to facilitate adoption of this promising technology.

Examples of R&D on Component Hardware

An example of a project that PIER is supporting to improve the performance of transmission system hardware in the near term is the Sagging Line Mitigator. This technology is currently being tested on utility systems and has near term potential to reduce brownouts, increase the energy transfer capability over existing lines, delay the need for new transmission lines in the short term, and reduce the risk of forest fires. This equipment automatically counteracts the sagging of high voltage transmission lines due to high ambient temperatures and current flows, thus avoiding loss of transfer capacity and risk of fire.

Another area that is very promising has to do with the failure of circuit breakers, transformer bushings and disconnect switches at the utility substations during earthquakes. Recent earthquakes, however minor, make it clear that restoring power quickly after one of these events is critically important. One of PIER's research projects has already found that porcelain transformer bushings used to insulate high voltage wires leading into substation transformers are very brittle and vulnerable during these events, and based on this information, researchers are testing new composite materials and anchorage designs for these bushings that will not only hold up better in an earthquake, but also require less maintenance as well. This information and new improved bushings have already proven to be more durable and reliable providing both safety and cost benefits.

Going Forward – A Five-Year Transmission R&D Plan

Recognizing the continued importance of these critical transmission problems, PIER is in the process of finalizing a Five-Year Transmission R&D plan that will be used to guide and coordinate the program's public interest research activities and focus the research on the highest public interest transmission issues during this time. After engaging stakeholders in a six month process during which information on potential transmission R&D investment opportunities appropriate for PIER were researched, meetings and a workshop held, comments solicited and received, a range of research initiatives that addressed the highest public interest transmission issues were identified. Recognizing that timeliness is critical when trying to apply research to critical problems, staff is recommending an initial focus on two critical transmission issues that require immediate research:

- How can PIER's research program help maximize the utilization of the existing grid?
- How can PIER's research help develop transmission planning tools and approaches that can be used to determine the need and location for new transmission infrastructure in California?

Building on the work that the program has done in the past, this new transmission research plan will focus our research efforts for the next five years. After reviewing all research initiatives included in the plan, staff determined that the following two initiatives have near-term applications, high potential benefits, and directly address the two critical transmission issues identified above. PIER staff has recommended that two research initiatives should be developed immediately to launch the program in the fall of 2003. They are:

1. Develop the information, procedures and technologies needed to use actual system conditions in place of worst-case conditions to increase functional capacity of the transmission grid; and
2. Refine and develop transmission expansion planning tools and approaches that can be used in a deregulated utility industry to: assure transmission reliability is maintained in a cost effective manner; the environment is protected; avoid unnecessary duplication of facilities; and provide for coordination with all parties involved in transmission operation and use.

The complete plan and all the underlying reports and comments are available on the Energy Commission website.[12]

CHAPTER 4: PROJECTS OF IMMEDIATE CONCERN

INTRODUCTION

The IEPR process in concert with the EAP were initiated in part to provide for collaborative identification of transmission system expansion needs, and state findings on the total benefits and costs of proposed transmission projects that can be used by decision makers in the permitting process.

As described in Chapters 3 and 5, there are numerous obstacles to the effective planning, permitting, construction, and operation of the interstate transmission system. The types of obstacles faced by any given project are a function of several factors, including the type of project proponent, the purpose(s) of the project, the size and location of the project, and the regulatory and economic climate. To that end, staff analyzed four representative transmission projects in this IEPR cycle: (1) a major interstate project proposed for economic reasons (Devers-Palo Verde 2); (2) a major intrastate, inter-utility project proposed to address local reliability needs (Valley-Rainbow); (3) an intra-utility project proposed to address local reliability needs (Jefferson-Martin); and (4) an intra-utility project proposed to address existing and likely future RPS needs (Tehachapi). In addition, the selected projects are ones that are of immediate concern to staff because they will (or do) require a CPCN from the CPUC; their ability to obtain a CPCN has been denied or is not yet certain; and staff believes that these projects could benefit from a timely analysis of strategic benefits beyond those analyzed in the CPCN process.

ANALYTICAL INNOVATION IS NEEDED

It is extremely important to the citizens of California that the state has the most accurate and comprehensive assessments available to underpin decisions to permit or deny construction of planned transmission projects. As an example of benefits that can be missed, transmission deficiencies greatly exacerbated the problems experienced during the 2000-2001 electricity market dysfunction. Constrained transmission and bottlenecks limiting power transfers from Southern to Northern California contributed to excessive electricity costs to consumers estimated in the range of $25 to $30 billion. While additional transmission would not have prevented this situation, it could have significantly mitigated the impact on consumers. In addition, wide-scale cascading outages as experienced by the Western Interconnection on August 10, 1996 and by the Eastern Interconnection on August 14, 2003 are examples of low-probability, high-impact events which are not adequately addressed in the consideration of the need for transmission expansion.

Historically, transmission expansion projects have provided benefits far in excess of the project costs. As examples of this, the interconnections to the Pacific Northwest were built for an investment of $ 1.1 billion, yet over 30 years of operation, through 1999, the benefits are estimated at $7.9 billion. The interconnections to the Desert Southwest were built for an investment of $1.2 billion, yet over 28 years of operation, through 1999, they realized a benefit estimated at $5.8 billion. These intertie systems are expected to continue to provide benefits for their remaining life, which is expected to be well in excess of the 50-year planned project life.

Staff believes that there is a critical need for innovation in the analytical methodologies that are used for evaluating the costs and benefits of transmission projects. Some of the factors that should be considered in analyses include:

- Incorporating the low-probability, high-impact event in the analysis;
- Incorporating strategic value of transmission such as:
  - Expanded access to regional markets
  - Enhancement of grid reliability;
  - Insurance against major contingencies;
  - Regional fuel diversity with bi-directional access
  - Use of longer term (more than five to ten years) planning;
- Alternative economic approaches to evaluation of projects; and
- Better understanding of the limits of generation and DSM as alternatives to transmission.

The Energy Commission has the opportunity within the IEPR process to provide a process which ensures a thorough approach in analyzing the benefits of transmission projects. The Energy Commission will need to implement a process that incorporates the factors above and ensures a balancing of all costs and benefits as a basis for decision making.

VALLEY-RAINBOW

Background

The SDG&E area experienced severe reliability problems in 2000 and early 2001. Outages occurred frequently and electricity prices increased because of lack of adequate supplies, changes in the operation of electricity markets, and market power problems. In turn, conservation programs helped to stimulate conservation, and electricity demand dropped significantly through early 2002. Electricity prices have since moderated; demand has begun to rebound and is expected to continue to increase in coming years. While reliability and price problems have not reoccurred recently, both the CA ISO and SDG&E anticipate future problems unless steps are taken to address the physical system and market-related issues underlying these problems.

The Valley-Rainbow project was proposed by SDG&E and the CA ISO to solve future reliability problems in the San Diego area. Specifically, the 500 kV Valley-Rainbow project was proposed to mitigate a CA ISO reliability criteria violation that could result from an overlapping outage involving the single largest generator and the single largest transmission line serving the San Diego area. The problem is known technically as a G-1/N-1 violation. It was identified through transmission planning studies conducted jointly by SDG&E, the CA ISO, and other parties as part of the CA ISO grid planning process. Those studies for 2005-2010 showed that in the case of a heavy summer peak load, an outage of SDG&E's largest generation project (Encina 5 at 329 MW) followed by an outage of SWPL would result in a generation deficiency in the San Diego area, requiring the CA ISO to drop customer load.

Project Description

The Valley-Rainbow project was proposed to interconnect the SDG&E existing 230 kV transmission system at a new Rainbow substation in northern San Diego County and the SCE existing 500 kV transmission system at the Valley substation in western Riverside County (see **Figure 4-1).**

Following are the four major elements of the project:

- A new 500 kV Transmission Line - rated at approximately 1000 MW would interconnect the new SDG&E Rainbow substation with the existing SCE Valley substation;
- A new Rainbow substation – would interconnect the new 500 kV transmission line with the SDG&E existing 230 kV and 69 kV transmission systems;
- Modifications to the existing SCE Valley substation – would accommodate the new 500 kV transmission line from the new Rainbow substation; and
- Additional SDG&E system fixes – would include upgrading an existing 230 kV transmission line, rebuilding an existing 69 kV transmission line and adding system voltage support.

Construction of the 31-mile Valley-Rainbow line was proposed to begin in 2002 with completion and operation by 2004. The estimated cost for the project was estimated to be approximately $300 million.

SDG&E proposed the Valley-Rainbow project to maintain reliable power delivery and serve continuing growth in customer load in the San Diego area in 2004 and beyond. The project was intended to mitigate the CA ISO reliability violation, and also improve the ability of SDG&E to import and export power into and out of San Diego, increase supply diversity, and enhance competition. The Valley-Rainbow project, or a similar project, would also significantly strengthen area reliability by providing a new high-voltage transmission interconnection within the CA ISO-controlled grid.

In addition to the enhanced reliability support to the SDG&E service territory, such a project would also enhance the operating flexibility of the CA ISO-controlled grid and improve the CA ISO's ability to restore service to customers in the event of major service disruptions in Southern California.

Figure 4-1
Proposed Valley-Rainbow and Devers-Palo Verde 2 Projects
Source: California Energy Commission

Finally, the Valley-Rainbow project was proposed to facilitate access to and produce a more competitive market for electricity by increasing the SDG&E import capability by approximately 1,000 MW, which equals about 25 percent of the current power demand in the SDG&E service territory. A project such as Valley-Rainbow could also help to deliver energy north from San Diego and Mexico to other load centers in the state, resulting in greater reliability while increasing economical energy exchanges between regions.

Current Status

SDG&E and the CA ISO identified the need for a Valley-Rainbow type project during the 1999 SDG&E Transmission Expansion Planning process. In that process SDG&E identified multiple criteria violations of the CA ISO Grid Planning Criteria that would occur by 2004, determined that reinforcements to their existing 230 kV system would be exhausted, and that new 500 kV transmission facilities would be needed to correct the 2004 violations. As a result, SDG&E undertook a joint study with SCE to identify and recommend a preferred transmission solution that could satisfy the CA ISO planning criteria and be operational by June 2004. The results of the study identified the preferred 500 kV transmission project to be a line between the existing SCE Valley substation and a new SDG&E substation at Rainbow in northern San Diego County.

In March 2001, SDG&E filed an application with the CPUC for a CPCN for the Valley-Rainbow project and in December 2002, the project was denied without prejudice as not needed for reliability purposes (CPUC Decision 02-12-066). On January 23, 2003 SDG&E filed two petitions, an Application for Rehearing of San Diego Gas & Electric Company Decision of 02-12-066 and a Petition to Modify Decision of 02-12-066. On May 12, 2003 the CPUC issued a decision denying rehearing of the Valley-Rainbow decision and on June 5, 2003, the CPUC issued a decision denying the Petition to Modify the Decision.

SDG&E is currently in the process of studying multiple alternatives to the original proposal, including two alternatives being considered in the Southwest Transmission Expansion Plan (STEP) process. It is unclear when SDG&E will be ready to file for permit approval.

Issues

Project Need and Reliability

SDG&E's reliability problems have resulted, in large part, from the characteristics of the San Diego electricity system. SDG&E is classified by the CA ISO as an LRA and as an RMR area. As a local reliability area, San Diego is characterized by limited in-basin generation and by limited transmission access to generation resources outside the area. This makes the area extremely vulnerable to disruptions of internal generation supplies and disruptions of transmission facilities supplying imports from outside of the San Diego area. Because of limited generation resources, SDG&E's electricity markets also lack sufficient competitiveness to prevent the exercise of market power by key generators under certain peak loading conditions. To mitigate against potential market power abuses, the CA ISO requires key generators to sign RMR contracts that require them to operate at specific price levels during times specified by the CA ISO. (An important issue raised by SDG&E is anticipated increases in RMR costs in the SDG&E area). This issue was raised after the December 19, 2002 denial of the CPCN when SDG&E filed a Petition to Modify the Valley-Rainbow Decision and a Petition for Rehearing.

The CPUC findings in the decision indicated that for purposes of G-1/N-1 reliability criteria planning, existing in-basin generating units should be assumed to continue to be available during the critical planning period in the absence of specific convincing evidence to the contrary. The CPUC decision denied the project a CPCN without prejudice saying the project was not needed at this time because SDG&E will continue to meet the WECC/NERC reliability criteria during the relevant planning horizon and that the project cannot be justified on the basis of providing economic benefits to ratepayers.

Demand Forecast and Planning Horizon

In the review of the project during the CPCN hearings, the CPUC held that the five-year demand forecast currently used by SDG&E should be applied to the Valley-Rainbow project. SDG&E and CA ISO argued that a ten-year demand forecast is more appropriate, however the CPUC concluded that forecasts of both generation supply and demand are more uncertain when moving beyond five years; the longer the planning horizon utilized, the greater uncertainty exists. It was noted in the hearings by SDG&E that the demand might have been skewed as a result of conservation efforts that occurred after the blackouts that occurred in 2001.

Supply Forecast: Existing In-Basin Generation vs. Proposed New Generation and Imports

During the CPCN hearings, parties discussed the supply forecast and reviewed existing in-basin generation, anticipated new and proposed generation and anticipated retirements. A number of projects were raised in the hearings and debated by the parties as to their level of availability; among them, South Bay Unit 4, Encina, Ramco Peaking Units, Navy Units, Otay Mesa, and proposed plants in Baja California, Mexico. The decision acknowledged that there was much uncertainty about anticipated new and proposed generation and future retirements. Some of the issues raised are presented below.

Existing SDG&E Basin Generation

SDG&E has available to it 2,348 MW of in-basin generation in the San Diego area. This includes 1,635 MW of gas-fired, base load generation at the Encina and South Bay facilities;

215 MW of combustion turbines; 220 MW of peaking facilities and 175 MW of cogeneration. The 1,600 MW at Encina and South Bay are relatively older, inefficient, and only marginally competitive facilities compared to new generation coming on line elsewhere at this time. Also, all but 220 MW of the 1635 MW of Encina and South Bay generation are classified by the CA ISO as RMR units and must perform as directed by CA ISO contracts.

Retirements

SDG&E raised concerns before the CPUC in the Valley-Rainbow case about the future of much of San Diego's in-basin generation. In a petition to the CPUC concerning its decision on Valley-Rainbow, SDG&E identified concerns about the status and availability of a number of existing generation facilities, the status of the Otay Mesa project, and the cost of future RMR contracts. Duke Energy placed its South Bay Unit 4 (221 MW) in cold storage in early 2003 until further notice. Duke's rationale for this step was the inability of South Bay 4 to compete effectively, especially in the face of anticipated new power plants such as Otay Mesa and Palomar. An additional consideration in choosing to retire South Bay 4 may be that the unit was not selected by the CA ISO for an RMR contract for the 2003 period. In addition to the Encina project, there is also a concern that because of age, efficiency problems, competitive pressures, and environmental issues, the owners of Encina and South Bay facilities may opt to retire more of those units as newer and more efficient generating units come on line.

Anticipated New Generation

Three large, new generation projects totaling over 2,200 MW of gas-fired generation could be available to San Diego in the 2005-2006 time frame. These include 1,000 of the 1,500 MW of new generation located near Mexicali in Northern Mexico and scheduled for commercial operation by mid-2003; the 510 MW Calpine Otay Mesa Power plant located in Southern San Diego County; and the 546 MW Sempra Palomar project which was approved by the Energy Commission on August 6, 2003. SDG&E has signed interconnection agreements with both Calpine Otay Mesa and for 1,000 MW of generation in Mexico. These three facilities could provide SDG&E needed new generation to accommodate additional basin retirements, plus provide additional reliability margins, in the event that new transmission facilities are not permitted by the CPUC. In the review of the Valley-Rainbow project, the CPUC assumed in the Administrative Law Judge decision that Otay Mesa had received all regulatory approvals and was under construction, and therefore it would be available to meet reliability criteria. The CPUC also assumed proposed plants in Baja California as being able to help meet SDG&E's reliability needs. These issues were debated by a variety of parties, and there were differing comments presented in an Alternate draft CPCN decision by Commissioner Duque who acknowledged that only minor construction had occurred on the Otay Mesa project.

SDG&E Import Capability

San Diego has about 2,300 MW of local or in-basin generation. With a peak load of about 4,500 MW, it must rely on imports from outside the San Diego area to meet the major portion of its peaking requirements. These requirements are supplied by two major transmission paths, Path 44 and the SWPL. Path 44, consisting of five 230 kV transmission lines, connects San Diego with the SONGS and is San Diego's only major connection with the CA ISO grid. The five lines have a transfer capability of approximately 2,200 MW. The second connection is the 500 kV SWPL, which connects San Diego to generation resources in Arizona via the North Gila and Imperial Valley substations. In addition to Path 44 and SWPL, SDG&E is connected to northern Mexico via Path 45. Path 45 has a path rating of 400 MW during heavy peak summer conditions and 800 MW winter peak. Import issues were debated in the CPUC hearings for the CPCN. The CPUC concluded in their decision that CFE will have a strong incentive to upgrade the capacity of its east-west transmission lines in order to make room for its own east-to-west transfers and these upgrades will increase the ability of SDG&E to rely on through-flow and exports from Mexico in the future. However, these issues were not supported by SDG&E, or the CA ISO, nor were they addressed as findings in the Alternate Decision by Commissioner Duque. In addition, the Alternate Decision was silent on issues of load rebounding from the 2001 levels.

Economic Need

Three sets of economic benefits were identified by SDG&E and the CA ISO that could be derived from the project. The following are estimates made by SDG&E and CA ISO:

- SDG&E's consultant has estimated that the Valley-Rainbow project could provide between $305 and $500 million in economic benefits in the event of a one-in-35 year drought. In addition, the consultant estimated that economic benefits would also be realized during one-in-ten low hydro years.
- SDG&E has projected that construction of the Valley-Rainbow project would stimulate increased generation development in northern Mexico for export to the San Diego area and through Valley-Rainbow to the CA ISO controlled grid. It estimated that this could result in increased competition and economic benefits of $225 to $370 million if new generation is developed to take advantage of the capacity of the line.

The CA ISO suggested that the Valley-Rainbow project would provide economic benefits through the reduction of market power. However, this is based on other studies conducted by the CA ISO. The CA ISO has not had the opportunity to study this problem in detail. The CPUC concluded in its decision for the CPCN that the market power mitigation value of the proposed project has not been quantified.

In both the CPCN decision and alternate decision, the CPUC made the following findings related to economics:

- Electricity consumption between October 2001 and April 2002 exceeded SDG&E's October 2001 forecast by 2.1 percent;
- The annual carrying charge for the Valley-Rainbow project using SDG&E's cost estimates is $60.7 million in 2005 dollars and $56.8 million in 2001 dollars;
- In nine of the ten economic benefit scenarios studied, the project costs over the 2005 through 2010 time frame exceed SDG&E's estimate of economic benefits;
- Project benefits only exceed SDG&E's projected project costs if six consecutive years of one-in-35 year drought conditions occur, all new generation in California is constructed in SDG&E's service territory or northern Baja California, Mexico, and the transmission capacity of Path 15 is expanded;
- Five of the six median hydro scenarios result in gross benefits of less than $9 million over the 2005 to 2010 time period;
- The sixth median hydro scenario results in gross benefits of $33.2 million over the 2005 to 2010 time period;
- The economic analysis assumes various generation scenarios but did not analyze the likelihood that the generation assumptions would come to pass;
- In all the scenarios where average hydro year conditions are assumed, the annual benefits of the proposed project are less than the costs, with the project costs exceeding benefits by at least $51.3 million/year or more, regardless of the level of new generation assumed; and
- The vast majority of the gross benefits that SDG&E's economic study identified were attributable to generation units coming on line, rather than the construction of the Valley-Rainbow Project.

Environmental Issues

The Valley-Rainbow study area lies in a part of California that is representative of some of the most difficult policy and trade-off decisions that the state faces in siting transmission lines. Undergoing rapid growth and planned development, balancing suburban and agricultural land uses, and struggling with preservation of the quality of life, the area is a microcosm of California. The project study area is predominantly private land, but includes Indian Reservation land, as well as public lands administered by the Bureau of Land Management and the National Forest Service.

Most of the alternatives for the Valley-Rainbow project were eliminated or rejected during the course of the CPUC CPCN proceedings. However, the key issues for a similar project in this study area could include the potential to cross Indian reservation land, Federal land and private property. In particular, the Pechanga Tribe and a grass roots collection of private landowners vigorously participated in the Valley-Rainbow proceedings in opposition to the project.

DEVERS-PALO VERDE 2

Background

Devers-Palo Verde 2 (DPV2) was initially proposed in the 1980s by SCE to provide increased transfer capability for purchases of economical energy as well as increased capacity from Arizona. The line was proposed to have a capacity of 1,200 MW with a commercial operation date of October 1990. The project, however, was not approved for certification by the CPUC. In 2001, a renewed interest in the project was detailed in two studies, the Southern California Long Term Regional Transmission Study ("Southern California Study"), and the AB 970 Long Term Regional Study Findings.

In February 2001, the CA ISO, SCE and SDG&E completed the Southern California Study assessing the need for new transmission from the Southwest and Mexico to Southern California. This was a conceptual study that identified regional bulk transmission system reinforcements in Southern California that would be necessary to access new generation resources from the vicinity of the Palo Verde Nuclear Power Plant in Arizona.

The Southern California Study concluded that major bulk transmission system reinforcements could be necessary within Southern California by 2008 to provide additional transmission capacity between plants located outside Southern California and Southern California load centers. In order to meet long-term reliability needs in the Southern California region, new 500 kV lines to the Palo Verde substation would be needed, along with upgrades to the existing Palo Verde-Devers and SWPL 500 kV lines. These transmission projects could increase the Southern California simultaneous import capability by as much as 3,200 MW. The SWPL, which is the southern portion of Path 46, was built between the Palo Verde Nuclear Generation Station in western Arizona and San Diego to enable San Diego to take advantage of Palo Verde’s (then) low cost power.

In response to a CPUC ruling on AB 970 in March 2001, a second study jointly prepared by the Energy Commission, CA ISO, SCE and SDG&E was completed in May 2001 that analyzed the cost-effectiveness of potential transmission upgrades for a Southern California-Southwest Power Link. The study supported the conclusion that under the most conservative generation development scenario, major improvements to transmission import capability may be needed to meet reliability requirements in Southern California starting in 2008. However, if a sufficient amount of additional new merchant generation is licensed and built within Southern California to serve load growth, the need for major transmission projects to new resource areas outside of Southern California could be deferred.

Although an economic analysis was not conducted for project feasibility, the report concluded that new transmission links to the Southwest or Mexico might be justified on economic grounds to access lower cost generation in those areas and/or increase the market for electric power accessible to Southern California. This would create a more competitive market and lead to lower power prices within the region.

Project Description

The existing Devers-Palo Verde transmission line is part of a group of high-voltage (500 kV) power lines that interconnect southern Nevada and Arizona to Southern California via the Path 46. The proposed DPV2 project would largely parallel the existing Devers-Palo Verde line (see **Figure 4-1**). DPV2 is an inter-regional project intended to move low-cost electricity from Southwest producers to California. The project is viewed by the CA ISO as a step in reinforcing the CA ISO-controlled transmission system and as a means of facilitating efficient bulk power markets between California and the Southwest. The project would help alleviate transmission constraints between the two areas. Approximately 6,000 MW of new gas-fired generation are developing in the Palo Verde area (3,000 MW of which is in place or under development with another 3,000 MW anticipated by 2004-5) and more could develop in the future. California markets may have a need for those supplies by that time because of area load growth and retirements of aging generation in both the SCE and SDG&E service areas. As noted in the issues section below, there are a variety of factors that may affect the project and result in changes to it.

This line is one of many projects being considered in the STEP process being led by the CA ISO. Twenty-six possible alternatives have been proposed and screened by the STEP group, and six have been recommended for further study. See Chapter 5 for more information on the STEP group.

Current Status

SCE has indicated an interest in filing for CPCN review of this project during 2004. The STEP group's recommendations will influence whether this particular project is pursued by SCE and CA ISO or not. If pursued, the STEP group would define the final project and its timing.

The STEP process includes the following timeline/highlights/ milestones:

- Complete stability and voltage support analysis of alternatives: August 2003;
- Complete initial production cost analysis: September 2003;
- Complete implementation plan that identifies preferred projects: November 2003.

Issues

Project Need and Reliability

As noted above, this project has been on the table since the 1980s and the need for the project has fluctuated during various market conditions. As noted in the Background section above, there is a renewed interest in this project as evidenced by the two major studies conducted in 2001. While this project is still being evaluated under various permutations in the STEP studies, more information regarding the need for the project will surface in the coming months.

Demand Forecast and Planning Horizon

In other CPCN hearings, such as Valley-Rainbow, the proceedings involved considerable debate about demand forecasting and the appropriate planning horizon. The CPUC concluded in the Valley-Rainbow decision that a five-year planning horizon was appropriate; however, the CA ISO and SDG&E argued throughout the case that a ten-year planning horizon takes into account the lengthy licensing process for these types of projects. To date, there has been no planning horizon identified for this project. Past examples of efforts to obtain licensing, like the Valley-Rainbow case, which was not licensed by the CPUC after a year and half of CPCN proceedings, appear to support the need to use longer planning horizons. This need was recognized in the recent filing of the Jefferson-Martin case, where the CCSF used a ten-year planning horizon. It is expected that this issue will continue to be debated by a variety of parties in any CPCN proceedings that may occur for this project.

Supply Forecast

Existing Transmission. As noted above, the existing Devers-Palo Verde transmission line is part of a group of high-voltage (500 kV) power lines that interconnect southern Nevada and Arizona to Southern California via Path 46. The existing transfer limit on Path 46 is 10,118 MW.

Proposed New Transmission. As noted in the description, the proposed DPV2 project would largely parallel the existing Devers-Palo Verde system; however, there are a wide range of interconnections possible and up to twenty-six possible alternatives have been screened for study. Six of those alternatives may be evaluated in the environmental process should SCE file for a CPCN with the CPUC. The demand forecast for Southern California, and the project most likely to meet those forecasts, will be further refined in the STEP process.

Additions of New Local Generation. Approximately 2,100 MW of new gas-fired generation is expected to be on line in the Los Angeles area by 2005. In addition, approximately 1,100 MW of new gas-fired generation is anticipated to be on line in the San Diego area within the 2005-06 time frame, although there are uncertainties associated with these projects. The Otay Mesa project has been permitted by the Energy Commission but has moved forward slowly with construction because of project changes. Its completion date is currently uncertain, but it seems unlikely to be on-line by December 2004. The 546 MW Sempra Palomar project was approved by the Energy Commission on August 6, 2003.

Arizona Supply Uncertainties. Uncertainties exist concerning generation development in the Southwest. Planners anticipate some 6,000 MW or more of new generation to locate in the Palo Verde area by 2005-06. This number could increase, or possibly decrease somewhat.

Most of the power is intended for California markets, but factors such as increased load growth in Arizona or other areas of the Southwest coupled with increasing electricity prices in those areas could redirect much of that power from California to supply those markets.

Other Sources of Supply. There are other sources of supply that could also help offset the need for DPV2. These include the development in California of distributed local generation, expansion of load management programs, and the development of renewable resources including solar, geothermal and wind.

Project Need and Economic Benefits

The STEP planning process, led by the CA ISO, is estimating the economic benefits of a number of transmission options it is considering to reinforce the Southern California-Southwest bulk transmission system. The process uses a market simulator to estimate both producer surplus (producer benefits) and consumer surplus (consumer benefits) for each project and area studied. Preliminary STEP studies estimate the consumer surplus from DPV2 for the CA ISO load-serving utilities at some $65 million annually, with another $8.4 million going to the LADWP. This estimate does not include the capital costs of transmission. It should be noted that benefits resulting from the addition of proposed new projects are estimated on both an incremental (single project benefits) and a cumulative basis (the inclusion of benefits derived from all preceding additions studied, plus the project itself). As noted above, the STEP group identified some $65 million in incremental benefits from a DPV2 addition.[13] The cumulative benefits from DPV2 plus a number of preceding upgrades is estimated at $354 million.

JEFFERSON-MARTIN

Background

The Jefferson-Martin Transmission Project (JMTP) resulted from a comprehensive, long-term planning process undertaken in April 1999 by several stakeholders. PG&E and the CA ISO formed a stakeholder study group to evaluate the adequacy of power supply to San Francisco and northern San Mateo County and to identify the best alternatives to meet future demand. This effort was initiated following the December 1998 accident that interrupted electric service to a significant portion of San Francisco and the northern Peninsula. Stakeholder group participants included PG&E, the CA ISO, the CCSF, the CPUC, the Energy Commission, generating companies, and others.

In October 2000, the stakeholders' study group submitted a report to the CA ISO that concluded that unless new generation resources are built in San Francisco, new transmission facilities would be needed to meet customer demand by the summer of 2006. Because of uncertainties related to existing and potential new power generation in San Francisco, the report identified a number of transmission alternatives. After consideration of feasibility, reliability, and cost, the stakeholders' group selected the JMTP as the preferred transmission solution. Later, in October 2000, the CA ISO Board of Governors approved the concept of the JMTP, without taking a position on a specific route. Subsequently, PG&E completed feasibility studies and updated cost estimates for the three main electrical alternatives discussed during the stakeholder process and for several routing variants of the JMTP for presentation to the CPUC.

In April 2002, the CA ISO granted final approval for construction and addition to the CA ISO controlled grid of the JMTP, also without taking a position on a specific route. Additionally, in response to comments from community groups, the CA ISO Board of Governors instructed its staff to work with the CCSF and interested stakeholders toward their goal of closing the HPPP.

In an effort to address the broad generation and transmission issues, the San Francisco Electricity Resource Plan (Plan) was adopted by the SF Board of Supervisors and signed by Mayor Willie Brown in December 2002. The Plan provides a long-term (ten-year time horizon) vision of the CCSF's possible electricity future. Key elements in the plan are the retirement of the HPPP and the development of renewable energy resources. The CCSF is also now considering siting four gas turbines in the city of San Francisco to generate power.

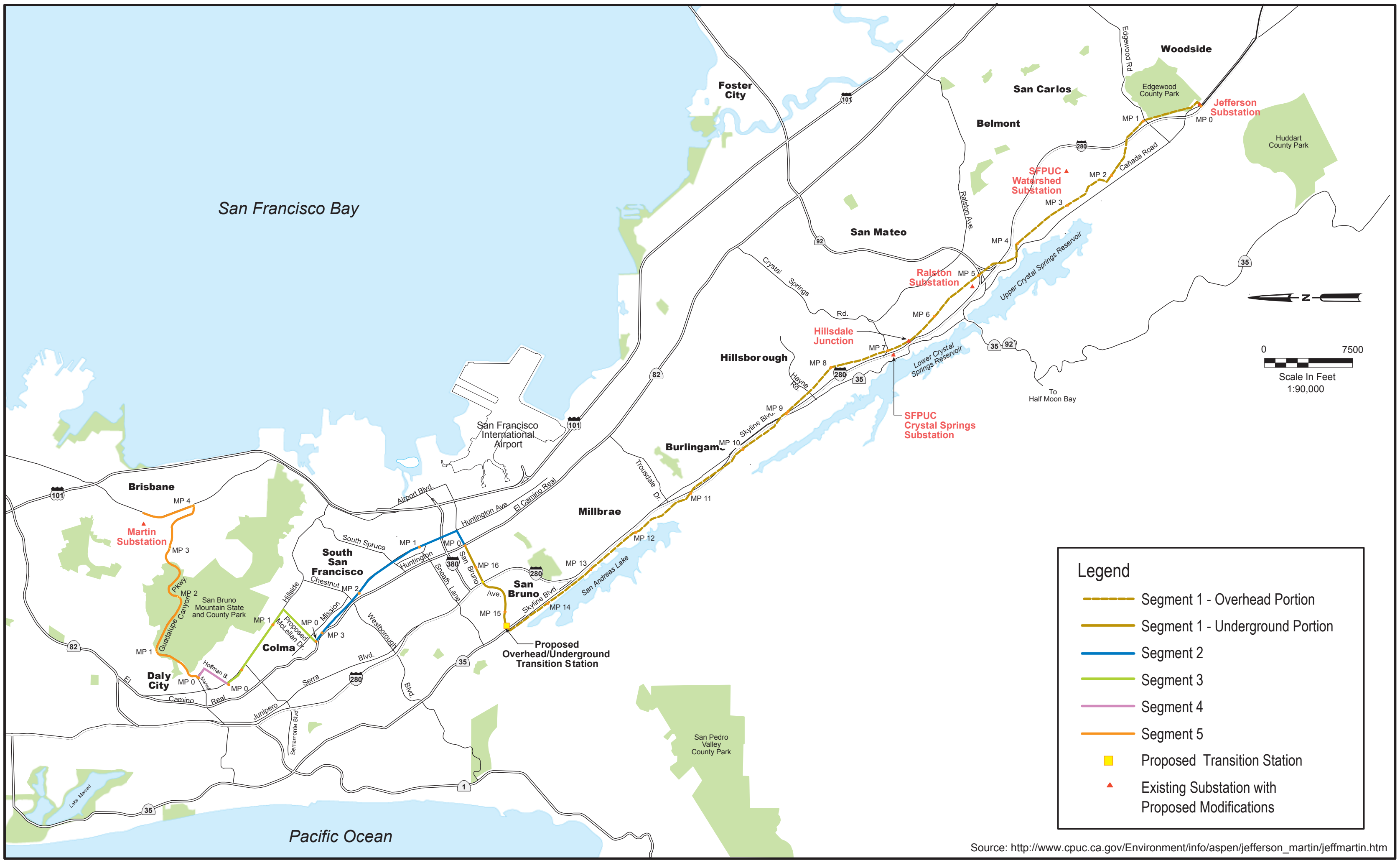
Project Description

The JMTP, running between the city of San Francisco and the Jefferson substation to the south, is a 27-mile project proposed by PG&E (see **Figure 4-2**).

The overhead section, a little over 14.2 miles, would replace the existing 60 kV double circuit tower line that runs between the Jefferson and Sneath Lane substations south of San Francisco, with a new 230 kV double circuit tower line. The existing Jefferson-Martin 60 kV double-circuit tower line would be dismantled and rebuilt in order to enable the east side to operate at 60 kV and the west side at 230 kV. The 60 kV circuit would serve local 60 kV distribution substations. The 12.4-mile underground section is a 230 kV cable running north from a station near the Sneath Lane substation on the peninsula to the Martin substation in San Francisco. The project is estimated to cost $179 million to permit, design, and construct. PG&E is also evaluating an all-underground 230 kV cable alternative.

The project is being proposed because the existing transmission system is projected to be unable to serve the load in the city and peninsula beyond 2005, even with proposed and completed reinforcements to the 115 kV system north of the San Mateo substation. These reinforcements are:
Reconductor San Mateo – Martin 115 kV lines;
Rebundle Ravenswood – San Mateo #2 line;
Convert San Mateo – Martin 60 kV to 115 kV; and
Construct new Potrero – Hunters Point 115 kV cable.

Figure 4-2
Proposed Jefferson-Martin Project



Source: http://www.cpuc.ca.gov/Environment/info/aspen/jefferson_martin/jeffmartin.htm

PG&E has identified the following four objectives for the proposed project:

1. Meet Electric Demand: To ensure that the electric system includes adequate capacity to safely and reliably serve the San Francisco and northern San Mateo County area under normal and reduced generation scenarios. The northern San Mateo County area includes areas of Daly City, Colma, South San Francisco, Burlingame, Brisbane, Westborough, and Serramonte, also considered to be the northern portion of the San Francisco Peninsula.
2. Comply with Planning Criteria: To ensure that the transmission system serving the northern San Mateo County area will continue to meet planning standards and criteria established by the CA ISO and the NERC. Compliance with these criteria would also result in continued consistency with the pre-CA ISO planning guide, which is considered to be part of the October 2000 stakeholder study.
3. Create a More Diverse Transmission System in the Area: To further increase transmission system reliability in the San Francisco and northern San Mateo County area by providing a second independent major transmission line pathway into the area. By meeting this objective, the project would eliminate the current concern that all the area's resources are like "all the eggs in one basket."
4. Implement the CA ISO Board of Governors' April 2002 Resolution approving the Jefferson-Martin Project for addition to the CA ISO-controlled grid, consistent with the CA ISO Tariff as adopted by the Federal Energy Regulatory Commission (FERC), pursuant to the Federal Power Act.

Current Status

PG&E projects that the JMTP will be needed by September 2005 in order to meet the basic project objectives. The October 2000 Long-Term Study stated that the project would be needed by the summer of 2006. PG&E filed an application with the CPUC in September 2002 for this CPCN (A.02-09-043). A determination regarding the need and timing of the proposed project will be made by the CPUC in its process of deciding whether to grant a CPCN. According to PG&E, assuming the CPCN is granted by April 2004, land acquisition and project construction would start immediately to achieve an in-service date of September 2005 or earlier.

Issues

Project Need and Reliability

PG&E asserts that the proposed project is necessary for four reasons:

- To reliably meet projected electric demand in the cities of Brisbane, Burlingame, Colma, Daly City, Millbrae, San Bruno, South San Francisco and the City and County of San Francisco (the Project Area);
- To satisfy applicable planning criteria;
- To diversify the transmission system serving the Project Area; and

- To implement the CA ISO Board of Governors' April 2002 Resolution approving the proposed JMTP for addition to the ISO-controlled grid.

The CA ISO has established the "San Francisco Greater Bay Outage Generator Standard" that would maintain the reliable supply of electricity in San Francisco even if both generators at HPPP, a third generator (not located on the Peninsula), and a transmission line fail simultaneously. While some residents in San Francisco are adamantly opposed to this standard, CA ISO states it established this standard because most of the generating units in the region are very old and if two plants are off-line, then 68 percent of the power to the city is unavailable.

At the Jefferson-Martin pre-hearing conference with the CPUC, the CA ISO emphasized its view that the project is very important for maintaining reliability in the area, and stated that it would assist the CPUC by presenting the information that was the basis for its determination. A key issue in determining the need for a project like JMTP is the determination of the ultimate level of load that can be served via the existing transmission system and various expansion and contraction scenarios for local generation. CA ISO has prepared a draft report on load serving capabilities that is likely to be an issue of discussion in any state need determination.

In the Valley-Rainbow CPCN proceedings, the CPUC weighed WECC and NERC reliability criteria and determined that the Valley-Rainbow project would be able to meet these criteria during the five-year planning horizon evaluated for that project's planning. For this project, the CCSF established a ten-year planning horizon to evaluate reliability. If project need is adjudicated in the CPCN process this will likely be a topic of debate during the CPCN proceedings. Also, in keeping with their filings on the Valley-Rainbow case and based on information currently filed on the JMTP CPCN with the CPUC, the ORA has contested the PG&E assertion that the CPUC has no authority to make findings regarding the need for the project in light of the CA ISO's determination of need. As in the Valley-Rainbow case, ORA continues to raise questions regarding the need for the project, the respective roles of the CPUC and the CA ISO in determining need, and the CPUC role in ratemaking for the project. Similar discussions are likely to continue for the JMTP CPCN proceedings. In addition, other protests have been received by the CPUC questioning the need for, and timing of, the proposed JMTP project.

Demand Forecast and Planning Horizon

There was much debate in the Valley-Rainbow CPCN hearings about demand forecasting and the appropriate planning horizon. The CPUC concluded in its decision of that case that a five-year planning horizon is appropriate; however, CA ISO and SDG&E argued that a ten-year horizon would take into account the lengthy licensing process for these types of projects. In this case, the CCSF has developed a ten-year planning horizon for the JMTP project. The 280 Citizen's Group assert in their scoping comments that a five-year planning horizon should be used consistent with the decision on the Valley-Rainbow CPCN case.

Supply Forecasts: Existing In-Basin Generation and Transmission vs. Proposed New Generation and Transmission

Existing Generation and Transmission. Power to the Peninsula is limited by geographical constraints since San Francisco is at the tip of a long peninsula. Power plants within the City of San Francisco are forecast to generate 598 MW, by 2005 including the 215 MW HPPP and the 363 MW PPP. PG&E also has plans to retrofit PPP Unit 3 with pollution control technology. There is also a 20 MW co-generation power plant (United Airlines Cogeneration) near the airport. The remainder of San Francisco's power is supplied by energy imported by transmission to the south.

Existing major transmission lines importing power into the area are located in a single corridor along Highway 101 between Martin substation (just south of the San Francisco boundary) and San Mateo substation. These facilities are capable of importing about 1,230 MW of power into San Francisco and northern San Mateo County.

The San Mateo substation receives power from several power plants in the South and East Bay areas. In addition, the San Mateo substation receives power from the 500 kV grid via interconnections to the Tesla substation.

The city of San Francisco has an alternative energy plan to meet its electricity needs without the new PPP Unit 7 (discussed below), using conservation and energy efficiency, renewable energy, transmission upgrades, and cleaner, more reliable, and more efficient fossil-fuel resources. The plan would put 195 megawatts of mid-sized power plants in the city by 2004 while ramping up about 480 MW of electricity efficiency measures, solar, wind-power, cogeneration, fuel cell, and other alternative technologies at many locations in and around the city by 2012. San Francisco seeks to phase out fossil fuel generation for the city's electricity over the next 20 to 30 years. It is expected that participants in the CPCN hearings on JMTP will raise the issue of alternative energy sources in the review of project alternatives.

Retirements. Many local citizens want the HPPP retired. They have voiced concern that the HPPP will not be retired until after the PPP Unit 3 is retrofitted and the Jefferson-Martin transmission line is upgraded and expanded, which is not until at least the first quarter of 2005. Closing HPPP is contingent on one or more variables, including whether and when the new four 45 MW peakers are operating, the JMTP is built, and whether Mirant's 540 MW Unit 7 at PPP is built.

Anticipated New Generation. The proposed PPP Unit 7 would be a 540 MW combined-cycle generating unit at the existing site. If built, this power could be an acceptable replacement for the aging HPPP Unit 4. However, on July 8, 2003 the city of San Francisco passed a resolution opposing the project and prohibiting any city agencies from entering into agreements for reclaimed water, or easements for once-through cooling, with Mirant. In addition, Mirant filed for bankruptcy on July 15, 2003. Nevertheless, in early August Mirant filed an amendment to their project proposing changes to the cooling system.

A second set of projects is proposed by the city of San Francisco, using four General Electric LM6000 gas turbines, with a combined total output of 195 MW. These were received from the state as part of its settlement with Williams Co. These total slightly greater than the maximum output of HPPP Unit 4 (170 MW). The City has informed the CA ISO of its intent to locate these gas turbines at two sites in a way that would enhance the electric reliability of San Francisco and enable the retirement of HPPP Unit 4.

Environmental Issues Including Environmental Justice

Environmental issues identified for the JMTP have included impact on open spaces, property values, scenic vistas, electric and magnetic fields, and construction impacts. Residents requested that additional alternatives be developed, such as underground transmission lines, revisiting the PG&E plan to retire the HPPP, or moving the transmission line west of Interstate 280 onto watershed lands. Conservationists argue that moving the transmission lines onto watershed land could negatively impact those lands, as could the larger transmission towers that the project would require. In favor of the JMTP, residents within the city of San Francisco are concerned with the environmental justice effects (increased rates of asthma, cancer, etc.) of the older, polluting power plants located within low-income and minority neighborhoods in San Francisco. Residents would like to see the entire HPPP retired, and see an upgraded and expanded transmission line as an avenue to eliminate old and polluting generating units in the city.

Additional issues were raised about possible federal jurisdiction by the National Park Service concerning easements on the San Francisco watershed property, which would subject the project to the requirements of the National Environmental Policy Act (NEPA). The CPUC has not yet taken a position on this issue, but CPUC staff has informed the Department of the Interior (DOI) that it would not be feasible for the CPUC to undertake the preparation of a NEPA document. To date, there have been ongoing disputes about whether the DOI has any federal jurisdiction related to the project. DOI has not yet determined the scope or form of a federal NEPA document for the project. The CPUC concluded in their scoping memo and ruling of assigned commissioner that expanding the scope of the CEQA document to comply with NEPA requirements would result in a substantial delay in this proceeding.

TEHACHAPI

Background

SCE and wind producers in the Tehachapi region have been working on a solution to transmission congestion in the Tehachapi region for many years. There currently is not enough transmission in the area to deliver existing wind generation to loads in the SCE service territory especially during spring run-off times when large quantities of hydroelectric power are available. In November of 2000 the CPUC initiated proceeding I.00-11-001 after being charged in AB 970 to identify constraints on the existing electrical transmission and distribution system and to take the actions necessary to reduce or remove them. Phase 6 of the proceeding "Tehachapi transmission for connection of renewable generation," is currently underway and evidentiary hearings were held in June of 2003.

The CPUC is also looking at transmission in the Tehachapi region as part of the SB 1038 and SB 1078 processes. This process requires the CPUC to determine the transmission facilities needed in order for utilities to meet the RPS discussed in Chapters 3 and 7 and should be complete by December of 2003.

SCE has developed a three-stage transmission plan for the Tehachapi area that solves both the current congestion problems and future congestion problems caused by the further development of wind resources as part of the RPS requirements.

Project Description

The Tehachapi wind resource area is located near SCE's Big Creek and San Joaquin Valley transmission networks (see **Figure 4-3**). These networks run north from the city of Lancaster almost to the Mono Lake area. SCE has proposed a three-stage solution to the current and expected transmission congestion problems on these networks. The staged process would allow transmission facilities to be constructed in conjunction with the wind resources.

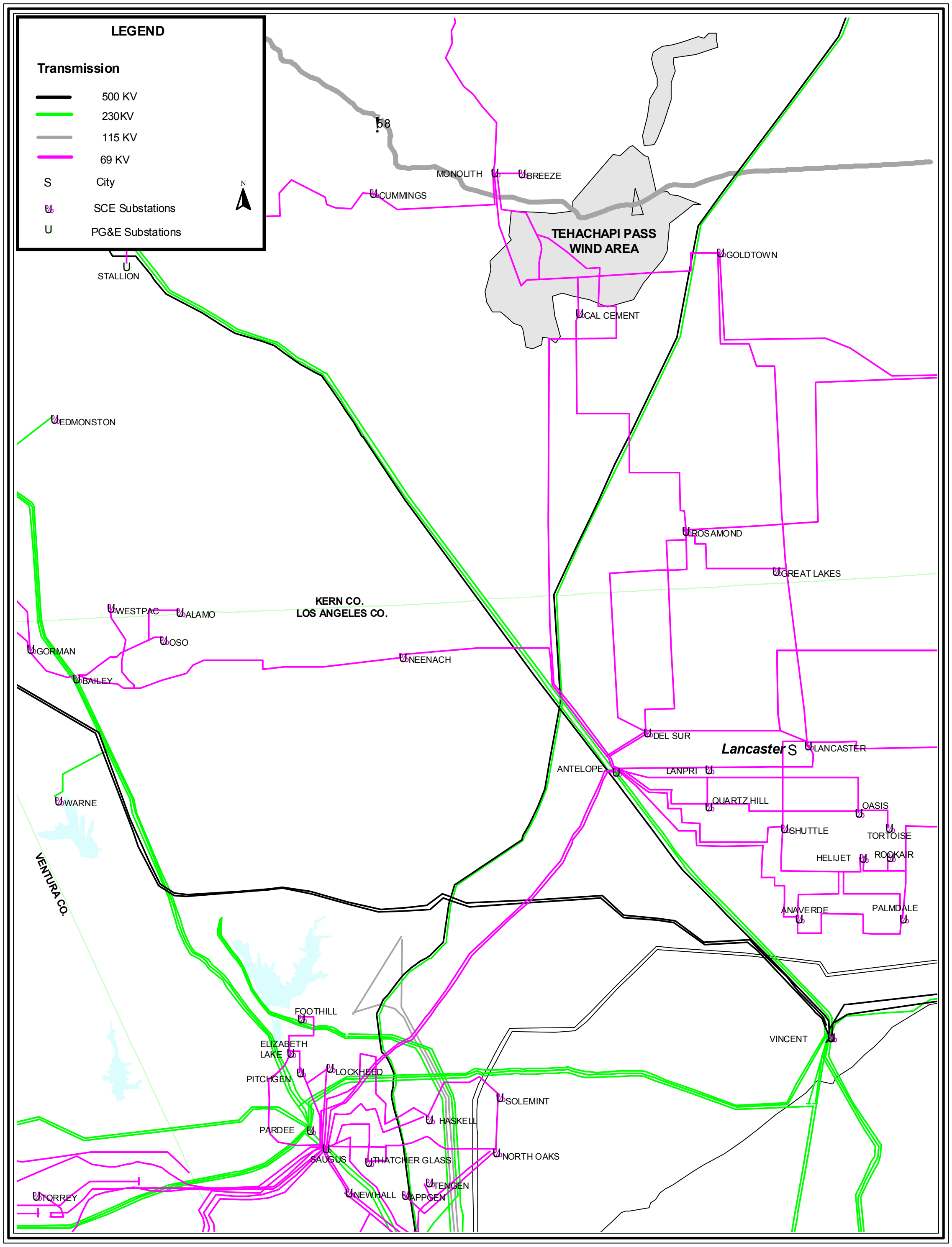
The first stage of the SCE proposal would provide transmission service for up to 1,140 MW of new wind generation in the Tehachapi area. The facilities would include up to three new feeder substations located near the new generation, a new 230 kV substation, facilities connecting the generation to the feeder substation and the feeder substation to the 230 kV substations, and 60-mile double circuit line connected to the Pardee substation.

The second stage would provide transmission for an additional 260 MW (1,400 MW total) of new wind. Stage two would consist of two new feeder substations, a new 230 kV substation and the first circuit of a 230 kV line connecting to the Vincent substation and a new 230 kV line connecting the new 230 kV substations constructed in Stage 1 and Stage 2.

The third stage would provide transmission for an additional 1,870 MW (3,270 MW total) of new wind generation. This final stage would consist of two new feeder substations and the second circuit of the 230 kV line to the Vincent substation.

If all three stages are constructed, the new network could accommodate 3,270 MW of new wind resources. The new facilities would consist of seven new feeder substations, two new 230 kV substations, two 230 kV double circuit lines, one single circuit 230 kV line, and many new lines connecting the generators to the feeder substation and the feeder substations to the new 230 kV substations. This is SCE's proposed method for interconnecting up 3,270 MW of wind in the Tehachapi region. There are still issues that need to be resolved, and alternatives that have been proposed by the CA ISO and other parties need to be addressed.

Figure 4-3
Tehachapi Area Transmission
Source: California Energy Commission



Current Status

SCE plans to file the application for a CPCN in February of 2004 with an expected on-line date of December 2006. SCE has completed some of the preliminary work on the environmental, engineering and property review of the project. According to SCE, sites for the proposed substations are adequate and have the access necessary for the 66 kV and 230 kV transmission lines. The CA ISO has indicated that it cannot support this project until alternatives are analyzed.

Issues

Project Need and Reliability

As discussed in Chapter 3, the transmission plan for renewable electricity generating facilities required under SB 1038 and the RPS program being developed under SB 1078 will affect the viability of proposed wind generation and the need for transmission facilities in the Tehachapi area. If a transmission facility is an integral part of a renewable project approved pursuant to the RPS process, it creates a prima facie finding that the facility will facilitate the achievement of the renewable power goals established in SB 1078. Thus, the first issue is whether or not any of the Tehachapi wind will be required as part of the RPS. The cost of the transmission improvements may make the Tehachapi resources too costly relative to other renewable alternatives.

By August 29, 2003 each of the IOUs is expected to identify the most likely renewable projects and the transmission facilities required to interconnect them. The exact project required for the interconnection of the Tehachapi resources will be unknown until then.

The exact nature of the Tehachapi area transmission improvements is also an issue. If the Tehachapi wind resources are approved as part of the RPS process, transmission upgrades will be needed in the Tehachapi area. SCE has started the detailed studies needed for the CPCN application for its three staged interconnection solution in Tehachapi. The CA ISO will not support the proposed transmission upgrades until alternatives are analyzed, specifically those alternatives described in its July 2003 Opening Brief filed at the CPUC. Thus the state's major transmission planning agency will not support the SCE proposed Tehachapi solution until alternatives are analyzed.

Demand Forecast and Planning Horizon

While the demand forecast and planning horizon are an issue in the need determination for transmission projects, neither will have very much impact on the Tehachapi region. The demand forecast could impact wind development and thus the need for transmission in the Tehachapi area only through the RPS. The RPS requires that each utility purchase 20 percent of its energy from renewable sources by 2017. A new demand forecast would impact the amount of energy SCE would be required to purchase from renewable sources, but these changes would probably be minor and have little or no impact on the need for transmission projects.

Supply Forecasts

Supply forecasts as they typically impact the need for new transmission do not affect the need for transmission in the Tehachapi region. The forecast of renewable needs relative to the RPS will impact the need for transmission in the Tehachapi region only through their impact on wind development in Tehachapi. If the RPS results in most of the renewable generation being developed outside of Tehachapi, then less transmission will be needed and vice versa. The issue in Tehachapi is centered on how much wind generation will be developed or required for the RPS and what transmission facilities are required to get the generation to loads. Thus the expected wind development is a key issue and is being discussed in proceedings at both the CPUC and the Energy Commission. The resource forecast for non-renewable energy in the rest of the state will have little impact on the transmission needs in Tehachapi.

Economic Need

The economic need for the Tehachapi project is a different determination from economic need for other types of projects. Essentially the Tehachapi project will provide economic benefits if the cost of the wind energy plus the cost of transmission facilities is part of the least cost portfolio that meets the 20 percent RPS requirement by 2017.

Environmental Issues

The environmental impacts of the Tehachapi transmission project are currently being studied by SCE but could be significant. The facilities will be sited in areas known to be habitat for the endangered desert tortoise. Without knowing the exact sites for the wind resources, substations and transmission line right of ways, impacts are impossible to determine. An environmental impact report would be completed as part of the CPCN process.

CHAPTER 5: GOVERNANCE ISSUES

GOVERNANCE ENTITIES

Energy Commission

The Energy Commission is the state's primary energy policy and planning agency with responsibilities for assessing future energy needs and assessing energy supplies and alternatives available to California. It is required by SB 1389 to assess electricity supply and demand trends and evaluate potential impacts of electricity infrastructure and resource additions on electricity systems, public health and safety, the economy and the environment as part of its IEPR process. The Energy Commission is required by SB 1389 to adopt an IEPR beginning November 1, 2003 and every two years thereafter. In preparing its report, the Energy Commission is required to consult with the CA ISO and state agencies. To assure collaborative development of state energy policies, agencies shall make a good faith effort to provide data, assessment and recommendations for review by the Energy Commission. The Energy Commission is required by SB 1389 to provide the IEPR to the CPUC and other agencies. For ensuring consistency in the underlying information that forms energy policies and decisions affecting the state, those entities shall carry out their energy-related duties based on information and analyses contained in the report. The Energy Commission is also required by SB 1389 to prepare an energy policy review update, beginning November 1, 2004 and every two years thereafter.

California Public Utilities Commission

The CPUC is required by the Public Utilities Code, Section 1001-1013 and General Order 131-D to review and make findings of public convenience and necessity prior to any electric utility beginning construction on a major electric transmission line designed for operation at 200 kV or more.

The CPUC is required by SB 1038, by December of 2003, to prepare a comprehensive transmission plan for renewable electricity generation facilities, to provide for the rational, orderly, and cost effective expansion of transmission facilities to facilitate development of renewable generation resources facilities.

California Independent System Operator

The CA ISO is the independent system operator for over 80 percent of California's electricity system with responsibility for system reliability and the identification and procurement of facilities to ensure system reliability. It was established by AB 1890 to operate the transmission system consistent with WECC reliability criteria, to acquire the transmission and generation resources necessary to ensure reliable operation, and to meet FERC requirements to provide all electricity generators open, non-discriminatory access to transmission.

The CA ISO is required under its tariff to work with the transmission owning utilities and the other market participants to annually develop a transmission system expansion plan and identify transmission facilities necessary to meet reliability requirements and, as necessary, order that facilities necessary for reliability be constructed. It is also required under its tariff to work with the transmission owning utilities to identify transmission facilities necessary for the reliable interconnection of new generation facilities.

Federal Energy Regulatory Commission

The FERC regulates rates, terms and conditions for transmission and sale of natural gas for resale in interstate commerce, as well as for bulk electricity transmission lines and wholesale sales of electricity in interstate commerce. In addition, FERC licenses and inspects private, municipal and state hydroelectric projects.

PLANNING AND PERMITTING ISSUES

Prior to the 2003 IEPR process, the processes for planning and permitting IOU bulk transmission lines in California were not adequately focused and were uncoordinated with the state's integrated energy planning process (pursuant to SB 1389). Lack of such coordination has hindered the timely expansion of the State's bulk electricity transmission system. This has limited the state's ability to ensure the reliability of electricity supply, provide needed regional and statewide bulk transmission system expansion, and integrate renewable generation into the state's supply system. This problem needs to be addressed immediately to avoid possible preemption by the FERC of the permitting and planning of transmission lines in California.

Planning Issues

Historically, the state had not included bulk transmission system planning in its energy planning and forecasting process. However, SB 1389 now explicitly requires that the Energy Commission's revised integrated energy planning process include an "assessment of the availability, reliability, and efficiency of the electricity and natural gas infrastructure and systems . . ." within the state. At present, planning for about 80 percent of the California bulk transmission grid, which is owned primarily by IOUs, is the responsibility of the CA ISO and the IOUs. The CA ISO planning process has focused primarily on local and regional short-term (i.e., five-year) system reliability problems, but has not adequately assessed the statewide economic benefits of bulk transmission system expansion in the same long-term context as the generation planning carried out by the Energy Commission. As a result, the bulk transmission planning process addresses issues important to the transmission owners and CA ISO, but has overlooked issues that are vital to the state's broader interests. These include the aforementioned economic benefits, future right-of-way needs, efficient use of existing right-of-ways, the environmental performance of the system, and trade-offs among generation, transmission, and DSM.

As a result of SB 1389, which created the IEPR process, the state's official role in transmission system planning is being initiated. California IOUs must participate in the CA ISO planning process, but participation is voluntary by publicly-owned utilities (POUs) and federal agencies. In most cases, they have chosen not to participate (see Chapter 2 for the exceptions). Merchant transmission line developers may propose economic projects for consideration in the CA ISO process. POUs and federal agencies, for the most part, propose, plan, and build transmission projects to meet their own reliability and economic needs. Consequently, no statewide perspective has been imposed on transmission planning, regardless of ownership.

The June 12, 2003 Joint Energy Commission and League of Women Voters workshop highlighted public opinion as a significant input to the planning and expansion of the transmission system. Public opposition to the construction of new transmission is considered one of the most common and serious impediments to transmission system expansion in California and therefore an important consideration in the transmission system planning process.

The consensus view emerging from the workshop is that soliciting public opinion on projects is essential to comprehensive planning, and opposition to transmission expansion is typically tied to a lack of information and understanding of the transmission planning process, costs and benefits of expansion projects, and whether and to what degree alternatives such as generation, DSM and alternative routes are considered in the process. To address this problem, workshop participants suggested the need for better forums for public involvement in transmission planning and improved actions to mitigate community impacts from planned projects.

Staff realizes that not all public opposition is objective, and that not all of the public is receptive to balanced decisions based on feasible mitigation of impacts and the broader public interest. However, staff believes that even if the interested public is opposed to a project, if they understand its benefits and costs, the alternatives that were considered, why the project is considered needed for broader state or regional benefits, and they can say that community impacts were mitigated and that the process was objective and provided opportunity for their involvement, then the process can represent the public interest and result in an informed and objective decision.

Permitting Issues

Three problems currently exist in the permitting of transmission lines in California: 1) permitting jurisdictions are fragmented and overlapping; 2) environmental analyses are inconsistent, and 3) the regional and statewide benefits of transmission lines are not adequately considered. As a result, existing permitting processes create duplication between local, State, and federal agencies, as well as delays in approvals, and denial of needed projects. Depending on the project proponent and where the project is located, a transmission line project is subject to review by one or more of the following agencies/entities:

- The CPUC;
- The Energy Commission;
- A POU;
- A city or county planning department;
- State agencies such as the State Lands Commission and Coastal Commission; or
- Any of several federal agencies that could have jurisdiction.

Due to the existence of several permitting jurisdictions, it may be difficult for a lead agency to conduct an environmental review of the entire project under the California Environmental Quality Act (CEQA). Merchant transmission projects are subject to review by all local land use agencies whose jurisdictions they cross. However, POUs, including municipal utilities and Western, are responsible for performing their own environmental reviews, regardless of the local jurisdictions they cross, potentially calling into question the objectivity and fairness of how transmission projects get reviewed and by whom. Projects proposed by IOUs are subject to CPUC review.

Divided permitting jurisdictions also affect need assessment. POUs determine if proposed projects are needed for reliability and economic purposes based on benefits and costs to their own ratepayers. The CPUC assesses the need for reliability and economic projects proposed by IOUs based on limited cost/benefit analyses that focus only on ratepayer impacts. In the process, the CPUC often re-examines planning issues, refusing to accept determinations made by the CA ISO in the planning process. As a result, projects with regional or statewide benefits that could help the state mitigate market power, stabilize electricity prices and enhance the reliability and environmental performance of the electricity system, have been denied permits by the CPUC or suffered long delays in the process due to an inadequate assessment of benefits. As an example, in the late 1980s the CPUC denied IOU participation in the California-Oregon Transmission Project (COTP). The project was subsequently built by municipal utilities, and now provides critical capacity for importing electricity from the Pacific Northwest. A more recent project that has experienced similar difficulties with the CPUC process is the Path 15 upgrade.

WESTERN REGIONAL TRANSMISSION PLANNING

Two major Western region entities address regional transmission issues: the WECC and the Seams Steering Group – Western Interconnection (SSG-WI).

Western Electricity Coordinating Council

The WECC is one of 10 electric reliability councils in North America, encompassing a geographical area equivalent to over half the United States. The WECC was formed on April 18, 2002 by the merger of the Western Systems Coordinating Council (WSCC), Southwest Regional Transmission Association (SWRTA) and Western Regional Transmission Association (WRTA). The new organization, WECC, continues to be responsible for coordinating and promoting electric system reliability as has been done by the WSCC since its formation 35 years ago. In addition to promoting a reliable electric power system in Western Interconnection, WECC supports efficient competitive power markets, assures open and non-discriminatory access among members and provides a forum for resolving transmission access disputes. WRTA and SWRTA are still of importance as they have been incorporated into the WECC to perform general grid planning functions.

For the Western Interconnection, FERC issued decisions looking favorably on three regional transmission organization (RTO) proposals, on the condition that they act as a single or virtual RTO with regard to primary RTO functions, including transmission pricing, regional planning and market operations and monitoring. The three RTOs proposed are CA ISO for California, RTO West for the Northwest, and West Connect for the Southwest. To comply with the FERC condition, the SSG-WI was developed to design and implement the functions and procedures that would enable the three Western RTOs to perform as a single regional RTO.

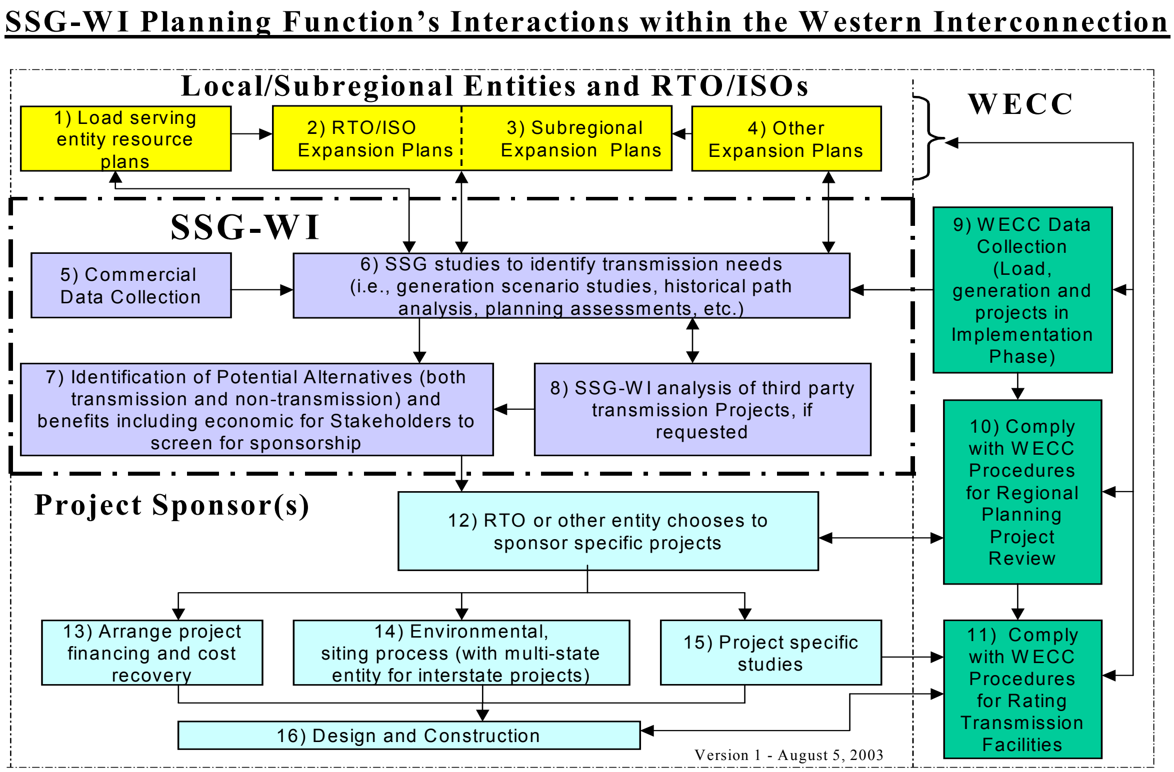
Seams Steering Group – Western Interconnection

As noted above, the SSG-WI was developed to design and implement functions and procedures that would enable the three Western RTOs to perform as a single regional RTO with regard to grid planning, pricing, market design, operations, and monitoring, pursuant to FERC requirements. We discuss only the grid planning function of the SSG-WI Planning Work Group here.

SSG-WI Planning Work Group

The SSG-WI Planning Work Group (PWG) is most directly concerned with transmission planning between the three RTOs in order to develop and maintain transmission networks that can facilitate an efficient regional electricity market within the Western Interconnection. This requires the three RTOs, once in place, to plan together to identify inter-RTO congestion constraints that limit economic transactions among them. The primary purpose of the PWG is to identify congestion problems, suggest general alternatives to relieve those problems, and leave it to affected parties to refine and implement study findings, including developing project support, actual planning studies, and to finance and permit projects they think would be beneficial to them. The relationship among the different levels of transmission planning performed within the Western Interconnection, as well as the steps in the SSG-WI planning process are illustrated in **Figure 5-1**.

Figure 5-1
SSG-WI Planning Functions and Organizations[14]



SSG-WI PWG: 2008 and 2013 Transmission Study

The SSG-WI PWG is completing a study of transmission expansion, with cases for 2008 and 2013. One goal is to identify transmission constraints that limit access to generation resources within the WECC. The study uses a 2008 base case that focuses on hydro and gas-fired resources. A 2013 base case focuses on gas, coal, and renewable resources. The report is scheduled to be completed in Fall 2003.

It should be noted that these regional level studies do not identify specific transmission expansions to relieve transmission constraints identified in the studies. They do attempt to estimate the value of such expansions that would increase access to constrained generation resources on specific paths based on specific resource cases. The assumption underlying this approach is that parties interested in relieving identified constraints would conduct their own planning studies, determine the value of relieving constraints to them, identify potential transmission or other alternatives, determine the costs of those alternatives, and weigh those costs against the benefits.

The 2008 study examined five gas/hydro cases using high, medium, and low gas prices and high, average, and low hydro levels. It uses an optimizing dispatch approach that does not include bidding behavior. Initial findings from the 2008 study show a number of interesting results, including constrained inexpensive resources of approximately $900 million dollars within the interconnection.[15] This finding suggests that transmission is under-built. The study indicated high expansion values from incremental expansions between Arizona and Southern California (Palo Verde and Devers) and from Nevada to Southern California (Eldorado to Lugo). In general, study findings suggest that by 2008 there will be amounts of constrained generation that cannot be exploited given assumptions concerning resource additions in the 2004 time frame and 2008 levels of transmission capacity.

SSG-WI is also conducting a study to identify transmission constraints based on coal and renewable resource additions through 2013. The study suggests that some 55 percent or about 8,900 MW of new coal-fired resources would be constrained without new transmission additions.[16] It also showed that renewable resources largely displaced gas-fired resources.

STEP Sub-Regional Planning Organization

Sub-regional planning organizations have emerged recently between California, the Southwestern states and Mexico. The CA ISO anticipates initiating an additional sub-regional organization between Northern California and the northwestern states in the near future. Below we discuss the activities of the STEP organization.

The STEP process is likely the most developed and involved of the sub-regional planning organizations at this time. Its focus is on improving transmission connections between loads in Southern California and new generation resources under development or in planning in Arizona, southern Nevada, and northern Mexico. This includes studies of WECC Paths 45 and 46.

STEP is an ad-hoc planning group composed of representatives from Southern California utilities, the CA ISO, and utility planners from Arizona, Southern Nevada, and Northern Mexico. A primary goal of the STEP Planning Group is to match generation development in the Southwest with electricity resource needs in Southern California. There are significant amounts of new market driven generation developing in areas of the Southwest. Arizona has experienced development in the Phoenix area and more recently in and around Palo Verde. Roughly 6,000 MW of new generation is expected in western Arizona by 2005. This is likely in excess of Arizona needs. Approximately 1,600 MW of new generation has been added in northern Mexico in the Mexicali area, 1,000 MW of which are contracted for sale in California. New generation capacity is also under development in southern Nevada with an interest in selling into California markets. Both San Diego and the SCE service area could provide ready markets for excess, marketable capacity from these areas.

STEP grid planning activities to assess transmission options began in late 2002. The first phase of the study process involved a series of scoping studies using power flow analysis to identify technically preferred options. The second phase employs a production cost model to assess the economic value of the technically preferred options. Results of the economic modeling work are not available at the time of this report, but will be assessed by staff and reported when they become available.

Based on these screening assessments, the most promising transmission options from Arizona to Southern California are a second Palo Verde to Devers 500 kV line and a West Wing to Devers 500 kV line to its north. The most promising option for completing the San Diego area loop is a 500 kV line from Imperial Valley to San Diego, either at Ramona or to a new Rainbow substation.

CHAPTER 6: STATE ACTIONS TO ADDRESS PROBLEMS WITH TRANSMISSION PLANNING AND PERMITTING

The importance of coordinated transmission planning including state involvement and consolidating electricity generation permitting with electricity transmission permitting has been discussed by various state government groups over the past 15 years. Efforts to make improvements have included legislative findings, recommendations of the Little Hoover Commission and most recently actions by state and nongovernmental agencies to coordinate their efforts to plan and permit electricity transmission facilities.

SENATE BILL 2431

In 1988 the Legislature expressed the importance of the efficient use of the existing bulk transmission system and the importance of coordinated transmission planning to the economic and social well-being of the state. In Senate Bill 2431 (SB 2431) (Chap. 1457, Stats. of 1988) the Legislature found and declared that establishing a high-voltage electricity transmission system capable of ensuring access to regions outside the state having a surplus of power available and accommodating the development of alternative energy supplies within the state, was vital to the economic and social well being of California.

The Legislature further found and declared that constructing new high voltage transmission lines within new right-of-ways may impose financial hardships and adverse environmental impacts on the state and its residents. As a result the Legislature identified four principles that Energy Commission staff has termed "principles of efficient use of the existing system and right-of-way." These include in order of preferred use:

- Encouraging the use of existing ROWs by upgrading existing transmission facilities where technically and economically justifiable.
- When constructing new transmission lines is required, encourage expansion of existing ROWs when technically and economically feasible.
- Provide for the creation of new ROWs when justified by environmental, technical, or economic reasons as determined by the appropriate licensing agency.
- Where there is a need to construct additional transmission capacity, seek agreement among all interested utilities on the efficient use of that capacity, thus recognizing the importance of coordinated transmission planning to improving system efficiency and the environmental performance of the system.

These principles were expressed by the Legislature when California's electricity industry was a regulated monopoly. However, these are rational principles in a competitive electricity industry as well and are very consistent with the direction of SB 1389 and the EAP (see below).

As a result of SB 2431, the Energy Commission provided recommendations to the Legislature in 1992 that in part are being implemented or are relevant today. These included:

- Non-discriminatory transmission access is in the state's best interest.
- Transmission pricing should not cause one utility's ratepayers to subsidize services provided to others, nor adversely affect the reliability of the transmission or generation systems.
- The state should encourage the implementation of long term coordinated transmission planning through a voluntary transmission service association.

LITTLE HOOVER COMMISSION

In 1996 the Little Hoover Commission published the results of its review of energy functions the state would need to perform to respond to a competitive electricity market and the agencies that were best equipped to perform these functions. The Little Hoover Commission considered the needs of the market and the core competencies and cultures of both the CEC and the CPUC, recognizing that each of these commissions should divest some responsibilities to ensure both commissions were responsible for what they could do best during the transition to competitive electricity markets. The Little Hoover Commission recommended that during the transition to competition, the Governor and the Legislature assign to the Energy Commission the new functions needed to make competitive energy markets operate. They concluded that among other needs, in a competitive electricity generation market, the state will need a consolidated siting, environmental review and safety compliance authority for generation and transmission facilities.

SENATE BILL 1389
STATE ENERGY PLANNING

In adopting SB 1389, the Legislature reinforced that government has an essential role to ensure a reliable supply of energy consistent with preservation of public health and safety, a sound economy, conservation and environmental protection. This legislation established that at least every two years the Energy Commission conducts assessments and forecasts of all aspects of energy supply, production, transportation, distribution, demand and prices, in collaboration with appropriate state and federal agencies. Results from the Energy Commission assessments and forecasts are made available to state agencies with energy responsibilities for purposes of ensuring consistency in the underlying information that forms the foundation of energy policy and decisions that affect the state. Those agencies are required to use the results of the IEPR process in making energy policy decisions.

The IEPR process was initiated in 2002 by the Energy Commission to carry out the mandates of SB 1389. The process will provide for collaborative identification of transmission system expansion needs, and state findings on the total benefits and costs of proposed transmission projects that can be used by decision-makers in the permitting process.

As described in Chapters 3 and 4, there are numerous obstacles to the effective planning, permitting, construction, and operation of the interstate transmission system. The types of obstacles faced by any given project are a function of several factors, including the type of project proponent, the purpose(s) of the project, the size and location of the project, and the regulatory and economic climate. To that end, staff analyzed four representative transmission projects in this IEPR cycle.

As noted above, one of the obstacles to encouraging private investment in electricity transmission system expansion is regulatory uncertainty. The state's actions through the EAP and the IEPR process related to transmission improvements are also intended to reduce regulatory uncertainty for project proponents and ensure that the planning and permitting processes are transparent to all interested parties.

ENERGY ACTION PLAN

The 2003 EAP is a collaborative effort among the CPUC, Energy Commission and the California Power Authority. One goal of the Plan is to ensure that the state will invigorate its planning, permitting and funding processes to ensure necessary expansions to the bulk transmission system are undertaken in a timely manner. In the plan, the state is committed to assure the necessary improvements and expansions to the distribution and bulk electricity grid are made on a timely basis. The above agencies will collaborate in partnership with other state, local and non-governmental agencies with energy responsibilities to ensure that state objectives are evaluated and balanced in determining transmission investments that best meet the needs of California's electricity users.

Specifically in the EAP the agencies agree to collaborate in the IEPR process to determine the statewide need for bulk transmission projects, and the CPUC agrees to propose changes to its CPCN process and use the results of the IEPR need determination for IOU-sponsored transmission projects without having to revisit questions of need during certification.

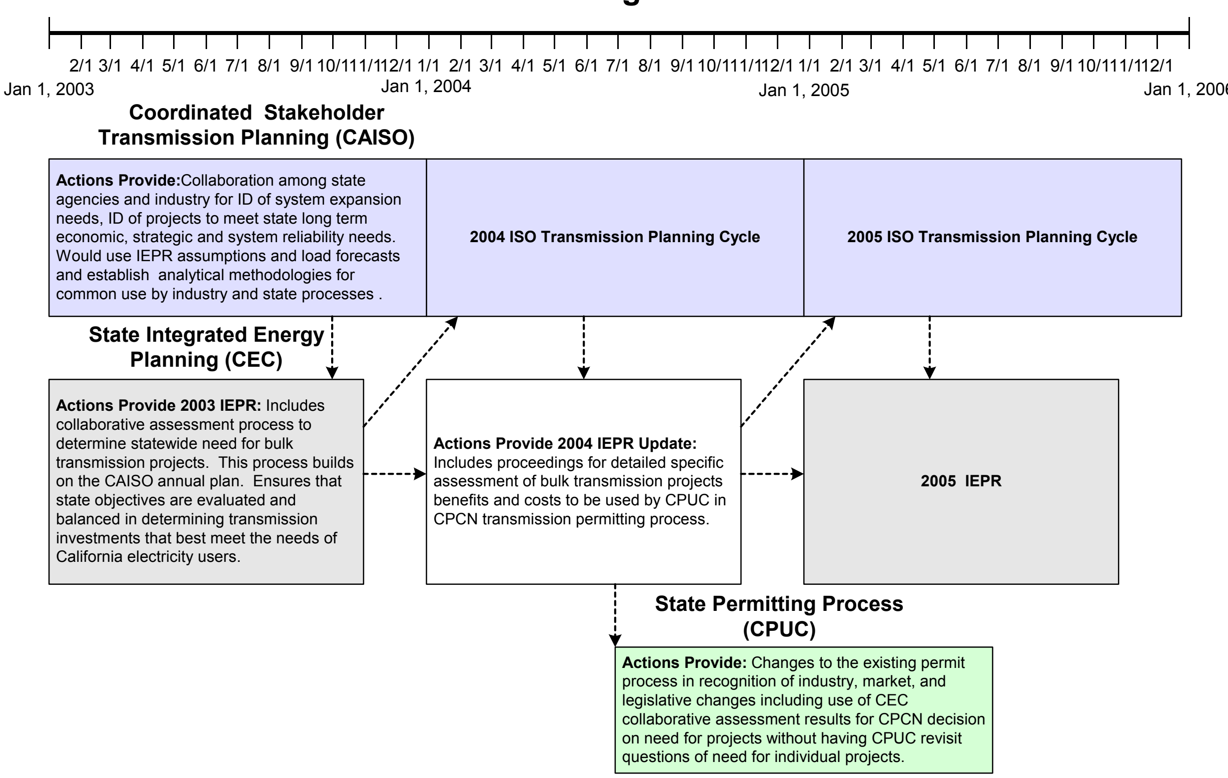
AGENCY COLLABORATION

SB 1389 and the EAP represent legislation and agency coordination agreements being implemented by governmental and nongovernmental agencies to ensure that the most crucial energy issues facing California can be addressed in the near term. Agency collaboration is a vital component of each of these efforts. To this end the staffs of the CA ISO and the Energy Commission are developing a memorandum of understanding for the effective participation of each staff in the other agency's process.

Energy Commission staff believes that the most crucial problem to solve from an electricity transmission perspective is the reinvigorating of the state's transmission planning and permitting processes to assure that necessary expansion to the bulk transmission system can be made on a timely basis. None of the requirements of SB 1389 or the EAP, standing alone, will assure necessary expansions on a timely basis. However, working together, the effects of these actions can resolve the problem. Whether or not the problems with transmission planning and permitting are resolved will depend in large part on the degree of cooperation realized among the key agencies. For example, it will be essential to the success of the EAP that the Energy Commission, CA ISO and the CPUC recognize each other's responsibilities and collaborate effectively towards solutions to questions of transmission project need and timely permitting of transmission projects.

The relationships among the actions for which these agencies are responsible are shown in **Figure 6-1**. As shown, these actions working together make it feasible to take a project originating in the CA ISO coordinated stakeholder transmission planning process, to the state permitting process with the basis for a need determination completed in the IEPR or IEPR Update, within about 18 months. With appropriate changes implemented for the CPUC CPCN process, that process will not re-visit questions of need for certifying individual projects. The CPCN process will use the IEPR Update need assessment as a basis for its need determination and focus its efforts on the CEQA requirements for permitting. This will represent a major efficiency improvement in the planning and permitting of bulk transmission projects and bring the state much closer to effectively addressing the crucial issue of timely permitting for transmission projects.

Figure 6-1
Actions for Overcoming Transmission Issues



Other actions that will help overcome issues in transmission planning and permitting include the CA ISO improving its transmission planning process to include longer-term transmission planning, valuing the strategic benefits of transmission projects, and developing analytical methodologies for common use by industry and state planning and permitting processes. The effects of these actions are to provide a more complete perspective of the value of individual planned transmission projects.

OTHER ACTIONS TO ADDRESS PROBLEMS WITH PLANNING AND PERMITTING

Common Analytical Methods

Efforts are underway on the part of the CA ISO to develop a common methodology to be used in the planning and permitting of transmission projects to determine the value of proposed projects which may be needed to provide economic benefits to the state. The complexity of developing such a robust methodology may require a lengthy period of development, testing, and verification. However having such a universally acceptable method for assessing the value of transmission additions provides a valuable common yardstick for measuring the range of benefits from proposed transmission expansion projects and provides a methodology for both planning and regulatory proceedings.

Strategic Long-Term Planning

This effort which is being initiated by the Energy Commission and CA ISO is intended to ensure that long term planning and strategic project benefits are included in the CA ISO transmission planning process and the IEPR process and these benefits are appropriately considered in the CPUC's permitting process for bulk transmission system expansion. Long-term strategic planning provides risk avoidance of unforeseen extreme events, as well as access to developing markets through the most cost-effective transmission expansion projects. This effort will take into account the value of the grid as insurance against fire, flood, drought, earthquake, fuel supply disruptions, and losses of major system assets.

CHAPTER 7: RECOMMENDATIONS

TRANSMISSION PROJECT PROCEEDING DURING THE 2004 AND FUTURE INTEGRATED ENERGY POLICY REPORT UPDATES

It is extremely important to the citizens of California that the state has the most accurate and comprehensive assessments available to underpin decisions to permit or deny construction of planned transmission projects. Staff believes that one or more of these projects will benefit from a comprehensive analysis during the 2004 IEPR update process. Staff also believes that there is a critical need for innovation in the analytical methodologies that are used for evaluating the costs and benefits of transmission projects. Current analytical methodologies used in project permitting typically employ short-term analytical horizons, economic valuation methodologies that do not recognize strategic benefits, present worth valuations that discount long-term project benefits, and utilization of average conditions.

Staff recommends that the collaborative transmission work identified in the EAP to determine the statewide need for bulk transmission projects be held during the 2004 and future IEPR updates for the purpose of assessing and comparing costs and benefits, and assessing alternatives and timing issues for projects subject to CPCN approval. As identified in the EAP, the proceedings are intended to build on the CA ISO annual transmission plan and evaluate transmission, generation and demand-side alternatives to help reinvigorate the state's transmission permitting process and assure expansion of the grid is made on a timely basis and state objectives are evaluated in determining transmission investments that best meet the needs of California.

Results from these proceedings would be carried forward into the IEPR Update report to the Governor and Legislature, and for use in the CPUC and other transmission permitting processes. With respect to the overall structure and content of this collaborative effort, staff recommends that the process be on the order of six to ten months in duration, depending on the complexity of issues addressed, and should represent a melding of the administrative processes used for past Electricity Reports and generation siting cases. Staff proposes that all IEPR Update transmission proceedings be handled by a Commission oversight committee and that a multi-disciplinary team of Energy Commission technical staff function as an arm of the Committee in collaboration with the CA ISO and CPUC staff.

This approach brings together the best expertise available in state service and industry to address the issues related to the need for transmission projects. The utilities will be an essential source of information and analyses on the individual projects and their costs and benefits, as well as alternatives considered in the planning process. The collection of expertise from state service will cover the areas of demand and price forecasting, transmission system assessment, supply options, project alternatives, financial impacts, and environmental benefits and costs, thereby providing an extremely broad scope of independent review.

This transmission work during the IEPR Update will be integrated with other IEPR electricity analyses and policy work, use appropriate IEPR assumptions for demand and price forecasting and supply options, and consider broader strategic benefits than the current process.

Some of the factors that should be considered in these proceedings include:

- Incorporating a low-probability, high-impact event in the analysis;
- Incorporating strategic value of transmission such as:
  - Expanded access to regional markets;
  - Enhancement of grid reliability;
  - Insurance against major contingencies;
  - Regional fuel diversity with bi-directional access;
  - Use of longer term (more than five to ten years) planning horizon;
- Alternative economic approaches to evaluation of project costs and benefits; and
- Better understanding of the costs and benefits of generation and DSM as alternatives to transmission.

The state has the opportunity within the IEPR process to provide a thorough approach coordinated with other electricity policy work in analyzing the benefits of transmission projects. Collaboration among the Energy Commission, CPUC, CA ISO, and utilities will be vital to successfully implement this process.

Staff also recommends that the Energy Commission hold a workshop toward the end of the 2003 IEPR process to identify transmission projects parties believe should be evaluated in the 2004 Update, and address information and data needs for those transmission projects.

STATE ACTIONS REGARDING PROJECTS THAT ARE IN THE STATE'S INTEREST

The Energy Commission staff conducted a preliminary analysis on the following projects: Valley-Rainbow, Devers-Palo Verde 2, Jefferson-Martin, and Tehachapi. These projects are those that are of immediate concern to staff because they will (or do) require a CPCN from the CPUC, and they have either been denied a CPCN based on a CPUC assessment of costs and benefits or their ability to obtain a CPCN is not yet certain. As a result, staff believes that one or more of these projects may benefit from a timely analysis during the 2004 IEPR Update transmission proceeding identified above.

As an alternative to examining a specific project in the IEPR Update, if the project is still in the planning process or in the process of being reconsidered against new alternatives, it would be appropriate to request that the project proponent file information on the project, including studies, project status and timing in the general IEPR Update process. This would help the collaborative process and provide the state updated information on projects as they stand in the transmission planning process. Recommendations for the treatment of each project during the 2004 IEPR Update are outlined below.

Valley-Rainbow

SDG&E is currently in the process of considering alternatives to the original Valley-Rainbow project. In the event that SDG&E is ready to file for CPCN approval during the 2004 IEPR Update for one of these alternatives, staff recommends that the assessment of project costs and benefits and project need be conducted in the 2004 IEPR Update transmission proceeding and the results of that effort be used by the CPUC in the CPCN determination of need.

In the event SDG&E is not ready to file for a specific project review during the 2004 Update, staff recommends that SDG&E file information in the 2004 IEPR Update process related to the project studies that are underway, project status and timing in the CA ISO transmission planning process.

Devers-Palo Verde 2

SCE has indicated an interest in filing for CPCN approval of this project during 2004. Staff recommends that the assessment of project costs and benefits and project need be conducted in the 2004 IEPR Update transmission proceeding and the results of that effort be used by the CPUC in the CPCN determination of need.

This project is one of many projects being considered in the STEP process being led by the CA ISO. Twenty-six possible alternatives have been screened by the STEP group, and six have been recommended for further study. The STEP group's recommendations will influence whether or not this particular project is pursued by SCE and the CA ISO. If pursued, the STEP group would define the final project and its timing. In the event SCE is not ready to file for a specific project review during the 2004 Update, staff recommends that SCE file information in the 2004 IEPR Update process on the STEP project studies, and status and timing of the project in the STEP and CA ISO processes.

Jefferson-Martin

PG&E filed an application with the CPUC in September 2002 for CPCN approval. According to PG&E, the CPCN is expected to be granted by April 2004. Staff believes that this project, which is needed for reliability in San Francisco, could be completed by the CPUC on schedule. However, there are intervening parties to the proceedings which could result in additional issues and complexity in the proceedings and an extended schedule.

Staff believes that the 2004 IEPR Update transmission proceeding described above is the most robust process the state will have for determining project benefits and costs and providing a balanced decision on the need for a project. While this process would offer a more robust review and analytical results, the Jefferson-Martin project schedule does not fit well with the 2004 IEPR Update schedule and any delay in getting a decision on this transmission project. Therefore staff recommends that the Jefferson-Martin project should not be moved into the 2004 IEPR Update transmission review and instead should move forward through the CPUC process.

Tehachapi

SCE and wind producers in the Tehachapi region have been working on a solution to transmission congestion in the Tehachapi region for many years. There currently is not enough transmission in the area to deliver existing wind generation to loads in SCE's service area, especially during spring run-off times when large quantities of hydroelectric power are available. If a transmission facility is an integral part of a renewable project approved pursuant to the RPS process, it creates a prima facie finding that the facility will facilitate the achievement of the renewable power goals established in SB 1078 and the project is determined to be needed.

SCE has indicated that it plans to file an application for a CPCN in February of 2004 with an expected on-line date of December 2006. However, the CA ISO has indicated that it cannot support this project until alternatives are analyzed. Thus, the state's major transmission planning agency will require alternatives to be analyzed. Staff believes the timing of the Tehachapi project and the fact that alternatives will be a consideration in the project analysis makes this project a candidate for the 2004 IEPR Update transmission proceeding.

Staff recommends that the assessment of the Tehachapi project costs, benefits and alternatives be conducted in the 2004 IEPR Update transmission proceeding and the results of that effort be used by the CPUC in its finding of need for the project.

LEAGUE OF WOMEN VOTERS COLLABORATIVE EFFORTS

As discussed under Planning Issues in Chapter 5, staff recommends the following action as a result of the Joint Energy Commission and League of Women Voters efforts. This action would be pursued during the 2004 IEPR Update. Staff would identify the most effective and efficient methods to implement public participation in the context of the IEPR process and the EAP and ensure community impacts associated with transmission expansion are appropriately considered in the IEPR process and the CA ISO transmission planning process.

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GLOSSARY

Constraints – Physical and operational limitation in the transfer of electrical power through transmission facilities.

Investor owned utility (IOU) – A utility entity whose assets are owned by investors.

CA ISO control area – The electrical region under the operational control of the CA ISO.

Kilovolt (kV) – One thousand volts.

Kilowatt (kW) – One thousand watts. A unit of measure of the amount of electricity needed to operate given equipment.

Kilowatt-hour (kWh) – The most commonly used unit of measure telling the amount of electricity consumed over time. It refers to one kilowatt of electricity supplied for one hour.

Megawatt (MW) – One thousand kilowatts, or one million watts.

Megawatt-hour (MWh) – One thousand kilowatt hours.

Municipal utility – A local publicly-owned electric utility that owns or operates electric facilities subject to the jurisdiction of a municipality, as opposed to being subject to FERC or CPUC jurisdiction.

Reliability – The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. May be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.

Reliability Criteria – Principles used to design, plan, operate, and assess the actual or projected reliability of an electric system.

Reliability Must Run (RMR) Generation – The minimum generation (number of units or MW output) required by the CA ISO to be on line to maintain system reliability.

Renewable energy – Resources that constantly renew themselves or that are regarded as practically inexhaustible. These resources include solar, wind, geothermal, hydroelectric and waste-to-energy.

Volt – A unit of electromotive force. It is the amount of force required to drive a steady current of one ampere through a resistance of one ohm.

ACRONYMS

AB – Assembly Bill

ALJ – Administrative Law Judge

CA ISO – California Independent System Operator

CCSF – City and County of San Francisco

CEQA – California Environmental Quality Act

CERTS – Consortium for Electric Reliability Technology Solutions

CFE – Comisión Federal de Electricidad

COI – California-Oregon Interface

COTP – California Oregon Transmission Project

CPCN – Certificate of Public Convenience and Necessity

CPUC – California Public Utilities Commission

DOE – U.S. Department of Energy

DOI – U.S. Department of the Interior

DPV2 – Devers-Palo Verde 2

DSM – Demand-Side Management

DWR – California Department of Water Resources

EAP – Energy Action Plan

EIS – Environmental Impact Statement

EIR – Environmental Impact Report

ESI – Energy System Integration

FERC – Federal Energy Regulatory Commission

Hi – High demand scenario

HPPP – Hunters Point Power Plant

IEPR – Integrated Energy Policy Report

IID – Imperial Irrigation District

IOU - Investor-owned Utility

JMTP – Jefferson-Martin Transmission Project

kV – Kilovolt

kWh – Kilowatt-hour

LADWP – Los Angeles Department of Water and Power

LBNL – Lawrence Berkeley National Laboratory

LMP – Locational Marginal Price

LRA – Local Reliability Area

ML – Most likely demand scenario

MW - Megawatt

MWh – Megawatt hour

NP 15 – North of Path 15

NEPA – National Environmental Protection Act

NERC – North American Electric Reliability Council

OIR – Order Instituting Rulemaking

ORA – Office of Ratepayer Advocates

PACI – Pacific AC Intertie

PDCI – Pacific DC Intertie

PG&E – Pacific Gas and Electric

PIER – Public Interest Energy Research

POU – Publicly-owned Utility

PPP – Potrero Power Plant

PRC – Public Resources Code

PRR – Project Rating Review

PWG – Planning Work Group

QF – Qualifying Facility

R&D – Research and Development

RAS – Remedial Action Scheme

RMR – Reliability Must Run

ROW – Right-of-Way

RPS – Renewable Portfolio Standard

RTO – Regional Transmission Organization

SB – Senate Bill

SCE – Southern California Edison

SDG&E – San Diego Gas and Electric

SMUD – Sacramento Municipal Utility District

SONGS – San Onofre Nuclear Generating Station

SP 15 – South of Path 15

SPS – Special Protection Scheme

SSG-WI – Seams Steering Group – Western Interconnection

STEP – Southwest Transmission Expansion Plan

SWPL – Southwest Power Link

SWRTA – Southwest Regional Transmission Association

WECC – Western Electricity Coordinating Council, formerly the WSCC – Western System Coordinating Council

WSCC - Western System Coordinating Council

Western – Western Area Power Administration

WOR – West of (Colorado) River

WRTA – Western Regional Transmission Association

ENDNOTES

[1] The contribution from the individual municipal utilities is as follows: City/County of San Francisco – 328 miles; California Department of Water Resources – 37 miles; Modesto Irrigation District – 69 miles; Northern California Power Agency – 40 miles; City of Redding – 67 miles; Sacramento Municipal Utility District – 444 miles; Transmission Agency of Northern California – 271 miles; Turlock Irrigation District – 117 miles; City of Vernon – 27 miles; Los Angeles Department of Water and Power – 3519 miles; and Metropolitan Water District of Southern California – 305 miles.

[2] The Energy Commission's jurisdiction over transmission lines is limited to those lines associated with power plant proposals before it.

[3] The market prices diverged often during low load periods as well, but those were created by local minimum load conditions that prevented the import of lower price power from other regions. Staff has removed these hours from the analysis to focus solely on Path 15 congestion.

[4] Personal communication with Kellan Fluckiger, CA ISO, May 2002.

[5] In May 2003, a U.S. Federal Court made a preliminary finding that the environmental reviews for the new projects and associated transmission facilities had not been properly performed, and ordered a stay, preventing power transfers to the U.S. until the issue is resolved.

[6] SDG&E 2002 Grid Assessment Study and Transmission Expansion Plan – Final Report, January 30, 2003, p. 7.

[7] Ibid, p. 10.

[8] CEC Forecast – 2001 (see citation on table 1) and SDG&E 2001 load forecast.

[9] CA ISO, 2002. *2003 Reliability Must-Run Technical Study of the ISO-Controlled Grid.*

[10] The Energy Action Plan sets an accelerated goal for achieving the 20 percent level by the year 2010.

[11] See California Public Resources Code 25620 through 25620.10 for a complete description of the program and its functions.

[12] "Draft Five-Year Transmission Research and Development Plan," June 2003, Publication Number 500-03-050D and supporting documents are located at http://www.energy.ca.gov/pier/strat/strat_research_trans6.html

[13] CA ISO, July 29, 2003, STEP Economic Screening Study PowerPoint presentation by Mohamed Awad, CA ISO Grid Planning. Accessed at: http://www2.caiso.com/docs/2003/07/31/2003073110204620001.pdf

[14] SSG-WI Planning Function and its Interactions within the Western Interconnection, August 5, 2003. Available at http://www.ssg-wi.com/documents/256-Planning_Process___Approved_by_SSG_August_5__2003.doc

[15] SSG-WI 2008-2013 Transmission Study, July 18, 2003, p. 8. Available at http://www.ssg-wi.com/documents/243-071803_2008_and_2013_Study_Presentation_SSG.WI.7.18.ppt

[16] Ibid, p. 63. Study being revised. More recent results available at http://www.ssg-wi.com