CALIFORNIA
ENERGY
COMMISSION

STRATEGIC TRANSMISSION INVESTMENT PLAN

COMMISSION REPORT

Prepared in Support of the *2005 Integrated Energy Policy Report* Proceeding (04-IEP-1K)

NOVEMBER 2005
CEC 100-2005-006-CMF

Arnold Schwarzenegger, *Governor*

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Table of Contents

List of Tables and Figures

EXECUTIVE SUMMARY AND RECOMMENDATIONS

Disruptions on California's more than 31,000-mile electric transmission system can be catastrophic. As recently as August 25, 2005, the loss of the 500 kV Pacific DC Intertie from Oregon to Southern California caused rolling blackouts in Southern California, blacking out large blocks of the service territories of Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E).This line loss occurred just before 4 p.m. as California was fast approaching its peak electricity demand on a hot summer day. The line loss forced the California Independent System Operator (CA ISO) to issue a Transmission Emergency Notice for Southern California and request that SCE and SDG&E reduce demand on the transmission system south of Path 26. This quickly escalated to the dropping of 800 megawatts (MW) of voluntary interruptible customers and 900 MW of firm load. The resulting outage to approximately 500,000 customers is the largest single disruption in California since the 2000-2001 energy crisis and is a graphic example of how a low-probability/high-impact event, relatively short in duration, takes a disproportionately high social and economic toll on all Californians. This outage clearly demonstrates the need for comprehensive improvements to and investments in California's transmission system and highlights the inadequacies of current institutional arrangements to do so.

In 2004, noting both the lack of an official state role in transmission planning and the failure of the existing process to consider broader state interests, the Legislature directed the California Energy Commission (Energy Commission) to develop a *Strategic Transmission Investment Plan (Strategic Plan)* identifying and recommending actions needed to stimulate transmission investments to ensure reliability, relieve congestion, and meet future growth in load and generation, including renewable resources, energy efficiency, and other demand reduction measures.

The *Draft Strategic Plan* was published in September 2005 and is available on the Energy Commission website at: [http://www.energy.ca.gov/2005publications/CEC-100-2005-006/CEC-100-2005-006-CTD.PDF].

The findings contained in the *Draft Strategic Plan* were presented at the California Energy Commission's (Energy Commission) September 23, 2005 Committee hearing.[1] Parties were invited to provide verbal comments at the hearing as well as written comments by October 14, 2005.[2]

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[1] See website: [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#092305].

[2] See website: [http://www.energy.ca.gov/2005_energypolicy/notices/2005-09-23_hearing_notice.html].

The Energy Commission considered all comments received and has incorporated relevant information into this report.

The following sections provide an overview of the significant transmission planning and system issues hindering development of a more robust high voltage grid and identify actions necessary to improve California's transmission system.

Transmission Planning and Permitting

A number of obstacles currently block an effective statewide transmission system planning and permitting process. These include a lack of widespread participation in the transmission planning process, resulting in a narrow focus on issues important to transmission owners and the CA ISO but which neglect broader state interests including the development of renewable resources. The state's present permitting process for bulk transmission is also unable to approve needed projects in a timely manner and often undervalues options for addressing reliability problems, as well as projects needed primarily for economic reasons. Taken together, these factors have hampered development of critically needed transmission investments and effectively blocked development of a responsive and reliable transmission grid.

The planning process should proceed in the context of a broad resource planning function that effectively evaluates and makes appropriate trade offs between transmission, generation, and demand side alternatives. The permitting process should properly focus on exercising the state's land use authority and assessing and mitigating environmental impacts in accordance with the California Environmental Quality Act (CEQA). The planning and permitting processes must also recognize the needs of state and federal agencies in carrying out their respective ratemaking responsibilities.

Recommendations

Consistent with Governor Schwarzenegger's August 23, 2005, *Review of Major Integrated Energy Policy Report Recommendations*, the Energy Commission recommends the following actions:

- **Establish a comprehensive statewide transmission planning process.** In order to provide regulatory certainty in the permitting process and facilitate the approval of needed transmission projects, the Energy Commission recommends that it collaboratively establish a comprehensive statewide transmission planning process with the CPUC, the CA ISO, other key state and federal agencies, local and regional planning agencies, investor-owned and municipally owned utilities, generation owners and developers, the public, and other interest groups to:
    - Assess statewide transmission needs for reliability and economic projects and support Renewables Portfolio Standard (RPS) goals.
    - Examine non-wires alternatives to transmission.

- Approve beneficial transmission infrastructure investments that can move smoothly to permitting. This process should include:
  - Examination of right-of-way needs.
  - Designation and environmental reviews of needed corridors.
  - Allowing investor-owned utilities (IOUs) to bank future transmission lands and easements for longer periods of time.
  - Assessment of transmission costs and benefits that recognize the long, useful life of transmission assets.
  - Incorporation of quantitative and qualitative methods to assess the long-term strategic benefits of transmission.
  - Use of an appropriate social discount rate.

- **Transfer transmission permitting to the Energy Commission.** The Energy Commission recommends that the permitting process for all new bulk transmission lines be consolidated within the Energy Commission, using the Energy Commission's power plant siting process as the model.
- **Disaggregate demand forecast for use in the statewide transmission planning process.** The Energy Commission recommends that it create new methodologies to develop bus-level load forecasts compatible with *Energy Report*-adopted load forecasts and other longer-term forecasting uncertainties. In the short term, create forecasts for load pockets and other areas that support local deliverability assessments and near-term procurement decisions.
- **Continue participation in the Western Assessment Group.** The Energy Commission recommends that it continue to participate in the Western Assessment Group initiative to ensure that California's interests are represented.
- **Establish a designation process for transmission corridors.** The Legislature should grant the Energy Commission the statutory authority to designate corridors for electricity transmission facilities.
- **Extend the length of time for rate-basing IOU corridor investments.** The CPUC should extend the length of time an IOU is allowed to keep the costs of land acquired for corridors in its rate base. The Legislature should direct the CPUC to act on this recommendation.
- **Authorize the Energy Commission staff to work collaboratively with federal agencies to determine where complementary state designated corridors can be aligned with federally designated corridors.** For example, the existing Palo Verde-Devers corridor contains a number of transmission lines and has been identified as the best location for future construction of the proposed PVD2 Project. Given the importance of this corridor for meeting California's energy needs, the Energy Commission recommends review of current land uses along this and other existing federally designated corridors to determine where complementary state designation makes sense.

- **Investigate changes to the CA ISO transmission expansion tariff.** The CA ISO transmission expansion tariff recognizes only two types of transmission projects for determining need: economically driven and reliability driven projects. The Energy Commission therefore recommends that the CPUC, the CA ISO, and the Energy Commission investigate changes to the CA ISO tariff to accommodate transmission for renewable generation interconnections.
- **Investigate regulatory changes to support clustered development of renewable projects.** In addition to efforts to modify the CA ISO transmission expansion tariff to allow for a third type of transmission project, the Energy Commission recommends investigating current changes to the CA ISO transmission expansion tariff and other regulatory policies to allow for and support the clustered development of renewables.

Transmission System Problems

California has many opportunities to improve transmission infrastructure, both within the state and with its interstate interconnections in the Western United States, Canada and Mexico. The challenge for regulators is to identify the best mix of transmission projects to ensure a reliable network, improve access to renewable generation, and minimize the cost of providing electricity to California. However, two main categories of transmission system problems continue to plague California: infrastructure issues, including ongoing concerns with congestion and local reliability, and prospective operational issues associated with renewables integration. Chapter 3 discusses these issues and highlights promising emerging technologies that, along with the transmission project recommendations in Chapter 4, could address existing transmission bottlenecks and enhance the development of a reliable, efficient, and diverse transmission system in California.

Recommendations to Address Reliability, Congestion, Renewables, and Future Growth in Load and Generation

- Support proposed transmission projects that will move less costly power from Arizona and the Southwest into Southern California.
- Support proposed transmission projects to improve access to in-state renewable resources.
- Support proposed transmission projects to meet reliability standards for major load centers.

Recommendations to Address Operational Integration of Renewables

- Operational challenges associated with renewables present potential barriers to meeting RPS goals. The state should continue to support the formation and efforts of stakeholder-based study groups addressing operational integration issues.

- Current transmission bottlenecks effectively limit the ability to transmit renewable generation from remote locations to major load centers. The state should continue to support the formation and efforts of stakeholder-based study groups developing transmission expansion plans that allow for the efficient movement of renewable energy to consumers.
- Minimum load issues may be exacerbated by the intermittent nature of some renewable resources. The state should initiate research to optimize operation of existing pumped hydro storage facilities and identify viable locations for new pumped hydro storage facilities that would complement intermittent renewable generation.
- Reducing uncertainty in resource availability will reduce the need for reserve backup for intermittent renewable generators. The state should continue to promote research efforts to improve forecasts of intermittent resource availability.

Emerging Technology Recommendations

- The state should continue to support the research and development of new transmission technologies through the Energy Commission's Public Interest Energy Research (PIER) program.

Transmission Projects

The present transmission system in California is not planned, designed, or operated for the maximum benefit to the state's ratepayers. The multiplicity of jurisdictions blocks effective statewide planning of the system. Present methods for approving and constructing new projects also appear to undervalue transmission system upgrades, especially in comparison with continued reliance on older, less efficient gas-fired power plants.

Operators are constantly adjusting the system to respond to fluctuating load conditions because of the limited ability to accurately forecast electric system load, generation needed to balance the system, and resultant transmission flows. Inaccurate load forecasts and physical transmission system bottlenecks are causing considerable congestion on the system, to the point of adversely impacting system reliability under some conditions. This congestion often forces operators to rely upon less efficient generation to address local reliability concerns due to the inability to transmit more efficient generation into load centers, which greatly increases costs. Congestion and reliability costs in 2004 alone are an estimated $1 billion statewide.

Unless addressed immediately, existing transmission problems could prevent the state from meeting RPS goals. Adding significant new renewable generation at many locations is already limited by transmission system constraints. Increased development of renewable generation, especially from remotely located wind farms and geothermal sources, appears impossible without upgrading the transmission system in many parts of the state.

Upgrading California's existing transmission system will provide many benefits to state ratepayers. A range of upgrades is needed, from relatively simple reconductoring projects (where the capacity of an existing line is increased by replacing the conductors), to construction of major new transmission lines. Increased transmission capacity will help ensure system reliability and provide access to both renewables and lower-cost conventional generation.

Project Investment Recommendations

Transmission projects described below will provide significant near-term benefits to California through improvements to system reliability, reduced congestion, and/or interconnection to renewable resources. The Energy Commission recommends investment in the following projects:

- **PVD2 500 kV Project -** The proposed PVD2 500 kV Project would provide significant near-term benefits by reducing congestion on lines connecting California and Arizona and providing access to lower-cost out-of-state generation. The proposed project would also provide strategic benefits to California ratepayers, including valuable insurance against abnormal system conditions and power outages. It would increase operating flexibility for California grid operators, reduce market power for generators, and reduce the need for additional infrastructure in California. The PVD2 Project is therefore a major component of California's Strategic Plan. The Energy Commission strongly believes that the proposed project offers significant benefits and recommends that the project be moved forward expeditiously so that California can begin realizing these benefits by 2010.
- **Sunrise Powerlink 500 kV Project** - The proposed 500 kV Sunrise Powerlink Project would provide significant near-term system reliability benefits to California, reduce system congestion and its resultant costs, and provide an interconnection to both renewable resources located in the Imperial Valley and lower-cost out-of-state generation. Without this proposed project, it is unlikely that SDG&E will be able to meet the state's RPS goals, ensure system reliability, or reduce RMR and congestion costs. The Energy Commission therefore believes that the proposed project offers significant benefits and recommends that it move forward expeditiously so that the residents of San Diego and all of California can begin to realize these benefits by 2010.
- **Tehachapi Transmission Plan, Phase I: Antelope Transmission Project -** The Energy Commission believes that the Antelope Transmission Project, proposed by SCE, is crucial to the development of wind resources in the Tehachapi region and will offer significant benefits to California. As such, the proposed project is considered a major component of California's Strategic Plan. The Energy Commission therefore recommends the project be moved forward expeditiously so that California can begin realizing benefits by 2010.

- **Imperial Valley Transmission Upgrade -** An Imperial Valley upgrade project would provide access to valuable renewable resources needed to meet future load growth, support California's RPS goals and provide significant near-term reliability benefits to California. The Energy Commission therefore believes that Phase 1 of the Imperial Valley Study Group's proposed plan, including a 500 kV link to SDG&E, would provide significant benefits to California and recommends that Phase 1 move forward expeditiously. Further transmission development in the Imperial Valley region should be carefully coordinated to avoid duplication and to create a transmission system that serves the needs of both California and the West.
- **Trans-Bay Cable Project** – Although the Trans-Bay DC Cable Project is not needed for reliability purposes until after 2011, the CA ISO has approved the project for early operation in 2009, consistent with Trans-Bay Cable LLC's plans. The Energy Commission agrees with the CA ISO's assessment that the advanced in-service date provides insurance benefits that outweigh the net cost to CA ISO ratepayers. Therefore, the Energy Commission recommends that the Trans-Bay DC Cable Project move forward expeditiously so that the San Francisco Peninsula and the CA ISO control area can realize these reliability benefits.

Actions to Implement Investments

- The CPUC should take action to ensure that the permitting processes for the DPV2 and Tehachapi Phase I projects are effective and completed within the 12 months required by law.
- The CPUC should take action to ensure that long-term strategic insurance benefits are fully addressed in CPUC permitting assessments of project benefits for transmission projects deemed vital to the state in the Energy Commission's Strategic Plan.
- The CPUC should assign great weight in its permitting process to the project need assessments submitted by the CA ISO.
- The CA ISO should take action to ensure that results from its new transmission planning process are available by January of 2006 and include an examination of strategic benefits for the SDG&E 500 kV Sunrise Powerlink Project.
- Consistent with the corridor designation recommendation to the Legislature and the Project Investment recommendations noted above, once the Legislature establishes a corridor designation process, the Energy Commission should take the following corridor-related actions:
    - **PVD2 500 kV Project -** Form a Corridor Study Group to review existing land uses along the existing Interstate 10 transmission corridor and coordinate with local, state, and federal agencies, landowners, and other interested parties. The Interstate 10 corridor is an important asset to California and, if granted corridor designation authority by the Legislature, the Commission

should consider corridor designation on non-federal lands to complement existing federal corridor designations.

  - **Sunrise Powerlink 500 kV Project –** Form a Corridor Study Group to ensure that coordination with local, state, and federal agencies, landowners, and other interested parties begins immediately.
  - **Tehachapi Transmission Plan -** Should land use in the Tehachapi region become problematic in the future, the Energy Commission should consider forming a Corridor Study Group to assist in addressing right-of-way routing issues associated with this project.
  - **Imperial Valley Transmission Upgrade -** In the absence of permitting progress, the Energy Commission should consider forming a Corridor Study Group to assist in addressing right-of-way routing issues associated with this project.

- As noted in Chapter 2, the Legislature should establish a designation process for transmission corridors and grant the Energy Commission authority to designate corridors for electricity transmission facilities. The Legislature should establish this process in time to assist with routing issues for the Sunrise Powerlink 500 kV Project.

CHAPTER 1: INTRODUCTION

Strategic Transmission Plan Background

History

California is criss-crossed by over 31,000 miles of bulk electric transmission lines, along with their supporting towers and substations. The transmission system links generation to load in a complex electrical network that balances supply and demand on a nearly instantaneous basis. An effective transmission system delivers lowest-cost generation to consumers and facilitates markets to stimulate competitive behavior, pools resources for ancillary services,[1] and provides emergency support in the event of major generating unit outages or natural disasters.

Most of California's electric transmission system was originally built to connect generating facilities with major load centers in the Los Angeles, San Francisco, and Sacramento areas. Thermal generating facilities, including large gas-fired and nuclear plants, were built either near the coast or in nearby valleys close to load centers, requiring relatively short transmission lines. Hydroelectric facilities in the Sierra Nevada have historically been the most remote generation sources in the state.

The state's investor-owned utilities (IOUs), Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E), designed, built, and operated their own systems to meet the needs of their customers. Until the mid-1960s, the three IOUs operated their transmission systems as islands, with only a few small electrical ties between utilities. As California's dependence on oil and gas generation increased and licensing large generating stations became increasingly difficult, the IOUs began planning and building higher-voltage, longer transmission lines to neighboring states. The 500 kilovolt (kV) transmission lines were built primarily for importing hydroelectric power from the Pacific Northwest and thermal generation from the Southwest. While these transmission lines primarily provided access to less costly out-of-state power, they also provided emergency interconnection support among the state's utilities to avoid potential wide-scale power disruptions. (On the other hand, this widespread interconnected Western Grid has also proven to be quite fragile. As the August 10, 1996, Western States outage showed, California utilities have increased their outage vulnerability to quite remote events, such as a transmission line sagging into a tree in an improperly maintained right-of-way in Oregon that initiated a cascading blackout from Mexico to Canada.) The 1965 East Coast blackout, the first such widespread outage in the U.S., affected almost 30 million people and prompted the creation of the North American Electric Reliability Council (NERC). Between 1968 and 1974, California utilities built or participated in construction of about 3,700 miles of 500 kV lines to remote generation sources. Since the 1980s, only two additional

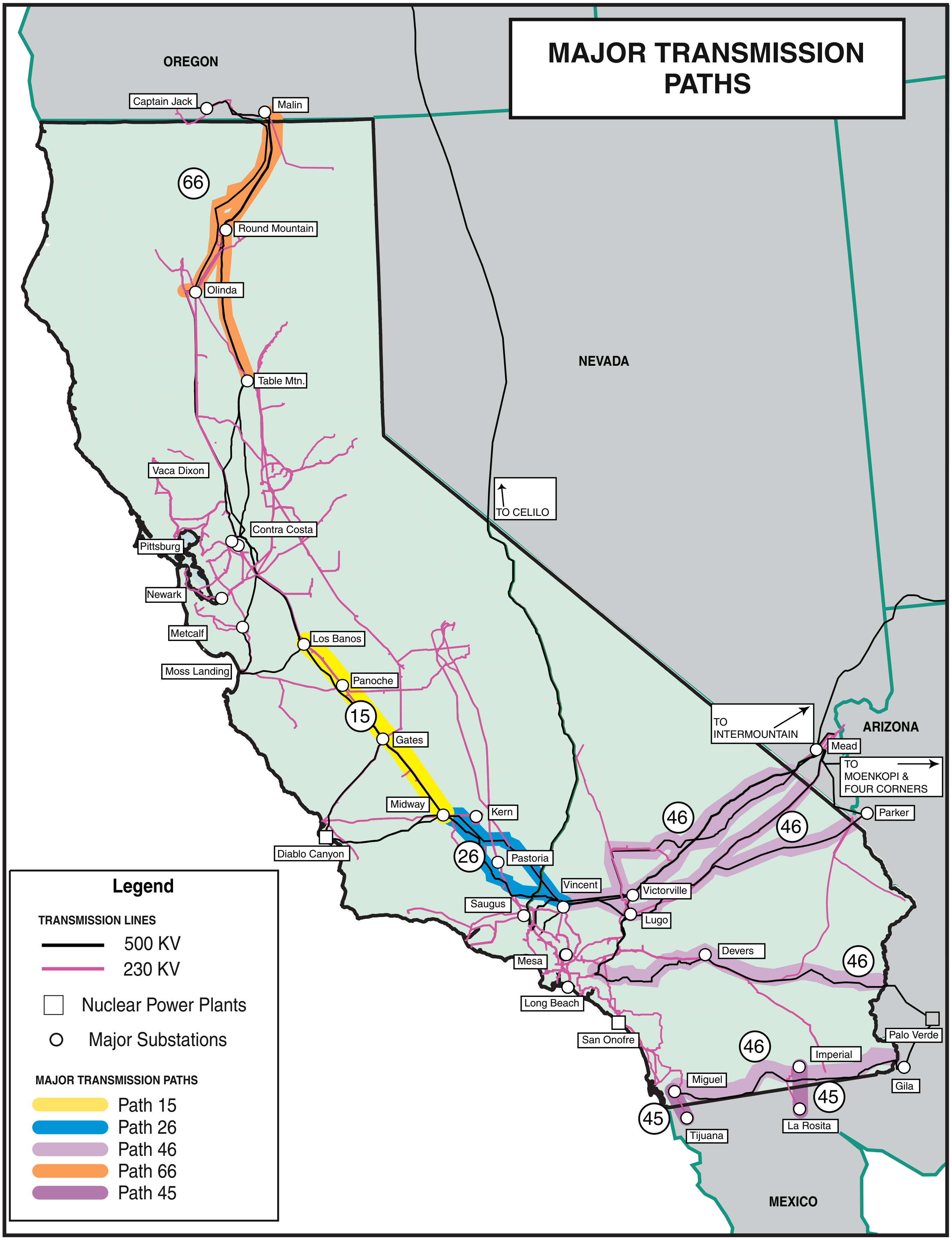
500 kV projects have been built to access out-of-state resources, and both of those projects were initiated by municipally owned utilities.

California's current bulk inter- and intra-state transmission system is shown in Figure 1.

With the 1996 passage of Assembly Bill 1890 (AB 1890, Brulte, Chapter 854, Statutes of 1996), which restructured California's electricity industry, the California Independent System Operator (CA ISO) was formed in 1998 to operate the state's wholesale power grid (covering over 25,000 miles), provide open and nondiscriminatory transmission service, ensure safe and reliable operation of the grid, and operate energy and reliability markets. The participating transmission owners (PTOs), consisting of the individual IOUs and participating municipal utilities,[2] continue to own their own lines and be involved in transmission planning by filing annual transmission expansion plans with the CA ISO. The CA ISO's coordinated planning process integrates individual plans, ensuring reliability at minimum cost, as well as ensuring that expansion projects do not negatively affect the western regional grid. However, this process is primarily reactive since the CA ISO acts only on projects submitted by the PTOs for approval. Transmission expansion projects mitigating costs associated with congestion on heavily utilized lines within the CA ISO control area have often only been completed after significant congestion costs have accrued. Recently, the CA ISO proposed a new planning process with the goal of proactively eliminating congestion and reliability must run (RMR) generation contracts where it makes economic sense to do so, creating a more robust transmission system.

Although economic expansion and population growth in California and the West continued throughout the 1990s, investments in generation and transmission infrastructure slowed dramatically, hindered by uncertainties over pending market restructuring and a defective and inadequate state permitting process. These circumstances threatened the efficiency and reliability of the transmission system, created significant system congestion, and limited access to and deliverability of low-cost electricity imports to California.

FIGURE 1
Major Transmission Paths (230 kV to 500 kV)



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, AUGUST 2005
SOURCE: CEC Staff

During the energy crisis of 2000-2001, the transmission system was plagued by widespread and uncontrolled congestion that precluded the effective transfer of electricity to load centers at critical times. System reliability was at an all-time low. Utilities responded by instituting rotating outages, or "rolling blackouts," on several occasions to maintain grid stability and prevent more severe and widespread blackouts throughout the state. In the end, transmission bottlenecks jeopardized system reliability and imposed hundreds of millions of dollars in additional wholesale electricity costs on consumers. The economic value of disrupted business activity has never been evaluated. The experience was an important lesson for California – failure to invest in the transmission system can be catastrophic, lead to excessive price volatility and, in some local areas, cause outages. Although the state acted to increase system reliability and stabilize electricity prices by entering into a series of long-term electricity supply contracts, California continues to face serious, near-term challenges in ensuring adequate investments in transmission capacity to meet the growing electricity needs of its businesses and residents. While the state has made solid progress in permitting and constructing power plants since the energy crisis, the transmission system still suffers from excessive congestion and its significant costs, defective transmission planning and permitting processes, and an overall lack of investment in an efficient and reliable transmission system.

Legislation

In 2002, noting the importance of reliable energy supplies, Senate Bill (SB)1389 (Bowen and Sher), Chapter 568, Statutes of 2002, added Section 25300 *et seq.* to the Public Resources Code (PRC), requiring the Energy Commission to adopt an *Integrated Energy Policy Report* (*Energy Report*) every two years. In preparing the *Energy Report*, the Energy Commission was directed to evaluate energy trends and issues facing California and develop and recommend policies for the state to ensure reliable and economical energy supplies. Energy Commission assessments and forecasts are available to state agencies with energy responsibilities to ensure consistency in the information that forms the foundation of energy policy and decisions. Those agencies are required to use the results of the *Energy Report* when making energy policy decisions.

In 2004, noting the lack of an official state role in transmission planning and the failure of the existing process to consider broader state interests, SB 1565 (Bowen), Chapter 692, Statutes of 2004, added PRC Section 25324:

> The [Energy] commission, in consultation with the Public Utilities Commission, the California Independent System Operator, transmission owners, users, and consumers, shall adopt a strategic plan for the state's electric transmission grid using existing resources. The strategic plan shall identify and recommend actions required to implement investments needed to ensure reliability, relieve congestion, and meet future growth in load and generation, including, but not limited to, renewable resources, energy efficiency, and other demand

> reduction measures. The plan shall be included in the integrated energy policy report adopted on November 1, 2005, pursuant to subdivision (a) of Section 25302.

With SB 1565, the Legislature acknowledged the importance of a state role in the transmission planning process and recognized the Energy Commission as the state agency best suited to undertake and accomplish this effort. The *Strategic Transmission Plan (Strategic Plan)* creates the opportunity to develop a blueprint for development of an efficient and reliable bulk transmission system for California.

Resources Used to Develop the Strategic Plan

Previous Integrated Energy Policy Report Work

In August 2003 Energy Commission staff published a report entitled *Upgrading California's Electric Transmission System: Issues and Actions*. Staff's report, developed in support of the Energy Commission's assessment of energy infrastructure issues for the *2003 Energy Report*, identified three types of major transmission problems faced by California. The problems included congestion on major transmission paths (both interstate and intrastate), transmission constraints in the San Francisco Bay Area and San Diego load centers, and the inability of the transmission system to provide adequate access to existing and future renewable generation. The staff report also noted several transmission planning and permitting problems faced by the state, including:

- Fragmented and overlapping permitting jurisdictions.
- Inconsistent environmental analyses of projects.
- Inadequately considered regional and statewide benefits.
- Ineffective methods of encouraging public participation.

The staff report also provided an assessment of four projects of immediate concern: the SDG&E Valley-Rainbow Project, the SCE Palo Verde-Devers No. 2 Project, the PG&E Jefferson-Martin Project, and the Tehachapi Expansion Project.

The *2003 Energy Report* identified four strategies to guide California's energy future and attract investments needed to meet California's demand for more energy resources while protecting the economy and environment. These strategies included:

- Expanding energy efficiency programs.
- Diversifying fuels and fuel sources of petroleum and natural gas with alternative fuels and renewable energy.
- Offering consumers energy choices.
- Strengthening the state's energy infrastructure.[3]

Regarding transmission infrastructure, the *2003 Energy Report* emphasized that major transmission upgrades and improvements were needed for the transmission system to provide reliable, efficient, and affordable energy to the state. However, numerous obstacles prevented the effective planning, permitting, and operation of the transmission system, including a lack of state participation in the transmission planning process and the state's flawed transmission permitting process. Lack of state participation in the planning process resulted in consideration of issues important to transmission owners and the CA ISO, but not to broader state interests including the development of renewable resources. In addition, several problems inherent in the state's transmission permitting process prevented approval of needed projects in a timely manner. The *2003 Energy Report* concurred with the findings of the staff report, noting the need to:

- Improve the analytical methodologies used to evaluate the costs and benefits of transmission projects.
- Evaluate the impact and value of low-probability but high-impact events.
- Compare the costs and benefits of transmission projects against non-transmission alternatives in the planning process instead of the permitting process.

In addition, the *2003 Energy Report* recommended that:

- The Energy Commission should continue to implement a fully collaborative state transmission planning process with the CA ISO, the California Public Utilities Commission (CPUC), and utilities.
- The state should "consolidate the permitting process for all new bulk electricity transmission lines within the Energy Commission, using the Energy Commission's power plant siting process as the model."[4]

In July 2004 Energy Commission staff published a sequel transmission report, *Upgrading California's Electric Transmission System: Issues and Actions for 2004 and Beyond*. Staff's report continued to support development of a coordinated long-term transmission planning process capturing strategic project benefits and plans for transmission corridors to reduce and prevent permitting delays, adequately assess project alternatives, and bring forward transmission investments to meet California's needs.

The *2004 Energy Report Update* continued this focus on upgrading California's energy infrastructure by providing additional analyses and recommendations on reliability, transmission planning, and renewable energy development, as well as a "report card" of the state's progress on the 2003 recommendations. Importantly, the *2004 Energy Report Update* highlighted the state's need to "…significantly alter its approach to transmission planning, not only to keep the lights on and hold down energy costs, but also to advance critical state energy, environmental, and economic policy goals."[5] The 2004 staff report and the *2004 Energy Report Update* recommended:

- Initiating a comprehensive and fully collaborative statewide transmission planning process with four major objectives:
  - Assess the statewide need for reliability and economic transmission projects and projects supporting implementation of the Renewables Portfolio Standard (RPS).
  - Approve beneficial transmission investments that can move directly to permitting without revisiting need.
  - Examine statewide corridor needs for future transmission projects, designate and conduct environmental reviews of corridors, and allow utilities to extend land cost recovery in rate bases.
  - Examine project alternatives early in the planning process so that environmental review can focus on routing alternatives and mitigation measures.
- Improving the transmission cost/benefit assessment to:
  - More accurately reflect the long-term value of transmission assets.
  - Quantitatively and qualitatively capture strategic benefits including insurance against contingencies during abnormal system conditions, price stability and mitigation of market power, increased reserve resource sharing potential, environmental benefits, and achievement of state policy objectives including development of renewable resources.
  - Reflect the "public good" nature of transmission through use of an appropriate discount rate.

With respect to meeting RPS goals, the *2004 Energy Report Update* recommended several actions to meet transmission needs:

- Increase Energy Commission participation in the Tehachapi Study Group in CPUC Proceeding I.00-11-001, Phase 6.
- Work with stakeholders to identify corridor and rights-of-way studies to ensure effective and efficient permitting for the Tehachapi Wind Resource Area.
- Establish a joint Transmission Study Group for the Imperial Valley area.
- Investigate, along with the CPUC and the CA ISO, whether changes are needed to the CA ISO tariff to provide for a third class of projects supporting RPS goals and designed to deliver renewable generation to the grid.

In July 2005, Energy Commission staff published its third annual transmission report, *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond*. Staff's report contains a comprehensive assessment of the status of transmission planning and permitting activities, ongoing system problems such as congestion and reliability, an update on transmission projects, the development of a state-led corridor planning process, and transmission issues associated with renewables integration.

The *2005 Energy Report* stresses the need to upgrade and expand California's transmission infrastructure to ensure a reliable supply of electricity, reduce electricity costs, and ensure delivery of electricity from present and future generation sources. Improving California's ability to plan for and economically reduce transmission congestion, while at the same time ensuring statewide and local reliability, is a critical policy issue for the state. The *2005 Energy Report* concluded that California must address three primary transmission issues:

- The state lacks a well-integrated transmission planning and permitting process, which inhibits critically needed transmission investments to counter the dramatic increases in congestion costs and eliminate serious threats to electric system reliability.
- California needs a formal transmission corridor planning process to identify critical transmission requirements well in advance of their need so utilities can acquire necessary lands and easements and local governments can avoid conflicting land uses.
- California will not be able to meet its RPS goals without major investments in new transmission infrastructure to access remotely located renewable resources in the Tehachapi and Imperial Valley areas.

Other Reports, Filings, and Materials

The record of the *Strategic Plan* incorporates all information, comments, filings, staff reports, consultant reports, and studies contained in the record for the 2003 Energy Report, the 2004 Energy Report Update, and the 2005 Energy Report. This information is available on the Energy Commission's website: http://www.energy.ca.gov/energypolicy/index.html.

Strategic Plan Organization

This Strategic Plan is organized as follows:

Chapter 2 focuses on the transmission planning, corridor planning, and transmission permitting process actions needed to ensure achievement of Strategic Plan goals.

Chapter 3 discusses two main categories of transmission system problems: infrastructure issues, including ongoing concerns with congestion and local reliability, and operational issues associated with renewables integration. In addition, this chapter highlights promising emerging technologies that may represent important investment opportunities for enhancing the planning for and operation of the transmission system.

Chapter 4 focuses on recommendations for specific transmission projects that the Energy Commission believes represent important project investment opportunities.

These projects, when constructed, will enhance the development of a reliable, efficient, and diverse transmission system in California. The chapter describes the evaluation criteria, including those contained in PRC section 25324 as a starting point, plus additional criteria consistent with the *2005 Energy Report* and Governor Schwarzenegger's August 23, 2005, response to the *2003 Energy Report* and the *2004 Energy Report Update.*[6]

Chapters 2 through 4 conclude with recommended actions to implement the plan.

Endnotes

[1] Ancillary services include those services other than scheduled energy which are required to maintain system reliability and meet Western Electricity Coordinating Council and North American Electric Reliability Council operating criteria. Such services include spinning, non-spinning, replacement reserves, regulation (automatic generation control), voltage control, and black start capability. (Source: http://www.caiso.com/aboutus/glossary/)

[2] The Los Angeles Department of Water and Power (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.

[3] California Energy Commission, December 2003, *2003 Integrated Energy Policy Report*, p. 2, Sacramento, CA, P100-03-019, [http://www.energy.ca.gov/reports/100-03-019F.PDF], (August 30, 2005).

[4] Ibid, p. 20.

[5] California Energy Commission, November 2004, *Integrated Energy Policy Report 2004 Update*, p. xviii, Sacramento, CA, P100-04-006CM, [http://www.energy.ca.gov/reports/CEC-100-2004-006/CEC-100-2004-006CMF.PDF], (August 30, 2005).

[6] Schwarzenegger, Arnold, *Review of Major Integrated Energy Policy Report Recommendations*, August 23, 2005, [http://www.governor.ca.gov/govsite/pdf/press_release_2005/IEPR_Response.pdf], (August 24, 2005.)

CHAPTER 2: ADDRESSING PLANNING AND PERMITTING ISSUES

Background

Over the last decade, transmission owners and operators have faced growing uncertainty in their efforts to deliver reliable, affordable power in environmentally acceptable ways. While California has taken modest steps in planning and permitting new transmission facilities, the state still suffers from inadequate infrastructure following years of underinvestment in transmission lines. California must continue to improve its transmission infrastructure planning and permitting processes in order to ensure development of a reliable, efficient and diverse transmission system allowing the achievement of RPS goals. To achieve this objective in the most cost effective and environmentally responsible manner, the corridors associated with needed transmission projects must also be planned, analyzed for environmental impacts, and set aside well in advance of need.

This chapter addresses three major aspects of transmission planning: the need for a coordinated long-term transmission planning process, the need for a state-led transmission corridor planning process, and the need for coordination among the Western states. It also addresses the major problems associated with fragmented and inadequate transmission permitting processes and the status of actions dealing with these problems. The chapter also introduces three major potential barriers to achieving RPS goals: funding for RPS transmission facilities, operational challenges associated with intermittent renewable generation, and existing transmission bottlenecks that are exacerbated by further renewables development, especially in remote locations.

The increasing difficulty of permitting new transmission lines has slowed development. Major California projects have been denied permits because of methodological differences in cost and benefit assumptions. Power lines are becoming more congested, increasing the cost and decreasing the reliability of the grid. Wholesale competition has also decoupled transmission line planning from new generation siting, resulting in inefficient generator siting. Coordinating generation and transmission siting is extremely important for meeting California's RPS goals since renewable energy resources such as wind and geothermal are often located in areas remote from transmission facilities.

While planning and permitting transmission facilities can take years, the cost of transmission to California ratepayers still makes up only a small fraction of the total cost of electricity. The October 2004 Rate Tariffs for SCE, SDG&E and PG&E included transmission costs varying between 3.82 mills per kilowatt-hour (mills/kWh) and 7.46 mills/kWh, or between 3.4 and 6.3 percent of the total electricity rate per kWh, depending upon the utility and rate class.[1] While the cost of transmission relative to the overall cost of electricity is small, the cost of failures in the transmission system can be catastrophic, leading to price spikes and, for some local areas, outages.

For the past two years, the Energy Commission has made recommendations for needed improvements to the transmission planning and permitting processes. The *2003 Energy Report* recommends that the Energy Commission continue to work toward a fully collaborative state transmission planning process and that the permitting process for new bulk transmission lines be consolidated at the Energy Commission. The *2004 Energy Report Update* recommends that the state implement a comprehensive proactive transmission expansion policy that recognizes the long useful life of transmission assets and their increasingly "public goods" nature. The report also recommends establishment of a process to effectively plan and designate transmission corridors well in advance of their need.

This Strategic Plan offers the opportunity to build a transmission blueprint that both serves as the "central nervous system" for the state's electricity delivery system and forges a more solid link between transmission planning and generation siting. A more proactive transmission planning process, coupled with changes in market design, could provide the appropriate signals so that generation is sited in locations enhancing the overall effectiveness of the electricity delivery system. Just as the interties between California and the Western states allow each region to achieve planning reserve margins with collectively less native generation than would be required by each region on its own, a similar intrastate, inter-utility assessment of the system may conclude that it is more cost-effective to upgrade the intrastate transmission system than increase planning reserve margins to deal with deliverability issues.

Transmission Planning

Collaborative Long-Term Transmission Planning

Over the last year, Energy Commission staff has worked with staff at the CPUC and the CA ISO to better integrate the electricity planning and procurement processes, including improving coordination between transmission and generation planning and procurement activities. In December 2004 the staffs of the Energy Commission, CPUC, and CA ISO collaborated on a proposal to develop a single electricity supply planning and procurement process that fully coordinates the individual processes and proceedings of the three agencies. The proposal was presented at the December 21, 2004 *Energy Report* Workshop on the Proposed Electricity Resource and Bulk Transmission Data Requests for the 2005 Energy Report. In conformance with the recommendations in the *2003 Energy* Report and the *2004 Energy Report Update*, the process goals for the proposal include:

- Eliminate duplication and overlap.
- Coordinate information requests.

- Clarify relationships between proceedings.
- Maximize the use of organizational expertise.
- Actively involve the utilities and industry.
- Be open and accessible to the public.
- Make decisions only once.

With respect to the transmission planning portion of the staff proposal, a key element of this integrated planning process will be the coordination of the Energy Report proceeding with the CA ISO's grid planning process. A vital input to the CA ISO grid planning process is the Energy Report's disaggregated load forecast and other relevant planning assumptions used in the analyses of transmission path upgrades and specific projects using integrated planning analyses. The CA ISO will rely on the Energy Report process for load serving entity (LSE) information not typically available to the CA ISO, as well as identification of broad statewide policy preferences and supply and demand assumptions. Transmission planning assessments will have to be made in a way compatible with state-approved load forecasts. This will require the Energy Commission to create new methodologies to develop bus-level load forecasts compatible with Energy Report-adopted load forecasts and other relevant longer-term forecasting uncertainties.

The New CA ISO Transmission Planning Process

The CA ISO has announced its proposal for a new planning process that allows the CA ISO to evolve from a predominantly reactive role to a proactive planning role. The CA ISO has confidential economic data needed to analyze transmission projects that the PTOs do not have authorization to use. Thus, the CA ISO can use this data to provide a more comprehensive basis for determining the economic impact of congestion and RMR-type costs that PTOs are expected to incur. This information can further support decisions about new facilities that would provide economic and/or reliability benefits to ratepayers. Therefore, the proposed CA ISO planning process can be more centralized to facilitate design of proposed solutions that will maximize benefits for all CA ISO market participants. Active participation is needed from PTOs and market participants to ensure both that the CA ISO has the relevant information it needs to design these solutions, and that PTO and market participants have the information they need to implement their respective plans. Further information on this process is available on the CA ISO website[2] and provided in the Addendum to the July 2005 Energy Commission Staff Report entitled *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond* (available in late September 2005).

A State-Led Transmission Corridor Planning Process

A corridor planning process is essential for California to develop a healthy transmission system to meet future electricity needs, integrate renewable resources, and meet demand in California's growth areas. The Energy Commission staff developed, with input from stakeholders, a proposed state-led transmission corridor planning process. The staff considered obligations and constraints faced by the Energy Commission and other parties participating in the collaborative *Energy Report* process. Some of the strengths of the *Energy Report* process include:

- Issues are reviewed publicly with stakeholders and other participants.
- The process provides agency positions on key assumptions.
- Decisions are made with input from the agencies, stakeholders, and the public.
- The process is revisited in odd-numbered years and vital information is updated in even years.

A state-led corridor planning process should consist of three essential components: a process to identify the need for corridors, corridor designation authority and a corridor designation process, and a change in the current CPUC policies to allow utilities to rate-base the cost of land acquired for future needs for longer periods of time:

- A corridor need identification process would allow all stakeholders, agencies, landowners and interested parties to collaborate, discuss and resolve issues is a critical aspect of planning for future corridors. This process would occur during the *Energy Report* cycle.
- It is essential that corridor recommendations (and land use requirements) be set aside for future use through a corridor designation process. Before designating a transmission corridor or conducting environmental reviews, the state must establish designation authority and a corridor designation process. The designation process should be coordinated with local land use permitting activities to ensure that local planning is factored in so that incompatible land uses do not limit future use of planned and designated corridors. This process would occur outside the *Energy Report* cycle.
- The most efficient way to acquire land for future corridors is to rely upon utilities to do it. Therefore, to ensure that planned and designated corridors are banked by the utilities, the state must extend the length of time a utility is allowed to keep the costs of land acquired for future needs in their rate bases. The current limit is five years, which is insufficient to allow for long-term planning.

As part of the *2005 Energy Report* process, it was staff's intention to develop a state-led transmission corridor planning process. In order for such a process to be effective, it must include all three of the vital components listed above. However, two of the three components highlighted above are not within the jurisdiction of the Energy Commission and must be addressed through legislative action or action by the CPUC. The Energy Commission therefore recommends that the Legislature give the Energy Commission the authority to designate corridors for electricity transmission facilities and direct the CPUC to extend the length of time an IOU is allowed to keep the costs of land acquired for corridors in rate base.

Coordination with the Federal Government on Transmission Corridor Designation

Section 368 of the Energy Policy Act of 2005, Energy Right-of-Way Corridors on Federal Land, offers opportunities to coordinate state and federal identification, planning, and designation of transmission corridors in California. Within two years of enactment, federal secretaries are required to designate corridors for electricity transmission and distribution facilities on federal land in the 11 contiguous Western states in consultation with the states, tribal governments, utility industry, and other interested parties. The secretaries must establish procedures ensuring additional corridors for transmission on federal land be promptly identified and designated; and applications be expedited to construct or modify transmission facilities within these corridors, taking into account prior analyses and environmental reviews undertaken during the designation of such corridors. In carrying out these responsibilities, the secretaries shall take into consideration the need for improved reliability, congestion relief, and enhanced capability of the national grid to deliver electricity. A corridor designated under this section is required, at a minimum, to have a specified centerline, width, and compatible uses.

This section of the Energy Policy Act provides the opportunity to begin coordination for both intrastate and interstate transmission corridor needs on federal lands between the state-led transmission corridor planning of the Energy Report process and federal designation for transmission corridors in the eleven contiguous Western states. Energy Commission staff is currently coordinating with the U.S. Forest Service and the Bureau of Land Management in anticipation of the Department of Energy's (DOE) congestion study and corridor Programmatic Environmental Impact Statement (PEIS) effort to ensure that California's RPS goals and the extensive planning efforts of the Tehachapi and Imperial Valley study groups are considered as the DOE identifies future federal transmission corridors.

The existing Palo Verde-Devers corridor contains a number of transmission lines and has been identified as the location for future construction of the proposed Palo Verde-Devers No. 2 Project. Given the importance of this corridor to meeting California's energy needs, the Energy Commission recommends review of current land uses along this existing federally designated corridor to determine where complementary state designation would be beneficial.

Coordination Among Western States

Given the high degree of interconnectedness between California's transmission system and its neighbors, it is essential that California plan its system in close coordination with them to ensure that California's interests are represented. Concurrent with that effort, the state should also plan for its own needs, recognizing the interconnectedness of in-state investor-owned utility and publicly-owned utility systems.

In January 2005 the Western Assessment Group (WAG), an ad hoc group of industry representatives with representation from the Western Electricity Coordinating Council (WECC) and the Energy Commission on Regional Electric Power Cooperation (CREPC), was formed in response to a resolution passed by the Western Governors' Association. Its purpose was to identify the major commercial issues affecting the Western Interconnection and evaluate whether the West has industry and regulatory institutions in place to effectively address and resolve these issues. The WAG produced a draft white paper on April 15, 2005, entitled *Addressing Commercial Issues on a West-Wide Basis,*[3] focusing on four critical issues: transmission expansion planning, resource adequacy, market monitoring, and commercial practices.

With respect to Western Interconnection transmission expansion planning, the draft white paper notes that many analysts concur that growth in electricity demand has far outstripped growth in transmission capacity in recent decades. The problems listed below parallel many of those facing California noted by the Energy Commission in both the *2003 Energy Report* and the *2004 Energy Report Update*.

> Among the reasons cited for lagging transmission investment are:
>
> - Costs and risks associated with planning, analyzing, siting, and permitting new transmission projects make it difficult to obtain sufficient funding and participation.
> - Benefits and beneficiaries are often widely distributed.
> - The process of identifying and allocating multi-system and multi-state costs, benefits, and transmission rights is complex.
> - Jurisdictional responsibility is often unclear and can involve multiple states and provinces, as well as the FERC.
> - Efforts to expand the system encounter increasing legislative and political challenges at the federal, state, and local levels.
> - Transmission investors face risks from unstable market rules.
> - There can be "free rider" problems under current financing methods.[4]

The paper further notes that transmission planning activities currently take place in a number of venues: the Seams Steering Group – Western Interconnection, the Rocky Mountain Area Transmission Study, the Southwest Area Transmission Study, the Southwest Transmission Expansion Plan, the Colorado Coordinated Planning Council, the Northwest Power Pool, and the CA ISO. It also notes that the WECC has recently amended its bylaws and is no longer expressly precluded from playing a role in transmission expansion planning.[5]

On May 23, 2005 the WAG held a stakeholder meeting to present the draft white paper and receive input on its initial findings. The June 2, 2005, letter from Frank

Afranji (Chair, WAG) to Colorado Governor Bill Owens (Chair, Western Governors Association), provides the following summary:

> There was consensus that the four major issues [see above] identified in the white paper are the right ones to consider and address initially. The meeting also covered the institutional options identified by the WAG. Most of the stakeholders at the meeting expressed a preference to first investigate whether the WECC would be able to address both reliability and commercial issues, and what if any structural or governance changes would be necessary for it to do so. If the WECC's membership and Board do not support these changes, then the effort will shift to creation of a new commercial organization in the West.[6]

At its July 28-29, 2005, WECC Board of Directors meeting, the Board discussed the WAG and any strategic measures the WECC might wish to develop in response. The Board accepted for strategic direction a proposal from Pacificorp,[7] with direction to WECC's CEO to flesh out details and return to the Board for approval in October. Details would include governance, timeframes, action steps, responsibilities, and member and stakeholder input.[8]

The Energy Commission is a member and active participant of the WECC. The Energy Commission's additional participation in the WAG initiative described above will ensure that the state's interests are represented in this effort.

Transmission Permitting

Three problems continue to affect 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 inadequately considered. Existing permitting processes therefore 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 publicly owned utility (POU)
- A city or county planning department
- State agencies such as the State Lands Commission and Coastal Commission
- Any of several federal agencies that could have jurisdiction.

Because of the multiple 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 the Western Area Power Administration (Western), are responsible for performing their own environmental reviews, regardless of the local jurisdictions they cross. This potentially calls into question the objectivity and fairness of how transmission projects are reviewed.

Projects proposed by IOUs are subject to CPUC review. The CPUC assesses the need for reliability and economic projects proposed by IOUs based on limited cost/benefit analyses that focus solely on impacts to ratepayers of the sponsoring IOU. In the process, the CPUC often re-examines planning issues and refuses to accept determinations made by the CA ISO in the planning process. As a result, projects with regional or statewide ratepayer 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. Governor Schwarzenegger's review of the 2003 Energy Report and 2004 Energy Report Update recommended with a sense of priority to: "Consolidate the permitting process for all new bulk electricity transmission lines within the Energy Commission, using the Energy Commission's power plant siting process as the model."[9]

Transmission projects provide a wide variety of benefits including strategic benefits, which have not been considered in the past when calculating the project costs and benefits. Major California projects have been denied permits because of methodological differences in cost and benefit assumptions. The Energy Commission has consistently supported the notion that transmission assets are long-lived, increasingly of a "public goods" nature, and often have strategic benefits, both qualitative and quantitative, which must be considered to fully evaluate the costs and benefits of a project. Examples of strategic benefits include the following:

1. Insurance against contingencies during abnormal system conditions such as low-probability but high-impact events.
2. Price stability and mitigation of market power.
3. The potential for increased reserve resource sharing.
4. Environmental benefits.
5. Reduction in infrastructure needs.
6. Achievement of state policy objectives like the development of renewable resources.

For example, transmission system upgrade case modeling assessments generally predict expected benefits under a range of normal conditions. To deal with the possibility that unlikely events could produce catastrophic consequences, low-probability, high-impact events are also modeled. Stakeholders and decision makers must use their best judgment in weighing the value of these cases in their assessments. Current base case descriptions are inadequate in facilitating these assessments or determining which cases are the most useful.

To address these deficiencies, on May 12, 2005, Governor Schwarzenegger proposed an energy agency reorganization that would vest authority for a unified, integrated state energy policy with a newly created Department of Energy (Department). The Cabinet Secretary of the Department would also serve as Chairperson of the Energy Commission. One component of the proposal would transfer the process for siting transmission lines from the CPUC to the new Department under the Energy Commission. The proposal notes that, "Transmission and generation are inextricably linked, and consolidating these activities into a single jurisdictional venue will result in better coordination and planning."[10]

On June 23, 2005 the Little Hoover Commission (LHC) responded to the Governor's Reorganization Plan (GRP 3).[11] The LHC noted that the Attorney General and the Office of the Legislative Counsel opined that modifying a "constitutionally" established transmission permitting function through the reorganization process needed further clarification. While the LHC made many positive comments about GRP 3, it recommended that the Legislature reject the proposal to "avoid legal challenges." The LHC encouraged the Governor to resubmit the reorganization plan with further clarification of issues identified in the June 23, 2005 letter. The Senate Energy, Utilities and Communications Committee held a hearing on August 24, 2005, voted against the GRP 3 and requested the Governor to resubmit for consideration a revised reorganization plan addressing the concerns identified by the LHC.

Coordination with the Federal Government on Transmission Permitting Needs

Passage of the Energy Policy Act of 2005 further established the need for a seamless transmission planning and permitting process in California that streamlines and reduces the redundancies of multiple processes. A seamless transmission planning and permitting process could move transmission projects with statewide and regional importance through the planning phase into permitting, and mitigate market power, reduce energy prices, and improve the reliability and environmental performance of the transmission system.

Without an effective and seamless transmission planning and permitting process, Subtitle B, Section 1221, of the Energy Policy Act of 2005 could pre-empt state permitting authority for transmission projects deemed to be in the national interest in the event California is unable to effectively permit projects in a timely manner. Within one year of enactment, and every three years thereafter, the Secretary of Energy will conduct a study of electric transmission congestion in the United States and issue a report based on the study. The report could designate any geographic area, including interstate areas, as national interest electric transmission corridors if capacity constraints or congestion adversely affect consumers. The Secretary has broad discretion and a wide range of reasons to make such a designation, including jeopardy of economic vitality, economic growth, energy independence of the United States, interests of national energy policy, and national defense and homeland security.

The FERC may issue a construction permit for electric transmission facilities in a designated national interest electric transmission corridor if a state does not have permitting authority or does not have the authority to consider interstate benefits expected of proposed facilities. The FERC may also issue a construction permit if a state has authority to permit proposed facilities but has withheld approval for more than one year after the filing of an application, or after designation of a corridor, or has conditioned approval in such a way that the proposed construction will not significantly reduce congestion. California will need to respond to federally designated national interest electric transmission corridors in a timely manner or risk preemption of its permitting authority by the FERC. Notably, the new legislation confers the power of eminent domain on FERC for electric transmission projects it permits.

Transmission for Renewable Power

Two major renewable resource regions in California, the Tehachapi Wind Resource Area and the geothermal resources in the Imperial Valley, are far from load centers. For California to realize the vast renewable potential of the Tehachapi and Imperial Valley regions, significant transmission facilities will be required to ensure that thousands of megawatts of renewable energy generated in these regions can be delivered to load centers. This is a challenge facing regulators, developers, and transmission system planners.

With legislation passed in 2002 requiring utilities to purchase renewable energy, interconnection with renewable power in remote locations has become a significant transmission issue for California. Transmission bottlenecks could greatly hinder the state’s ability to meet the RPS goals of 20 percent renewable generation by 2010 and procure additional renewable generation in the future.

Several existing transmission issues present potential barriers to meeting the RPS goals. These issues were not created by the introduction of renewable resources, but have become more complicated because of them. These issues include:

- Federal and state policies pose significant barriers to meeting the RPS goals, especially those concerning the rules for funding transmission system facilities.
- From an operations perspective, large scale integration of renewable generation into the grid creates major, interrelated challenges.
- Current transmission bottlenecks effectively limit the ability to transmit renewable generation from remote locations to major load centers.

Funding Mechanisms for Renewable Transmission

Federal and state policies concerning funding of transmission system development pose barriers to meeting the state's accelerated renewable energy goals. Participants at the workshops held during preparation of the Consortium for Electric Reliability Technology Solutions (CERTS) report acknowledged the need for additional transmission capacity to develop renewable generating capacity in remote areas. The Tehachapi Wind Resource Area is a good example of a region with considerable potential to develop new wind parks, but actual development is severely limited by transmission bottlenecks. The state's transmission system owners (primarily IOUs, several municipal utilities, and a few unique entities) understand that additional transmission capacity is critical for moving renewable energy from these remote regions to the load centers where it is needed. But since they do not know who will use the additional capacity, they cannot identify who will pay for it. Without identifying the parties that will use and pay for the new capacity, present FERC policy effectively bars the advanced planning and construction of new transmission facilities.

Even when a party requests new transmission capacity, present FERC regulations lay the bulk of cost responsibility onto the developer whose project pushes the transmission system beyond its existing limits. The first generator to cause the need for a transmission upgrade therefore foots the bill for a large portion of the cost.[12]

While developers of large fossil-fueled generating plants often have the resources to manage these costs, most renewable project developers do not. This regulatory structure poses a cost burden too great for a single renewable energy project to manage. This issue is so urgent that it warranted the following summary in a January 2005 CPUC workshop, although it was outside the purpose of the meeting:

> Once this total cost [of delivering an anticipated amount of generation to load] is established, it is presently the responsibility of the generator to fund the necessary upgrades, with reimbursement from ratepayers over the ensuing five years. Experience in California demonstrates that this is a burden that many renewable developers cannot bear, and the uncertainty of transmission finance under the present policy approach makes both planning and procurement difficult. Parties expressed an active interest in developing alternative methods of financing upgrades for renewable generation – such as pro-rating cost responsibility based on the share of each upgrade used by each generator, or encouraging the IOUs to move forward on transmission financing themselves… While this issue was outside of the scope of the workshop, it represents an important area for further policy development – resolution of which may allow the [CPU] Commission to take a more proactive role in planning for transmission of renewable energy.[13]

The RPS statute requires the CPUC to promote transmission expansion needed to reach RPS goals. However, parties to this study have consistently expressed frustration with the slowness of the transmission expansion approval process by the mixed jurisdiction of the CPUC and FERC and the “chicken and egg” problem of expanding transmission in an area without firm developer commitments to build facilities.

Trunk Lines

Recognizing that current rules governing cost recovery pose a barrier to transmission construction, in March 2005 SCE proposed a new category of transmission facility called a “renewable-resource trunk line.” The trunk line would be operated by the CA ISO and interconnect large concentrations of potential renewable generation resources located a reasonable distance from the existing grid. The cost of developing the new line could be recovered through general transmission rates.[14]

The trunk line proposal was included in SCE’s March 2005 petition to FERC concerning cost recovery of transmission facilities developed for renewables in the Antelope Transmission Project in the Tehachapi Wind Resource Area. The facilities would allow as much as 1,100 MW of these resources to be used by SCE, PG&E, SDG&E, and other CA ISO grid users to help meet their RPS goals. [15]

SCE identified three segments in its petition for a declaratory order. As a group, the three segments were expected to move 700 MW out of the wind resource area at a cost of about $207 million.[16] Segments 1 and 2 would be part of the looped transmission system, with energy flowing in one direction or the other depending upon the location of load relative to generation. SCE argued that these two segments would be network resources. The third segment would be a radial line designed to connect multiple generators to the CA ISO grid, which SCE characterized as a “renewable-resource trunk-line transmission facility.” [17] As noted earlier, under current rules, the third line would be funded by the first generator causing the need for its construction.[18]

SCE requested that FERC issue a declaratory order providing assurance that SCE would be entitled to roll in the cost of the three transmission projects into the CA ISO high-voltage charges. SCE’s proposal to roll in the costs of the first two segments was consistent with established precedent since the costs of “network resources” are routinely rolled in. However, SCE’s proposal was unique in proposing that the third segment, the “renewable-resource trunk-line transmission facility,” be considered a new category of transmission facility with three characteristics:

- It would be a new high voltage, trunk-line transmission facility necessary to interconnect large concentrations of potential renewable generation resources located a reasonable distance from the existing grid.
- CA ISO would operate the line.

- Costs of developing the new line would be eligible for recovery through general transmission rates.[19]

SCE's petition also requested that FERC issue an order providing assurance that:

- SCE be permitted cost recovery for all prudently incurred costs for 500 kV transmission lines regardless of whether generation develops as expected. SCE's proposed transmission capacity for Antelope/Tehachapi was based on forecasted renewable energy development rather than completed interconnection agreements, which exposed SCE to the risk that it may be left with sizeable quantities of unused transmission.
- SCE be permitted to recover 100 percent of the costs even if the projects were abandoned or cancelled. Ordinarily, the costs of abandoned and cancelled plants are split equally between shareholders and ratepayers.

On April 14, 2005, the Energy Commission and the CPUC filed motions to intervene and make comments supportive of the trunk line concept as a tool for statewide renewable energy development, employed at the discretion of state regulatory agencies.[20] As of April 15, 2005, more than 20 parties had filed comments to support or protest SCE's petition.

On July 1, 2005, the FERC issued its order.[21] The four FERC Commissioners who voted filed three separate opinions. Commissioners Kelliher and Kelly issued the majority opinion. Commissioner Brownell filed a separate concurring opinion. Chairman Wood dissented in part.

All four FERC Commissioners agreed that Segments 1 and 2 are network upgrades and eligible for rolled-in rate treatment. However, the FERC Commissioners did not agree on how to rule on SCE's renewable resource trunk line proposal. The majority opinion of Commissioners Kelliher and Kelly ruled that the third segment (that SCE had characterized as a "renewable resource trunk facility") was not eligible for rolled-in rates since this segment resembles more of a "generation tie" facility than a "network upgrade." These Commissioners noted that SCE had not shown that all users of the CA ISO-controlled grid would receive the benefits of these facilities or how the segment would provide benefits to the grid. In addition, these Commissioners noted that FERC did not have a determination from the CA ISO on whether these facilities should be transferred to its operational control. Significantly, FERC did not address the arguments raised by intervenors regarding the complexities of multiple generators planning and financing transmission while in the role of market competitors.

The separate opinions of Commissioners Brownell and Wood reveal that FERC was not in agreement on how to address SCE's renewable resource trunk facility proposal. In her concurrence, Commissioner Brownell indicated that renewable resource trunk facilities are "a new category of facilities" that "function as a multi-use on-ramp" to the grid and that these facilities would provide benefits to all users of the

CA ISO grid by creating the potential to interconnect significant new and diverse supplies of energy. In his dissent, Commissioner Wood indicated that he agreed that the trunk facilities fall into a “heretofore-undefined category of high voltage facilities which serve as a multi-user extension of the transmission grid,” and would have granted SCE’s request, although he preferred to address the issue in the context of a filing by the CA ISO to establish a region-wide cost allocation policy.

Regarding the rest of the requested rate relief, FERC ruled that, relative to the first and second segments, it would: (1) defer the issue of appropriate sizing of the segments until after the CPUC issues certificates of public convenience and necessity (CPCNs) for the projects, and (2) grant SCE’s request for assurance of 100 percent cost recovery in the event that there are abandoned or cancelled plant expenses. FERC declined to issue a ruling on the third segment because it ruled that these issues were moot in light of its denial of SCE’s request that this segment be considered a “renewable resource trunk facility.”

FERC’s decision on the first and second segments is likely to permit further work on these segments to proceed. However, it is not clear how the third segment will be financed. In light of FERC's decision, the Energy Commission believes the Energy Commission’s *2004 Energy Report Update* recommendation that it, the CPUC, and the CA ISO investigate changes to the CA ISO tariff to recognize a new category of transmission projects suitable for renewable generators[22] is even more necessary for meeting California's renewable goals than it was a year ago. If efforts to change the CA ISO tariff are unsuccessful, it may be necessary to invoke the “back-up” provisions of the California RPS statute for payment of transmission costs. California law directs the CPUC to request that FERC include the costs of transmission lines required to facilitate achievement of the renewable power goals in transmission rates. However, if FERC does not approve such rates, the statute permits cost recovery in retail electric rates (see Cal. Pub. Util. Code § 399.25(b)).

Clustering

Other states have also encountered the chicken-and-egg dilemma of whether to build renewable generation plants or transmission first. In West Texas near McCamey, for example, wind energy development has outpaced transmission system upgrades.[23] The state is looking into the possibility of energy storage, discussed below, to help address the problem.

Rather than generation without transmission, SCE’s proposal may create transmission without renewable generation, unless it is built in sufficient quantities near existing or planned transmission development. One method of renewable energy development that might achieve this end is referred to as “clustering” generation projects. However, citing CPUC D.04-06-010, the Tehachapi Collaborative Study Group noted that clustering renewable energy projects is not allowed under the current ISO tariff and FERC interconnection policies, which focus on linking individual projects to the grid. The Study Group recommends regulatory changes to support clustered development of renewables, limiting the risk of overbuilding transmission by tying permitting and construction approvals closely to market demand."[24]

The Energy Commission recommends investigating regulatory changes needed to support clustered development of renewables.

Operational Issues for Renewables

Present transmission-related operational constraints may affect California's ability to meet RPS goals. These constraints were not created by introduction of renewable resources, but have become more complicated because of them. For more information, please see Chapter 3.

Transmission Planning for Renewables

Transmission infrastructure bottlenecks and related policy solutions will greatly affect the state's ability to meet the RPS goal of 20 percent renewable generation by 2010. For more information, please see Chapter 4.

Recommendations for Planning and Permitting

The planning and permitting environment for transmission investments in California is not improving. Although the CPUC has attempted to make improvements to its permitting process over the two years since the *2003 Energy Report* was published, California consumers still suffer from the effects of an illogical separation of generation and transmission planning and permitting. While the cost of transmission relative to the overall cost of electricity is small, the cost of failures in the transmission system can be catastrophic, leading to price spikes and, for some local areas, power outages. California needs a seamless process for moving transmission projects through the planning phase into permitting that streamlines and reduces the redundancies of the existing process.

Consistent with Governor Schwarzenegger's August 23, 2005, *Review of Major Integrated Energy Policy Report Recommendations*, the Energy Commission recommends the following actions:

- **Establish a comprehensive statewide transmission planning process.** In order to provide regulatory certainty in the permitting process and facilitate the approval of needed transmission projects, the Energy Commission recommends that it collaboratively establish a comprehensive statewide transmission planning process with the CPUC, the CA ISO, other key state and federal agencies, local and regional planning agencies, investor-owned and municipally owned utilities, generation owners and developers, the public, and other interest groups to:
    - Assess statewide transmission needs for reliability and economic projects and support Renewables Portfolio Standard (RPS) goals.
    - Examine non-wires alternatives to transmission.

- Approve beneficial transmission infrastructure investments that can move smoothly to permitting. This process should include:
  - Examination of right-of-way needs.
  - Designation and environmental reviews of needed corridors.
  - Allowing investor-owned utilities (IOUs) to bank future transmission lands and easements for longer periods of time.
  - Assessment of transmission costs and benefits that recognize the long, useful life of transmission assets.
  - Incorporation of quantitative and qualitative methods to assess the long-term strategic benefits of transmission.
  - Use of an appropriate social discount rate.

- **Transfer transmission permitting to the Energy Commission.** The Energy Commission recommends that the permitting process for all new bulk transmission lines be consolidated within the Energy Commission, using the Energy Commission's power plant siting process as the model.
- **Disaggregate demand forecast for use in the statewide transmission planning process.** The Energy Commission recommends that it create new methodologies to develop bus-level load forecasts compatible with *Energy Report*-adopted load forecasts and other longer-term forecasting uncertainties. In the short term, create forecasts for load pockets and other areas that support local deliverability assessments and near-term procurement decisions.
- **Continue participation in the Western Assessment Group.** The Energy Commission recommends that it continue to participate in the Western Assessment Group initiative to ensure that California's interests are represented.
- **Establish a designation process for transmission corridors.** The Legislature should grant the Energy Commission the statutory authority to designate corridors for electricity transmission facilities.
- **Extend the length of time for rate basing IOU corridor investments.** The CPUC should extend the length of time an IOU is allowed to keep the costs of land acquired for corridors in its rate base. The Legislature should direct the CPUC to act on this recommendation.
- **Authorize the Energy Commission staff to work collaboratively with federal agencies to determine where complementary state designated corridors can be aligned with federally designated corridors.** For example, the existing Palo Verde-Devers corridor contains a number of transmission lines and has been identified as the best location for future construction of the proposed Palo Verde-Devers No. 2 project. Given the importance of this corridor to meeting California's energy needs, the Energy Commission recommends review of current land uses along this and other existing federally designated corridors to determine where complementary state designation makes sense.

- **Investigate changes to the CA ISO transmission expansion tariff.** The CA ISO transmission expansion tariff recognizes only two types of transmission projects for determining need: economically driven and reliability driven projects. The Energy Commission therefore recommends that the CPUC, the CA ISO, and the Energy Commission investigate changes to the CA ISO tariff to accommodate transmission for renewable generation interconnections.
- **Investigate regulatory changes to support clustered development of renewable projects.** In addition to efforts to modify the CA ISO transmission expansion tariff to allow for a third type of transmission project, the Energy Commission recommends investigating current changes to the CA ISO transmission expansion tariff and other regulatory policies to allow for and support the clustered development of renewables.

Endnotes

[1] The rate tariffs are modified throughout the year although the transmission charge doesn't usually change significantly.

[2] http://www.caiso.com/

[3] Western Assessment Group, April 15, 2005, *Addressing Commercial Issues on a West-wide Basis Draft White Paper*, [http://www.wecc.biz/documents/2005/General/April%2015%202005%20Draft%20WAG%20Paper.doc], (June 14, 2005). Page 2 of the white paper notes the following:

> The WECC already addresses West-wide reliability issues effectively. Identifying the best means to address West-wide commercial issues begins with two fundamental questions:
>
> 1. Which aspects of planning, building, operating, or providing services over the West's electric power system should be addressed on a West-wide basis?
> 2. What are the best processes or institutions to address these West-wide issues?

[4] *Ibid*., p. 2.

[5] *Ibid.*, p. 3.

[6] Western Assessment Group, June 2, 2005, letter from Frank Afranji (Chair, WAG) *et al.*, to Governor Bill Owens (Chair, Western Governors' Association), pp. 1-2, [http://www.wecc.biz/documents/2005/News/WAG%20-%20Governors%20Letter%20-%20final.doc], (June 14, 2005).

[7] PacifiCorp, July 2005, "WECC Role: Regional Transmission Planning," [http://www.wecc.biz/documents/meetings/board/2005/July/Presentations/DeWolf_Summary_PAC_views_on_WECC_Role_07-05.pdf], (August 24, 2005).

[8] Western Electricity Coordinating Council, Board of Directors Meeting Highlights, July 28-29, 2005. [http://www.wecc.biz/documents/meetings/board/2005/July/July2005_Board_Highlights.pdf], (August 24, 2005).

[9] Office of the Governor, August 23, 2005, *Review of Major Integrated Energy Policy Report Recommendations*, p. 7, [http://www.governor.ca.gov/govsite/pdf/press_release_2005/IEPR_Response.pdf], (August 24, 2005).

[10] Schwarzenegger, Arnold, *A Vision for California's Energy Future: Department of Energy,* p. 6, May 12, 2005, [http://www.lhc.ca.gov/lhcdir/reorg/EnergyGRP.pdf], (June 13, 2005).

[11] Little Hoover Commission, June 23, 2005 letter to Governor Arnold Schwarzenegger, Senator Don Perata, President pro Tempore of the Senate, Assembly member Fabian Nunez, Speaker of the Assembly, Senator Dick Ackerman, and Assembly member Kevin McCarthy.

[12] Federal Energy Regulatory Commission, 2003, "Standard Large Generator Interconnection Agreement (Appendix 6 to the Standard Large Generator Interconnection Procedures)," Article 11, p. 48.

[13] California Public Utilities Commission, March 17, 2005, "TerKeurst Ruling on Workshop Report Regarding Transmission Costs Used in Renewable Portfolio Standard Procurements - Attachment A,

Proceeding: I0011001," p. 4, [http://www.cpuc.ca.gov/WORD_PDF/ RULINGS/44759.PDF], (April 18, 2005).

[14] Federal Energy Regulatory Commission, July 23, 2003, "Standardized Large Generator Interconnection Final Rule Fact Sheet," FERC Docket No. RM02-1-000, [http://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen/LG-Fact-Sheets.pdf], (April 30, 2005).

[15] Southern California Edison identified three transmission segments in its petition. The first two would be part of the looped transmission system, with energy flowing in one direction or the other depending on the location of load relative to generation. The third segment is a radial line designed to connect multiple generators to the CA ISO grid. The Tehachapi Collaborative Study Group approved the three transmission segments submitted by SCE as Phase 1. In D.04-06-010 (June 9, 2004, I.00-11-001), the CPUC ruled that "it is reasonable initially to conclude that the first phase of Tehachapi transmission upgrades are necessary to facilitate achievement of the renewable power goals established in the State's renewable portfolio standard." For further details regarding the proposed transmission lines, see CPUC, March 16, 2005, Docket I.00-11-001, *Report of the Tehachapi Collaborative Study Group*, [http://apps.pge.com/regulation/search.aspx?CaseName=Elec%20T-D%20OII%20AB970], (April 15, 2005).

[16] California Public Utilities Commission, March 16, 2005, Docket I.00-11-001, *Report of the Tehachapi Collaborative Study Group*, p. 6 of the Executive Summary, [http://apps.pge.com/regulation/search.aspx?CaseName=Elec%20T-D%20OII%20AB970], (April 15, 2005).

[17] The Tehachapi Collaborative Study Group recommended these three segments as Phase 1. In D.04-06-010 (June 9, 2004, I.00-11-001), the CPUC ruled that "it is reasonable initially to conclude that the first phase of Tehachapi transmission upgrades are necessary to facilitate achievement of the renewable power goals established in the State's renewable portfolio standard." For further details regarding the proposed transmission lines, see CPUC, March 16, 2005, Docket I.00-11-001, *Report of the Tehachapi Collaborative Study Group*, [http://apps.pge.com/regulation/search.aspx?CaseName=Elec%20T-D%20OII%20AB970], (April 15, 2005).

[18] Southern California Edison Company, March 23, 2005, "Southern California Edison Company's Petition for Declaratory Order," United States of America, Before the Federal Energy Regulatory Commission, Docket: EL05-80-000," pp. 5-6. SCE also noted that, "Collecting the money from generators after the transmission facilities have already been constructed may prove impossible. For example, an interconnecting generator may file for bankruptcy or simply refuse to pay…" at p. 6.

[19] *Ibid.*

[20] California Energy Commission, April 14, 2005, "Motion to Intervene and Comments of the California Energy Commission in Support of Petition for Declaratory Order," FERC Docket No. EL05-80-000. CPUC, April 14, 2005, Notice of Intervention And Comments of the California Public Utilities Commission in Support of the Petition of the Southern California Edison Company," FERC Docket No. EL05-80-000.

[21] Southern California Edison, 112 FERC ¶ 61,014 (2005). A request for rehearing of this decision has been filed by the Transmission Association of Northern California regarding FERC's decision to waive the abandoned plant rule. As of August 24, 2005, this request for rehearing is still pending.

[22] California Independent System Operator, Tariff Section 3.2.1.1 outlines the requirements for a need determination for economically driven projects, while Section 3.2.1.2 outlines the requirements for a

need determination for reliability projects. Neither of the categories adequately accommodates the unique circumstances of renewable transmission projects.

[23] Texas State Energy Conservation Office, 2003, *Texas Wind Power*, [http://www.seco.cpa.state.tx.us/re_wind.htm] (April 18, 2005).

[24] Tehachapi Collaborative Study Group, p. 44, *Report of the Tehachapi Collaborative Study Group*, March 16, 2005, [http://www3.sce.com/law/cpucproceedings.nsf/vwUFiling?SearchView&Query=tehachapi&Start=1&Count=30] (September 7, 2005).

CHAPTER 3: SYSTEM PROBLEMS

This chapter discusses two main categories of transmission system problems: infrastructure issues, including ongoing concerns with congestion and local reliability, and prospective operational issues associated with renewables integration. This chapter also highlights promising emerging technologies that, along with the transmission project recommendations in Chapter 4, could address existing transmission bottlenecks and enhance development of a reliable, efficient, and diverse transmission system in California.

Transmission Infrastructure Issues

California has many opportunities to improve transmission infrastructure, both within the state and with its interstate interconnections in the Western United States, Canada and Mexico. The challenge for regulators is to identify the best mix of transmission projects to ensure a reliable network, improve access to renewable generation, and minimize the cost of providing electricity to California. However, in evaluating potential transmission projects, several existing transmission infrastructure issues must also be considered. These include congestion, local reliability, the prospective operational integration of renewables, and existing transmission bottlenecks. Specific projects addressing these issues are discussed in Chapter 4.

Due to lack of transmission investments and the current market design, California has and continues to experience, significant transmission system congestion and its costs. Without significant transmission upgrades and expansions, congestion costs are likely to further increase in coming years. Congestion results from both physical limitations of the transmission network and market design. Intrazonal and interzonal congestion occurs when scheduled power flows overload the transfer capability of grid facilities. Intrazonal congestion refers to congested lines within a CA ISO zone.[1] Interzonal congestion occurs when transmission lines between CA ISO zones, or between a CA ISO zone and another control area, have scheduled power flows exceeding the lines' transfer capability.

The scope of CA ISO congestion management on forward market schedules is limited to interzonal transmission paths and ignores potential congestion or intrazonal constraints. By design, the CA ISO manages real-time intrazonal congestion by first redispatching resources based on market incremental and decremental energy bids, then, if necessary, dispatching reliability must run (RMR), Out-of-Sequence, and Out-of-Market resources, in that order.[2]

The state must both secure reliable power from within the state and consider the benefits of importing power from out of state. In the absence of sufficient transmission infrastructure, the CA ISO has relied upon RMR contracts to support local reliability. However, regulators and utilities are generally faced with choosing between continuing expensive RMR contracts, signing longer than five year contracts with generators, or improving the transmission network to more reliably serve loads. RMR costs are increasing; in 2004 total RMR contract costs were approximately $644 million.

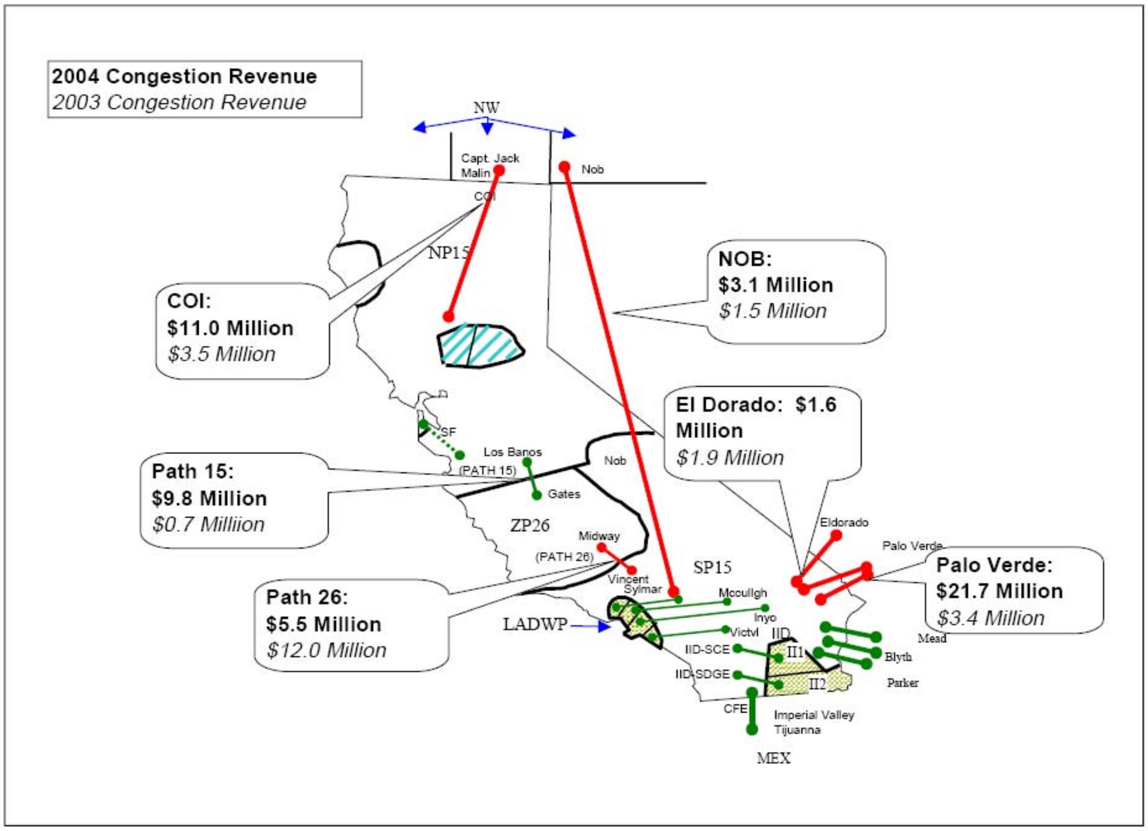
As noted in Chapter 2, California faces challenges in complying with RPS goals. Interconnection with renewables resources has become a significant transmission infrastructure issue because the largest sources of renewable generation are located in remote areas and will require major transmission investments to deliver renewable energy to load centers. The intermittent nature of some renewable generation can also make it more difficult for the transmission system operator to balance generation supply and electricity demand.

Congestion Issues

Congestion continues to be a major transmission issue in California.[3] According to the CA ISO's 2004 Annual Report on Market Issues and Performance, interzonal congestion revenues in 2004 were $55.8 million, a $29.7 million increase from 2003 (p. 5-5).[4] The total congestion revenue of $55.8 million in 2004 increased from $26.1 million in 2003. Of the total $55.8 million in congestion revenue, approximately $21.7 million was attributable to Palo Verde in the east-to-west direction, and $11 million to the California-Oregon Intertie in the north-to-south direction (see Figure 2.) The report further states that "The (2004) congestion was mostly caused by frequent and intensive scheduled work on a number of lines and substations…"[5] However, the same CA ISO report estimates the cost of intrazonal congestion in 2004 at $426 million (see Table 1 below), which represented a $275 million increase from the total 2003 intrazonal congestion cost of $151 million[6]. As the CA ISO noted at the June 2, 2005, Joint Conference on Energy Infrastructure and Investment in California, the total cost of transmission congestion (including both direct congestion costs plus RMR costs) in 2004 was approximately $1 billion, and is increasing. The CA ISO noted that this figure does not include interzonal congestion and is only for the CA ISO-controlled grid.[7]

While the CA ISO planning process addresses the reliability of the California transmission network, concern is rising over congestion costs. Improving the ability to plan for and economically reduce transmission congestion is therefore a major concern. One of the main drivers for recent congestion is that generators scheduling into the CA ISO have developed new power plants faster than the CA ISO or Participating Transmission Owners (PTOs) have provided new transmission. This is a structural problem that cannot be addressed except by significantly reducing the time it takes to complete the path rating, environmental permitting, and site licensing processes.[8]

Figure 2 2003 and 2004 California ISO Major Congested Interties and Congestion Costs



Source: CA ISO, April 2005, *2004 Annual Report on Market Issues and* Performance, p. ES-25, Figure E.17, [http://www.caiso.com/docs/2005/04/28/2005042814580818934.pdf], (September 1, 2005.)

Table 1 Total Estimated Intrazonal Congestion Costs for 2003 and 2004

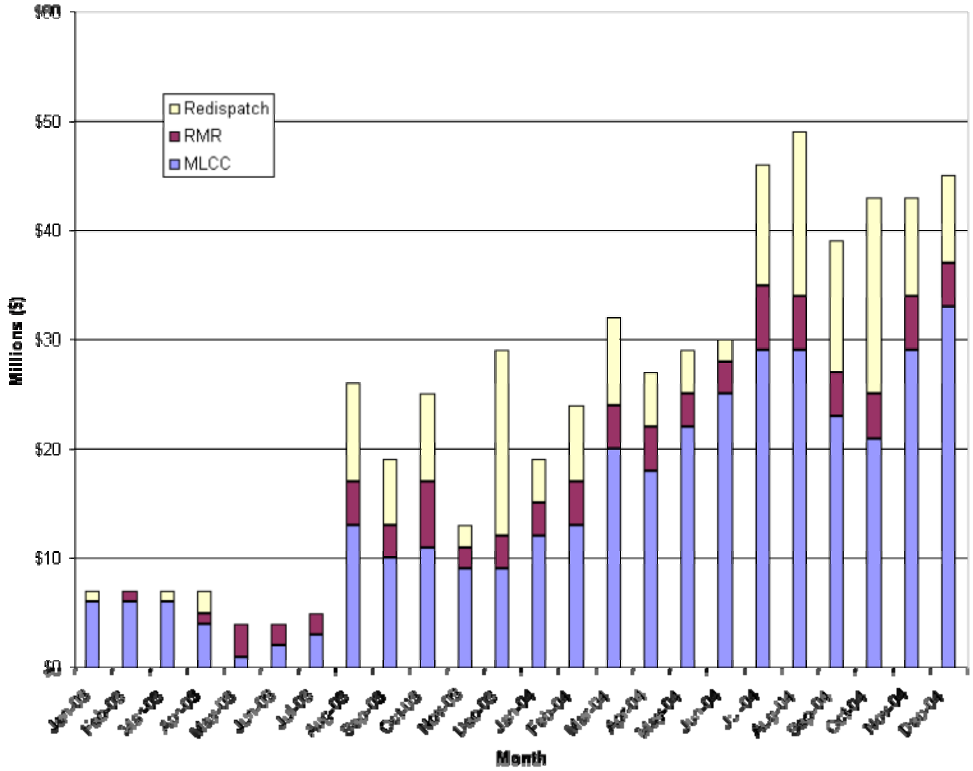
Month	2003 Monthly Total (millions of dollars)	2004 Monthly Total (millions of dollars)
January	$7	$19
February	$7	$23
March	$7	$31
April	$7	$27
May	$3	$28
June	$4	$30
July	$5	$47
August	$25	$50
September	$19	$39
October	$25	$43
November	$13	$44
December	$29	$45
Total	**$151**	**$426**

Source: Adapted from CA ISO, April 2005, *2004 Annual Report on Market Issues and* Performance, p. ES-21, Table E.5, [http://www.caiso.com/docs/2005/04/28/2005042814580818934.pdf], (September 1, 2005.)

Intrazonal congestion occurs most frequently in load pockets, or areas where load is concentrated with insufficient transmission to allow access to competitively priced energy. The intrazonal congestion costs for the years 2003 and 2004 for the CA ISO-controlled system are shown in Figure 2. Real time congestion costs are generally broken down into three categories:

- Costs due to redispatch of market resources.
- Costs of dispatching RMR units.
- Minimum load cost compensation (MLCC) associated with committing units for local reliability.

Figure 3 CA ISO Monthly Total Intrazonal Congestion Costs for 2003 and 2004



Source: Adapted from CA ISO, April 2005, *2004 Annual Report on Market Issues and* Performance, p. ES-21, Table E.5, [http://www.caiso.com/docs/2005/04/28/2005042814580818934.pdf], (September 1, 2005.)

As noted in Chapter 2, the CA ISO has proposed a more proactive and comprehensive transmission expansion planning process that it believes will speed up proposed solutions that will maximize benefits for all CA ISO market participants. The Energy Commission supports this proposed process and is hopeful it will lead to the development of effective transmission projects that will significantly reduce congestion costs in the future. Improving the transmission infrastructure, both within California and with the grid connecting California with other Western states, will decrease congestion and could ultimately lower the cost of providing electricity to California. In addition, Energy Commission and CA ISO staff are working together to improve the CA ISO's transmission evaluation methodology to develop a planning tool to forecast transmission congestion.

Southern California System Congestion

In San Diego, limited transmission capacity from the Imperial Valley area and Mexico, coupled with significant new generation development outside of California, have created significant transmission congestion. The partially completed 230 kV Miguel-Mission No. 2 Project, which should reduce some of this congestion, is expected to begin full operation in June 2006. An interim upgrade was completed in June 2005 to ensure that higher levels of reliability would be available during summer 2005 before completion of Phase 2 of the project.

A source of potential congestion for SCE could be the limited interconnection between SCE and the Los Angeles Department of Water and Power (LADWP). There is concern that under high summer load (1-in-10 year peak load conditions), electricity supplies in the CA ISO Southern California control area south of Path 26 might not be adequate to serve loads.[9] LADWP could be a source of either less expensive or reserve power that could help mitigate price spikes or prevent power outages.

Local Reliability Areas

Local reliability concerns in San Diego and the Greater San Francisco Bay Area have received recent attention. The needs of other areas, including SCE's service territory, are also growing. In the absence of sufficient transmission infrastructure, the CA ISO has relied upon RMR contracts to support local area reliability. According to the CA ISO, the total RMR contract cost[10] for the three California investor-owned utilities in 2004 was $644 million. Table 2 shows the 2004 RMR cost by utility. More transmission capacity is needed to reduce RMR costs and allow the shutdown of aging power plants.

Table 2 Reliability Must-Run Costs in 2004 by Utility

Investor-owned Utility	Total RMR costs in 2004 (Millions)
PG&E	**$418**
SDG&E	**$173**
SCE	**$ 53**
Total	**$644**

Source: CA ISO, April 2005, *2004 Annual Report on Market Issues and* Performance, p. 6-12, [http://www.caiso.com/docs/2005/04/28/2005042814343415812.html], (June 16, 2005).

Operational Challenges Associated with Renewables

This section discusses the operational challenges with renewables and potential barriers to meeting RPS goals. From an operational standpoint, integration of renewable generation into the grid creates two major, interrelated challenges:

1. Accommodating intermittency in generation from wind farms and, to a lesser extent, solar facilities. Intermittency is an issue with both availability of specific facilities and production in different regions of the state. Generation of a given wind project varies greatly over a given day, and the amount of windpower produced in each region of the state also varies significantly from day to day.

2. Transmitting renewable generation, mostly from remote locations, to major load centers: Major transmission bottlenecks already exist in the state and limit the ability to transmit renewable generation to load centers. The high variability of wind and solar power generation makes this even more challenging, since one area may peak on one day while another area peaks the next day, depending upon wind patterns. Large amounts of intermittent generation on an intertie can affect the transfer capability of that tie. Forecasting this variability and allocating transmission capacity accordingly will be the main transmission challenge in meeting RPS goals.

Intermittency

Though highly interconnected, California's grid is a closed system: Total demand must match total supply. Operators balance demand with supply, ramping up generation during the day to meet afternoon peaks and backing down generation as demand falls. To add renewable generation to the system on a given day requires one or both of two things to happen: the demand for power must increase by an equal amount, or some other generator must be backed down by an equal amount.

Though small hydroelectric, geothermal and biomass plants[11] can be dispatched to match load, wind and solar generation are generally dictated by the weather. Wind and solar can send large amounts of power into the transmission system when the wind is blowing or the sun is shining, but these supplies drop off rapidly as winds die or clouds move in. As power from renewable generation ebbs and flows, system operators must constantly balance the system by ramping production up or down at other facilities. Integrating large amounts of windpower into the system offers a special challenge, as most wind occurs at night. Full integration of wind energy would require turning down gas-fired generation. However, California has added gas peaking plants offering load following capabilities that complement wind generation. These new load following gas-fired generating plants can be used to balance the long-term power fluctuations because they are designed for increased start-stop cycles.[12]

Renewable energy-related intermittency is only one potential source of intermittency on the system and may have a relatively modest effect compared with other factors. Recent research concludes that intermittency caused by inaccurate load forecasts and unscheduled generator outages would probably have more of an impact on the transmission system than integration of large amounts of highly variable renewable resources.[13]

Integrating small numbers of as-available or intermittent resources into the system could be accommodated with minor adjustments. However, experience in Europe shows that high levels of wind (20 percent or greater) relative to other resources on the electricity grid could require changes in the operation and equipment use on the transmission system.[14]

Siting multiple generators over large areas also reduces intermittency, since wind speed variability tends to even out over large areas. In large areas such as Altamont or Tehachapi, for example, for every kilowatt (kW) lost from a generator that is ramping down, another is gained from a generator ramping up. In contrast, generation from a windfarm in New Mexico, where all generators are in a single north-south line on top of a mesa, is much more intermittent.

Another factor is the size of the control area. Larger control areas tend to have more diverse intermittency, which tends to self-cancel and require significantly less system rebalancing. In the CA ISO Control Area, winds could be decreasing at Altamont but building at Solano. Similarly, air conditioning load intermittency tends to cancel out over large areas as hot spots move around the state. Smaller control areas generally have greater percentage differences between load peaks and valleys since the weather in those areas is more homogeneous. In general, regions with larger numbers of smaller control areas will experience greater difficulty in accommodating renewable intermittency than regions with comparably fewer, but larger, control areas.

Transmission System Constraints

Within California, transmitting large amounts of wind or solar power into the load centers of Southern California could be especially challenging because of existing transmission bottlenecks on the interties. Imbalances on any of those interties can affect the transfer capability of other lines. The process of balancing all the interties feeding those load centers is complicated and challenging, involving constant adjustments in generator power levels to maintain system stability. The exact combination of balances on the ties is never the same, so operators in any given area have no pre-set procedures for handling imbalances and must respond in real time to each unique situation. Attempting to add intermittent remote renewables generation to the mix will further complicate matters, not only because that generation has limited ability to provide frequency or voltage support, but because interconnection to the grid could lower inertia[15] on the affected intertie and reduce import capability overall.

This operational difficulty in accommodating highly variable renewable generation was highlighted in an April 2005 Energy Commission consultant report by the Consortium for Electric Reliability Technology Solutions (CERTS) on renewable transmission integration and planning.[16] CERTS concluded that recent changes in the portfolio of generating resources in the Western U.S. could reduce the amount of electricity that could be delivered over the existing transmission grid.[17] CERTS's forecast of system operational changes needed to support the state's goal of 20 percent renewable generation by 2010 showed changes in average and maximum daily load swings. Although the effects are not significant relative to the size of the CA ISO system, the amount of wind in the scenario (42 percent of eligible renewables in 2010, up from 20 percent in 2004) makes the timing of the swings less predictable. To address this concern, CERTS suggests improved day-ahead planning, changes in the renewable mix (such as including more solar resources) and procuring resources with the ramping capability to match system needs.

The CERTS study also found that control area operators might need to reduce other generation output during high runoff and high wind periods, making it difficult to manage generation during lightly loaded early morning hours. CERTS suggested three actions: combining wind generation with pumped storage hydro to create load during early morning high runoff and high wind periods, sending clear price signals to end-use customers to shift loads to minimum load time periods, and procuring generation with turn-down flexibility.

Another issue complicated by rapid development is the effect of renewable resources, especially intermittent generation, on the ability to address grid frequency and voltage support reliability needs. This affects both the relative capability of intermittent resources to provide such support and their ability to import power into the state's grid and transfer power within the state. The common control room solution to frequency or voltage support problems is increasing power to the prime movers of the generators in that region (frequency support) or increasing excitation to generator fields of local synchronous generators (voltage support). Intermittent resources have limited ability to provide either service, and their large scale integration will probably further complicate existing frequency support problems on the grid.

Frequency response of generating resources in the WECC has been deteriorating over the past two decades. Increased variability and reduced inertia in generating performance in the WECC area could negatively affect existing transmission path ratings into California and throughout the Western states. This reduced performance is a result of:

1. Operation of many generating resources at base load (e.g., coal), limiting upward capability.
2. Operation of nuclear resources, under regulatory mandate, with blocked (non-responsive) governors.
3. Modified combustion control systems on conventional thermal resources.
4. Design characteristics of the new combined-cycle plants.[18]

The frequency response of generating resources is already a problem requiring a solution. Research in this area is needed, especially relating to night-time windpower generation peaks. To date, much of the research on intertie transport capability has studied conditions at maximum peak load rather than at maximum times of wind generation.

Emerging Technologies

Transmission operators face growing uncertainty in predicting how the grid will respond to certain events or operator actions. This raises the possibility of grid instability that could lead to power quality problems and increased risk of delivery interruptions. Varying degrees of wholesale competition and market restructuring in different regions of the West, coupled with new generation technologies including modern natural gas-fired combined-cycle combustion turbines and wind generators, have reduced the ability of the grid operator to dispatch generators in a deterministic manner, or even to know when some generators will be available. Importing power from neighboring states and countries to gain access to additional and economic supplies of electricity has created a geographically vast, interconnected transmission grid that is fragile and vulnerable to rapid and widespread system outages, often initiated by seemingly small events, such as a single transmission line sagging into a tree. Even the models that grid operators use to predict how electricity consumers will react under different situations are no longer trustworthy because of changes in the design and mix of electric-consuming appliances and equipment. Yet the operator still relies upon operating and planning tools designed for a time when power plants were more readily dispatchable and models could reasonably predict electric consumption behavior.

New technologies promise to expand the power delivery capacity of existing transmission corridors and reduce the risk of interruptions by managing operational uncertainties. Many have the potential to assist California in meeting its renewable generation goals by strengthening weak transmission circuits in renewable energy resource areas of the state and increasing the ability to import generation from other states. These promising technologies consist of new hardware, software, and integrated systems able to leverage new technology solutions for the benefit of an entire region of the grid.

Technology Availability and the PIER Transmission Research Program

Most of the California Energy Commission's Public Interest Energy Research (PIER) Program's transmission research is conducted within the Transmission Research Program (TRP) and in partnership and coordination with other PIER programs in environment, energy storage, renewables, demand response and distributed generation. PIER transmission research is also guided by technology development needs identified in Energy Commission transmission and energy planning activities, including this plan and the *Energy Report*. The TRP is also guided by a number of state policy documents including the State EAP and the Governor's Ten Point Electricity Plan. Economic, reliability, environmental and security public interest goals are included in these policies.

TRP strategies are shaped by transmission-related trends in policies, markets and technologies. To ensure that the TRP focuses on the research and development of technologies most relevant to public interest needs, with the best chance of moving forward, a Policy Advisory Committee (PAC) provides strategic guidance and enhances technology transfer and adoption. It is composed of high-level management from: California IOUs, the CA ISO, Energy Commission, CPUC, Center for Energy Efficiency and Renewable Technologies (CEERT), Bonneville

Power Authority (BPA) and the U.S. Department of Energy (DOE). Technology Advisory Committees also provide technical advice on certain topics. Many stakeholders, including California IOUs and the CA ISO, help develop and host TRP research projects and provide co-funding for contributions in kind of labor, software, and hardware.

High-Temperature, Low-Sag (HTLS) Conductors

The application of HTLS conductors could raise power delivery capacity through existing transmission corridors by simply replacing original lines with these new conductors. This approach to greater power delivery capacity is potentially cheaper, faster, and more environmentally friendly than either building new transmission lines or replacing existing lines with larger and heavier conventional conductors requiring modification or replacement of existing towers.

Within an Electric Power Research Institute (EPRI) industry consortium (of which PIER is a co-funder), SDG&E is the principal investigator for a field test demonstrating the feasibility and economic benefits of HTLS transmission line conductors. In this test, an existing transmission line causing a power delivery bottleneck is reconductored. SDG&E identified an appropriate transmission line for a test bed and the appropriate HTLS conductor technology, and performed both the engineering work and installation. Data is collected and analyzed in accordance with consortium protocols. The conductor supplier assisted SDG&E’s line crew with installation and any special provisions needed for the new conductor. A final report will document SDG&E’s experience with the conductor, including any installation difficulties, special handling, and provide an evaluation of its economic benefits.

Real-Time Rating (RTR) of Transmission Systems

Another approach to increasing the power delivery capacity of existing transmission corridors is increasing the effective capacity of existing conductors through real-time ratings (RTR). Too high a current can overheat a line, damaging the conductor material or causing it to sag. To prevent operators from sending too much power through a line, transmission engineers establish fixed upper-limit criteria called static ratings. Because the actual maximum power carrying capacity of the line varies with factors including air temperature and wind speed (at various locations and times over the length of the line), static limits are usually based on conservative assumptions of worst-case conditions. This practice leaves potential line capacity untapped for much of its operating time. The RTR approach permits the operator to raise the power capacity of a line beyond its static rating through a “dynamic” rating based on real-time monitoring of actual ambient conditions and/or line parameters: for example, temperature, wind speed and direction, line tension, or actual visible sag. With this information, the real upper limit power capacity of the line can be more accurately determined and utilized.

There are a number of technologies available for RTR, including temperature sensors, line tension and sag monitors, weather/environmental monitors, thermal models, predictive methods, and static line loading equations. These technologies can be combined in various ways to produce different RTR systems to fit certain circumstances and applications. Although most commonly applied to transmission line conductors, the RTR principle is also valid for transformers and other transmission equipment.

Considerable research, development and demonstration of RTR have been conducted for over 20 years by utilities, research organizations and others; however, its use by utilities and regulators and integration into industry standards and practices has not been widespread. The barriers to acceptance and implementation of RTR technologies need to be identified and analyzed and strategies formulated for overcoming these barriers.

Similar to HTLS conductor technologies, RTR does not provide a universal solution for increasing the power delivery capacities of all transmission corridors under all conditions; but it does promise to increase power delivery of existing assets in a number of situations.

There are four research projects at various California utilities and the CA ISO involving PIER participation. The first is the PG&E-CA ISO Real-Time Integration Project. Its objective is to determine the feasibility of using a dedicated auxiliary data server to perform the data collection, processing and energy management system (EMS) integration functions, enabling real-time transmission line operations. This data system is an alternative to the more costly and complex approach of implementing new functions in the existing EMS.

The second project, hosted by PG&E and Western, demonstrates the regional benefits of linking applications between transmission paths. The goal is to demonstrate the feasibility of implementing real-time transmission line ratings for a large multi-utility area under normal system conditions by linking benefits from real-time thermal ratings with simultaneous mitigation of voltage constraints and developing real-time ratings forecasting methods.

The third project in this area involves CA ISO and SDG&E, using real-time ratings for congestion relief. Its objective is to test and evaluate the benefits of real-time line ratings to relieve congestion on the transmission system. The test location will be the transmission system in the vicinity of Miguel Substation in SDG&E's service territory. This area experiences frequent transmission congestion and is of particular concern to the CA ISO since lines in the area are key components of the Southern California Import Transmission (SCIT) Nomogram.

SCE is taking the lead in developing a PIER Research Project for the evaluation of RTR systems for clearance management. In many cases the limiting factor is not temperature but sag or clearance, in particular how close a line comes to the ground without breaching absolute safety limits set by regulation. In this project, two candidate technologies will be evaluated for the purpose of managing line clearances in real time. One technology contains video imaging that essentially gives system operators a real-time visual measurement of line clearances. The other relies upon tension-monitoring to compute line clearance from conductor tension readings.

Real-Time System Operations (RTSO)

Traditional tools used by grid operators to manage voltages, frequencies, power flows and generation reserves have become increasingly inadequate, while the stakes for failure have become increasingly high. The August 14, 2003, Eastern Interconnection blackout affected 50 million people in eight states and Ontario, with an estimated range of total cost in the U.S between $4 and $10 billion.[19] Although the failure of one Ohio utility, FirstEnergy, to adequately manage tree growth in its transmission right-of-way caused the outage of three 345 kV transmission lines, this localized problem likely would not have cascaded into the multi-state crisis if the utility and independent system operators had had the real-time tools to assess and diagnose the situation. The April 2004 *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* noted four major groups of causes. The Group 2 cause is "Inadequate situational awareness at FirstEnergy. FirstEnergy did not recognize or understand the deteriorating condition of its system." The Group 4 cause is "Failure of the interconnected grid's reliability organizations to provide effective real-time diagnostic support."[20]

On August 10, 1996, the WECC experienced a blackout that affected approximately 7.5 million people in seven states as well as two Canadian provinces and Baja California that was triggered by a seemingly inconsequential local event, a high-voltage line sagging into a tree in Oregon. Again, lack of real-time information and appropriate actions caused the local event to quickly cascade into a widespread event, costing over a billion dollars.

One way to reduce uncertainty is to gather simultaneous and comparable information, and convert it quickly to action in real time. A package of real-time system operations tools for grid operators is being developed to reduce the chance and contain the consequences of outages.

At the heart of these tools is a relatively new data collection device called a "Phasor Measurement Unit" (PMU). Collecting satellite time-stamped data at speeds between 30 and 60 times a second, PMUs, optimally placed in the transmission grid, provide operators an "over the horizon" real time, early warning view of the grid, better equipping them to handle unexpected distant events.

These tools are developed to "predict" future grid conditions minutes and hours ahead. This capability will not only improve reliability but help operators reduce power flow congestion on the grid, which can cost Californians hundreds of millions of dollars a year, and transport more power through existing transmission rights-of-way, reducing the need for new transmission lines.

PIER provides funding to several current and future projects supported by both California utilities and the CA ISO.

SCE is taking the lead in developing a PIER research project using Phasor information to inform a remedial action scheme near one of its hydro power plants. With Phasor technology, SCE hopes to eliminate several unnecessary transmission circuit trips per year while improving the accuracy and reliability of the control system. This will be the first demonstration of real-time control using Phasor data. Up until now, demonstrations have been limited to BPA control simulations. If this control project is successful it will provide a roadmap for others in using Phasor control on a larger scale to make the grid more responsive and reliable.

SDG&E is taking the lead in developing a PIER research project using Phasor information to increase the accuracy of its State Estimator, which predicts the state of the transmission grid by sampling key parameters and locations. Phasor information will provide key instantaneous input to define the boundary of the SDG&E grid. It is eventually expected that results of this research will contribute to enhanced transfer capability at the Miguel Substation, helping to relieve a significant congestion problem. This congestion issue is also addressed by research work related to real-time system ratings as described above.

PIER is also coordinating with a DOE-supported Phasor Project called the Eastern Integrated Phasor Project (EIPP). Within the last couple years a number of Eastern utilities, joined by regional ISOs and national labs, installed many PMUs and developed a data base protocol and agreements to share information. This could improve wide-area communications and real-time understanding of the Eastern grid. The EIPP is one example of PIER coordination with multi-million dollar DOE R&D transmission programs. The knowledge gathered through this coordination activity will be useful in identifying the steps necessary for a widespread deployment of PMUs throughout the WECC based on experience gained from the EIPP.

Other PIER Research

Other PIER research is being conducted or developed with utility, CA ISO and other stakeholder involvement.

SCE is taking the lead in developing PIER research relating to the development of fault current limiters (FCL, also referred to as fault current controllers, or FCC).The existing transmission system is becoming stressed beyond its design capability due to load growth and heavy power transfers, coupled with a lack of investment in new infrastructure. On the T&D component level, the load is increasing and the fault current duty of the circuit breakers is exceeding its design capabilities, limiting power flow on the network. It would take years and massive capital investment to replace overloaded transmission line conductors, transformers and circuit breakers on today's system in order to stay ahead of the problem. A single FCL at a substation can extend the usefulness of many conventional circuit breakers and reduce current and voltage peaks, resulting in increased power flow and asset utilization. This project promotes development of FCLs from distribution-level size and capability to transmission-level capability and applications.

The PG&E-PEER (Pacific Earthquake Engineering Research) Research Program, later known as the PEER Lifelines Program, was formed in 1996 to address important earthquake issues. It has successfully leveraged more than $13 million in funding from PIER, the California Department of Transportation (CalTrans), PG&E, and others, to support more than 100 scientific and engineering research projects. The rapid implementation of results from the PEER Lifelines Program by California utilities is already benefiting California ratepayers through cost savings.

PIER is currently performing tech transfer and outreach activities to disseminate results and incorporate findings into new industry standards. Further research efforts to investigate utility equipment and build seismic performance and emergency response are under consideration.

PIER, through its Energy Storage Program, currently sponsors two energy storage system demonstration projects at the Distributed Utility Integration Test facility, located at PG&E's Technical and Ecological Services facility: a flywheel and a zinc-bromine battery. As technologies mature and prove feasible they will need to be scaled-up for transmission application. The flywheel project demonstrates that the 100 kW/12 kV flywheel system can respond to signals from CA ISO and dispatch its energy to perform a frequency regulation function. This is a function primarily of the inverter and telecommunications capabilities of the system, and can theoretically be implemented with any size storage system. Results can be extended to other grid functions and ancillary services.

Siting new transmission lines is a complex and time-consuming matter of identifying and evaluating numerous environmental, social and economic factors affecting many stakeholders and segments of society. The PIER Environmental Program funds development of a web-based decision tool for siting transmission lines called "Planning Alternative Corridors for Transmission (PACT)." The objective is to assess alternative transmission lines for their environmental, health/safety, engineering, and economic values. Once developed it should help planners, policy decision makers and the public better understand the tradeoffs between proposed alternatives. PACT builds upon an existing Decision-Support Tool developed by SCE. PIER is also exploring development of other planning tools that would address the "insurance" value of transmission and how to manage congestion.

Other Areas of Research for Transmission Systems

The 3M Composite Conductor Program, in coordination with various federal and private entities, has developed and extensively tested an Aluminum Matrix Composite Conductor. Known as the Aluminum Conductor Composite Reinforced (ACCR), it can provide increases in transmission capacity of 1.5 to 3 times greater than conventional conductors for the same amount of sag. This product promises to provide opportunities for transmission upgrades with reduced costs and environmental impacts.

The use of the ACCR product would enable transmission line upgrades within existing rights of way without significant tower modifications through replacement of the existing conductor material. The ACCR product offers superior characteristics to conventional overhead conductors because it is lightweight, has low thermal expansion, excellent fatigue resistance and is corrosion resistant. These characteristics result in increased ampacity on existing towers while maintaining required clearance, reduced environmental impacts through reconductoring, no increased visual impact, and reduced installation time due to avoided construction of new towers. Extensive laboratory and field testing through a multiyear program with the U.S. Department of Energy to validate its performance over a wide range of conditions, has been successfully completed and the ACCR has moved into commercial application.

Recommendations

Recommendations to Address Reliability, Congestion, Renewables, and Future Growth in Load and Generation

- Support proposed transmission projects that will move less costly power from Arizona and the Southwest into Southern California.
- Support proposed transmission projects to improve access to in-state renewable resources.
- Support proposed transmission projects to meet reliability standards for major load centers.

Recommendations to Address Operational Integration of Renewables

- Operational challenges associated with renewables present potential barriers to meeting RPS goals. The state should continue to support the formation and efforts of stakeholder-based study groups addressing operational integration issues.
- Current transmission bottlenecks effectively limit the ability to transmit renewable generation from remote locations to major load centers. The state should continue to support the formation and efforts of stakeholder-based study groups developing transmission expansion plans that allow for the efficient movement of renewable energy to consumers.
- Minimum load issues may be exacerbated by the intermittent nature of some renewable resources. The state should initiate research to optimize operation of existing pumped hydro storage facilities and identify viable locations for new

pumped hydro storage facilities that would complement intermittent renewable generation.

- Reducing uncertainty in resource availability will reduce the need for reserve backup for intermittent renewable generators. The state should continue to promote research efforts to improve forecasts of intermittent resource availability.

Emerging Technology Recommendations

Emerging technologies offer benefits that may assist in the planning, development, and operation of a reliable, efficient, diverse and expanded capacity transmission system.

- The state should continue to support the research and development of new transmission technologies through the Energy Commission's PIER program.

Endnotes

[1] The CA ISO control area is divided into three zones: North of Path 15 (NP15), Zonal Path 26, and South of Path 15 (SP 15).

[2] Navigant Consulting, August 25, 2005, *Draft Task 2 Report – Southern California Transmission Congestion,* p. 2, Sacramento, CA.

[3] Transmission congestion is a cost issue in that congestion occurs when loads have to be served by generation that is more expensive than generation that would be used without the limitations of the transmission network.

[4] California Independent System Operator, April 2005, *2004 Annual Report on Market Issues and Performance*, p. 5-5, Folsom, CA.

[5] *Ibid*., page 5-3.

[6] *Ibid.*, page 6-16.

[7] Federal Energy Regulatory Commission, Transcripts from the June 2, 2005 Technical Conference on Energy Infrastructure and Investment in California, (FERC Docket no. AD05-11-000), p. 62. [http://ferc.gov/EventCalendar/Files/20050614073401-AD05-11-06-02-05.pdf], (June 15, 2005).

[8] Navigant Consulting, *op. cit.*, p. 3.

[9] California Independent System Operator, March 23, 2005, *2005 Summer Operations Assessment*, p. 2, Folsom, CA, [http://caiso.com/docs/09003a6080/35/46/09003a60803546fd.pdf], (September 7, 2005).

[10] RMR contracts provide a mechanism for compensating generating unit owners for the costs of operating when units are needed for local reliability but may not be economical to operate based on overall energy and ancillary service market prices.

[11] Most geothermal and biomass plants presently operate as base-load plants. Parties to this proceeding have commented that such plants do have ability to act as load-followers, and could be designed to better provide that service in the future (May 10, 2005 *Energy Report* Workshop).

[12] KEMA-XENERGY, June 1, 2004, *Intermittent Wind Generation: Summary Report of Impacts on Grid System Operations*, California Energy Commission Consultant Report, 500-04-091, [http://www.energy.ca.gov/pier/final_project_reports/CEC-500-2004-091.html], (September 1, 2005).

[13] California Energy Commission, April 2005, *Assessment of Reliability and Operational Issues for Integration of Renewable Generation*, Consultant Draft Report, p. 34, prepared by Electric Power Group, LLC, and Consortium for Electric Reliability Technology Solutions, CEC-700-2005-009-D, [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#051005], (September 1, 2005).

[14] KEMA-XENERGY, *op. cit.*. See also New York State Energy Research and Development Authority, March 4, 2005, The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations Report on Phase 2: System Performance Evaluation, prepared by General Electric International, Inc., [http://www.nyserda.org/rps/default.asp], (April 30, 2005), and Excel Energy and the Minnesota Department of Commerce, *Wind Integration Study – Final Report*, [http://www.uwig.org/XcelMNDOCStudyReport.pdf], (September 28, 2004), as well as Nancy Rader, February 17, 2005, “Reply Comments of the California Wind Energy Association on operational

integration issues associated with transmission and renewable generation, Energy Commission Docket No. 04-IEP-01F, p. 5.

[15] Inertia is a function of both the mass and speed of the rotating parts of any generator. The system inertia is the ability of the power system to oppose changes in frequency. If system inertia is high, then frequency will change slowly during a system disturbance. Inertia is supplied by the physical rotating mass of the generators on the system. For rotating machinery, the inertia constant H is defined as:

$$H = \frac{\text{kinetic energy stored in the rotor at synchronous speed (in Joules)}}{\text{Machine nominal power (in VA)}}$$

The inertia constant H is expressed in seconds. For large machines, this constant is around 3 to 5 seconds. An inertia constant of 3 seconds means that the energy stored in the rotating part could supply the nominal load during 3 seconds. For small machines, H is lower. Wind turbine generators are typically smaller than most generators connected to the grid. Therefore, because of their larger size and faster speeds, gas plant generators have larger inertia ratings per installed MW.

[16] California Energy Commission, April 2005, *Assessment of Reliability and Operational Issues for Integration of Renewable Generation*, Consultant Draft Report, prepared by Electric Power Group, LLC, and Consortium for Electric Reliability Technology Solutions, CEC-700-2005-009-D, [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#051005], (September 1, 2005).

[17] *Ibid.*, p. 38.

[18] *Ibid.*, p. 38.

[19] U.S. – Canada Power System Outage Task Force, April 2004, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, p. 1. [ftp://www.nerc.com/pub/sys/all_updl/docs/blackout/ch1-3.pdf], (September 7, 2005).

[20] *Ibid*., pp. 18.

CHAPTER 4: TRANSMISSION PROJECT INVESTMENTS FOR CONSIDERATION

Chapter 2 focuses on the transmission planning, corridor planning, and transmission permitting process actions needed to ensure that Strategic Plan goals are achieved. Chapter 3 focuses on transmission system problems and emerging R&D solutions. This chapter identifies actions required to implement transmission investments needed to ensure reliability, relieve congestion, and meet future growth in load and generation, including renewable resources and energy efficiency.

Evaluation Criteria

The criteria contained in PRC section 25324 represent core evaluation criteria as the starting point for evaluation of 21 projects from the Energy Commission staff report entitled *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond*. These criteria have been combined with additional transmission evaluation criteria to ensure identification of strategic transmission investments needed in the next five years. PR C section 25324 states:

> The [Energy Commission], in consultation with the Public Utilities Commission, the California Independent System Operator, transmission owners, users, and consumers, shall adopt a strategic plan for the state's electric transmission grid using existing resources. The strategic plan shall identify and recommend actions required to implement investments needed to ensure reliability, relieve congestion, and meet future load growth in load and generation, including, but not limited to, renewable resources, energy efficiency, and other demand reduction measures. The plan shall be included in the integrated energy policy report adopted on November 1, 2005, pursuant to subdivision (a) of Section 25302.

Ensure Reliability

Electrical reliability is the critical balance between the supply of and demand for electricity.[1] Every second of every day the demand for electricity must be balanced – supply must equal demand. As part of balancing electricity supply and demand, megawatts must be available on standby to prevent blackouts.

The CA ISO exercises operational control over its portion of the transmission grid in compliance with reliability criteria established by the North American Electric Reliability Council (NERC), the Western Electricity Coordinating Council (WECC), local reliability criteria (criteria unique to the transmission systems of each of the transmission owners participating in the CA ISO), and requirements of the Nuclear Regulatory Commission (NRC).[2]

Several types of power help maintain the reliability of the power grid:

- Ancillary services are secured for operating reserves in the form of standby power that can be dispatched within seconds, minutes or hours.
- Space on available transmission lines is allocated, if available. When transmission lines are congested, power must be curtailed; when transmission lines are not congested but demand is high, more power can be generated and dispatched to meet load.
- Supplemental energy (real time imbalance energy) is dispatched every five minutes to accommodate changes in energy forecasts moments before the electricity is consumed.[3]

Local reliability areas (LRAs) which are 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, as defined by the CA ISO. Due to this combination of conditions, LRAs are susceptible to reliability problems. To alleviate these problems, the CA ISO requires certain generators within LRAs to sign reliability must run (RMR) contracts requiring them to operate their facilities at specific contracted prices during periods designated by the CA ISO. Frequently, RMR generators are older facilities with higher air pollutant emission rates.[4]

Transmission projects that expand or upgrade the existing grid can help ease reliability concerns, and support safe and reliable operation of the transmission grid.[5] For end-use consumers, business and residential, reliability means their electricity is on around the clock.[6]

Relieve Congestion

Due to lack of transmission investments and the current design of the market, California has experienced, and continues to experience, significant transmission system congestion and its resultant costs. As noted in Energy Commission staff's transmission report, *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond,* when the costs of RMR contracts are combined with costs of intrazonal congestion, California's yearly congestion expenditures are approaching $1 billion. While investments in transmission infrastructure can continue to provide significant benefits to Californians over many years, congestion expenditures serve only to increase the cost of electricity and offer no economic return to ratepayers. Without significant transmission upgrades and expansions, congestion costs are likely to further increase in future years.

Meet Future Growth in Load and Generation

The transmission system is used to connect generation resources to the electric distribution system for delivery to customers. The transmission system needs to adequately accommodate existing generation and be planned concurrently with new generation additions to ensure that the system can deliver this energy to load centers. While energy efficiency and demand response are the first priority for investment under the Loading Order, California continues to experience population and economic growth that spurs new demand. To meet the state's future needs, additional generation and transmission capacity will be needed over the next decade. Generation from renewable resources will play an important role in meeting these future energy needs, thereby placing additional emphasis on the need to resolve the operational integration issues associated with renewable resources.

Additional Transmission Evaluation Criteria

In addition to the criteria in PRC Section 25324, the Energy Commission believes several other evaluation criteria that should guide the selection of transmission projects for the 2005 Strategic Plan.

On Line Within Five Years

The focus of this first Strategic Plan is on near-term projects that could be on line by 2010. Projects further out than five years are not typically well defined and are deferred until the next Strategic Plan.

Siting Approval Required

Projects included in the Strategic Plan recommendations require siting and permitting approval in the near future if they are to be in service by 2010. The recommendations of the Strategic Plan are intended to highlight the importance of specific projects in meeting the needs of California. Projects that have already received a siting permit and are required for reliability or economic purposes or generator interconnection are not considered here.

Provides Strategic Benefits

As noted in Chapter 2, potential strategic benefits include the following:

- Insurance against contingencies during abnormal system conditions, such as low-probability but high-impact events.
- Price stability and mitigation of market power.
- Potential for increased reserve resource sharing.
- Environmental benefits.
- Reduction in infrastructure needs.
- Achievement of state policy objectives.

Conforms to SB 2431 Policy

The Legislature has for many years recognized the value of the state's transmission system, the importance of avoiding single-purpose lines where possible, and the need for effective, coordinated long-term transmission corridor planning. 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 SB 2431 (Garamendi), Chapter 1457, Statutes of 1988, the Legislature identified that the planning and siting of new transmission facilities should be pursued in the following order:

1. Encourage the use of existing rights-of-way (ROW) by upgrading existing transmission facilities where technically and economically feasible.

2. When construction of new transmission lines is required, encourage expansion of existing ROW, when technically and economically feasible.

3. Provide for the creation of new ROW when justified by environmental, technical, or economic reasons defined by the appropriate licensing agency.

4. Where there is a need to construct additional transmission capacity, seek agreement among all interested utilities on the efficient use of that capacity.

Although this policy was expressed by the Legislature when California's electricity industry was a regulated monopoly, it remains an appropriate policy in a competitive electricity industry and is consistent with the more recent direction of SB 1389 (Bowen), Chapter 568, Statutes of 2002, and the 2003 *Integrated Energy Policy Report*.

Project Assessment

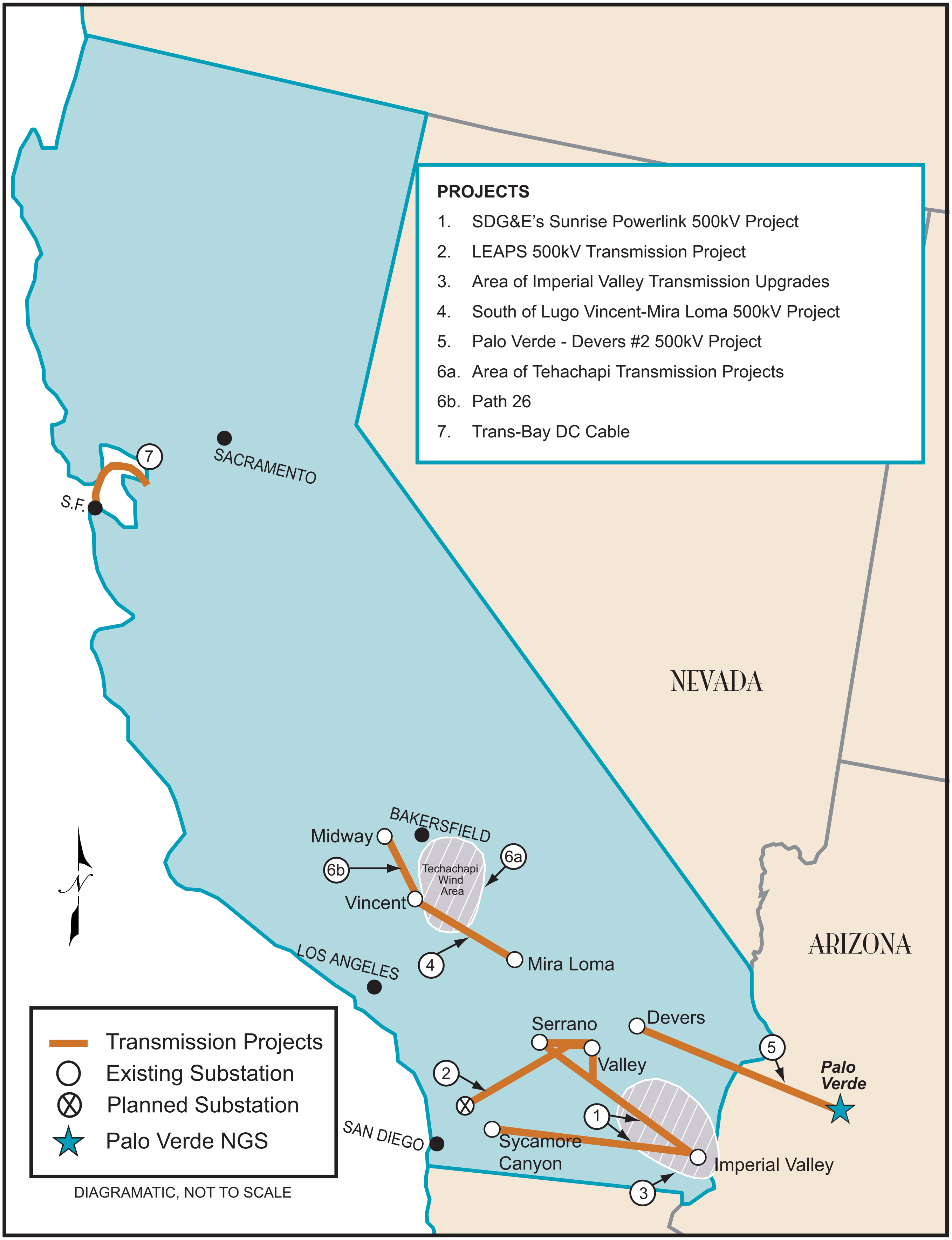
The following section provides an assessment of transmission projects from the Energy Commission staff report, *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond*. This assessment used the criteria discussed above to screen 21 projects from the staff report. Of the 21 projects screened, seven projects passed the criteria and are reviewed below for Energy Commission identification as vital near-term projects in the 2005 *Strategic Transmission Plan.* The seven projects are shown in Figure 4.

San Diego and Imperial Valley Region

San Diego 500 kV Sunrise Powerlink Project

The Sunrise Powerlink Project is proposed as a 500 kV transmission line connecting Imperial Valley to the San Diego service territory. While the route and exact interconnections for the project have not been determined, SDG&E's April 8, 2005 filing at the Energy Commission stated the 500 kV project would connect load centers to areas with significant renewable resource potential, reduce RMR costs for San Diego ratepayers, and help lower the cost of energy to all of California by providing greater access to a diverse set of supply resources.[7]

FIGURE 4
Major Transmission Projects



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, AUGUST 2005
SOURCE: CEC Staff

A 500 kV project to improve the San Diego interconnection to the rest of California and Arizona has been studied for several years. In 2001, SDG&E filed an application at the CPUC for a Certificate of Public Convenience and Need (CPCN) for the 500 kV Valley to Rainbow Project, a northern connection with SCE. The CPUC denied this application in 2003. According to the testimony of Jim Avery at the July 28, 2005 *Energy Report* hearing, "Had it [the Valley-Rainbow Project] been allowed to go into service in 2004, as we had requested, it would have saved our customers in RMR costs from the Minimum Load Cost Compensation (MLCC) side, as well as just the fixed option payment equation, about $191 million in the first two years."[8] Thus, the project with an estimated cost of $340 million could have saved more than half of its total costs in benefits to ratepayers in the first two years of a 50-year lifetime. At the June 29, 2005 *Energy Report* hearing on the Investor-Owned Utility Resource Plan Assessment Report, Susan Freedman from the San Diego Area Association of Governments, stated, "In looking at Valley-Rainbow, that would have been a great benefit."[9] The Sunrise Powerlink Project would provide many of the same benefits as the Valley-Rainbow Project, as well as enhance the development of in-state renewable resources.

SDG&E initiated work on the proposed 500 kV Sunrise Powerlink Project in October 2004 to identify and evaluate 500 kV options to help meet its long-term reliability and economic needs.[10] SDG&E formed a technical working group comprised of utility planners, regulators, and interested parties to identify needs, propose transmission options to meet needs, and design an assessment approach to evaluate alternative proposals. The working group initially selected six potential alternatives for assessment, each of which contained between two and four sub-options, for a total of 18 alternatives.[11] After additional studies, the technical working group arrived at two viable options:[12]

- The Imperial Valley to a proposed central San Diego County substation, with two 230 kV lines to the Sycamore Canyon Substation.
- The Imperial Valley Substation to a proposed central San Diego County substation, then to a new substation on the 500 kV Serrano - Valley line in SCE's service territory.

SDG&E has presented the proposed Sunrise Powerlink Project and the preferred options noted above at several transmission planning forums, including meetings of the Southwest Transmission Expansion Plan (STEP) and the Imperial Valley Study Group (IVSG).

The proposed 500 kV Sunrise Powerlink Project would reduce congestion and the cost of meeting load growth in San Diego. According to testimony at the July 28, 2005 *Energy Report* hearing, RMR costs for San Diego could approach $550 to $600 million in 2010 without contracts with generators, the Miguel-Mission No. 2 Project, and this proposed transmission project.[13]

A conceptual diagram of the proposed project, including a possible future 500 kV northern interconnection, is shown in Figure 5. The project would increase SDG&E's ability to reliably serve loads and deliver power into San Diego. SDG&E estimates that without the proposed 500 kV project, and assuming the aging generators at Encina and South Bay continue to operate, San Diego will be 333 MW short of required capacity reserves by 2010. This deficiency would grow to 700 MW by 2014. The proposed 500 kV project would allow SDG&E to meet reserve requirements for many years, depending on the development or retirement of local generation. This project would also lower costs by reducing San Diego's reliance on aging generators at Encina and South Bay. These aging generators are inefficient compared with new generators in Mexico, Arizona, and the Desert Southwest, and the cost impact of these efficiency differences is exacerbated by rising gas prices.

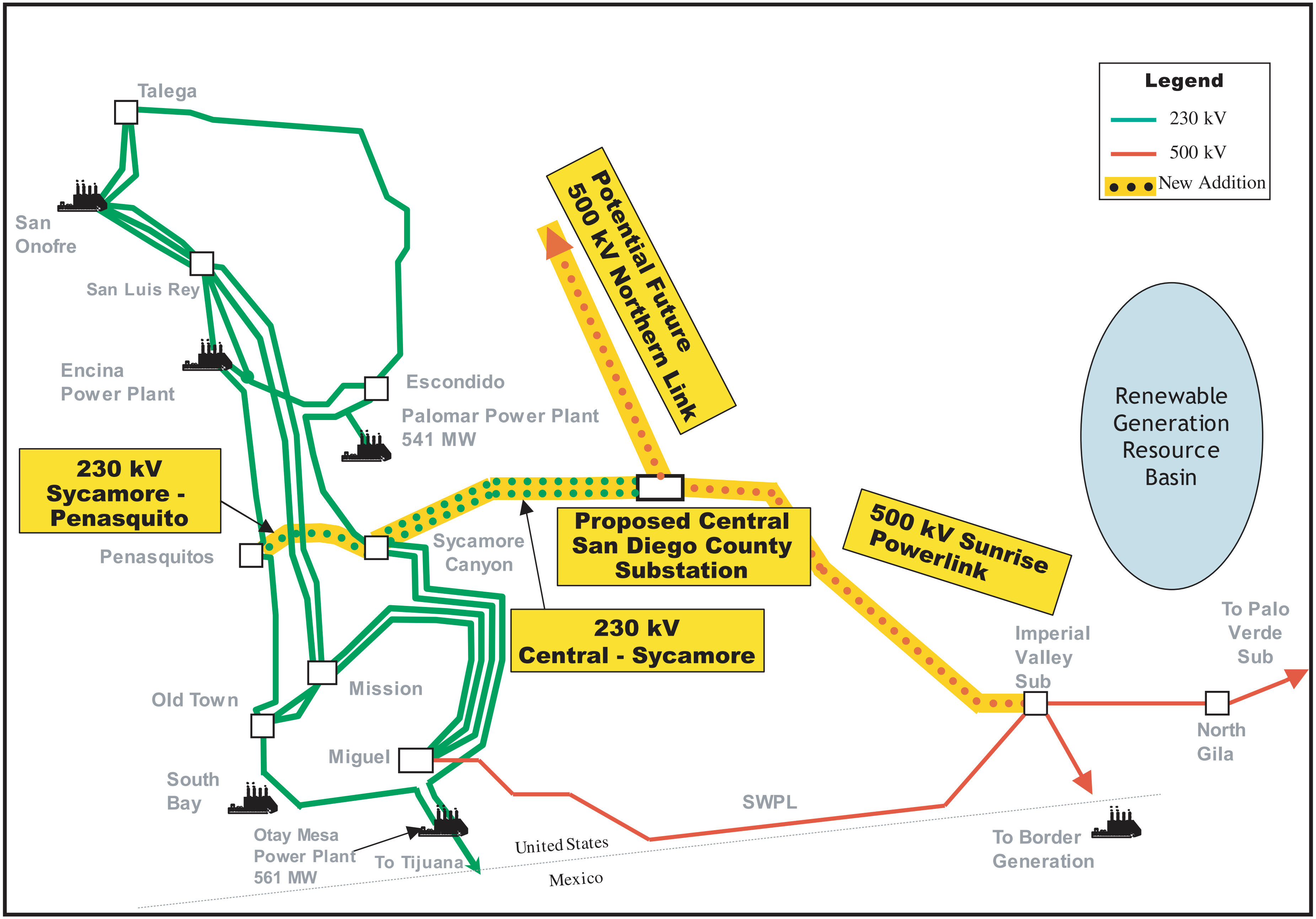
The proposed 500 kV Sunrise Powerlink Project is a key component of SDG&E's strategy to meet RPS goals. The proposed project would provide access to renewable resources needed to meet state goals by 2010. SDG&E has previously indicated in filings and testimony that "SDG&E's renewable assessment reveals that major transmission infrastructure is needed for deliverability of renewable resources to achieve the State's goals."[14] At the July 28, 2005, *Energy Report* hearing Jim Avery testified,

> "San Diego, take us back three years ago, had less than one percent of its portfolio in renewables. When the state came out with the direction to be at 20 percent by 2017, San Diego stepped up very aggressively. Today, just a couple of years later, we're at 5.7 percent. And we're negotiating contracts that potentially could put us at the 20 percent target by 2010. But we cannot do that without the new 500 kV line. We have literally signed virtually every contract for renewable resources that has come to us in the San Diego Basin. And yet with that, and the resources we've been able to sign outside, we're still below 6 percent."[15]

SDG&E is conducting a community outreach campaign to solicit public input on its potential routing options. SDG&E also plans to file the need portion of its application for a CPCN by the end of 2005, and the environmental and routing portion by the second quarter of 2006.[16]

In summary, the proposed 500 kV Sunrise Powerlink Project would provide significant near-term system reliability benefits to California, reduce system congestion and resultant congestion costs, and provide an interconnection to renewable resources located in the Imperial Valley and lower-cost out-of-state generation. Without the proposed project, it is unlikely that SDG&E will be able to meet the state's RPS goals, ensure system reliability, or reduce RMR and congestion costs. Therefore, the Energy Commission believes the proposed project offers significant benefits and recommends that the project be moved forward expeditiously so that the residents of San Diego and all of California can begin realizing these benefits by 2010.

FIGURE 5
SDG&E 500 kV Sunrise Powerlink



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, AUGUST 2005
SOURCE: SDG&E, 2005

A northern interconnection addition to the proposed project could also strengthen the CA ISO grid by providing a 500 kV interconnection between the SDG&E and SCE service territories. The state's existing 500 kV bulk transmission backbone runs from the Oregon border through SCE's service territory but does not connect with the San Diego area. San Diego's system currently connects to the rest of California through 230 kV lines running north through San Onofre Nuclear Generating Station and east to Imperial Valley through 500 kV lines. A northern 500 kV interconnection would both improve the reliability of California's transmission system and increase the state's overall ability to import lower-cost power from Arizona, Mexico and the Desert Southwest.

It should be noted that SDG&E faces significant land use constraints that will require resolution prior to completion of the project. The areas to the east of San Diego contain national and state parks, military bases, tribal lands, and new residential and other developments. The state-led transmission corridor planning process proposed in the Energy Commission staff's transmission report, *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond,* could assist in addressing ROW routing issues associated with this project. The Energy Commission recommends forming a Corridor Study Group to ensure that coordination with local, state, and federal agencies, tribal organizations, landowners, interested parties, and other stakeholders begins immediately.

Lake Elsinore Advanced Pumped Storage Project

The Lake Elsinore Advanced Pumped Storage (LEAPS) project, planned by the Elsinore Valley Municipal Water District and The Nevada Hydro Company, Inc., is proposed as a combined generation and transmission project located at Lake Elsinore in Riverside County. The transmission portion of the project would primarily be located in the Cleveland National Forest, which is located in both San Diego and Riverside Counties. The 29-mile, 500 kV transmission component of LEAPS would connect to a new substation or tap on SCE's 500 kV Serrano-Valley line, as well as to a new substation near the existing Talega-Escondido 230-kV line where the line enters Camp Pendleton in northern San Diego County.[17] This would provide an additional interconnection between the SDG&E and SCE service territories. The 500 kV line would have a nominal rating of 1,500 MW. Project costs are estimated at approximately $250 million for the transmission line and substations and $450 million for the pumped storage facility, not including the costs of necessary upgrades that would be required by SCE and SDG&E.[18]

Both the pumped hydro generation and transmission component of the LEAPS project are currently undergoing federal licensing and environmental compliance review. Utility Systems Integration Inc. completed a Phase I transmission system study in January 2005. Additional system and economic studies are underway. FERC published a Notice of Intent to prepare an Environmental Impact Statement (EIS) to the FERC in August 2004 (Federal Register: Aug 13 2004).[19] FERC accepted the application submitted by the project sponsors for a license for the hydro generation project in January 2005.[20]

The LEAPS transmission project would deliver pumped storage hydro power to the grid, reduce congestion and improve reliability in the San Diego area. The transmission component of LEAPS could complement the Sunrise Powerlink 500 kV project as a potential northern interconnection to the SCE service territory. This would require continued coordination between the project sponsors and SDG&E. Furthermore, the transmission component of LEAPS could strengthen the CA ISO grid by providing a 500 kV interconnection between the SDG&E and SCE service territories. As noted above, the state's existing 500 kV bulk transmission "backbone" runs from the Oregon border through the SCE service territory but does not connect with the San Diego area. San Diego's system currently connects to the rest of California via 230 kV lines running north through San Onofre Nuclear Generating Station and 500 kV lines running east to Imperial Valley. A northern 500 kV interconnection would improve the reliability of California's transmission system and increase the state's overall ability to import lower-cost power from Arizona, Mexico and the Desert Southwest. In its April 2, 2004, Motion to Intervene at the FERC, the CA ISO noted that "The transmission line proposed in association with the Lake Elsinore Pumped Storage Project would allow the San Diego area to import substantially more power from surrounding areas and would greatly enhance electric system reliability."[21]

The Nevada Hydro Company, Inc. has made significant licensing progress with federal agencies. According to The Nevada Hydro Company, Inc., the U.S. Forest Service (USFS) has agreed to (i) be a cooperating agency for purposes of carrying out the requirements of the National Environmental Policy Act (NEPA)[22], (ii) produce a single environmental impact statement (EIS) for the project that will address the needs of both the USFS and the FERC, and (iii) stated their willingness to issue appropriate permits and has submitted preliminary licensing conditions to the FERC.[23] The FERC-authored Draft EIS is expected in November 2005, while the Final EIS and Record of Decision are expected in April 2006.[24]

However, the proposed LEAPS project has unresolved concerns, including:

- Incomplete economic studies.
- Incomplete transmission system impact studies, which could identify further environmental impacts.
- Because the proposed transmission component of LEAPS would travel through the Cleveland National Forest and portions of Department of Defense and other public lands, the project would be subject to the requirements of the USFS, the Environmental Protection Agency, and the Bureau of Land Management (BLM).

The transmission component of LEAPS may offer substantial benefits to California and is worthy of further monitoring and future consideration. However, pending completion of system and economic studies, as well as FERC approval, the Energy Commission believes the project does not warrant a recommendation at this time.

The Energy Commission recommends monitoring and future consideration of the project in the 2007 *Energy Report* cycle.

Imperial Valley Transmission Upgrade Project

The Imperial Valley is a critical source of renewable generation in California. Currently, geothermal resources produce about 450 MW in the Imperial Valley area, and developers estimate that there is the potential for an additional 1,350 to 1,950 MW that could be developed over the next 15 years.[25] However, the Imperial Valley area does not have the transmission capacity to deliver new geothermal resources to loads in California. Both the Imperial Irrigation District (IID) and the Imperial Valley Study Group (IVSG), a consortium of utilities, developers and regulators,[26] have developed transmission plans designed to deliver generation in the Imperial Valley to loads in California and the West. The IID plan, called the Green Path Initiative, is a phased transmission project that would connect generation in the Imperial Valley to SDG&E, SCE, the Western Area Power Authority (Western) and Arizona. The Imperial Valley Study Group plan focuses on the delivery of power to California through SDG&E and SCE.

The Green Path Initiative proposed by IID would increase transmission capacity and provide access to valuable renewable resources needed to meet future load growth in California. As noted by IID at the April 11, 2005 *Energy Report* workshop, "Without a coordinated effort on energy and transmission, the development of the geothermal resources will be impaired."[27]

The Green Path Initiative sponsored by IID is a four-phased plan[28] that includes:

- Phase 1, which would be completed by 2010 and deliver approximately 600 MW of new geothermal capacity to the SCE service territory by upgrading the transmission facilities between the Coachella and Devers substations. The west of Devers upgrades, which are included as part of the proposed Palo Verde - Devers No. 2 (PVD 2) 500 kV Transmission Project discussed below, would likely assist in the delivery of geothermal generation to SCE's service territory and other areas of the state.
- Phase 2, which would be completed by 2016 and upgrade the southern portion of IID's network and the connection with Arizona Public Service (APS). This would allow delivery of an additional 600 MW of geothermal generation.
- Phase 3 is a long-term solution consisting of a new 500 kV Sunrise Powerlink - San Felipe Substation connected to IID's Bannister Substation via a new 500 kV transmission line that would bring the total export capability to approximately 2,000 MW.
- Phase 4 would bring the overall export capability to over 2,000 MW by upgrading the interconnection between IID and Western.

Figure 6 shows the fully developed Green Path Initiative proposed by IID, with 230 kV interconnections to SCE, Western and Arizona and a 500 kV interconnection to SDG&E.

The IVSG initially identified seven transmission alternatives for study based on proposals from group participants. Each of the alternatives is capable of delivering 2,000 MW of geothermal output to delivery points at Blythe, Coachella Valley, Highland-Pilot Knob and other substations. Technical studies have been used to assess seven transmission alternatives, five of which were rejected by the IVSG. Additional technical studies are underway and CA ISO will conduct an economic analysis of the project once these are refined.

The IVSG development plan includes three phases:

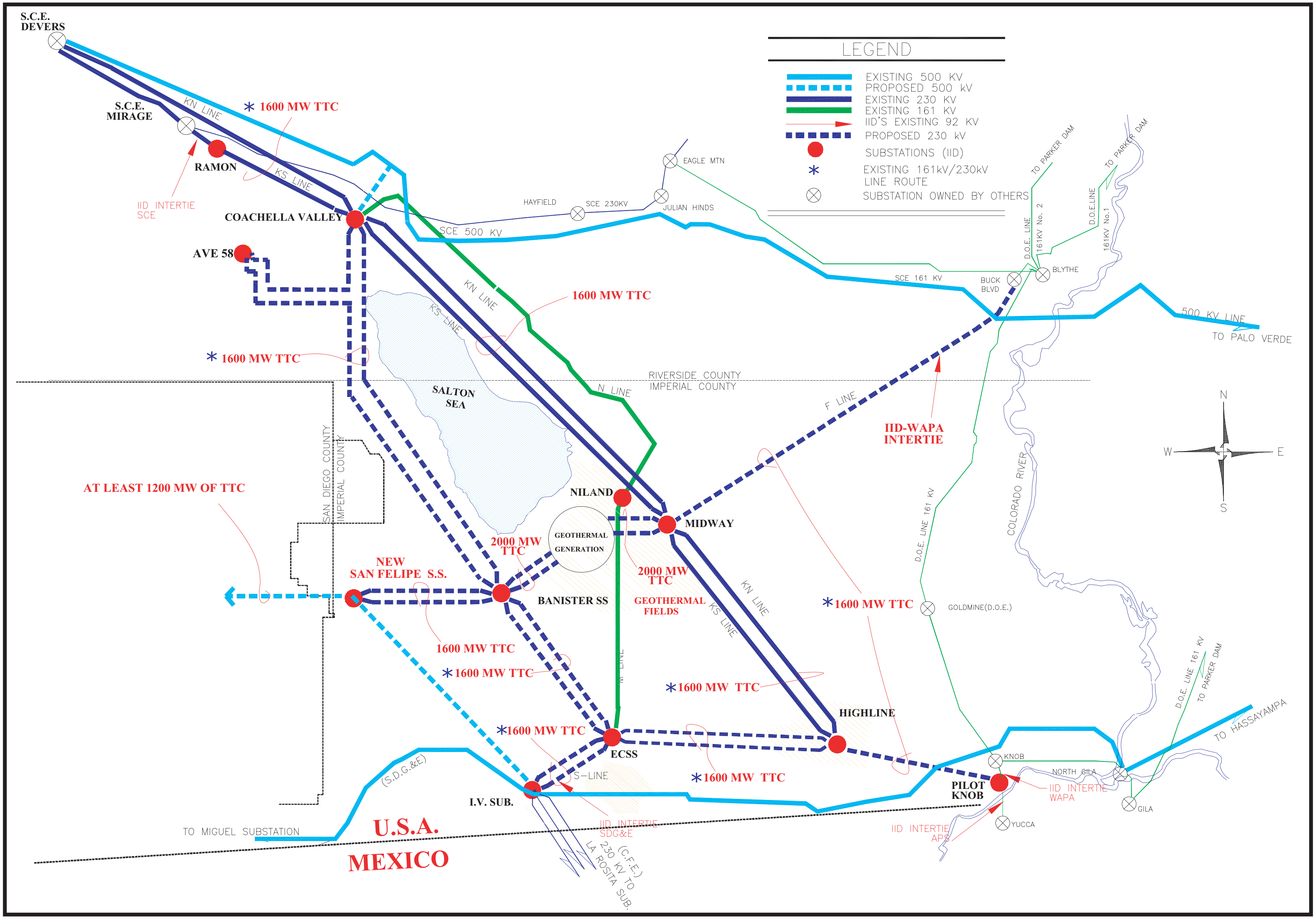
Phase 1
Export capacity: 645 MW
In Service Year: 2010
Estimated cost, IID Upgrades: $ 72 million
(cost of the 500 kV line into San Diego not included)

Lines:	Upgrade Highline to El Centro and to IV substations, 40 miles New Geo Collector Substation 1 to Midway, approx. 15 miles New IV to San Diego-Central, approx. 90 miles, 500 kV; with 230 kV lines into SDG&E's load center
Substations:	New Geothermal Collector Substation 1, 230 kV Expand El Centro Substation; expand Midway Substation

Phase 2
Export capacity: 645 MW (1,290 MW cumulative)
In Service Year: 2016
Estimated cost, IID Upgrades: $ 60 million

Lines:	New Bannister to San Felipe Substation, 20 miles, 230 kV Upgrade existing El Centro to Bannister, approx. 25 miles New IID Collector Substation 2 to Bannister, 230 kV
Substations:	New IID Collector Substation 2, 230 kV New IID San Felipe 500/230 kV substation

FIGURE 6
Imperial Valley Transmission Upgrade Project



AUGUST 2005

TRANSMISSION SYSTEM ENGINEERING

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SOURCE: IID, 2005

Phase 3
Export capacity: 910 MW (2,200 MW cumulative)
In Service Year: 2020
Estimated cost, IID Upgrades: $ 105 million

Lines:	Upgrade existing Coachella Valley to Mirage/Devers, 40 miles Upgrade existing Bannister to Coachella Valley, 55 miles Tie Bannister to Collector substations to Midway, 1 mile
Substations:	Expand Coachella Valley Substation (Upgrades to west of Devers Substation not included)

The Los Angeles Department of Water and Power (LADWP) has released a transmission plan that includes a new 500 kV line from IID to LADWP. The proposed LADWP project would allow more than 400 MW of generation to be delivered from IID to LADWP.[29] LADWP's proposed transmission plan includes:

- New Indian Hills to Upland 500 kV line, 100 miles.
- Upgrade existing Upland to Victorville line to 500 kV, 34 miles.
- New Coachella to Indian Hills line.
- New Indian Hills 500/230 kV substation.
- New Upland 500 kV substation.

In summary, an Imperial Valley upgrade project would provide access to valuable renewable resources needed to meet future load growth, support California's RPS goals and provide significant near-term reliability benefits to California. Therefore, the Energy Commission believes Phase 1 of the Imperial Valley Study Group's proposed plan, including a 500 kV link to SDG&E, would provide significant benefits to California and recommends that Phase 1 move forward expeditiously. Further transmission development in the Imperial Valley region should be carefully coordinated in order to avoid duplication, and to develop a transmission plan that serves the needs of both California and the West.

Currently, transmission development in the Imperial Valley region faces significant land use constraints that will require resolution before any proposed project can be completed. Existing land uses in the immediate area include the Chocolate Mountain Naval Aerial Gunnery Range, Anza-Borrego State Park, and new residential and other developments. The IVSG has identified potential permitting and land use issues, including the absence of IID's proposed transmission corridors from the BLM's Desert Conservation Area Plan.[30] The IVSG is forming a permitting group to consolidate permitting of the combined generation and transmission project and to coordinate with concerned state, county and federal agencies.[31] The Energy Commission recommends the IVSG begin coordination with local, state, and federal agencies, landowners, interested parties, and other stakeholders immediately. In the absence of permitting progress, the Energy Commission could recommend forming a Corridor Study Group to assist in addressing ROW routing issues associated with the project.

Southern California and Tehachapi Region

South of Lugo (Vincent-Mira Loma 500 kV Project)

The proposed Vincent-Mira Loma 500 kV Project would consist of a new 77-mile single circuit 500 kV transmission line between the Vincent and Mira Loma Substations in SCE service territory. The proposed project may be needed by 2009 or 2010 to reliably serve growing loads in Southern California, reduce congestion, and enable the delivery of renewable generation from the Tehachapi area into Southern California.

CA ISO identified the need for this project in its *Controlled SCE Transmission Expansion Plan 2005-2014*.[32] According to SCE, the proposed project would help deliver power from Northern California and the Pacific Northwest to load centers of Southern California. In addition, the project would enable the delivery of renewable generation from the Tehachapi area into Southern California. SCE system studies indicated that under base case conditions, the south of Lugo line could exceed its 5,600 MW limit and violate reliability criteria by 2009 or 2010. Studies also found that the system operated within its 5,600 MW limit with the new Vincent-Mira Loma line in place. SCE concluded that the new line along with other generation and transmission projects represented in the studies would ensure reliable system performance under 2014 heavy summer and light spring conditions.

The proposed project is currently in the planning stage and neither project costs nor significant issues associated with the project have been identified. In addition, the proposed project would require CA ISO Board of Governors approval and a CPCN by the CPUC. However, any planning and permitting delays could mean that the Vincent to Mira Loma 500 kV line would not be operational in time to prevent violation of reliability standards south of Lugo starting in 2009 or 2010.

The proposed Vincent-Mira Loma 500 kV Project may offer substantial benefits to California and is worthy of further monitoring and future consideration. However, due to the lack of specific project details and studies, the project does not warrant a recommendation for action at this time. To warrant future consideration in the 2007 *Energy Report* cycle, additional project documentation of benefits is necessary.

Palo Verde - Devers No. 2 500 kV Transmission Project

The Palo Verde - Devers No. 2 (PVD2) 500 kV Transmission Project, proposed by SCE, would consist of a new 500 kV transmission line from the Palo Verde area of

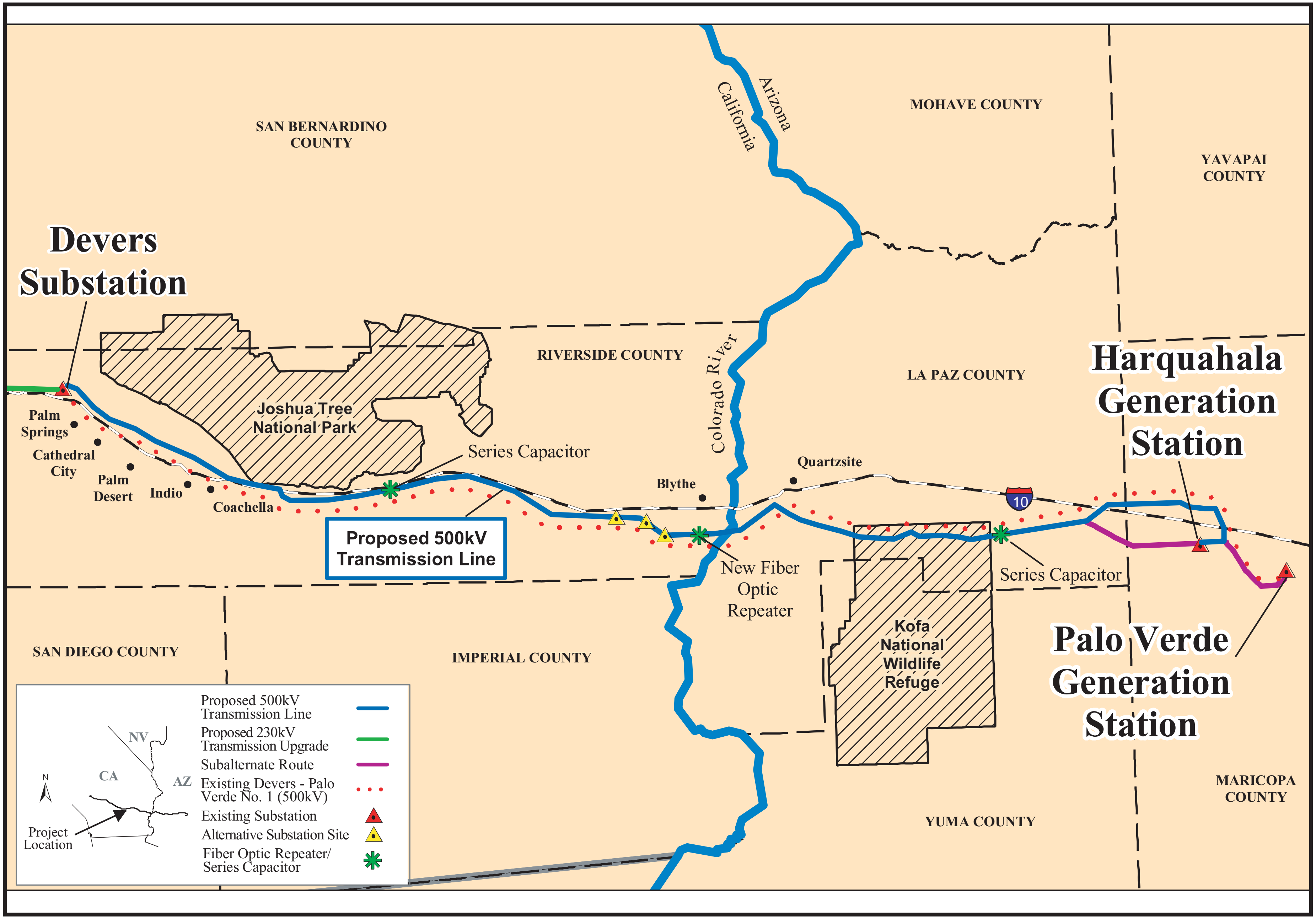
Arizona to Southern California Edison service territory. SCE believes generation surpluses will be available from Arizona starting in 2008 and continue even as loads grow in the Desert Southwest, in part because "new generation in Arizona will continue to have economic advantages over new projects in California."[33] According to SCE's environmental assessment of the PVD2 Project, the benefits of increasing California's access to surplus, lower cost resources in Arizona would be $1 billion over the life of the project.[34] SCE studies also indicate that the PVD2 Project will provide insurance against the effects of major transmission or generation outages resulting from fires, earthquakes or other catastrophic events, but SCE did not attempt to quantify these benefits.[35]

SCE has presented and discussed the benefits of the PVD2 Project in several documents and forums including:

- The SCE *Devers - Palo Verde No. 2 Cost-Effectiveness Report*.
- The March 17, 2005 update to SCE's April 7, 2004 Report to the CA ISO entitled *Devers-Palo Verde No. 2 Cost-Effectiveness Report.*
- Southern California Edison Company's 2005 *Energy Report* Transmission Submittal.
- The Southern California Edison April 11, 2005, *Proponent's Environmental Assessment- Devers Palo Verde No. 2 Transmission Line Project (Volume I)*.

The proposed PVD2 Project, as shown in Figure 7, would consist of a new 500 kV transmission line from Harquahala Substation in the Palo Verde area of Arizona to the Devers Substation in Southern California. The project would be located in the same corridor as the existing Palo Verde-Devers 500 kV transmission line and significantly reduce congestion on transmission facilities linking California to Arizona. According to the CA ISO, $21.7 million of the $55.8 million in total congestion revenues for 2004 was attributable to Palo Verde in the east-to-west direction.[36] Studies by the CA ISO and SCE have shown that, over the life of the project, the PVD2 project could provide significant benefits to California ratepayers by reducing congestion and the cost of providing electricity to California's growing load centers. Several other system improvements, including the upgrade of four 230 kV transmission lines west of the Devers Substation, are also included as part of the proposed project and are shown in Figure 8. (As noted above in the Imperial Valley Transmission Upgrade Project discussion, the west of Devers upgrades would likely assist in the delivery of geothermal generation to the SCE service territory and other areas of the state.) The project is expected to cost $680 million in 2009 dollars and would increase the import capability from Arizona and the Desert Southwest into Southern California by 1,200 MW.[37] If the project is approved by the end of 2006, it could be operational by the end of 2009.

FIGURE 7
Palo Verde-Devers No. 2 500 kV Transmission Project



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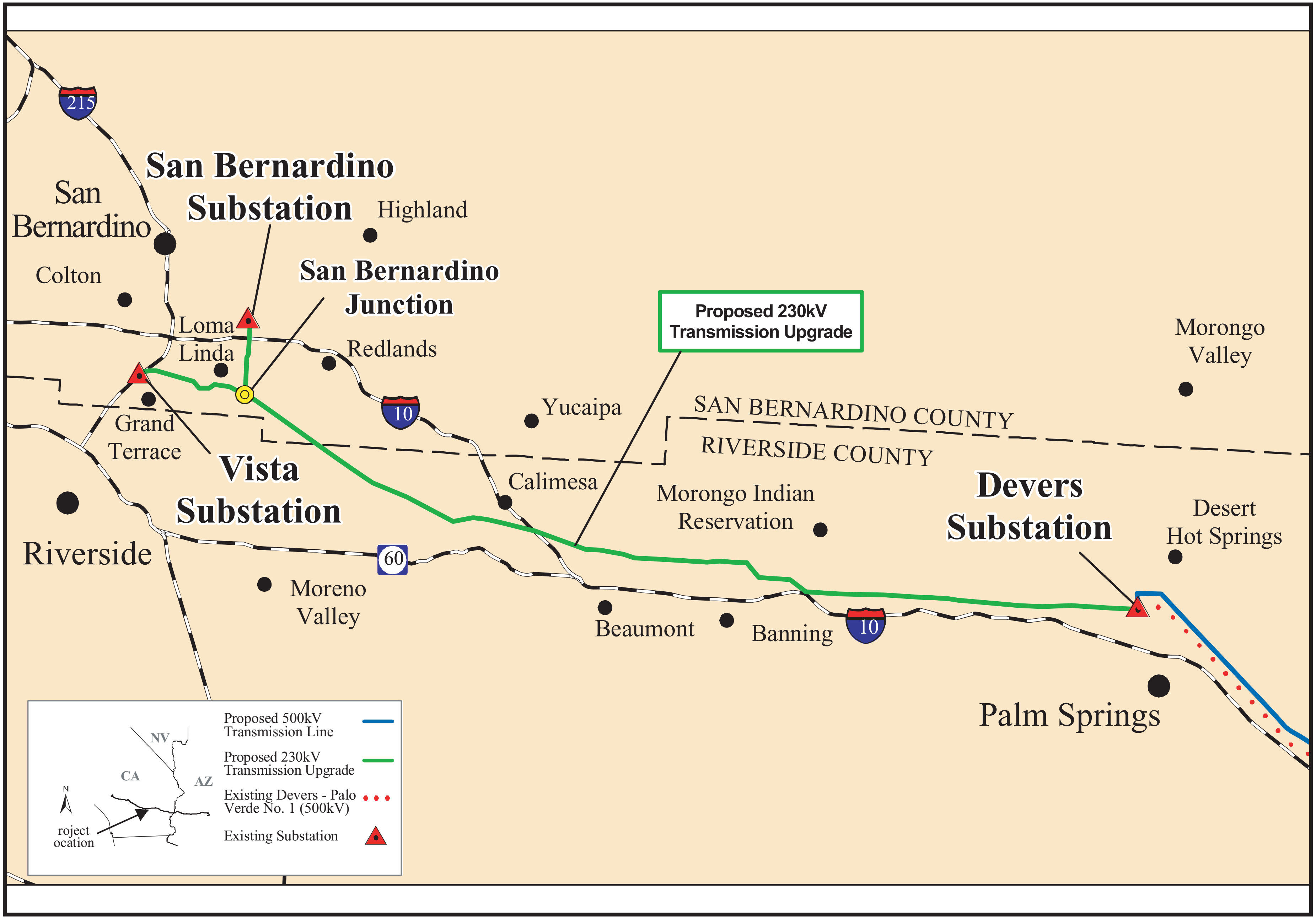
SOURCE: SCE, 2005

FIGURE 8
West of Devers Upgrades (Included as Part of PVD2 Project)



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SOURCE: SCE, 2005

The CA ISO produced two studies analyzing the PVD2 Project. One study was reviewed and assessed as part of the coordinated transmission planning work of the Southwest Transmission Expansion Plan (STEP).[38] The other, *Economic Assessment of the Palo Verde – Devers No. 2*, provides a detailed analysis of the project using the CA ISO Transmission Economic Assessment Methodology (TEAM). The assessment accounted for the energy, operational, capacity, system loss savings and emissions benefits of the project. The CA ISO analyzed the benefits of the PVD2 Project under a large number of scenarios and estimated the expected annual benefits of the project to be between $84 million and $225 million, depending on how benefits are calculated.[39] Compared with annual costs of $71 million, the DPV2 Project would have a benefit-to-cost ratio between 1.2 and 3.2, depending on how benefits are allocated. During an *Energy Report* workshop on May 19, 2005, the Consortium for Electric Reliability Technology Solutions/Electric Power Group (CERTS) acknowledged that CA ISO's methodology continues to understate potential project benefits, as transmission projects have a 30 to 50 year lifespan and it is difficult, if not impossible, to model a reasonable projection of grid operations over such a long period. CERTS also indicated that while the magnitude of benefits calculated for the PVD2 Project by CA ISO resulted in a benefit-to-cost ratio of greater that 1.0 under all cases, strategic values such as insurance value during abnormal system conditions, environmental benefits (besides NO_x reductions), and a decrease in the need for additional infrastructure (such as gas pipelines) are not fully captured in the CA ISO report.

CERTS also reviewed SCE's *Proponents Environmental Assessment* for the PVD2 project and presented results at an Energy Commission hearing on July 28, 2005. According to CERTS, the SCE study indicated a benefit-to-cost ratio of 1.7 for CA ISO ratepayers. In addition, CERTS noted that potential strategic benefits associated with the project were not captured in SCE's production simulation modeling assessment used to evaluate the project. These potential benefits included attracting new generation development east of Devers Substation, reducing the potential for generators to exercise market power, and providing emergency value during a major import line and/or generating facility outage.

The PVD2 project has been studied in California for several decades and showcases many of the pitfalls of the state's reactive approach to transmission planning. A detailed procedural history of the PVD2 Project is contained in Appendix A, which is excerpted from two prior CPUC decisions. In 1985, SCE applied for a CPCN for a second 500 kV line between Devers and Palo Verde. In 1988, SCE was granted a CPCN for the second line, but the project was not constructed due to uncertainties in the electric utilities industry. In 1997, due to regulatory uncertainty and deregulation, SCE requested abandonment of the project.[40] Thus, as early as 1988, state regulators found the project beneficial to California ratepayers.

The PVD2 Project currently faces two significant permitting issues. First, the significant cost of the project, $680 million in 2009 dollars, and uncertainty concerning the measurement of project benefits could pose difficulties in the CPUC's permitting process. Recognizing this, the CPUC has coordinated this proceeding with its ongoing assessment of transmission evaluation methods. Second, LADWP filed a written petition requesting that SCE remove its CPCN application for the PVD2 Project because LADWP was exercising an option to build it.[41] If LADWP were to take over the project, the CPUC's permitting approval would be replaced by a process conducted by the City of Los Angeles.

In summary, the proposed PVD2 Project would provide significant near-term benefits by reducing congestion on lines connecting California and Arizona and providing access to lower cost out-of-state generation to meet California's growing electricity needs. The proposed project would also provide strategic benefits to California ratepayers, including valuable insurance against abnormal system conditions and power outages, increased operating flexibility for California grid operators, reduced market power for generators, and reduced need for other infrastructure in California. Therefore, the Energy Commission believes the proposed project offers significant benefits and recommends that the project be moved forward expeditiously so that California can begin realizing these benefits by 2010.

In addition, the Energy Commission recommends forming a Corridor Study Group to review existing land uses along the existing Interstate 10 transmission corridor and coordinate with local, state, and federal agencies, landowners, interested parties, and other stakeholders. The Interstate 10 corridor is an important asset to California and, if granted corridor designation authority by the Legislature in the future, the Commission should consider corridor designation on non-federal lands to complement the existing federal corridor designation.

Transmission for the Tehachapi Wind Resource Area and Expansion of Path 26

The Tehachapi area transmission projects proposed by SCE are a key component of California's energy strategy that would both provide access to valuable renewable resources needed to meet future load growth and reduce congestion on transmission lines serving Southern California. The Tehachapi area is critical to development of renewable wind resources in California. The region could provide over 4,000 MW of new wind generation to California, which would be a significant portion of the renewable generation that California utilities need to meet RPS by 2010. The Tehachapi Collaborative Study Group (TSG) has created a conceptual transmission plan that, when complete, would collect and deliver approximately 4,500 MW of Tehachapi wind generation to loads in California.[42]

The TSG conceptual transmission plan consists of facilities to collect power from Tehachapi area wind projects, interconnection facilities to connect that power into the state's backbone transmission grid, and network upgrades to deliver reliable power to load centers. Transmission facilities would be built in four phases with the first two phases reinforcing the existing Tehachapi connection to the Southern California grid and the third and fourth phases adding a northern interconnection to PG&E that would also function as an expansion of Path 26. Phases One and Two of the plan would connect 1,600 MW of new wind resources to the Southern California grid but would not reduce congestion on Path 26. Phases Three and Four would allow for the interconnection of an additional 2,900 MW or more of new wind generation and would expand the network's ability to move power from Northern and Central California into resource-constrained Southern California.

Table 3 provides a brief description of each phase of the Tehachapi conceptual plan. Phased development will allow wind generators to pursue projects with the certainty that the generation will not be stranded by transmission congestion and will help protect ratepayers from investing in a transmission network that is never utilized. The plan also includes a "collector" system that will consist of between four and six 230 kV substations (depending on the quantity and location of the wind projects) that will connect to a 500 kV backbone system through a new 500 kV Tehachapi #1 Substation.

Phase 1: The Antelope Transmission Project

Phase 1 will permit the reliable export of approximately 700 MW of new wind generation from the Tehachapi area and will cost approximately $207 million. Phase 1, Segments 1 through 3, is shown in Figure 9. SCE filed a CPCN application for Phase 1 on December 9, 2004. The conceptual plan for Phase 1 has several components including:

- A new 500 kV, 25-mile, transmission line from the Antelope Substation to the Pardee Substation that will be designed to 500 kV standards but initially energized at 230 kV.
- A new, approximately 44-mile long 500 kV Tehachapi #1-Antelope-Vincent transmission line.
- Two new Tehachapi substations.
- Expansion of both the Pardee and Antelope Substations to accommodate the new transmission line.
- A new wave trap on the Vincent-Mesa 230 kV line at the Mesa Substation.
- Special Protection Systems at seven SCE substations.

In July 2004, the CA ISO Board of Governors approved the project and requested that SCE proceed with project design and environmental permitting activities necessary to construct the project.[43] A CPUC decision on the CPCN is presently anticipated in December 2005. Acquisition of ROW and construction of Phase 1 facilities are expected to begin as soon as the permitting process is complete. The project is expected to be complete in December 2006.

Table 3

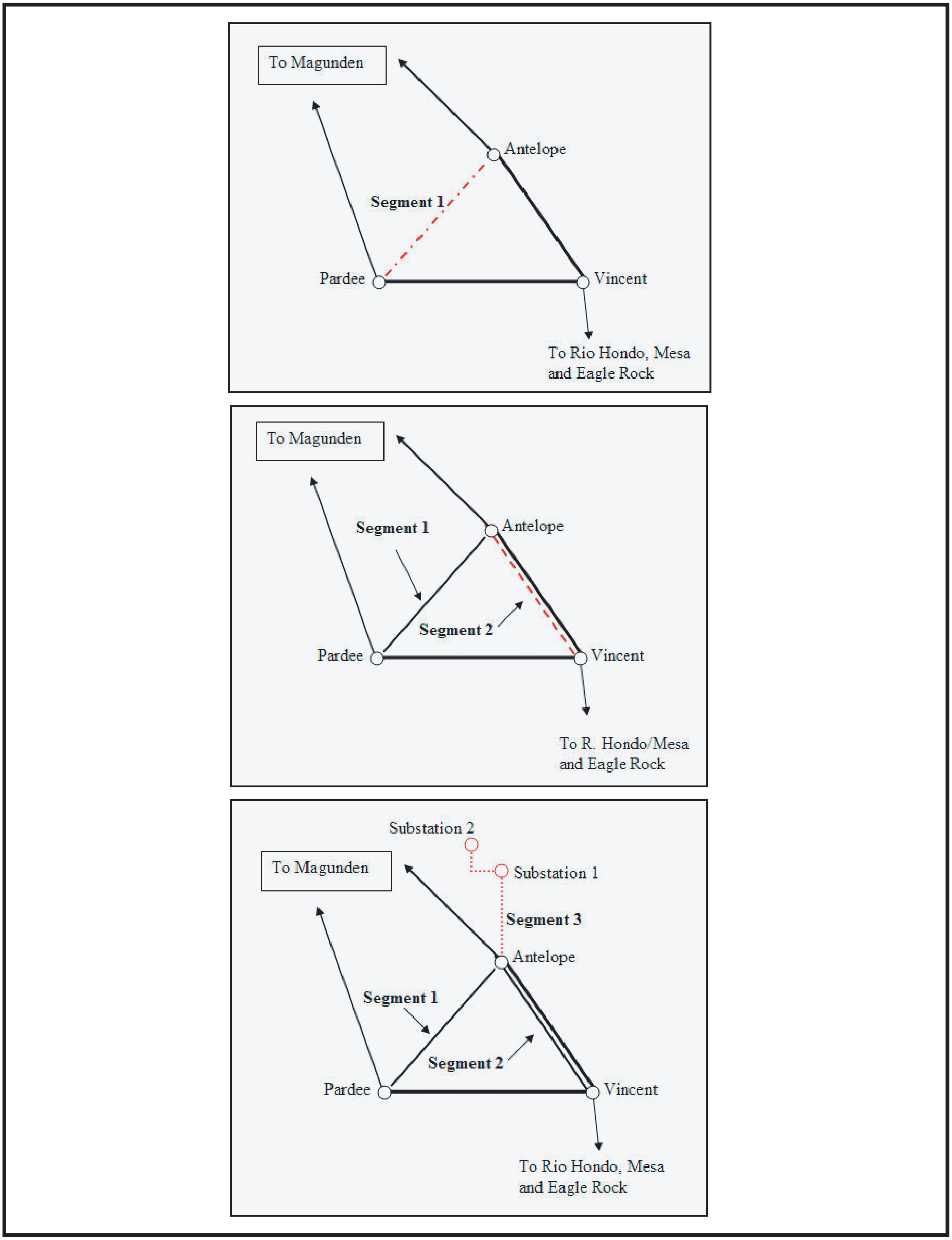
Tehachapi Area Transmission Plan

Project Phase	Capacity MW	Project Element	Task	Proposed year to be completed	Estimated Cost $Millions
1	700	*Segment 1* Antelope-Pardee 500 kV Line – initially energized at 230 kV	CPCN application CPCN approval ROW Acquisition and construction complete	Dec 2004 Dec 2005 Jun 2007	Phase 1 Segments 1 ,2 &3 $207
		Segment 2 Tehachapi Substation #1 Antelope-Vincent 500kV line - initially energized at 230 kV	CPCN application CPCN approval ROW Acquisition and construction complete	Jun 2005 Jun 2006 Jun 2008	
		Segment 3 Antelope-Tehachapi #1 500 kV initially energized at 230 kV	CPCN application CPCN approval ROW Acquisition and construction complete	Jun 2005 Jun 2006 Jun 2008	
2	900	Upgrade Antelope-Mesa 230kV Line	CPCN application CPCN approval ROW Acquisition and construction complete	Jun 2006 Jun 2007 Jun 2009	$281

Table 3 Continued

Project Phase	Capacity MW	Project Element	Task	Proposed year to be completed	Estimated Cost $Millions
3A	750	Tehachapi-Vincent 500 kV PG&E upgrades (under study)	Planning CPCN application CPCN approval ROW Acquisition and construction complete	Jan 2006 Jan 2006 Jan 2007 Jan 2010	$66
3B		PG&E Upgrades (under study)	Planning CPCN application CPCN approval ROW Acquisition and construction complete	Jan 2006 Jan 2007 Jan 2008 Dec 2010	$972
4	1,200	Tehachapi to PG&E And Path 26 upgrades	Planning CPCN application CPCN approval ROW Acquisition and construction complete	Jan 2006 Jan 2007 Jan 2008 Dec 2010	$750

FIGURE 9
Antelope Transmission Project - Phase 1, Segments 1-3



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SOURCE: CERTS, 2005

However, in a September 15, 2005 letter from Ms. Jody Noiron of the USFS to the CPUC, the USFS expressed her concern about the ability of the USFS to meet the timeframe for publishing the final EIS/R in March 2006:

> The Forest entered into a Memorandum of Understanding with the CPUC in May 2005 to move forward on a joint National Environmental Policy Act (NEPA)/CEQA Environmental Impact Statement/Report (EIS/R). When the Forest entered into the agreement I fully intended to attempt to meet the Final EIS/R publication date of March 2006, knowing this was a very ambitious timeline for the NEPA process. As we moved further into the analysis I have become more aware of the challenges of meeting this timeframe and want to formally inform you that I am concerned that attempting to meet this timeframe may compromise our ability to complete a thorough analysis that complies with NEPA and the Forest Land and Resource Management Plan.
>
> …Based on the Draft Purpose and Need for the Antelope-Pardee Transmission Project it appears the Fairmont Wind Project is connected to this Antelope-Pardee Transmission Project and must be considered a connected action in compliance with NEPA (40 [Code of Federal Regulations] 1508.25(a)).
>
> …In addition, constructing the line for 500-kV, instead of 220-kV (which is the sized line SCE feels would be required to bring the power from the proposed Fairmont Wind Project into SCE electric system) brings up the concern of connecting this project with the larger Tehachapi Windfarm Project. In order to determine whether this larger Tehachapi Windfarm Project is connected to the Antelope-Pardee Transmission Project, the Forest needs additional information on how the Antelope-Pardee Transmission Project and the Tehachapi Windfarm Project are inter-dependent. Presently this inter-dependence is not clear and this will need to be resolved before the proposed action (project) can be finalized.
>
> According to past court decisions on NEPA documents, if a project includes multiple phases with independent state and federal jurisdiction, the federal agency can rely on the state's environmental analysis. Unfortunately, in this case, my understanding is there has been no CEQA completed on the Fairmont or Tehachapi Windfarm Projects. I believe at a minimum our analysis and EIR/S must address these projects in the context of indirect and cumulative effects associated with the Antelope Transmission Project.[45]

In light of these concerns, the development schedule for Phase 1 could be delayed, which could impact the delivery of renewable generation to load centers and possibly impact RPS goals.

Phase 2: Antelope-Mesa 230 kV Upgrade
The Antelope-Mesa 230 kV Upgrade would cost approximately $281 million and allow the export of 900 MW of new wind generation beyond the Phase 1 projects. The *Report of the Tehachapi Collaborative Study Group* describes Phase 2 as a new transmission line in three segments, some of which would be 230 kV and others that would be constructed as 500 kV facilities initially energized at 230 kV. The CPCN for Phase 2 could be filed by June of 2006, allowing a total of 1,600 MW of Tehachapi wind generation to reach Southern California by April 2009.

Phase 3: Tehachapi-Vincent 500 kV Transmission Line and Other Upgrades
Phase 3 would increase the export capacity from Tehachapi by 1,700 MW and cost approximately $1.038 billion. Phase 3 incorporates several facilities including:

- A second Tehachapi-Vincent 500 kV line energized at 230 kV.
- Substation facilities needed to operate 230 kV facilities from Phases 1 and 2 at 500 kV.[46]
- SCE and PG&E upgrades as needed.

The details of the Phase 3 facilities are still being studied but the expectation is that they could be constructed and operating by the end of 2010.

Phase 4: Tehachapi-PG&E 500 kV
Phase 4, like Phase 3, requires more detailed planning, but a 500 kV Tehachapi-to-PG&E interconnection is estimated to cost $750 million and to increase the Tehachapi export capacity by 1,200 MW to a total of 4,500 MW. The exact interconnection to the PG&E network has not been defined and any 500 kV Tehachapi upgrades to PG&E are expected to require significant upgrades to the PG&E network. A 500 kV Tehachapi-to-PG&E interconnection could also serve as a fourth 500 kV leg of Path 26, which currently limits the import of power into Southern California from Central and Northern California. This interconnection with the PG&E system would provide PG&E access to renewable resources in the Tehachapi region.

In its October 14, 2005, response comments to the *Draft Strategic Plan*, SCE noted:

> SCE would like to highlight a transmission concern that appears to have received little attention in the Draft Strategic Transmission Investment Report, namely, the continuing congestion which exists on the primary transmission path from northern to southern California (i.e., Path 26)… As a means to address these ongoing Path 26 congestion concerns, consideration should be given to accelerating the development of a 500kV connection from northern California to the Tehachapi area… [A]t the September 12, 2005 Energy Action Plan meeting, SCE expressed that it is considering to add to its current proposed Tehachapi transmission planning proposal an extension of its planned 500kV system from the Tehachapi area to central California (Midway). Although this extension is just in the preliminary study

> phase, it is believed that projects like this, along with an acceleration of Phase 4, would not only help mitigate Path 26 congestion on a more permanent basis, but also greatly expand the State's access to the renewables resources in that region.[47]

The Energy Commission agrees that Path 26 congestion continues to be an issue and welcomes SCE's proposal to accelerate Phase 4 as a means to both mitigate congestion and promote increased access to renewable generation for both Northern and Southern California. The Energy Commission encourages SCE to move forward with this proposal as a means to meet statewide RPS goals.

In summary, the conceptual Tehachapi Transmission Plan would increase access to over 4,500 MW of renewable resources needed to serve California's growing electricity needs. The Energy Commission supports the conceptual Tehachapi Transmission Plan developed by the TSG because it could provide access to 4,500 MW of renewable generation and will assist California utilities in meeting RPS goals by 2010. The Energy Commission believes the Antelope Transmission Project proposed by SCE is crucial to the development of wind resources in the Tehachapi region and will offer significant benefits to California. Therefore, the Commission recommends the project be moved forward expeditiously so that California can begin realizing benefits by 2010.

Future phases of the conceptual Tehachapi Transmission Plan may face land use constraints that will require resolution prior to completion of the project. The state-led transmission corridor planning process proposed in Energy Commission staff's transmission report, *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond,* could assist in addressing ROW routing issues associated with this project. The Energy Commission recommends that utilities begin coordinating with local, state, and federal agencies, landowners, interested parties, and other stakeholders immediately to ensure the availability of potential future transmission routes as they are needed. Should land use issues become problematic in the future, the Energy Commission could recommend forming a Corridor Study Group to assist in addressing ROW routing issues associated with this project.

Northern California Region

Trans-Bay DC Cable Project

The Trans-Bay DC Cable Project, proposed by the City of Pittsburg and Trans Bay Cable LLC (TBC), a subsidiary of Babcock and Brown, would consist of an approximately 50-mile underwater DC cable connecting the Pittsburg Substation to the Potrero Substation in San Francisco.[48] The proposed project would help ensure reliability, serve growing loads, and hasten retirement of aging generators in the San Francisco Peninsula area. The Trans-Bay DC Cable Project would provide 400 MW of new import capacity into downtown San Francisco, eliminating the need for RMR contracts at the Hunters Point and Potrero Power Plants while ensuring electricity reliability beyond 2011. Along with other proposed strategies, the project has the potential to ensure the retirement of all older generation in San Francisco, resulting in significant environmental benefits.

Since this project is not under the jurisdiction of the CPUC, TBC requested approval of their finance proposal from FERC. FERC approved the TBC Operating Memorandum for the $300 million project on July 22, 2005.[49] The CA ISO has recently completed its technical review of the project for the San Francisco Peninsula study group and recommended[50] the Trans-Bay Cable as its preferred alternative for meeting the long-term reliability needs of the San Francisco Peninsula. While TBC supports the completion of the project in 2009, the CA ISO study indicates economic benefits from the project would not be realized until 2012.

The Committee *Draft Strategic Plan*, posted in early September 2005, noted that the Trans-Bay DC Cable required the CA ISO Board of Governors' (Board) approval, and if approved, the project could be operational by 2009.[51] Because of the pending Board approval, the Energy Commission recommended both monitoring and future consideration of the project.

The CA ISO Board approved the Trans-Bay Cable Project at its meeting on September 8, 2005.[52] In the letter to the CA ISO Board recommending approval for the project, the CA ISO staff noted the following:

> This Project is needed for reliability and is being recommended to mitigate violation of reliability planning standards beginning in 2012, but is being recommended for early operation. The Project, as currently structured, is planned to be in-service by 2009… [T]he ISO performed technical and economic analyses to assess the reliability benefits and the cost to the ISO ratepayers for advancing the in-service date by three years to 2009. ISO's technical analysis concluded that installation of this project in 2009 would significantly improve reliability of the San Francisco Peninsula electrical system… This Project, with a 2009 in-service date, will significantly reduce expected Locational Capacity Requirements and the need for Special Protection Schemes that are currently in place to shed firm load for critical double contingency disturbances for San Francisco Peninsula. Further, ISO's economic analysis concluded that while the Project does have identified benefits, the present value of the revenue requirements of the benefits and costs over the three-year advancement results in a net cost to the ISO ratepayers of $26 million. This "net cost" is viewed as an assurance cost against intangible benefits such as immediate increased reliability to the San Francisco Peninsula Area, unforeseen load forecast errors and consideration of unknowns such as project siting, schedule, cost risks, and economic benefits. Overall, ISO Management considers this assurance cost

acceptable in return for the certainty that the Project will be there when it is needed.[53]

At the September 23, 2005*, Energy Report* Committee Hearing on the Committee *Draft Strategic Plan*, Commissioner Geesman requested that PG&E provide a written statement explaining its position on the Trans-Bay Cable Project in its written comments on the *Draft Strategic Plan*. To that end, PG&E noted that, "In light of the ISO Board's decision to approve the [Trans-Bay Cable] Project, and as required by our tariff, PG&E will continue to work with the proponent TransBay Cable LLC to complete the ISO-required studies necessary to effect the interconnection of the [Trans-Bay Cable] Project to the ISO-controlled grid at PG&E's Pittsburg and Potrero substations."[54]

The Energy Commission agrees with the CA ISO's assessment that the advanced in-service date provides insurance benefits that outweigh the net cost to CA ISO ratepayers. Therefore, the Energy Commission recommends that the Trans-Bay DC Cable Project move forward expeditiously in order for the San Francisco Peninsula and the CA ISO control area to realize these reliability benefits.

Actions Needed to Implement Project Investments

Disruptions on California's more than 31,000-mile electric transmission system can be catastrophic. As recently as August 25, 2005, the loss of the 500 kV Pacific DC Intertie from Oregon to Southern California caused rolling blackouts in Southern California, blacking out big blocks of the service territories of Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E).This line loss occurred just before 4 p.m. as California was fast approaching its peak electricity demand on a hot summer day. The line loss forced the California Independent System Operator (CA ISO) to issue a Transmission Emergency Notice for Southern California and request that SCE and SDG&E reduce demand on the transmission system south of Path 26. This quickly escalated to dropping 800 megawatts (MW) of voluntary interruptible customers and 900 MW of firm load. The resulting outage to approximately 500,000 customers is the largest single disruption in California since the 2000-2001 energy crisis and is a graphic example of how a low-probability/high-impact event, relatively short in duration, takes a disproportionately high social and economic toll on all Californians. This outage clearly demonstrates the need for comprehensive improvements to and investments in California's transmission system and highlights the inadequacies of current institutional arrangements to do so.

In the July 28, 2005 Energy Commission hearing SDG&E also provided an example of how tenuous the existing transmission system is in the San Diego area. The morning of the hearing, SDG&E was repairing one of two lines to southern Orange County that serves approximately 35,000 customers. The recent rains had damaged a number of footings beneath a 138 kV line to Laguna Nigel. While the line was taken down and repairs were underway, the second line was lost, causing a local blackout.[55]

In addition to these reliability risks, due to lack of transmission investments, California continues to experience substantial system congestion and high costs. Without significant transmission upgrades and expansions, congestion costs are likely to further increase in the coming years.

Project Investment Recommendations

Transmission projects described below will provide significant near-term benefits to California through improvements to system reliability, reduced congestion, and/or interconnection to renewable resources. The Energy Commission recommends investment in the following projects:

- **PVD2 500 kV Project -** The proposed PVD2 500 kV Project would provide significant near-term benefits by reducing congestion on lines connecting California and Arizona and providing access to lower-cost out-of-state generation. The proposed project would also provide strategic benefits to California ratepayers, including valuable insurance against abnormal system conditions and power outages. It would increase operating flexibility for California grid operators, reduce market power for generators, and reduce the need for additional infrastructure in California. The PVD2 Project is therefore a major component of California's Strategic Plan. The Energy Commission strongly believes that the proposed project offers significant benefits and recommends that the project be moved forward expeditiously so that California can begin realizing these benefits by 2010.
- **Sunrise Powerlink 500 kV Project** - The proposed 500 kV Sunrise Powerlink Project would provide significant near-term system reliability benefits to California, reduce system congestion and its resultant costs, and provide an interconnection to both renewable resources located in the Imperial Valley and lower-cost out-of-state generation. Without this proposed project, it is unlikely that SDG&E will be able to meet the state's RPS goals, ensure system reliability, or reduce RMR and congestion costs. The Energy Commission therefore believes that the proposed project offers significant benefits and recommends that it move forward expeditiously so that the residents of San Diego and all of California can begin to realize these benefits by 2010.
- **Tehachapi Transmission Plan, Phase I: Antelope Transmission Project -** The Antelope Transmission Project proposed by SCE is crucial to the development of wind resources in the Tehachapi region and will offer significant benefits to California. As such, the proposed project is considered a major component of California's Strategic Plan. The Energy Commission therefore recommends the project be moved forward expeditiously so that California can begin realizing benefits by 2010.
- **Imperial Valley Transmission Upgrade -** An Imperial Valley upgrade project would provide access to valuable renewable resources needed to meet future load growth, support California's RPS goals and provide significant near-term

reliability benefits to California. The Energy Commission therefore believes that Phase 1 of the Imperial Valley Study Group's proposed plan, including a 500 kV link to SDG&E, would provide significant benefits to California and recommends that Phase 1 move forward expeditiously. Further transmission development in the Imperial Valley region should be carefully coordinated to avoid duplication and to create a transmission system that serves the needs of both California and the West.

- **Trans-Bay Cable Project** – Although the Trans-Bay DC Cable Project is not needed for reliability purposes until after 2011, the CA ISO has approved the project for early operation in 2009, consistent with Trans-Bay Cable LLC's plans. The Energy Commission agrees with the CA ISO's assessment that the advanced in-service date provides insurance benefits that outweigh the net cost to CA ISO ratepayers. Therefore, the Energy Commission recommends that the Trans-Bay DC Cable Project move forward expeditiously so that the San Francisco Peninsula and the CA ISO control area can realize these reliability benefits.

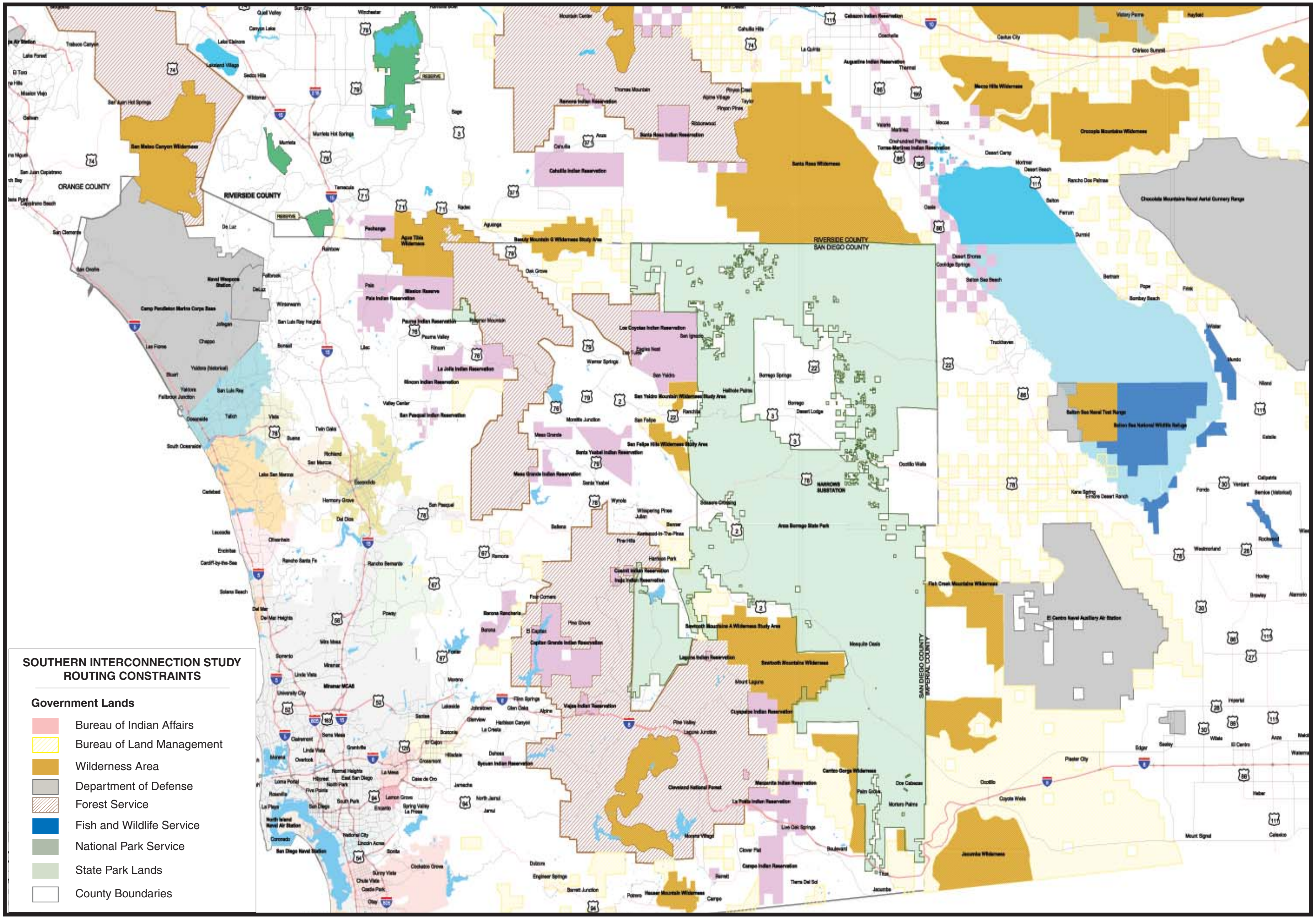
Actions to Implement Investments

- The CPUC should take action to ensure that the permitting processes for the DPV2 and Tehachapi Phase I projects are effective and completed in the 12 months required by law.
- The CPUC should take action to ensure that long-term strategic insurance benefits are fully addressed in CPUC permitting assessments of project benefits for transmission projects deemed vital to the state in the Energy Commission's Strategic Plan.
- The CPUC should assign great weight in its permitting process to the project need assessments submitted by the CA ISO.
- The CA ISO should take action to ensure that results from its new transmission planning process are available by January of 2006 and include an examination of strategic benefits for the SDG&E 500 kV Sunrise Powerlink Project.
- Consistent with the corridor designation recommendation to the Legislature and the Project Investment recommendations noted above, once the Legislature establishes a corridor designation process, the Energy Commission should take the following corridor-related actions:
  - **PVD2 500 kV Project -** Form a Corridor Study Group to review existing land uses along the existing Interstate 10 transmission corridor and coordinate with local, state, and federal agencies, landowners, and other interested parties. The Interstate 10 corridor is an important asset to California and, if granted corridor designation authority by the Legislature, the Commission should consider corridor designation on non-federal lands to complement existing federal corridor designations.

- **Sunrise Powerlink 500 kV Project –** Form a Corridor Study Group to ensure that coordination with local, state, and federal agencies, landowners, and other interested parties begins immediately.
- **Tehachapi Transmission Plan -** Should land use in the Tehachapi region become problematic in the future, the Energy Commission should consider forming a Corridor Study Group to assist in addressing right-of-way routing issues associated with this project.
- **Imperial Valley Transmission Upgrade -** In the absence of permitting progress, the Energy Commission should consider forming a Corridor Study Group to assist in addressing right-of-way routing issues associated with this project.

- As noted in Chapter 2, the Legislature should establish a designation process for transmission corridors and grant the Energy Commission authority to designate corridors for electricity transmission facilities. The Legislature should establish this process in time to assist with routing issues for the Sunrise Powerlink 500 kV Project. Figure 10 shows the existing land use constraints in the San Diego and Imperial Valley region.

FIGURE 10
Existing Land Use Constraints in the San Diego and Imperial Valley Region



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, AUGUST 2005
SOURCE: SDG&E, 2005

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APPENDIX A: PROCEDURAL HISTORY OF PVD2

Excerpts from CPUC Decision 88-12-030

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY (U-338-E) for a certificate that the present and future public convenience and necessity require or will require the construction and operation by Applicant of a 500 kV transmission line between Palo Verde Switchyard and Devers Substation

Decision 88-12-030, Application No. 85-12-012 (Filed February 26, 1986; amended August 15, 1988)

California Public Utilities Commission

1988 Cal. PUC LEXIS 774; 30 CPUC2d 4

December 9, 1988

Philip Walsh, Carol A. Schmid-Frazee, Arthur L. Sherwood, Attorneys at Law, for Southern California Edison Company, applicant; James F. Walsh, E. Gregory Barnes, William L. Reed, and Manning W. Puette, Attorneys at Law, for San Diego Gas & Electric Company and Emanuel H. Blum, for Sky Valley Chamber of Commerce and S. V. Homeowners, protestants; Howard V. Golub, Andrew L. Niven, and John W. Busterud, Attorneys at Law, for Pacific Gas and Electric Company; William S. Shaffran, Deputy City Attorney, for the City of San Diego; Morse, Richard, Weisenmuller and Associates by Robert Weisenmuller; Jeffrey E. Jackson, Attorney at Law, for Southern California Gas Company; Michael Peter Florio, Attorney at Law, for T.U.R.N.; Nancy J. Albers, for Unocal Corporation; and Edward J. Terhaar, for MSR Public Power Agency; interested parties; James Scarff, Attorney at Law, Michael Burke, Burt Mattson, and Stuart Chaitkin, for the Division of Ratepayer Advocates.

PANEL:

Stanley W. Hulett, President; Donald Vial, Frederick R. Duda, G. Mitchell Wilk, John B. Ohanian, Commissioners

OPINION: INTERIM OPINION

I. Decision Summary

This proceeding has been bifurcated into two phases. This order addresses the issues pertaining to Phase I of the proceeding.

By this order, we approve the application of Southern California Edison Company (SCE) for a certificate of public convenience and necessity (CPC&N) to construct Devers Palo Verde No. 2

(DPV2), a second 500 kilovolt (kV) transmission line between Palo Verde Switchyard and Devers Substation. The DPV2 project is certified for no earlier than a June 1, 1993 in-service date, subject to several conditions stipulated to by SCE and the Division of Ratepayer Advocates (DRA).

First, SCE is required to enhance near-term project benefits so that the impact on ratepayers during the 1993-1997 period will not be substantially different than under DRA's 1997 in-service date case. Second, the construction of DPV2 will be suspended if an SCE/SDG&E merger is still an active possibility as of January 1, 1990. Third, SCE is required to file by November 1, 1989 all transmission service contracts associated with this project. Finally, SCE is required to file detailed studies on wind-loading and the likelihood of simultaneous outages of Devers Palo Verde No. 1 (DPV1) and DPV2.

Our approval is subject to implementation of all mitigation measures described in the environmental documents, where applicable. Our decision also provides for a mitigation monitoring program and adopts a cost cap of $ 172,400,000 for SCE's share of project costs. This cap may be adjusted to reflect the actual costs of mitigation measures, SCE's final ownership share, and the actual line rating of DPV2.

II. Procedural History

In December 1985, SCE filed its original Application (A.) 85-12-012 requesting a CPC&N to construct DPV2. As originally proposed, DPV2 was scheduled for a June 1990 in-service date. The application was accepted for filing on February 26, 1986.

> On January 2, 1986, the Executive Director notified SCE that the December, 1985 application tendered for filing was incomplete and would not be accepted for filing. SCE subsequently submitted additional information on January 27, 1986. The supplemented application then was accepted for filing on February 26, 1986.

Shortly thereafter, a protest was filed by San Diego Gas & Electric Company (SDG&E). SDG&E had responded to a solicitation for participation in the project. SDG&E had requested a share of the project's capacity, but did not receive one from SCE. Through this protest, SDG&E alleged anticompetitive behavior and sought an allocation by this Commission of 400 megawatts (MW) of capacity on the project. This protest was settled in July 1986 under an agreement whereby (1) SCE granted SDG&E an option for 100 MW of transmission service on the Devers-Palo Verde No. 1 line and (2) SCE and SDG&E agreed to an exchange of 200 MW of transmission capacity between SCE's Devers-Palo Verde system and SDG&E's Southwest Powerlink (SWPL). This agreement was made contingent upon construction of DPV2.

> The settlement agreement between SCE and SDG&E occurred after Administrative Law Judge Wu denied an SCE motion to dismiss SDG&E's protest and ordered both utilities to submit showings on comparative need for capacity.

In August 1986, SCE submitted a revised economic analysis of the DPV2 project. On October 9, 1986, the Public Staff Division (subsequently renamed Division of Ratepayer Advocates (DRA)) filed a motion to "suspend the clock." DRA alleged that SCE's revisions amounted to a second base case requiring substantial new analysis by DRA. DRA also requested direct access to SCE's computer models.

> Under the Permit Streamlining Act an agency must issue a decision within certain time limits. Unless the "clock" was "suspended," the applicable time period could have run before DRA completed its analysis.

In December 1986, SCE and DRA settled this dispute. A new procedural schedule was arranged, and an alternative way of validating SCE's computer models was adopted.

The Draft Environmental Impact Report (DEIR) was completed in March 1987. Public participation hearings were held to receive comments on the DEIR from March 24-26, 1987, in Riverside, Desert Hot Springs, and Blythe.

Evidentiary hearings began on May 11, 1987 and continued until May 14 when it was discovered that SCE's computer models had been run with inconsistent data inputs. This inconsistency resulted in an exaggeration of the calculated project benefit of economy power purchases in the Southwest. DRA then moved for dismissal of the application. SCE opposed this motion and suggested that a two-month delay in the proceeding schedule would enable both SCE and DRA to correct the errors that had been discovered.

On June 5, 1986, an assigned commissioner ruling denied DRA's motion but ruled that SCE could not rely upon the alleged benefit of economy power from the Southwest as a justification for the project unless it filed a new application. SCE was given the option of proceeding with the current application using transmission service revenues and other benefits as justification for the project.

SCE elected to proceed with the original application without any reliance upon the alleged benefit of economy power purchases from the Southwest. SCE submitted additional testimony which for the first time quantified the value of benefits other than transmission service revenues and the now excluded benefit of economy power purchases.

The Final Environmental Impact Report (FEIR) was issued in August, 1987. Evidentiary hearings were held from September 14-17, 1987. Opening and closing briefs were submitted by October 15, 1987 for decision by the Commission at its December 9, 1987 meeting.

After submittal of the case, DRA discovered a letter of agreement between SCE and Los Angeles Department of Water and Power (LADWP) which confirmed the willingness of SCE and LADWP to exchange transmission capacity rights on the Pacific Intertie and the DPV2 transmission systems. In DRA's view, this agreement affected the cost effectiveness of the proposed DPV2 transmission line. DRA then filed a second petition to either dismiss SCE's application or, in the alternative, to set aside submission and reopen the proceeding.

DRA also filed in SCE's general rate case proceeding, A.86-12-047, a motion to set aside submission with respect to the high voltage DC terminal expansion project (DC Expansion). DRA also believed that the recently discovered SCE-LADWP letter agreement affected the cost effectiveness of the DC Expansion.

In response to these two motions, action on the Administrative Law Judge's (ALJ) proposed decision for A.85-12-012 was withheld pending resolution of the relevance of the SCE-LADWP agreement to the proposed DPV2. And in Decision (D.) 87-12-066 on SCE's general rate case, the Commission denied DRA's motion to set aside that proceeding, but ordered that further consideration of the cost effectiveness of the DC Expansion be given in SCE's application for DPV2.

On January 4, 1988, the ALJ for the DPV2 proceeding issued a ruling ordering SCE to submit any contemporaneous documentation supporting its claim of confidentiality for the SCE-LADWP letter agreement. The ruling also required SCE to file an accounting of all expenses incurred for DPV2, stating that "the Commission may consider a disallowance of regulatory expense incurred for work which was performed but is now useless due to the concealment of the 1985 letter agreement." SCE made this filing on February 3, 1988.

On February 23, 1988 a prehearing conference was held to address the consolidated DPV2 and the DC Expansion projects. SCE and DRA proposed to jointly conduct a preliminary study to determine if DPV2 could be cost effective, assuming an operating date later than June 1, 1990. Based on the results of this study, SCE would decide whether or not to supplement the application and move forward with DPV2, or not to proceed with DPV2 at all.

On March 4, 1988, LADWP forwarded to SCE an executed copy of the Exchange Agreement and Supplemental Letter Agreement for the Dismissal of the Suppliers' Litigation (Exchange Agreement). The Exchange Agreement was executed on December 18, 1987, and made effective as of July 29, 1988. An overview of the terms of the Exchange Agreement is presented in Figure 2 (see Section VI.A).

On May 24, 1988, a second prehearing conference was held. At that time SCE announced that, based on the preliminary results of the SCE/DRA joint study, it planned to file an amended application for DPV2 on August 8, 1988. In addition, DRA and SCE presented a joint proposal for a two-phase approach to the proceeding. Phase I would address the amended DPV2 application, including consideration of certain aspects of the Exchange Agreement. Phase II would address the cost-effectiveness of the DC Expansion Project, including applicable aspects of the Exchange Agreement. The prudence of the Exchange Agreement would be addressed partially in Phase I and in Phase II. This two phase approach was adopted by the ALJ.

SCE's Amended Application and Amended Proponent's Environmental Impact Assessment (PEA) were filed on August 15, 1988. DRA filed its prepared testimony on September 12, 1988. Evidentiary hearings on Phase 1 issues were held on September 22 and 23, 1988. The Addendum to the FEIR (FEIR Addendum) was filed on September 23, 1988 and entered into the record as Exhibit 30.

ALJ Gottstein presided at the September 1988 hearings. James Kahle and Gary Schoonyan appeared as witnesses on behalf of SCE. DRA stipulated to introducing into evidence the testimony of the remaining SCE witnesses. Michael Burke, Robert Weatherwax, and Karen Shea appeared as witnesses for DRA. No other parties participated in either direct or cross examination during the September 1988 hearings. DRA and SCE filed concurrent briefs on October 12, 1988. Comments on the ALJ proposed decision were filed by DRA and SCE. We have considered them carefully, and have made changes where appropriate.

Excerpts from CPUC Decision 97-05-081

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY (U-338-E) for a Certificate that the Present and Future Public Convenience and Necessity Require or Will Require the Construction and Operation of Applicant of a 500 kV Transmission Line Between Palo Verde Switchyard and Devers Substation and Related Appurtenances

Decision No. 97-05-081, Application No. 85-12-012 (Filed February 26, 1986; Amended August 15, 1988)

California Public Utilities Commission

1997 Cal. PUC LEXIS 261; 72 CPUC2d 552

May 21, 1997

APPENDIX

Historical Background

I. Phase 1--DPV2

A. Conditional Grant of CPCN

D.88-12-030 *(30 CPUC2d 4)*, issued on December 9, 1988 in Phase I of this proceeding, conditionally granted Edison a CPCN to construct DPV2, a proposed 500 kilovolt transmission line between the Devers Substation near Palm Springs and the Palo Verde switchyard located 50 miles west of Phoenix Arizona. It would parallel an existing transmission line between those points (DPV1). The authorization was for an operating date no sooner than June 1993.

D.88-12-030 completed the Phase I examination of this application. (*Id., at 35.)* However, the Commission found that the pending Edison/SDG&E merger "...could dramatically effect [sic] the economic benefits of DPV2 and possibly make 'no project' alternatives preferable." (*Id., at 37,* Finding of Fact 27.) Accordingly, one of the conditions imposed by the Commission required suspension of construction and reevaluation of DPV2 in the event that the merger was an active possibility as of January 1, 1990. That possibility was realized with the filing of A.88-12-035 and subsequent merger-related events.

D.88-12-030 has been modified twice. D.89-06-064 *(32 CPUC2d 231)* was issued to correct clerical errors. By D.89-12-022 *(34 CPUC2d 110)* the Commission granted Edison additional time to fulfill certain conditions in the original order.

B. Status of DPV2

Ordering Paragraph 6 of D.88-12-030, as modified by D.89-12-022, required Edison to submit, by February 1, 1990, copies of signed agreements implementing benefit enhancement measures as well as copies of signed contracts for transmission service over DPV1 from 1990-93, over DPV2, and over Edison's existing system west of the Devers substation, including all final amendments to the LADWP Exchange Agreement. Ordering Paragraph 12 of D.88-12-030, as modified, required Edison to submit an amended cost estimate for DPV2 by February 1, 1990.

In response to these directives, Edison reported in a February 1, 1990 filing that it was unable to file either the signed agreements or the amended cost estimate. Edison stated that it had met certain of the requirements of D.88-12-030, including Ordering Paragraphs 3, 4, 5, 7, and 8. Edison concluded its report by stating:

> "As the operating date becomes finalized, Edison will recommend adoption of a procedural schedule that permits sufficient time for reevaluation of DPV2 consistent with the proposed operating date. Finally, Edison intends to keep the CPUC apprised of material developments regarding DPV2." (*Filing of Southern California Edison Company (U 338-E) In Compliance With Ordering Paragraph Nos. 6 and 12 of Decision No. 88-12-030, as Modified by Ordering Paragraph Nos. 4 and 5 of Decision No. 89-12-022,* p. 7.)

By D.91-05-028 issued on May 8, 1991 in the Edison/SDG&E merger proceeding, the Commission found that "Edison is making no effort to construct DPV2 prior to 1997..." *(40 CPUC2d 159, at 197;* also at 247, Finding of Fact 117.) The Commission also found that "...the merger is not responsible for the delay in DPV2 which is keyed to the difficulty applicants have encountered in meeting other Commission requirements regarding revenue enhancements." (*Id., at 221;* also at 260, Finding of Fact 315.)

On August 14, 1991 Edison representatives advised the assigned ALJ that signed contracts still had not been received and that required environmental mitigation measures (Ordering Paragraph 9 of D.88-12-030) had not been completed. Edison considered the DPV2 project inactive.

II. Phase II--HVDC Project

C. Cost Cap

Phase II of this proceeding was established to examine the cost effectiveness of the HVDC Project (also referred to variously as the DC Expansion, the DC Expansion Project, the DC Upgrade, and the HVDC Expansion). The HVDC Project is a major augmentation of an existing transmission line connecting Southern California with the Pacific Northwest. Originally, the HVDC Project cost effectiveness issue was considered in Edison's 1988 GRC, A.86-12-047. In that GRC, Edison had requested $ 104.6 million in estimated plant additions for the HVDC Project. By D.87-12-066 *(26 CPUC2d 392)* the Commission adopted a ratemaking cost cap of $ 80 million and provided for further consideration of the cost effectiveness of the HVDC Project in this proceeding. (*Id., at 443-444;* also, 613-614, Ordering Paragraph 13.) The need for further consideration arose upon discovery of an agreement between Edison and the LADWP which linked DPV2 and HVDC Project issues through an exchange of transmission service over the Pacific Intertie and the Devers-Palo Verde system. The Commission stated:

> "The cost-effective amount of investment in the DC Upgrade should be litigated in Edison's application for a CPCN to construct the Devers-Palo Verde line. The amount of investment ultimately found to be reasonable may not exceed the amount of investment determined to be cost-effective in the context of the Devers-Palo Verde proceeding. Should our subsequent cost effectiveness review yield different results, the HVDC Project cap adopted in this decision should be adjusted." (*Id.*, at 589, Finding of Fact 121.)

By D.89-01-039 *(30 CPUC2d 576)* the Commission clarified D.87-12-066 by specifying that the HVDC Project cost cap could be adjusted downward but not upward.

The 1988 GRC decision addressed the maximum amount that would be allowed in rate base, but it did not authorize ratemaking treatment of the HVDC Project. *(26 CPUC2d 443.)* In A.89-10-001, Edison sought authority to transfer recovery of HVDC Project costs to base rates. By D.93-02-007 *(48 CPUC2d 14)* the Commission approved a settlement between Edison and DRA which resolved the issues in that proceeding. Among other things, the settlement addressed a DRA recommendation that base rates authorized in that proceeding be made subject to refund in recognition of the possibility that a final determination of the cost-effectiveness of the HVDC Project could result in the Commission reducing the previously authorized $ 80 million cost cap. As provided in the settlement (*Id., at pp. 27-28),* the parties agreed that if the value of the HVDC Project is demonstrated to be $ 75 million or higher, Edison would be authorized to recover all of its reasonable HVDC Project costs up to $ 80 million. The cost cap would be lowered only in the event the Commission later determines the project's value to be less than $ 75 million, in which case the cap would be set equal to the project's value as determined by the Commission.

D. Regulatory Expense Issue

An ALJ ruling issued in this docket on January 4, 1988 reviewed Edison's failure to disclose the LADWP Exchange Agreement. Among other things, the ruling directed Edison to file an accounting of all expenses incurred to date on the DPV2 project. It provided further that "after this accounting is received, the Commission may consider a disallowance of regulatory expense incurred for work which was performed but is now useless due to the concealment of [a] 1985 letter agreement." (*Administrative Law Judge's Ruling*, January 4, 1988, p. 4.)

On February 3, 1988 Edison filed a response to the January 4 ruling. Edison reported that it had incurred about $ 3.4 million in unreimbursed project expenses through November 1987. Regulatory expenses represented $ 1.1 million of this amount. Edison asserted that the regulatory expense which might be duplicated as a result of the further hearings required because of its failure to disclose the LADWP Exchange Agreement would not exceed an estimated $ 300,000.

Pursuant to an ALJ ruling issued on August 15, 1988, Phase II was deemed to be the appropriate forum to consider regulatory expenses incurred by Edison through January 4, 1998 in connection with the DPV2 application.

In D.91-12-076 *(42 CPUC2d 645)*, the Phase 1 decision in Edison's test year 1992 GRC (A.90-12-018), the Commission concurred with Edison's position that this proceeding, not the 1992 GRC, is the appropriate forum to consider disallowance of DPV2 costs. (*Id., at 715;* also, at 750, Finding of Fact 259.)