CALIFORNIA
ENERGY
COMMISSION

UPGRADING CALIFORNIA'S ELECTRIC TRANSMISSION SYSTEM: ISSUES AND ACTIONS FOR 2005 AND BEYOND

STAFF REPORT

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Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

Lynn Alexander
James Bartridge
Judy Grau
Mark Hesters
Don Kondoleon
Clare Laufenberg Gallardo
Matt Trask
Principal Authors

Robert Strand
Manager
ENGINEERING OFFICE

Sandra Fromm
Assistant Program Manager
2005 ENERGY REPORT

Kevin Kennedy
Program Manager
2005 ENERGY REPORT

Terrence O'Brien
Deputy Director
SYSTEMS ASSESSMENT AND FACILITIES SITING

B. B. Blevins
Executive Director

Abstract

This staff report documents the Energy Commission staff's efforts to provide the *2005 Integrated Energy Policy Report* Committee with a public forum for evaluating the critical items necessary to achieve a fully collaborative state transmission planning process. The report also documents the Energy Commission staff's efforts to identify and evaluate the actions and strategies necessary to develop the foundation for the state's first Strategic Transmission Investment Plan (Strategic Plan).

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This Staff Report was prepared with contributions from the following additional Energy Commission staff and contractors:

Energy Efficiency, Renewables and Demand Analysis Division
Pamela Doughman
Drake Johnson
Melinda Merritt

Energy Research and Development Division
Merwin Brown, California Institute for Energy and Environment, University of California
Linda Kelly
Virgil Rose, California Institute for Energy and Environment, University of California
Laurie ten Hope

Systems Assessment and Facilities Siting Division
Sudath Arachchige
Ajoy Guha
James McCluskey
Albert McCuen

Editing/Publication
Peggy Falgoust, Project Secretary, *2005 Energy Report*
Marilyn Davin

Cartography
Jacque Gilbreath
Terry Rose

Technical Assistance Contractor for the Staff Report (Contract no. 700-02-004)
Lynn Alexander, LMA Consulting
Matt Trask, Aspen Environmental Group

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EXECUTIVE SUMMARY

A robust transmission system is necessary for the effective and efficient operation of California's electric system. While more than 9,808 megawatts[1] of new generation capacity has been brought on line since 1999, the absence of a well-integrated transmission planning, resource planning, and transmission permitting process has kept transmission infrastructure from keeping pace with growth in demand and new generation capacity. In fact, the transmission infrastructure's ability to effectively transmit electricity between generation and load centers is often stressed, creating significant congestion costs ultimately borne by California consumers. While the cost of transmission is a small part of overall electricity costs, the cost of transmission system failures can be catastrophic, leading to price spikes and, for some local areas, outages. Current and projected operating reserve margins in the Southern California region during hot summer temperatures (1-in-10 conditions) point to the immediate need for additional transmission expansion.

The *2004 Energy Report Update* recommends that the state implement a comprehensive proactive transmission expansion policy recognizing 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 process would coordinate with interested stakeholders including the public, affected landowners, utilities, and state, local, and federal agencies to ensure that local and regional land use plans identify necessary land for future transmission lines and options for utility acquisition of necessary rights-of-way.

In addition, because the Energy Action Plan (EAP) sets the goal that 20 percent of investor-owned utilities' energy mix will be generated from renewable energy sources by 2010, there is a critical need to ensure that renewable generation can be delivered to load centers. Many of these resources, such as wind and geothermal, are located far from major load centers and will require transmission infrastructure investments to ensure their energy delivery. In order to provide orderly access to these renewable resources, it is crucial that transmission planning and resource planning are functionally integrated.

To ensure reliable service, the state must both secure reliable power from within the state and consider the benefits of importing power from out of state. Importantly, the *2004 Energy Report Update* cautions that "while pressing for short-term solutions, California must not lose sight of its long-term goals for planning transmission and developing renewable energy supplies."

This staff report focuses on five areas:

- Transmission policy status (Chapter 2).
- Transmission problems and project update (Chapter 3).

- Transmission corridor planning and development (Chapter 4).
- The impact of transmission on renewable development (Chapter 5).
- Transmission policy options (Chapter 6).

Transmission Policy Status

As demonstrated by input from this year's studies and workshops, agencies, utilities and other stakeholders recognize the critical need to improve and coordinate the state's planning process for siting and permitting transmission infrastructure. Over the last year, Energy Commission staff has worked with the staffs of the California Public Utilities Commission (CPUC) and the California Independent System Operator (CA ISO) to better integrate the electricity planning and procurements processes and improve coordination between transmission and generation planning and procurement activities. A key element of this integrated planning process will be coordination of the *Energy Report* proceeding with the CA ISO's grid planning process.

The staffs of the Energy Commission and the CA ISO are working together to ensure that a joint transmission planning process is consistent with the Energy Commission's *Integrated Energy Policy Report (Energy Report*) process. The Energy Commission, recognizing the CA ISO as the primary transmission planning entity for the state, would provide resource planning inputs based on information collected from transmission-owning load serving entities to the CA ISO for development of a statewide grid plan. In contrast to current planning practices, the CA ISO announced on June 2, 2005, that it would develop a more proactive transmission planning process in order to provide transmission owners the information they need to guide their planning efforts. As part of that process, the CA ISO would publish an annual comprehensive transmission plan and evaluate projects proposed by participating transmission owners against the plan. The CA ISO's statewide grid plan would then be vetted in the *Energy Report* process and integrated into the Strategic Plan.

Transmission Problems and Project Update

A coordinated and comprehensive transmission infrastructure is critical to reducing the costs of providing electricity to California, ensuring a reliable transmission system, and meeting the state's present and future electricity needs.

As power lines become more congested, costs increase because loads must be served by more expensive generation than the generation that could be used without limitations on the transmission system. Specifically, the CA ISO's 2004 Annual Report on Market Issues and Performance, inter-zonal congestion costs totaled $55.8 million in 2004, a considerable increase from $29.7 million in 2003. The same report estimates that the cost of intra-zonal congestion in 2004 was $426 million, an increase of $275 million from 2003 (see Table 3 in Chapter 3). In 2004, total reliability-must-run contract costs were approximately $644 million. According to CA ISO estimates, when the costs of reliability-must-run contracts are combined with the costs of intra-zonal congestion, California's total yearly congestion expenditures are approaching $1 billion.

Although transmission owners face increasing difficulty siting and building new transmission lines, interstate, intrastate, and local transmission system expansion opportunities do exist. Proposed projects and projects under study are identified in Chapter 3 and Appendix F.

California regulators may soon consider a number of regional transmission opportunities, including major transmission facilities for delivering renewable power and projects that could bring generation and loads closer together in the Western United States, Canada and Mexico. The Frontier Line, a proposed 500 kV transmission project, would connect renewable and non-renewable generators in Wyoming and other Western states to California. A similar proposal, the Northern Lights Project, could connect California with future power plants in the Oil Sands region of Northern Alberta, Canada. Without a strong transmission network within California, the benefits of large regional projects like these will be limited.

Projects have also been identified that could increase supplies to California and solve local area short-term transmission needs. Greater effort is required to ensure that long-term needs are also met.

- In Northern California, several studies and projects are underway to improve local reliability. In San Francisco, the 230 kV Jefferson-Martin line is under construction and will enable loads in the Northern Peninsula to be reliably served until 2011. Other studies analyze future transmission needs for the entire Peninsula.
- In Southern California, congestion and supply adequacy concerns have increased the need for new generation and transmission. Southern California Edison (SCE) has submitted an application to the CPUC for a Certificate for Public Convenience and Necessity for the Devers-Palo Verde No. 2 Project, which would help reduce congestion on transmission lines bringing power from Arizona.
- In San Diego, San Diego Gas & Electric is studying a major 500 kV addition that could improve reliability, reduce congestion and allow the utility to meet the Renewables Portfolio Standard (RSP) by 2010. In addition, the first phase of the 230 kV Miguel-Mission No. 2 Project was completed in October 2004. An interim upgrade was completed in June 2005 in order to ensure that higher levels of reliability would be available for summer 2005, and the project is scheduled for completion in June 2006.

Another issue facing California is the decoupling of new generation development from the siting of transmission lines. As a result of wholesale competition among generators, power plants are often developed in remote locations without adequate transmission. This results in an inefficient transmission system that is forced to respond to generation. This is not an effective way to direct new transmission investment. Instead, the transmission system should be planned first and generation should develop around it.

Transmission Corridor Planning and Development

A corridor planning process is essential to ensure that California develops a healthy transmission system to meet future electricity needs, integrate renewable resources into the state's energy mix, and meet demand in California's growth areas. The need for a long-range state-led transmission corridor planning process was recognized in both a staff paper[2] entitled *Upgrading California's Electric Transmission System: Issues and Actions for 2004 and Beyond,* and the *2004 Energy Report Update.*[3]

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

- A corridor need identification process that 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.
- In order for the corridor identification process to be effective, 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 also 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 on utilities to do it. Therefore, to ensure that planned and designated corridors will be 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 the rate base. The current limit is five years, which is not sufficient to allow for long-term planning.

A Committee workshop on May 19, 2005, addressed corridor planning. Several parties expressed concerns that a state-led corridor planning and designation process could affect property owners, pre-empt local agency land use permitting authority, and burden local governments with the costs associated with updating land use plans to reflect designated transmission corridor zones. Other issues included the need for coordination with local agencies and development of a comprehensive program to educate the public about the need for transmission in California.

Also presented at the May 19, 2005, workshop was a description of the Energy Commission's Public Interest Energy Research (PIER) project entitled Planning

Alternative Corridors for Transmission. The project involves the development of a web-based transmission corridor modeling program intended to assess a number of corridor factors, including environmental concerns, health and safety issues, engineering issues, and economic considerations. The goal of the program is to facilitate the identification of transmission corridors and allow the public and decision makers to understand the trade-offs between proposed and alternative transmission routes based on objective, comprehensive, consistent, and transparent analysis.

Additional information about the proposed state-led transmission corridor planning process and the Planning Alternative Corridors for Transmission project is detailed in Chapter 4.

Impact of Transmission on Renewable Development

Ensuring that renewable energy generated from remote locations in California can be delivered to load centers is a challenge facing regulators and developers. For example, two potential renewable resource centers, the Tehachapi wind and solar resource area and the Salton Sea geothermal area, require significant transmission facilities in order to deliver thousands of megawatts of new renewable generation to load centers. Staged transmission development in key renewable areas could provide a flexible solution to allow the transmission network to grow as generation comes online while reducing the risk that transmission is built for generation projects that do not materialize.

Two stakeholder study groups (Tehachapi and Imperial Valley) are discussing transmission interconnections that will bring renewable generation from these areas to the grid. The contributions of transmission working groups are critical to a project's planning process. These local and regional groups are typically made up of a wide range of stakeholders involved in the study of transmission issues. These groups, like the Tehachapi Study Group, can develop alternative solutions for controversial issues and environmental impacts and provide recommendations to improve efficiency and reliability. These groups can help remove policy and operational roadblocks and provide a valuable contribution to the state planning process.

In addition to basic issues associated with lack of transmission, characteristics of intermittent renewable generation could affect the operation of the transmission system. These operational complications include minimum load issues and scheduling and dispatch challenges. Research is underway to address these and other issues, but these efforts need to be accelerated if the state is to meet its RPS goals. Transmission for renewable energy is discussed in Chapter 5.

Transmission Policy Options

Improvements in transmission system planning, transmission corridor planning, and transmission issues associated with renewables integration are needed to ensure that California's transmission system expands in an environmentally responsible, cost effective manner that considers public input, enhances reliability, and meets strategic statewide objectives - including effective integration of renewable generation. The Energy Commission staff recommends the following policy options be considered.

Transmission Planning

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

Regional Planning

In January 2005 the Western Electricity Coordinating Council (WECC) and the Committee on Regional Electric Power Cooperation formed the Western Assessment Group (WAG) to identify the major commercial issues affecting the Western Interconnection and evaluate whether the West has the necessary industry and regulatory institutions to effectively address and resolve these issues. The WAG April 2005 draft white paper identified transmission expansion planning as one of four critical issues. Most of the participants at the May 23, 2005 stakeholder meeting expressed a preference to investigate whether the WECC would be the most appropriate organization to address both reliability issues as well as the newly identified major commercial issues.

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

Statewide Planning

Recognizing the Energy Commission's interest in ensuring that long-term state objectives are met and the CA ISO's interest in ensuring that needed projects are identified and constructed in a timely manner, it is essential to recognize the strengths and expertise of each entity. Interactions between the Energy Commission's *Energy Report* work and the CA ISO's grid planning work could follow these principles:

- The transmission-owning load serving entities would submit their load forecasts, resource plans, and price information to the *Energy Report* proceeding.
  - The Energy Commission could develop data requirements for future *Energy Report* proceedings in collaboration with the CA ISO and other parties to ensure that CA ISO information needs are met with respect to statewide transmission planning.
  - The Energy Commission could require that certain transmission planning information from transmission-owning load serving entities be provided

annually so it could be used for developing staff forecasts and incorporated in grid planning by the CA ISO.

- The information would be analyzed and publicly reviewed in the *Energy Report* proceeding, resulting in adopted resource plans and scenarios.
  - The Energy Commission could develop formal agreements with transmission-owning load serving entities to ensure non investor-owned utility participation in the *Energy Report* transmission planning process.
  - The Energy Commission could work with the CA ISO and stakeholders to ensure that a disaggregated Energy Commission demand forecast is available for use in the CA ISO planning process during the next *Energy Report* cycle.
- Resource plans and scenarios, along with the municipal utility transmission plans, would be submitted to the CA ISO.
  - The Energy Commission could assist the CA ISO by providing publicly reviewed planning results for projects for inclusion in the California grid plan, including the identification of strategic benefits and the consideration of comparative alternatives.
- The CA ISO would use that information -- along with the Energy Report load forecast information, participating transmission owner grid plans, and WECC plans -- to develop the California grid plan.
  - The Energy Commission could develop a Memorandum of Understanding with the CA ISO for a single electricity transmission planning process fully coordinating the individual processes and proceedings of the Energy Commission and the CA ISO, while recognizing the CA ISO as the transmission planning analysis entity for the state in preparing the California grid plan.

Transmission Corridor Planning

Corridor planning is essential to California's development of a healthy transmission system able to meet future electricity needs. Therefore, Energy Commission staff has developed, with input from stakeholders, a proposed state-led transmission corridor planning process. In developing this process, staff considered obligations and constraints faced by the Energy Commission and other parties participating in the collaborative *Energy Report* process. Time constraints on the *Energy Report* process can limit achievements in each cycle. However, 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, and the process is revisited in odd-numbered years and vital information is updated in even years.

This proposed process consists of the following three components:

- Part 1: An *Energy Report* Corridor Identification Process

- Part 1 of the proposed process recommends collecting corridor information early in the *Energy Report* process. The Energy Commission could authorize staff to begin collecting corridor information so that adequate information is available.
- Part 1 of the proposed process recommends developing collaborative Corridor Study Groups to review potential corridors. The Energy Commission could authorize staff to develop Corridor Study Groups in areas where a need has been identified.

- Part 2: Designation Authority and a Transmission Corridor Designation Process
  - The state should establish designation authority and a corridor designation process that sets land aside for future corridor use.
  - Future state corridors should be aligned with federally designated corridors when appropriate. The Energy Commission could authorize staff to work collaboratively with federal agencies, the public, local agencies, and other stakeholders to review the land uses along existing federally designated corridors and determine where complementary state designation would be beneficial.
- Part 3: Land Acquisition and Banking
  - Consistent with the *2004 Energy Report Update* recommendation for the development of a process to identify and bank utility corridors, the Energy Commission should encourage the CPUC to begin a proceeding on land banking to ensure that this issue moves forward. This corridor planning process can only be successful if the length of time utilities can keep land acquired for future needs in the rate base is extended beyond the current five-year limit.

The following additional corridor-related options complement staff's proposed state-led transmission corridor planning process described above. These options could serve as short-term alternatives to establish a foundation for future corridor planning efforts:

- Educating the general public about the fundamentals of the state's electrical grid and the need for additional transmission infrastructure would be beneficial. The Energy Commission could support development of a statewide education program, perhaps in coordination with the PIER program's ongoing Planning Alternative Corridors for Transmission web-based modeling project.
- In the absence of state authority to designate transmission corridors, benefits could still be realized by identifying future corridors in areas where transmission infrastructure will be needed in the future. The Energy Commission could recommend in the Strategic Plan that utilities work with local agencies, stakeholders, and the public to identify a possible future corridor from the Imperial Valley into the San Diego region, a possible future corridor or corridors in the Tehachapi area that would complement projects

already under consideration, and possible future corridors in other high priority areas.

Transmission and Renewables Development

Transmission bottlenecks in California may greatly hinder the state's ability to meet the EAP's RPS goals of 20 percent renewable generation by 2010, and to procure additional renewable generation in the future. The Draft EAP II: Implementation Road Map for Energy Policies, released on June 8, 2005, notes that "[A]n expanded electric transmission system infrastructure is required to mitigate grid congestion and bring new renewable and conventional power plants on line." Several existing transmission issues already present potential barriers to meeting the Renewables Portfolio Standard (RPS) goals. These issues were not created by introduction of renewable resources, but have become more complicated because of them.

- Federal and state policies pose significant barriers to meeting the Renewables Portfolio Standard goals, especially those concerning the rules for funding transmission system facilities.
    - The *2004 Energy Report Update* recommends investigating changes to the CA ISO tariff to encourage projects needed to commercialize renewable resources. To that end, Southern California Edison proposed the trunk line concept in its application to the Federal Energy Regulatory Commission (FERC), and the Energy Commission and the CPUC supported that effort. However, on July 1, 2005, the FERC disapproved it. Additional analysis and coordination is needed to address this issue.
    - The Energy Commission could continue its collaboration with the CA ISO in developing mitigation of the negative cost effects that the FERC's marginal loss policy could have on siting renewable resources such as wind and geothermal. See Chapter 5 for additional information.
- From an operations perspective, integration of renewable generation into the grid offers major, interrelated challenges.
    - The Energy Commission could ensure that the operational integration work activities initially undertaken by staff continue through a collaborative effort.
    - To address the intermittent nature of wind resources and increase the effectiveness of existing energy storage facilities, the Energy Commission could promote coordination between system operators and storage owners. The Consortium for Electric Reliability Technology Solutions report notes, "…a more holistic strategy for the operation of all the pumped storage facilities in the state would yield a more efficient overall operation."[4]
    - Because minimum load issues may be exacerbated by intermittent resources, the Energy Commission could assist in the identification of viable locations for storage facilities that would complement intermittent renewable resources.
    - To reduce the uncertainty of resource availability, the Energy Commission could continue to promote research efforts to improve forecasts of

intermittent resource availability. Reducing uncertainty in resource availability could reduce the need for costly reserve power that provides backup for intermittent renewable generators.

- Current transmission bottlenecks effectively limit the ability to transmit renewable generation from remote locations to major load centers.
    - The Energy Commission could continue to support the formation and implementation of stakeholder-based study groups to develop transmission plans allowing for the efficient movement of renewable energy to consumers.

Endnotes

[1] California Energy Commission. 2005 Power Plant Fact Sheet, updated 7/6/05. http://www.energy.ca.gov/sitingcases/FACTSHEET_SUMMARY.PDF

[2] California Energy Commission. Upgrading California's Electric Transmission System: Issues and Actions for 2004 and Beyond. July 2004, p.2.

[3] California Energy Commission. 2004 Energy Report Update. November 2004, p. xv, xvii, 27.

[4] 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], p. 35.

CHAPTER 1: INTRODUCTION

Background

This report is third in a series of staff reports addressing California's electric transmission issues in support of the California Energy Commission's (Energy Commission) *Integrated Energy Policy Report* (*Energy Report*) proceedings.[1] For more information on the 2003 and 2004 *Energy Report* transmission proceedings, see the section below entitled "Relationship to Prior *Energy Report* Work." This report documents the efforts of staff, other agencies, and stakeholders in addressing critical transmission issues for consideration by the *Energy Report* Committee (Committee) in formulation of its policy. It also summarizes other available information on this topic, including related staff products and input from utilities, government agencies, and stakeholders in the *Energy Report* process.

This report provides information that the Energy Commission may include in developing the Strategic Plan on transmission issues. Public Resources Code section 25324[2] requires that the Energy Commission adopt a Strategic Plan for the state's electric transmission grid in consultation with the CPUC, the CA ISO, transmission owners, users, and consumers. The legislation requires that the Energy Commission include the Strategic Plan in its *Energy Report,* to be adopted on November 1, 2005. The strategic plan creates the opportunity to build the blueprint for a bulk transmission system 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, eliminating the problem of adding to the transmission system piecemeal when transmission is built reactively to connect to whatever generation is proposed and built.

An effective transmission planning process is critical to a coordinated electricity planning, procurement, and permitting process. The state is beginning to implement an integrated transmission planning process that will ultimately provide greater regulatory certainty. An effective planning process, coupled with a strategic transmission plan, will ensure that appropriate investments are made in California's transmission infrastructure. As San Diego Gas and Electric (SDG&E) noted at the June 2, 2005, Joint Conference on Energy Infrastructure and Investment in California:

> Transmission represents roughly 5 percent of the [electric] rates our customers pay. Yet if we look at the cost of congestion or if we look at the cost of these [Reliability Must Run] type contacts that we pay to…support the deficiencies in the transmission infrastructure, that's another 10 percent of our retail rates. So there's a significant opportunity to make transmission investments in San Diego that would mitigate those costs.[3]

This staff report describes California's progress in developing and implementing an effective transmission planning process that addresses corridor needs and renewables integration needs. The report also outlines potential policy options and pros and cons associated with each.

Relationship to Other 2005 *Energy Report* Products

Energy Commission staff prepared many reports and papers in the 2005 *Energy Report* process. This section summarizes other *Energy Report* products that address issues related to the status of transmission planning and permitting, transmission system problems and solutions, long-term corridor needs, and transmission issues associated with renewable resource integration.

The June 2005 staff report entitled *2005 Environmental Performance Report of California's Electrical Generation System* (publication no. CEC-700-2005-016) focuses on the environmental impacts of electric generation facilities and transmission lines. Transmission lines can damage wildlife habitats, cause wildfires, disrupt fragile desert ecosystems, kill birds through electrocution and collision, and interfere with agricultural operations. The report notes that few people find lines aesthetically appealing, yet most understand the need for new transmission. It also concludes that as existing lines are reconductored and new corridors are established, planners and regulators will need more information on their environmental impacts. For more detailed information on the environmental impacts of transmission lines, please see the *2005 Environmental Performance Report of California's Electrical Generation System*, which is available on the Energy Commission website at the following address: http://www.energy.ca.gov/2005publications/CEC-700-2005-016/CEC-700-2005-016.PDF

Given extensive coverage of environmental issues in that document, this report focuses instead on engineering and policy issues associated with transmission lines.

Another June 2005 staff report entitled *Investor-owned Utility Resource Plan Summary Assessment* (publication no. CEC-700-2005-014) provides Energy Commission staff's review of resource plans filed by California's three large investor-owned utilities (IOUs). If an IOUs reference case assumes construction of a major new transmission project, an additional case without the transmission project was required to explain the project's impact on the resource plan. As noted in Chapter 8, entitled "Transmission," SCE assumes in its reference case that the Palo Verde-Devers No. 2 (PVD2) Transmission Project is constructed, while SDG&E assumes construction of a new 500 kV transmission interconnection project. Both SCE and SDG&E also filed variations on their reference cases without the new transmission projects. Since Pacific Gas and Electric's (PG&E's) reference case included only network reinforcements contained in its CA ISO-approved Grid Expansion Plan, it did not provide a "without transmission" alternative reference case.

The June 2005 consultant report entitled *Strategic Value Analysis (SVA) for Integrating Renewable Technologies in Meeting Target Renewable Penetration* (publication no. CEC-500-2005-106), utilized a SVA methodology developed by the Energy Commission PIER renewables staff and Davis Power Consultants team to evaluate the evaluate the economic feasibility of using in-state renewable resources to meet California's RPS targets and to assess the impacts of deploying those resources on the state's electricity system. The report notes that renewable technologies can be optimally located to reduce transmission system overloads and describes how each technology location can be evaluated by its transmission benefit and its cost of energy. The report notes that the SVA methodology can be used to select renewable energy sites to meet the 20 percent renewable energy penetration goal.

The Energy Commission published a consultant report in May 2005 entitled *Energy Supply and Demand Assessment for the Border Region* (publication no. CEC-600-2005-023) that describes the SDG&E, Imperial Irrigation District, and Baja California transmission systems, as well as connections among them. It notes that there is significant congestion on the lines from Mexico and the Imperial Valley into the SDG&E service area. It describes the status of proposed transmission projects in the area which have been proposed to mitigate congestion. The report recommends policy options for addressing the challenge of improving the efficiency of the energy exchange across the California-Mexico border.

The final report on borders issues entitled *California-Mexico Border Energy Report,* consolidates the report discussed above with three other borders-related reports and recommends final policy options for dealing with the issues brought forward in the four border-related reports. It will be published by the Energy Commission in mid- to late-July 2005.

The July 2005 staff report entitled *Implementing California's Loading Order for Electricity Resources*[4], reports trends, outlook, and barriers to implementing the preferred resources in California's "loading order" – energy efficiency, demand response, renewables, and distributed generation – established in the 2003 State EAP. The report notes that integrating high levels of as-available or intermittent renewable energy will likely require changes in equipment and operation of the electricity and transmission system. See Chapter 5 of the report for a detailed discussion of this challenge.

Relationship to Prior *Energy Report* Work

In August 2003 staff published a report entitled *Upgrading California's Electric Transmission System: Issues and Actions*. The report identified three types of major problems: congestion on major transmission paths (both interstate and intrastate), constraints in the San Francisco Bay Area and San Diego load centers, and the inability of the system to provide adequate access to existing and future renewable generation. The report provided an assessment of four projects of immediate concern: the SDG&E Valley-Rainbow Project, the SCE PVD2 Project, the PG&E Jefferson-Martin Project, and the Tehachapi Expansion Project. The report noted several transmission planning and permitting problems, including: fragmented and overlapping permitting jurisdictions, inconsistent environmental analyses of projects, inadequately considered regional and statewide benefits, and ineffective methods of encouraging public participation.

The *Energy Report* Committee held a workshop on that staff report in August 2003. In development of the Energy Commission's first *Energy Report*, published in December 2003, the Committee considered the staff report; input received at and after the Committee workshop; all other staff products; and input from utilities, government agencies, and stakeholders.

The *2003 Energy Report* concurred with the staff report that there was a need for improvement in the following planning areas:

1. Improving analytical methodologies for evaluating the costs and benefits of transmission projects.
2. Evaluating the impact and value of low-probability but high-impact events and sharing that evaluation with decision-makers.
3. Comparing the costs and benefits of transmission projects against non-transmission alternatives early on in the planning process, instead of waiting until the permitting process.

The *2003 Energy Report* recommended that the Energy Commission continue to implement a fully-collaborative state transmission planning process with the CA ISO, the CPUC, and utilities. The process would build upon the CA ISO's annual transmission plan to both determine the statewide need for bulk transmission projects and assess and compare the costs, benefits, and alternatives to individual transmission projects. It also recommended that the state "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."[5]

In July 2004 the staff published a sequel transmission report entitled *Upgrading California's Electric Transmission System: Issues and Actions for 2004 and Beyond*. The *Energy Report* Committee held a workshop and considered the staff report and input from utilities, government agencies, and interested stakeholders in creating the *2004 Energy Report Update*. The 2004 staff report and the *2004 Energy Report Update* concurred in their major recommendations.

The first major recommendation is to initiate a comprehensive statewide transmission planning process with four major objectives:

1. Assess the statewide need for reliability and economic transmission projects and projects supporting the RPS implementation.
2. Approve beneficial transmission investments that can move directly to permitting without revisiting need.
3. 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.

4. Examine alternatives to the transmission project early in the planning process so that environmental review can more appropriately focus on routing alternatives and mitigation measures.

Another major recommendation arising from both the 2004 staff report and the *2004 Energy Report Update* is improvement of the transmission cost/benefit assessment to:

1. More accurately reflect the long-term value of transmission assets.
2. Explore various methods that 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.
3. Use an appropriate discount rate reflecting the "public good" nature of transmission.

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

1. The Energy Commission should increase its participation in the Tehachapi Study Group in CPUC proceeding I.00-11-001, Phase 6.
2. The Energy Commission should work with stakeholders to identify corridor and rights-of-way studies to ensure effective and efficient permitting for the Tehachapi Wind Resource Area.
3. The State should establish a joint Transmission Study Group for the Imperial Valley area.
4. The Energy Commission should, along with the CPUC and the CA ISO, investigate 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.

Update on Activities Since Publication of the *2004 Energy Report Update*

Since publication of the *2004 Energy Report Update*, there has been some progress in implementation of the above recommendations. These are described in more detail in the remainder of this report:

- On January 19, 2005, the Energy Commission adopted a report entitled *Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*. The report required all transmission-owning load serving entities (LSEs) to file:[6] general descriptions of their transmission planning and permitting processes, 10-year transmission plans describing all transmission facilities over 100 kilovolts (kV) needed to meet reliability and planning standards, 20-year plans that discuss more general or generic transmission needs and strategies, and corridor needs vital to the long-term development of strategic transmission projects, including possible corridors not yet associated with specific transmission projects but which could be designated as transmission corridors.

- On February 22, 2005, State Senators Escutia and Morrow introduced Senate Bill (SB) 1059, which would authorize the Energy Commission to designate a transmission corridor zone on its own motion or by application of a person planning to build a high-voltage electric transmission line within the state (see Chapters 2 and 4).
- On March 23, 2005, SCE filed a Petition for Declaratory Order with the FERC that would, among other things, introduce a new category of transmission facilities — new, high-voltage, trunk line facilities able to interconnect large concentrations of renewable generation located a reasonable distance from the existing grid.[7] The facilities proposed by SCE would allow as many as 1,100 megawatts (MW) of wind resources in the Tehachapi area to be used by SCE, PG&E, SDG&E, and other CA ISO grid users to help meet their RPS goals.[8] The Energy Commission has consistently supported the concept that transmission projects necessary to meet RPS goals represent a new kind of transmission project for the state. On April 14, 2005, the Energy Commission and the CPUC filed motions to intervene and submitted comments in support of SCE's petition.[9]
- On May 12, 2005, California Governor Schwarzenegger proposed an energy agency reorganization based upon the 2003 *Energy Report* recommendation to consolidate the permitting process for all new IOU bulk electric transmission lines, modeled after the Energy Commission's power plant generation licensing process (see Chapter 2).
- The Energy Commission has funded research and development (R&D) projects through its PIER program, enhancing the efficiency and reliability of the transmission system (see Chapter 3 and Appendix D).
- The CA ISO modified its Transmission Economic Assessment Methodology (TEAM) to incorporate some of the Energy Commission's recommendations on strategic benefits (see Chapter 2).
- The Imperial Valley Study Group (IVSG) was created (see Chapter 5).

There have been other significant developments since the *2004 Energy Report Update* was published. In many cases, however, specific projects noted below were identified many years ago as solutions to specific problems, and their recent progress through the permitting, construction, and operation phases is long overdue. Because of the time lag, the projects noted below represent the mitigation of impacts caused by existing deficiencies instead of a proactive response to a coordinated planning process.

- On December 9, 2004, SCE filed an application for a Certificate of Public Convenience and Necessity (CPCN) with the CPUC to construct the Antelope-Pardee Transmission Project (Proceeding A.04-12-007) and the Antelope-Vincent and Antelope-Tehachapi Transmission Projects (Proceeding A.04-12-008).
- Governor Schwarzenegger commissioned the Path 15 upgrade at a CA ISO ceremony on December 14, 2004.

- Governor Schwarzenegger signed the Frontier Line Transmission Project multi-state Memorandum of Understanding (MOU) on April 4, 2005.
- SCE filed an application for a CPCN for the PVD2 Project on April 11, 2005 (A.05-04-015).
- The Los Angeles Department of Water and Power (LADWP) filed a protest to SCE's DPV2 CPCN on May 16, 2005, claiming that LADWP alone has the contractual right to build DPV2. The LADWP and SCE are (at this writing) negotiating this issue.
- Since the CPUC granted a CPCN to PG&E for the Jefferson-Martin Project on August 19, 2004 (D.04-08-046), PG&E has begun construction, with an expected in-service date of the first or second quarter of 2006.
- In December 2004 SDG&E received approval from the CPUC (D.04-12-052) to complete temporary modifications allowing addition of new transmission capacity one year before the entire Miguel-Mission No. 2 Transmission Project is completed. On June 1, 2005, the new temporary line (Phase 1) was energized. Construction of the permanent line (Phase 2) is expected to be completed in June 2006.
- The rating of Path 26 in the north-to-south direction was recently increased from 3,700 to 4,000 MW, effective June 23, 2005.
- On June 30, 2005 the CPUC approved the Otay Mesa Power Plant Transmission Project, which consists of transmission improvements necessary to interconnect the Otay Mesa Power Plant.

Critical Issues

In creating both this report and the record leading up to it, the Energy Commission staff's goal was consideration of the following issues:

1. Creating effective transmission planning and permitting processes to recognize all costs and benefits of transmission projects and alternatives.
2. Ensuring that decision makers have both the qualitative and quantitative information needed to make informed decisions understandable by the public.
3. Providing a complete record as the Committee develops a Strategic Plan under Public Resources Code section 25324.
4. Ensuring that the *2005 Energy Report* transmission effort is integrated with work in other project areas.
5. Ensuring stakeholder involvement is effective, appropriate, and timely.
6. Ensuring that transmission corridors will be available when needed.
7. Ensuring that the investment community has the transparency and certainty it needs to stimulate investment in transmission.

Report Organization

This staff report contains a comprehensive assessment of the status of transmission planning and permitting, transmission system problems and project updates, long-term corridor needs, and transmission issues associated with renewables integration.

Chapter 2 covers the status of transmission policy in California — including planning and permitting processes — and transmission coordination among Western states. The staff addresses the need for following items:

1. Collaborative long-term transmission planning.
2. Examination of transmission alternatives early in the planning phase.
3. Improved assessment of transmission costs and benefits.
4. A state-led transmission corridor planning process.

Chapter 3 assesses near- and long-term transmission projects and paths, focusing on the San Diego/Imperial Valley areas, Southern California, the Tehachapi area, and the San Francisco Bay Area/Northern California area. Staff analyzed transmission projects — from conceptual to planning to permitting to construction — that provide partial solutions to transmission problems (such as local reliability area concerns, congestion issues, and transmission issues associated with interconnecting renewable resources). Chapter 3 also includes an update on major interstate projects and initiatives and opportunities for PIER Research and Development solutions to address specific transmission problems.

Chapter 4 focuses on development of a proactive transmission corridor planning and identification process leading to designation of corridors that would meet California's long-term needs.

Chapter 5 describes some of the major transmission issues facing renewables development. This chapter draws from the following sources:

1. *Energy Report* workshops on February 3 and May 10, 2005, focusing on operational issues associated with integrating renewables.
2. The *Energy Report* April 11, 2005 workshop on geothermal issues.
3. The May 9, *2005 Energy Report* workshop on renewable resource potential in California and interstate renewable resources.
4. Related PIER Research and Development work at the Energy Commission.

Chapter 6 brings together policy options from the preceding chapters and presents a concise summary of items for the *Energy Report* Committee to consider, along with input from utilities, government agencies, and other stakeholders.

Next Steps

An *Energy Report* Committee hearing on this staff report is set for Thursday, July 28, 2005. The hearing will provide an opportunity for interested parties to comment on all aspects of this report. Following the hearing, the Committee will prepare a draft *2005 Energy Report* and a draft 2005 Strategic Plan, for release in September. Committee workshops and/or hearings on these documents will be held in late September or early October. A Energy Commission hearing to adopt these documents is scheduled for November 2005.

Endnotes

[1] Senate Bill 1389 [SB 1389 (Bowen), Chapter 568, Statutes of 2002] amended Public Resources Code section 25300 *et seq.* to require the Energy Commission to prepare an integrated energy policy report (*Energy Report*) on or before November 1, 2003, and every two years thereafter. Specifically, section 25303(a)(3) states the following:

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

Furthermore, section 25302(d) created the *Energy Report Update* process:

> Beginning November 1, 2004, and every two years thereafter, the commission shall prepare an energy policy review to update analyses from the integrated energy policy report prepared pursuant to subdivisions (a), (b), and (c), or to raise energy issues that have emerged since the release of the integrated energy policy report.

The August 2003 staff report entitled *Upgrading California's Electric Transmission System: Issues and Actions* was prepared in support of the *2003 Energy Report*, while the August 2004 staff report entitled *Upgrading California's Electric Transmission System: Issues and Actions for 2004 and Beyond* was prepared in support of the *2004 Energy Report Update*.

[2] SB 1565 (Bowen), Chapter 692, Statutes of 2004, added section 25324 to the Public Resources Code.

[3] 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), pp. 203-204. [http://ferc.gov/EventCalendar/Files/20050614073401-AD05-11-06-02-05.pdf]. (June 15, 2005).

[4] Publication No. CEC-400-2005-043

[5] December 2003, *2003 Integrated Energy Policy Report*, Sacramento, CA, p. 20, P100-03-019, [http://www.energy.ca.gov/reports/100-03-019F.PDF].

[6] California Energy Commission, January 2005, *Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, Sacramento, CA, p. 60, CEC-100-2005-002-CMF, [http://www.energy.ca.gov/2005_energypolicy/electricity_forms/CEC-100-2005-002-CMF.PDF].

[7] See p. 2 of "Southern California Edison Company's Petition for Declaratory Order," filed on March 23, 2005 with the FERC, docket no. EL05-80-000.

[8] SCE 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], accessed April 15, 2005.

[9] 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. [http://www.ferc.gov/docs-filing/elibrary.asp]], accessed April 19, 2005. 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. [http://www.ferc.gov/docs-filing/elibrary.asp]], accessed April 19, 2005.

CHAPTER 2: CALIFORNIA'S TRANSMISSION POLICY STATUS

As noted in Chapter 1, the Energy Commission has made recommendations in the past two years regarding the need for improvements to the transmission planning and permitting processes. The *2003 Energy Report* recommended that the Energy Commission continue to work towards a fully collaborative state transmission planning process and the permitting process for new bulk transmission lines be consolidated at the Energy Commission.

Transmission Planning Status

Collaborative Long-term Transmission Planning

The need to improve and coordinate the process by which transmission projects are planned was recognized before publication of the *2003 Energy Report*. In May 2003 the Energy Commission, CPUC, and the California Consumer Power and Conservation Financing Authority (California Power Authority) collaborated on the state's first EAP. Section IV of the EAP states:

> Reliable and reasonably priced electricity and natural gas, as well as increasing electricity from renewable resources, are dependent on a well-maintained and sufficient transmission and distribution system. The state will reinvigorate its planning, permitting, and funding processes to assure that necessary improvements and expansions to the distribution system and the bulk electricity grid are made on a timely basis:
>
> 1. The agencies will collaborate, in partnership with other state, local, and non-governmental agencies with energy responsibilities in the Energy Commission's integrated energy planning process to determine the statewide need for particular bulk transmission projects. This collaboration will build upon the CA ISO's annual transmission plan and evaluate transmission, generation, and demand side alternatives. It is intended to ensure that state objectives are evaluated and balanced in determining transmission investments that best meet the needs of California electricity users.[1]

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. 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. Interaction between the Energy Commission and the CA ISO would ensure that information provided by transmission-owning load serving entities is available to both entities. Transmission-owning load serving entities would submit their load forecasts, resource plans, and price information to the state. That information would be analyzed, vetted, and further coordinated with the CA ISO in the *Energy Report* proceedings. The Energy Commission, recognizing the CA ISO as the primary transmission planning entity for the state, would provide planning results to the CA ISO for development of a statewide grid plan. The statewide grid plan could also be vetted in the *Energy Report* process and integrated into the Strategic Plan.

At the June 2, 2005, Joint Conference on Energy Infrastructure and Investment in California, Mr. Yakout Mansour (President and Chief Executive Officer, CA ISO) noted that the CA ISO management intends to develop a more proactive approach to transmission planning and to present it to its Board of Directors in the near future. Mr. Mansour was responding to a recognition that transmission owners do not have all the information they need from the CA ISO to guide their planning efforts.[2] Mr. Armando Perez (Director of Grid Planning, CA ISO) elaborated on this point:

> First, we will be publishing an annual comprehensive long-term transmission plan. Second, projects proposed by the PTOs will be evaluated rigorously against the published plan. Projects that appear in the ISO plan but are not included in any of the PTOs' plans will be offered back to the PTOs for a right of first refusal. If they do not want to or decide not to build a project, they will be offered to a third party.[3]

The staffs of the Energy Commission and the CA ISO are working together to ensure that the CA ISO proposal is consistent with the *Energy Report* process, timeline, and products.[4] Close collaboration will ensure that this effort is an effective means for achieving the process goals outlined in the December 21, 2004, *Energy Report* Committee Workshop and can be implemented in time for the *2007 Energy Report*/Strategic Plan cycle.

The 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 rather than increase planning reserve margins to deal with deliverability issues.

On June 8, 2005 the Energy Commission and CPUC published the *Draft EAP II: Implementation Road Map for Energy Policies*. It notes that "… [A]n expanded electric transmission system infrastructure is required to mitigate grid congestion and bring new renewable and conventional power plants on line. Transmission planning and permitting must provide a more [timely], seamless, and comprehensive statewide process for moving transmission projects through the planning phase and into construction." It recommends the following key actions:

- Develop and implement an integrated, comprehensive, statewide transmission planning process that eliminates bottlenecks, improves reliability, and opens access to new renewable resources.
- Establish a statewide transmission corridor planning process to create and protect critical transmission corridors for potential future development.
- Develop a streamlined method to expedite siting and certification review of proposed transmission projects.[5]

Proposed Criteria for Evaluation of Transmission and Alternative Sources

Energy Commission staff retained a consultant to develop evaluation criteria to compare alternative resource portfolios at a state level for possible use in long-term transmission planning, policy development, and implementation. Project alternatives being evaluated include demand-side management, renewables generation, other generation alternatives, and transmission alternatives.

At the May 19, 2005, *Energy Report* Committee Workshop, the consultant presented the results of the first step of his work, which was to survey stakeholders in the California market and develop a list of suggested evaluation criteria. Stakeholders surveyed include the CPUC, CA ISO, consumer groups, environmental groups, generators, investor-owned utilities, municipal utilities, renewables groups, and transmission owners. Evaluation criteria were then grouped into four categories: reliability, least-cost, risk, and environmental. The next step was to recommend a short list of the top criteria, along with measurement(s), that decision makers can use to evaluate future resource portfolios and projects.

Based on his analysis of the stakeholder survey results, the consultant proposed six evaluation criteria for resource evaluation purposes:

1. Least-cost
2. Reliability
3. Risk
4. Market Efficiency
5. Fuel Diversity
6. Resource Flexibility

While other stakeholder-suggested criteria are considered valuable, they were not selected because they may be more difficult to measure, less comprehensive in scope, or should instead be included in the "minimum requirements" set by state policy. See Appendix A for a complete discussion of these minimum requirements, the complete set of stakeholder-suggested criteria, and the rationale for the six selected evaluation criteria.

Improved Assessment of Transmission Costs and Benefits

Economic Evaluation of PVD2 Transmission Project

Energy Commission staff retained a consultant to review the CA ISO Board of Governors' February 2005 Report on the economic evaluation of the PVD2 transmission project. See Appendix B for the PowerPoint presentation given by Mr. Eto at the May 19, 2005, *Energy Report* Committee Workshop. The purpose of the review was to compare the economic evaluation against recommendations made by the Energy Commission in the *2003 Energy Report* cycle and *2004 Energy Report* cycle, and to determine the impact of a social discount rate on the benefit-to-cost ratios calculated for the various perspectives (societal, modified societal, and two CA ISO perspectives). Table 1 summarizes the extent to which the major categories of strategic benefits recommended in the 2004 *Energy Report* cycle were captured in the original CA ISO Transmission Economic Assessment Methodology (TEAM) staff analysis conducted in April 2004, versus the updated economic evaluation presented in the February 2005 CA ISO Board report.

Some of consultant recommendations are summarized below:

- There is a need to refine the capacity value estimation and capture the interaction between transmission and generation expansion.
- Using the expected value for energy benefits, the insurance value of transmission expansion during abnormal system conditions is not fully captured.
- Environmental benefits should include benefits other than NO_x reduction.
- Decreasing California's need for additional infrastructure such as gas pipelines should be considered in assessing strategic values.[6]

Table 1 Comparison of Strategic Values for the SCE PVD2 Transmission Project

	CEC Report [1]	Original CA ISO [2]	CA ISO Board Report [3]
Price Stability Market Power			
Potential for Increased Sharing and Firm Capacity Purchase			
Insurance Against Contingencies During Abnormal System Conditions			
Environmental Benefits			(NOx)
Reduction in Construction of Additional Infrastructure			

(1) Economic Evaluation of Transmission Interconnection in a Restructured Market prepared for the Energy Commission by EPG/CERTS June 2004.
(2) Presentations made by CA ISO TEAM staff April 2004.
(3) Board Report: Economic Evaluation of the PVD2 Line 2 prepared by CA ISO Department of Market Analysis & Grid Planning February 2005.[7]

The use of a social discount rate to calculate the present worth of PVD2 benefits from a societal perspective will more than double the benefit-to-cost ratio of the project when compared with using the weighted cost of capital to discount future benefits.

The Energy Commission retained Mr. Eto to perform a similar review of SCE's Proponent Environmental Assessment filed on April 5, 2005 and its Cost-effectiveness Report prepared on April 7, 2004 and updated on March 17, 2005. Appendix C contains the presentation that Mr. Eto plans to give at the July 28, 2005, *Energy Report* Committee hearing. Based on the magnitude of energy benefits calculated by SCE, the benefit-to-cost ratio of PVD2 is higher than 1.0 for the CA ISO ratepayer perspective. From the WECC perspective, using the numbers provided by SCE, even with a 5% social discount rate, the quantified benefits from energy and third-party transmission revenue are not sufficient to create a benefit-to-cost ratio greater than 1.0. The WECC regional benefit is low in part because strategic values such as insurance value during abnormal system conditions, reduction in generator market power, potential for development of new generation outside of California, operational benefits, environmental benefits other than NO_x

reduction, and the decrease in California's need for additional infrastructure such as natural gas pipelines are not quantified in the WECC regional benefit calculation.

Assessment of Low-Probability/High-Impact Events

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 descriptions are inadequate to facilitating such assessments or determining which cases are the most useful.

To help assess possible methods for studying low-probability but high-impact events, Energy Commission staff has retained a consultant to produce a report that would:

- Explain to the public the importance and general method in selecting low-probability, high-impact sensitivity cases.
- Propose a standard method for deciding which cases should be tested.
- Illustrate the range of cases and propose techniques for providing greater public understanding of the value of this information.

The consultant work will be available at the July 28, 2005, *Energy Report* Committee hearing and will be summarized in an addendum to this report, which will be revised based on the results of the hearing and published shortly thereafter.

Assessment of Operational Reliability Benefits of "Economic" Transmission Projects

Current evaluation methods for so-called "economic" transmission projects (i.e., projects proposed for economic reasons, such as providing access to lower cost power, rather than projects needed to meet specific reliability criteria or projects connecting renewable generation) do not consider or quantify reliability benefits that could also result from the project. Energy Commission staff has retained a consultant to generically examine the potential reliability benefits of primarily economic projects, using the PVD2 Project as a model.

The consultant work will be available at the July 28, 2005, Committee hearing and will be summarized in an addendum to this report, which will be published shortly thereafter.

A State Transmission Corridor Planning Process

A corridor planning process is essential to ensure that California develops a healthy transmission system to meet future electricity needs, integrate renewable resources into the state's energy mix, and meet demand in California's growth areas. Recognizing that transmission corridors play an important role in permitting critical transmission projects, the *2004 Energy Report Update* recommended that the state enact legislation authorizing the Energy Commission to designate needed transmission corridors as part of its planning responsibilities. Please see Chapter 4 "Transmission Corridor Planning and Development" for a more detailed discussion of this year's activities concerning identification of transmission corridors to meet California's long-term needs.

Potential Legislation

Senate Bill 1059 (Escutia and Morrow) was introduced as draft legislation on February 22, 2005. It was last amended in the Senate on May 27, 2005 and has moved to the Assembly as a two-year bill that will not be heard until the 2006 legislative session. The bill would authorize the Energy Commission to designate suitable transmission corridor zones for high-voltage electric transmission lines that are consistent with the Strategic Plan to ensure reliable and efficient electricity delivery. The designation of a transmission corridor zone could be proposed by the Energy Commission or by application to the Energy Commission from any person or entity planning to build an electric transmission line in the state. The bill would identify the Energy Commission as the lead agency responsible for preparing an environmental impact for each corridor designation. The bill would also require that cities and counties amend their general plans as needed to be consistent with the Energy Commission's designations. The Energy Commission would be required to work with cities and counties, federal agencies, and California Native American tribal governments to identify appropriate areas within their jurisdictions that could be suitable for a transmission corridor zone.

Transmission Permitting Status

Action item No. 2 of Section IV of the May 2003 EAP states:

> The Public Utilities Commission will issue an Order Instituting Rulemaking to propose changes to its CPCN process, required under Public Utilities Code § 1001 et seq., in recognition of industry, marketplace, and legislative changes, like the creation of the CA ISO and the directives of SB 1389. The Rulemaking will, among other things, propose to use the results of the Energy Commission's collaborative transmission assessment process to guide and fund IOU-sponsored transmission expansion or upgrade projects without having the PUC revisit questions of need for individual projects in certifying transmission improvements.

To that end, the CPUC opened Rulemaking Proceeding R.04-01-026 in January 2004. The proceeding sought to amend General Order (GO) 131-D, which governs the planning and construction of investor-owned utility electric generation and transmission facilities in California. As noted in the May 23, 2005 Draft Decision of Administrative Law Judge Vieth, the proceeding focused on GO 131-D as "a practical means to streamline transmission planning by eliminating duplication between processes at the [CPUC] and the [CA ISO]. The [Order Instituting

Rulemaking] assumed that a necessary predicate, the CA ISO's economic methodology for assessing transmission need (i.e. the TEAM methodology) would be reviewed in a parallel proceeding at the [CPUC], Investigation 00-11-001, in time for incorporation into this rulemaking."[8]

However, because issues surrounding the TEAM methodology have been contentious, the rulemaking proceeding was closed as required to meet legislative timelines. On June 30, 2005, the CPUC opened a new Order Instituting Investigation (I.05-06-041) in parallel with consideration of the application for a CPCN for the PVD2 Project, filed by SCE on April 11, 2005, to assess the TEAM methodology for use in all transmission CPCNs. Commissioner Grueneich, who is presiding over the PVD2 proceeding, will also head the transmission economic methodology investigation.

Assembly Bill 974 (Nunez) was introduced on February 18, 2005 and amended in the Assembly on April 12, 2005.[9] The draft bill moved to the Senate on May 19, 2005, and is a two-year bill to be heard during the 2006 legislative session. This bill would require the CPUC, by July 1, 2006, to prepare and implement a comprehensive plan to streamline the transmission permitting and siting process to support orderly, cost effective construction or expansion of transmission facilities needed to integrate renewable generation, increase import capability, or accommodate load growth. In developing the plan, the CPUC would be required to consult with the Energy Commission, the CA ISO, the Electricity Oversight Board, electrical corporations, appropriate federal, state, and local agencies, California Native American tribes, and the public.

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. In doing so 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]

One June 23, 2005 the Little Hoover Commission (LHC) responded to the Governor's Reorganization Plan (GRP 3) by letter.[11] The LHC noted that the Attorney General and the Office of the Legislative Counsel opined that modifying a "constitutionally" established function through the reorganization process needed further clarification. While the LHC made many positive comments about GRP 3, they 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.
In summary, there is widespread recognition that the current transmission permitting process is inadequate, and various methods have been proposed to address the

problem. However, none of the solutions described above have yet been implemented.

Coordination Among Western States

In January 2005 the WAG, an ad hoc group of industry representatives with representation from the WECC and the Committee 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,*[12] 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 the following problems (which parallel many of the problems facing California noted by the Energy Commission in both the *2003 Energy Report* and the *2004 Energy Report Update*):

> Many analysts concur that growth in electricity demand has far outstripped growth in transmission capacity in recent decades. 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.[13]

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.[14]

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, WGA), provides a summary of that meeting:

> 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.[15]

The WECC Board will next hold a strategic planning session at its July 2005 meeting and will discuss options contained in the WAG analysis. Later in 2005 the WECC Board will be asked to take formal action on the recommendations, perhaps including approval of associated funding and staffing to implement the recommendations, and to initiate action to revise the WECC bylaws as required. The target date for resolving the WECC's role in transmission planning and expansion is December 31, 2005. If the WECC fails to approve and propose funding for a work plan by December 31, WAG will develop a new organization proposal and form a new organization in 2006.[16]

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

Endnotes

[1] State of California, *Energy Action Plan*, p. 7, May 2003, [http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF] (June 13, 2005).

[2] 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. 39. [http://ferc.gov/EventCalendar/Files/20050614073401-AD05-11-06-02-05.pdf]. (June 15, 2005).

[3] Ibid, p. 175.

[4] Ibid, pp. 212-213.

[5] State of California, *Draft Energy Action Plan II: Implementation Road Map for Energy Policies*, p. 8, June 8, 2005, [http://www.energy.ca.gov/energy_action_plan/2005-06-08_ACTION_PLAN.PDF], (June 13, 2005).

[6] Eto, Joe, May 19, 2005, PowerPoint presentation entitled "Review of CAISO's Economic Evaluation Methodology for the Palo Verde Devers Line No. 2 (PVD2)" slide no. 10, [http://www.energy.ca.gov/2005_energypolicy/documents/2005-05-19_workshop/ETO_JOE_PVD2_EPG.PDF]. (June 17, 2005.)

[7] Ibid., slide no. 9.

[8] California Public Utilities Commission, Draft Decision of Administrative Law Judge Vieth, "Opinion Closing Proceeding," pp. 1-2, May 23, 2005 (R.04-01-026).

[9] Regardless of the outcome of the legislation, the Energy Commission will proceed with transmission planning activities as required by PRC section 25324. In meeting these requirements, staff will examine the need for corridors in future Energy Report cycles.

[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] WAG, 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?

[13] Ibid, p. 2.

[14] Ibid, p. 3.

[15] WAG, 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).

[16] Ibid, p. 2 and attached matrix entitled "Industry Consensus on Addressing Commercial Issues."

CHAPTER 3: TRANSMISSION PROBLEMS AND PROJECT UPDATE

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 is making some progress by constructing, permitting, and planning new transmission facilities, the state still suffers from inadequate infrastructure following years of under-investment in transmission lines. Transmission operators also face growing uncertainty in predicting how the grid will respond under these circumstances, increasing the likelihood of errors and potential blackouts. California must continue to improve its transmission infrastructure and tools for system operators in order to ensure a reliable, efficient and diverse electric system.

The increasing difficulty of siting, financing, building and paying for new transmission lines has slowed development. 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, sometimes resulting in inefficient generator siting. Coordinating generation and transmission siting is extremely important for meeting California's renewable generation goals since renewable energy resources are often located in areas far away from transmission facilities.

While planning and permitting transmission facilities can take years, with denial of major projects because of methodological differences in cost and benefit assumptions, 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 from 3.82 mills per kilowatt-hour (mills/kWh) and 7.46 mills/kWh, or between 3.4 and 6.3 percent of the total per kWh electricity rate, 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.

This chapter provides a narrative description of the three primary transmission infrastructure problems and operational challenges facing California. A discussion of each infrastructure problem is followed by a brief description of transmission projects that are proposed to address specific problems. Each project is numbered to correspond with Figure 1, Major Transmission Projects. For a discussion of PIER transmission research, see Appendix D. For a detailed description of each project shown in Figure 1, see appendix F.

Figure 1: Major Transmission Projects

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. To resolve local reliability problems within the state, regulators and utilities are generally faced with choosing continuing expensive reliability must-run (RMR) contracts, signing longer than five year contracts with generators, or improving the transmission network to more reliably serve loads. Complying with the RPS will be a major transmission infrastructure challenge in California because the largest sources of renewable generation are located in remote areas far from major load centers. Several potential regional transmission opportunities could improve California's access to diverse generation in other states and countries.

Most transmission lines in California are single purpose lines built for reliability, to reduce congestion, or, more recently, to access renewable power. Future transmission projects will more likely provide a variety of benefits. Comparing the costs and benefits of multi-purpose transmission projects will be more complex and difficult than for single purpose lines.

Local Reliability Areas

Local reliability concerns have been addressed with transmission infrastructure additions or RMR contracts. San Diego and the Greater San Francisco Bay Area have received recent attention to ensure that local reliability concerns have been addressed. The needs of other areas, such as the SCE service territory are growing as well, raising additional concerns. 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[2] 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. A number of projects identified below address these issues and mitigate local reliability concerns.

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.)

Projects proposed or underway in Northern California:

- Project #1: The Jefferson-Martin 230 kV Project will allow San Francisco and the Northern Peninsula to reliably meet loads through 2011, while allowing the shutdown of the Hunters Point and possibly other aging fossil-fueled power plants in the city.
- Project #2: San Francisco long-term upgrades are intended to eliminate the need for RMR contracts at the Hunters Point and Potrero power plants in San Francisco, while ensuring reliability beyond 2011.[3] The upgrades would both improve reliability and improve air quality in San Francisco.
- Project #3: The Trans-Bay Direct Current (DC) Cable Project is designed to allow the CA ISO to discontinue RMR contracts with the Potrero Power Plant while maintaining reliability in San Francisco and the Peninsula through at least 2015.
- Project #4: The Metcalf-Moss Landing 230 kV Reinforcement Project would increase the amount of power imported into the San Francisco Bay Area from new power plants in California's Central Valley and at Moss Landing and Morro Bay.
- Project #5: Two Greater Fresno area projects, the Gregg- Henrietta 230 kV Line Reconductoring Project and the Gates-Gregg 230 kV Double-Circuit Transmission Line, are key projects in the Greater Fresno area. These projects will serve growing loads in the Fresno area and allow for greater use of the Helms Pumped Storage Plant, which would increase availability of summer peaking power.
- Project #6: The Sacramento Area Voltage Support Project will ensure that loads reliability in the Sacramento area. The project would also eliminate the need to reduce output at the Sutter Energy Center Power Plant.

Projects proposed or underway in the San Diego area:

- Project #7: The SDG&E 500 kV Project would improve reliability, reduce congestion and increase access to renewable energy sources, in addition to playing a key role in California's overall grid plan.
- Project #8: The transmission facilities connected with the Lake Elsinor Advanced Pumped Storage Hydro Project would be very similar to the northern portion of the SDG&E 500 kV Project. This project would improve reliability in San Diego and reduce the cost of serving loads in California.
- Project #9: The Otay Mesa Power Plant Transmission Project, which the CPUC approved on June 30, 2005, would allow delivery of the full output of the Otay Mesa Power Plant to San Diego. Because SDG&E signed a long-term (10-year) power purchase agreement with the Otay Mesa Power Plant, this transmission project would also reduce RMR costs in San Diego.
- Project #10: The Miguel-Mission No. 2 230 kV Project will significantly reduce congestion in the San Diego area and improve the transmission network's ability to deliver renewable resources from the Imperial Valley region. On July 8, 2004, the CPUC granted SDG&E a CPCN for the project. The first phase, the Miguel Substation Improvement, was completed in October 2004. Phase 2 is on schedule and should be completed by June 2006. An interim upgrade was completed in June 2005 to ensure higher levels of reliability would be available during summer 2005 prior to completion of Phase 2 of the project.

The following project has been proposed in the SCE area:

- Project #11: The Vincent-Mira Loma 500 kV Transmission Line will allow SCE to reliably serve growing loads in Southern California through 2014.

Congestion Issues

While the CA ISO planning process is designed to address the reliability of the California transmission network, concern is increasing over the cost of congestion. Improving the ability to plan for and economically reduce transmission congestion is therefore an additional state goal.

Congestion continues to be a major transmission issue in California.[4] At the May 19, 2005*, Integrated Energy Policy Report (Energy Report*) Committee Workshop, an Energy Commission consultant presented data showing monthly interzonal congestion in Southern California.[5] According to the CA ISO's 2004 Annual Report on Market Issues and Performance, inter-zonal congestion revenues in 2004 were $55.8 million, a $29.7 million increase from 2003 (p. 5-5)[6]. The report further states that "The (2004) congestion was mostly cause by frequent and intensive scheduled work on a number of lines and substations…"[7] The same CA ISO report estimates the cost of intra-zonal congestion in 2004 at $426 million (see Table 3 below), which represented a $275 million increase from 2003[8]. Congestion can result from both physical limitations of the transmission network and the design of the market. As Mr. Jim Detmers of 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. Mr. Detmers noted that this figure does not include interzonal congestion and is only for the CA ISO-controlled grid.[9]

Table 3 Total Estimated Intra-zonal Congestion Costs for 2004

Month	Monthly Total (millions of dollars)
January	$19
February	$23
March	$31
April	$27
May	$28
June	$30
July	$47
August	$50
September	$39
October	$43
November	$44
December	$45
Total	**$426**

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

Energy Commission staff has retained a consultant to study congestion in Southern California to determine whether congestion is due to limitations of the physical transmission network or market design. The consultant's work will be available at the July 28, 2005 Committee hearing and will be summarized in an addendum to this report, which will be published shortly thereafter.

Energy Commission staff is also working with CA ISO staff to improve the CA ISO's transmission evaluation methodology. One goal is to eventually develop the methodology into a planning tool to forecast transmission congestion. Improving the transmission infrastructure, both within California and with the grid connecting California with the other Western states, will also decrease congestion and could ultimately lower the cost of providing electricity to California. Progress has also been made in identifying new transmission infrastructure that could reduce congestion.

Projects in the planning stage or under construction in the SCE area:

- Project #12: Path 26 is the main path limiting delivery of power into Southern California from Central and Northern California. Upgrading Path 26 will improve summer resource adequacy concerns in Southern California. The transfer capability from Northern California to Southern California over Path 26 is being increased with an improved remedial action scheme, and further expansion of the path is being considered as part of system upgrades needed to deliver renewable power to loads in California.

- Project #13: The Blythe area is located near the California/Arizona border, far from Southern California load centers. Power plants in the Blythe area could, therefore, supply lower cost energy--like that produced in Arizona and other parts of the Southwest--to California if firm long-term transmission capacity from Blythe to the CA ISO grid is available. Tying the proposed Blythe area generators to the PVD1 and No.2 lines through the proposed Midpoint Substation would allow the generators to deliver their power to Southern California loads.
- Project #14: The Short-Term Southwest Transmission Expansion Plan (STEP) Upgrades will increase the network's ability to move power from Arizona and the Southwest into Southern California by upgrading several existing substations.
- Project #15: The 500 kV PVD2 Transmission Project is before the CPUC for permitting. The PVD2 project significantly reduces congestion on transmission facilities linking California to Arizona. The project will increase California's ability to import less costly power.

Another source of potential congestion for SCE could be the interconnection between SCE and the LADWP. There is some 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 may not be adequate to serve loads[10]. LADWP could be a source of either less expensive or reserve power that could help mitigate price spikes or prevent power outages. The Energy Commission staff has retained a consultant to study the interconnection between SCE and LADWP in order to determine the potential for imports from LADWP to the CA ISO control area. The consultant work will be available at the July 28, 2005 Committee hearing and will be summarized in an addendum to this report.

In San Diego, limited transmission capacity from the Imperial Valley area and from Mexico, coupled with significant new generation development outside of California, has created significant transmission congestion. The partially completed 230 kV Miguel-Mission No. 2 Project (Project #10), 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 prior to completion of Phase 2 of the project.

Transmission for Renewable Power

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. Two major renewable resource regions in California, the Tehachapi wind area and the Salton Sea geothermal area, are far from load centers with limited transmission.[11]

Two major projects that would provide access to renewable resources are being studied:

- Project #16: The Tehachapi area is critical to development of renewable wind resources in California. Significant new transmission facilities are required to deliver any new Tehachapi generation to California.
- Project #17: Developers estimate that an additional 1,350 to 1,950 MW of geothermal potential in the Imperial Valley area could be developed over the next 15 years. Geothermal generation in the Imperial Valley would provide a significant source of renewable energy needed by California utilities to meet RPS goals.

Renewable generation could also be imported from outside California, but the transmission for these resources, while under discussion, will require significant planning and permitting efforts.

The Tehachapi area transmission issues have been addressed largely through the Tehachapi Regional Transmission Plan. SCE has applied for a Certificate of Public Convenience and Necessity (CPCN) for the first stage of the plan, but cost issues still need to be resolved. A potential transmission interconnection from the SCE Big Creek system to PG&E, while not part of the SCE plan, is being discussed by the Tehachapi Implementation Study Group.

The cost issue is complicated because major network connections are needed to deliver renewable generation in the Tehachapi region to loads in California. Essentially the project sponsor, SCE, wants to ensure it will recover the cost of the transmission whether or not the generation is built, and generators want to be certain their projects will not be stranded by a lack of transmission. This issue is further discussed in Chapter 5.

The other option in the Tehachapi region is an interconnection to the PG&E system, which is not part of the SCE plan. The SCE plan is essentially a large feeder system connecting to the SCE network. However, the Tehachapi region is located north of most of SCE's territory and in some places existing SCE transmission lines either cross or are very close to PG&E facilities. An interconnection with the PG&E system could have the added benefit of expanding Path 26 transmission capacity into Southern California. The Tehachapi Implementation Group is studying this potential interconnection of Tehachapi generation to the PG&E system.

The Salton Sea area in the Imperial Valley has significant renewable energy generation potential but requires both a transmission feeder system and a larger connection to loads in either San Diego or north to the SCE service area. The Imperial Irrigation District's Green Path Initiative is designed to provide a feeder system for geothermal development in the Salton Sea area[12]. The IVSG is developing a comprehensive interconnection plan for both a feeder system and a larger interconnection for renewable resources in the Salton Sea region. The SDG&E 500 kV Project is also being designed as a multi-purpose line that would increase SDG&E's access to renewable resources.

Renewable power from outside California could be imported to serve California loads. Northern Mexico has potential to produce both geothermal and wind power, but transmission from Mexico into California is limited. Many planning and permitting issues would complicate expanding transmission from Mexico into California, as discussed extensively in the May 2005 Energy Commission staff paper entitled *Environmental Issues and Opportunities in the California-Mexico Border Region*[13]. Northern Nevada has significant renewable potential but a very limited transmission interconnection with California. According to a report on renewable generation, "To get access to 2,000 to 3,000 MW of developable renewable power from Northern Nevada in the period to 2017, significant new transmission facilities must be constructed.[14]"

Another potential source of renewable generation is wind power in Wyoming and other parts of the Western United States. Two transmission projects, the Northern Lights Project and the Frontier Transmission Project, would increase the transmission network's ability to bring various types of power (including both renewable and non-renewable), into California. Both of these projects still require significant planning and permitting efforts, but could access significant renewable generation resources located outside California.

SDG&E is still studying a major 500 kV transmission addition and plans to file a CPCN application at the CPUC when the studies are complete. SDG&E received CPUC approval for the Otay Mesa Power Plant Transmission Project, which allows them to reduce RMR needs (compared with the 2004 RMR contract costs of $173 million) in the San Diego area.[15] Without additional new generation or transmission in San Diego, maintaining long-term reliability will continue to be an issue[16].

Regional Transmission Projects

Regional transmission lines are proposed that could bring generation and loads together in the Western United States, Canada and Mexico.

Proposed regional projects:

- Project #18: The Frontier Line, a major 500 kV transmission project, would connect generators in western states from Wyoming to California. Given the potential for wind and coal generation in Wyoming and other western states, a project like the Frontier line could help reduce some of California's dependence on natural gas for electricity generation.
- Project #19: A similar project, the Northern Lights Project, could connect California and other load centers to potential cogeneration power plants in the Oil Sands region in Northern Alberta, Canada.
- Project #20: The SWIP, in conjunction with proposed coal generation, would serve loads in the Southwest and increase available energy for import into California.

- Project #21: The East of River (EOR) 9000+ Project could increase EOR transfer capability from 8,055 to 9,300 MW and increase economic transfers between the desert Southwest and California. The project complements SCE's PVD2 project (Project #15.)

Operational Challenges

Transmission operators face growing uncertainty in predicting how the grid will respond under certain events or operator actions. This situation 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 subject 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.

For more information on operational issues associated with the integration of renewable resource generation into the grid, see Chapter 5 entitled "Impact of Transmission on Renewables Development."

The Role of Emerging Transmission Technologies

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 - mitigating some renewable generation intermittency and unpredictability - and increasing the ability to import generation from other states. These promising technologies consist of new hardware, software, and integrated systems able to leverage several new technology solutions for the benefit of an entire region of the grid.

Descriptions of some of these technologies and advanced systems, along with some examples of research efforts, are contained in Appendix D.

These transmission technologies are in various stages of development. Some are close to widespread commercial availability, meaning that transmission owners or operators are already deploying them in niche applications. But widespread adoption requires more experience with these technologies and lower costs. Other technologies are in early stages of development, requiring more fundamental research and development. California's PIER programs, managed by the Energy Commission, provide resources to help conduct needed research and field testing. PIER is working with a broad-cross section of stakeholders and partners to target these funding efforts and ensure that technology is transferred into productive use in the public interest. For more information on the PIER Program, see the following website:

http://www.energy.ca.gov/pier

Next Steps

California needs to plan transmission for future needs. State transmission infrastructure is beginning to catch up after years of underinvestment, but more needs to be done. Reliability, congestion and access to renewable resources continue to be issues due to the growing demand for, and changing supply of, electricity in California.

Endnotes

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

[2] 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.

[3] CA ISO, April 1, 2004, *San Francisco Peninsula Long-Term Transmission Planning Study Phase 2 Study Plan,* Folsom, CA, page 6.

[4] 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.

[5] Mackin, Peter, Navigant Consulting, Inc., May 19, 2005 PowerPoint presentation entitled "Overview of Southern California Congestion and Quantification of Operational Benefits Status Report," [http://www.energy.ca.gov/2005_energypolicy/documents/2005-05-19_workshop/MACKIN_P_NAVIGANT.PDF].

[6] CA ISO, April 2005, *2004 Annual Report on Market Issues and Performance*, Folsom, CA, page 5-5.

[7] Ibid., page 5-3.

[8] Ibid., page 6-16.

[9] 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).

[10] CA ISO, March 23, 2005, *2005 Summer Operations Assessment*, Folsom, CA, Page 2, http://caiso.com/docs/09003a6080/35/46/09003a60803546fd.pdf.

[11] Chapter 5 of this document discusses the transmission operational issues associated with renewable resource development in California.

[12] Barbera, Frank M, April 11, 2005, Presentation at April 11, 2005 Energy Report Committee workshop, Sacramento, CA, http://www.energy.ca.gov/2005_energypolicy/documents/2005-04-11_workshop/Barbera_IID_Green_Path.PDF.

[13] California Energy Commission, May 2005, *Environmental Issues and Opportunities in the California-Mexico Border Region, Staff Report*, pub. no. CEC-600-2005-022, Sacramento, CA, http://www.energy.ca.gov/2005publications/CEC-600-2005-022/CEC-600-2005-022.PDF

[14] California Energy Commission, April, 2005, *Renewable Energy and Electric Transmission Strategic Integration and Planning: Interstate Generation and Delivery of Renewable Resources Into California from the Western Energy Coordinating Council States, Draft Consultant Report*, page 49.

[15] CA ISO, *Memorandum from Armando Perez to the CA ISO board of Directors, April 29, 2005, Re: Otay Mesa Power Plant Agreement Transmission Project*, Page 5.

[16] San Diego Gas & Electric, April 11, 2005, *April 1 Common Forecasting Methodology Filing*, San Diego, CA, page 5.

CHAPTER 4: TRANSMISSION CORRIDOR PLANNING AND DEVELOPMENT

Introduction

As noted in the *2003 Energy Report*, ensuring reliable and reasonably-priced electricity supplies – increasingly from renewable resources – requires a well-maintained and adequate transmission and distribution system.[1] However, before transmission facilities can be permitted and constructed in a timely fashion the process by which the transmission grid is planned must be improved. The state must develop a new, comprehensive transmission and resource planning process that addresses both the physical and economic need for transmission projects, as well as the environmental and land use issues associated with them. A vital component of any improved transmission planning process would be a state-led effort to pro-actively plan for transmission corridors in order to minimize future siting conflicts.

The need for a statewide transmission corridor planning process[2] was put forward in the staff paper entitled *Upgrading California's Electric Transmission System: Issues and Actions for 2004 and Beyond,* and the *2004 Energy Report Update.*[3] Both reports cited this planning process as an essential component of ensuring that California develops a healthy transmission system to meet future electricity needs and integrate renewable resources into the state's energy mix. The *2004 Energy Report Update* also recommends that the Energy Commission establish a comprehensive planning process with the CPUC, the CA ISO, other key stakeholder agencies, investor-owned and publicly owned utilities, interest groups, and the public.[4] Recommendations for this process include examining the rights-of-way needs for future transmissions projects, designating and conducting environmental reviews of needed corridors, and allowing utilities to set aside or bank needed land for longer periods of time.[5]

For the *2005 Energy Report* cycle, the Energy Commission staff collaborated with various stakeholders and the public to investigate long-term transmission corridor planning issues and needs.[6] As with the *2004 Energy Report Update* cycle, staff found significant support for the concept of transmission corridor planning, with the understanding that such corridors would facilitate development of transmission infrastructure projects in critical areas of the state. However, while not disputing the need for corridors, several parties expressed concerns that a state-led corridor planning and designation process could affect property owners, pre-empt local agency land use permitting authority, and burden local governments with the costs associated with updating land use plans to reflect designated transmission corridor zones.[7]

This chapter summarizes transmission planning activities and efforts during the *2005 Energy Report* cycle and options for consideration from the staff.

Proposed Energy Report Corridor Planning

Overview

Transmission corridor planning is a key element in a comprehensive long-term transmission planning process. Corridor planning can help prevent costly permitting delays, ensure that optimal routes are used to lessen environmental impacts, consider possible alternatives to meet project reliability or economic goals, and ensure that corridors are set aside and available when needed.[8]

In developing its proposal for the state-led transmission corridor planning process, staff considered various obligations and constraints faced by the Energy Commission and other parties participating in the collaborative Energy Report process. Time constraints on the Energy Report process can limit achievements in each cycle. However, some of the strengths of the Energy Report process include: issues are vetted publicly with stakeholders and other participants, the process provides agency positions on key assumptions and the use of those assumptions, decisions are made with input from the agencies, stakeholders, and the public, the process is revisited in odd numbered years, and vital information can be updated in even-numbered years.

Input from multiple stakeholders and the recommendations of the *2004 Energy Report Update* guided development of staff's proposed state-led transmission corridor planning process. Energy Commission staff believes the proposed process must consist of the following three essential components, and that the success of the proposed process is dependent upon state actions to effectively implement each one:

> <u>Part 1: An *Energy Report* Corridor Identification Process:</u> This process would allow all parties, stakeholders, and the public to come to the table early on in the planning process, ensuring that consideration is given to all participant input and that agreement is reached on the need for future corridors. The process would build on the strengths of the Energy Report process in determining future corridor needs, involving stakeholders, and identifying issues, constraints, and actions necessary for resolution.
>
> <u>Part 2: Designation Authority and a Transmission Corridor Designation Process:</u> A vital component to this corridor planning process is state designation of corridors in order to provide utilities with future permitting certainty and an incentive to acquire land for future system expansion. A coordinated process is also required for corridor designation and local permitting of land uses to ensure that future incompatible uses don't limit the use of planned corridors. Before designating a transmission corridor or conducting an environmental review, the state must establish designation authority and a corridor designation process that sets land aside for future corridor use. Establishing legal authority and a designation process will give

utilities more permitting certainty and incentive to acquire land for future uses. This process should be separate from the Energy Report Corridor Identification Process and should not be limited to the Energy Report process timeframe.

Part 3: Land Acquisition and Banking: Staff believes that the most efficient way to acquire land for future corridors is to rely on utilities to do it. To ensure that planned and designated corridors will be banked by the utilities, the state must extend the length of time an investor-owned utility (IOU) is allowed to keep the costs of land acquired for future needs in the rate base. The current limit is five years, which is not sufficient to allow for long-term planning.

As part of the *2005 Energy Report*, 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 Term Corridor Defined

For the *Energy Report* corridor planning process, staff proposes that a transmission corridor be defined as a linear strip of land with width determined by land use, environmental, and topographical factors and study needs. The term "corridor" does not imply entitlement of use; environmental and regulatory review of the corridor is required. The width of a corridor, for corridor designation purposes, is directly related to system needs determined during the *Energy Report* process. Corridor use must also be consistent with those needs as defined in the Strategic Plan. If a corridor for two 500 kV transmission lines is identified, the final width of the designated corridor would be based upon safe maintenance and operation requirements for the transmission lines, the minimum distance required between the lines, and the distance required from the side of each tower to the edge of the right-of-way.

Part 1: An Energy Report Corridor Identification Process

The following section describes Energy Commission efforts during the *2005 Energy Report* cycle to solicit and consider input on development of a state-led transmission corridor planning process. As noted above, staff believes this process should consist of three components, two of which are beyond the jurisdiction of the Energy Commission. Therefore, the following section focuses primarily on staff's attempt to develop Part 1 of this process, including establishment of an *Energy Report* Corridor Identification Process. This process would survey the corridor needs of transmission-owning load serving entities (LSEs) and develop participation in the process by state, local, and federal agencies.

Energy Commission staff believes it is important to limit the corridor work performed during an Energy Report cycle to essential activities required to provide informative recommendations to the Energy Commission for the Transmission Strategic Plan.

Energy Commission staff should focus on corridor identification and planning activities during the *Energy Report* cycle. Therefore, Energy Commission staff's *Energy Report* Corridor Identification Process is built on the assumption that the following items must be accomplished during the *Energy Report* process in order to make recommendations for the Strategic Plan:

1. Identify the corridor needs of transmission-owning LSEs.
2. Establish corridor priorities.
3. Identify major permitting, environmental, and land use issues associated with potential corridors, based on screening-level analysis.
4. Identify affected agencies whose participation is critical to resolving issues.

As shown in Figure 2, staff believes that more detailed corridor studies and environmental assessments must be done outside the *Energy Report* schedule, as part of a designation filing. This would typically be initiated by applicants wishing to file an application for designation. This would allow the transmission-owning LSE to work in coordination with local agencies with the guidance of the Strategic Plan corridor need recommendations and the filing requirements that would be associated with a designation process, to come up with the most suitable set of corridors and alternative routes within each corridor. (In Figure 2, applicants are assumed to be utilities, but need not be.)

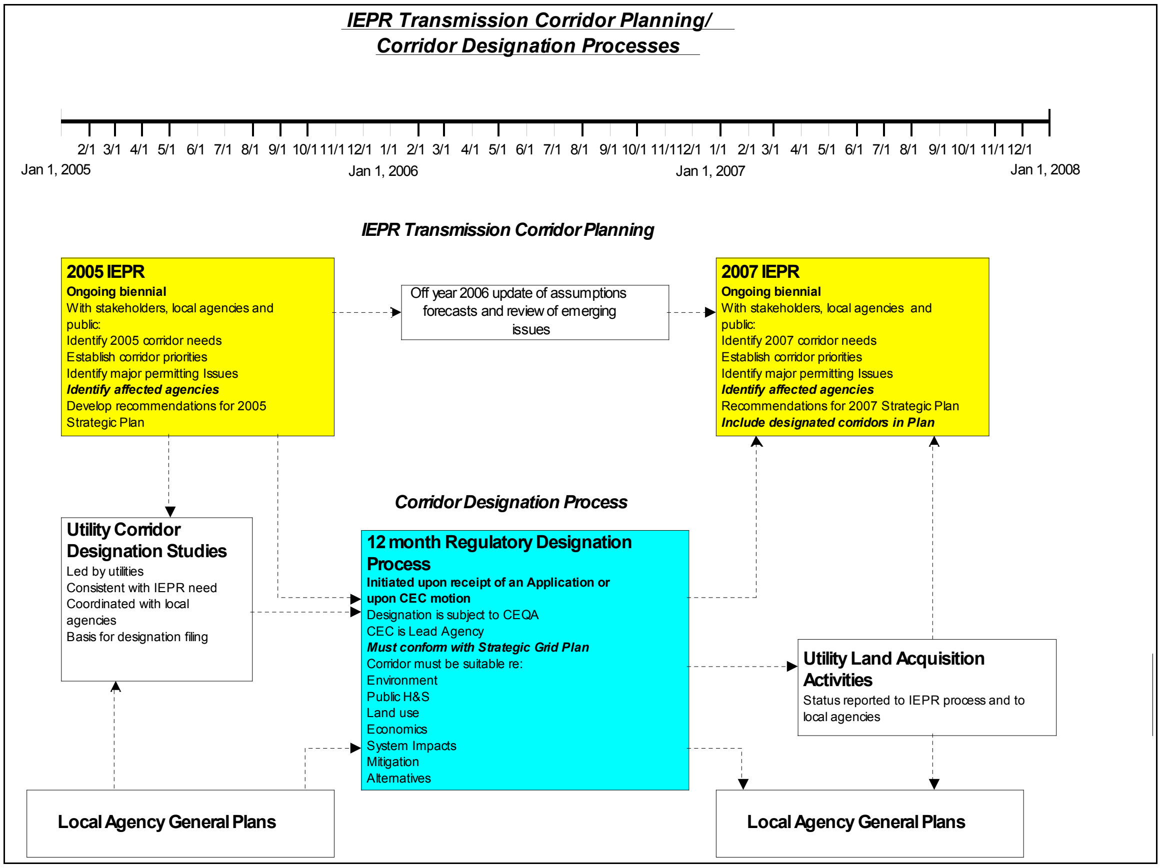


Figure 2: Energy Report Transmission Corridor Planning

Staff prepared a background paper prior to the May 19, 2005 workshop explaining the proposed *Energy Report* Corridor Identification Process.[9] Several workshop participants supported both the need for corridor planning and the proposed process:

- California Department of Parks and Recreation (State Parks) expressed support for this type of central planning effort. State Parks noted that a number of field staff is working on energy planning issues, but not always in the same manner; the Energy Commission's planning effort would allow headquarters a presence in the overall process to ensure continuity.[10]

- SDG&E began its presentation by "recognizing the absolute importance of an overriding state effort to site transmission lines."[11] During the panel discussion, SDG&E also supported the proposed corridor planning process:

> "I think your proposed transmission approach is very critical and important. I think it will raise awareness in the state."[12] Later, SDG&E added that "we're faced with conflicting missions and they're all legitimate, and these are important societal issues that need to be

addressed. And I commend the Energy Commission for wanting to address them."[13]

SDG&E noted that the process is a typical and "conservative process that identifies general needs and works down to the particular."[14] However, SDG&E warned that, when getting down to particular details and the local agencies:

> "…you're going to have problems resolving conflicts. It's a good process; it's a tried and true traditional process. But it takes a long time, and it may or may not work."[15]

- SCE made several important points regarding corridor planning:

> "We believe that…developing a corridor planning process…will establish formal communication channels regarding the role of future infrastructure needs in community development."[16]
>
> "It will establish the context for future facility planning,…establish the context for future public involvement," and "…minimize future siting conflicts."[17]
>
> "And lastly, it will encourage the inclusion of utility transmission and distribution plans into local land use plans. And that, in and of itself,…will go a long way into facilitating future development of transmission facilities."[18]

- PG&E noted:

> "So to garner all this information and then come up with a plan, you've got to get all these people around a table. I have been, and I will admit, unsuccessful in 30 years figuring out how to do that. It's almost impossible to get these people to agree, first that there's a need."[19]

LSE-Identified Corridors

The first and most critical component of the *Energy Report* Corridor Identification Process is obtaining the most up-to-date and accurate information available from transmission-owning LSEs. Receiving this information at the beginning of an Energy Report cycle will allow for early identification of future corridor needs, as well as the re-evaluation of previously identified corridors. This would allow Energy Commission staff to work with interested stakeholders, federal, state, and local agencies, California Native American governments, landowners, and the public to identify corridor needs and effectively plan for them.

On January 19, 2005, the Energy Commission requested that transmission system owners provide bulk transmission information by April 1, 2005, for the *2005 Energy Report*. In early March, Energy Commission staff also asked transmission-owning LSEs to prioritize all short- and long-term transmission projects identified in their filings, including any known additional information (e.g., purpose, likely end points, date needed, potential in-state project mileage, range of estimated project costs, identification of stakeholders for which coordination will be necessary, and estimated strategic benefits to California).

SCE: In the Tehachapi region, future corridors would be needed for the Antelope-Pardee 500 kV line, Antelope-Vincent 500 kV line, and Antelope-Tehachapi 500 kV line. In the north of Lugo area, future corridors are needed for: a new 230 kV line to the Lugo Substation, either from the Victor or Kramer substations, a new 230 kV line between the Kramer and Inyokern substations (depending upon generation development), and a new 500 kV line between the Inyokern area and Vincent Substation. A preliminary assessment of generation retirement scenarios provided a conceptual basis to identify potential corridor needs in the SCE area. These include new 230 kV lines on the Serrano-Lewis /Villa Park-Barre corridor and a Rio Hondo 500/230 kV Substation. SCE also has a conceptual forecast for new corridors from the Eldorado Substation area into the Lugo Substation area, and from the Midway Substation to Vincent Substation areas; these would increase the import capability into the SCE service area.[20]

SDG&E: SDG&E recommended that the Energy Commission consider a transmission corridor from the Imperial Valley into the San Diego area. Three possible points of origin were suggested: SDG&E's Imperial Valley Substation, Arizona Public Service's (APS) North Gila Substation, or SCE's Serrano/Valley Substation.[21]

City of Palo Alto: The City of Palo Alto stated that …"it is important to expand the utilization of existing transmission corridors supplying the Greater Bay Area from the Vaca/Dixon and Tesla/Tracy substations and from Moss Landing Power Plant."[22]

Energy Commission staff agree with potential corridor needs identified by SCE and SDG&E that would provide access to renewable resources. The *2003 Energy Report* and the *2004 Energy Report Update* highlighted the importance of renewable energy resources in meeting California's future energy needs, calling the RPS program the "centerpiece of the state's strategy for diversifying the electricity system."[23] Noting that over 80 percent of renewable resources are located in the Tehachapi Wind Resource Area and Imperial County's Geothermal Resource Area, the reports suggest that transmission projects accessing these areas should be considered the "highest priority."[24]

Energy Commission staff also agree with the input from the City of Palo Alto encouraging review of existing corridors supplying the Greater Bay Area.

Overall, Energy Commission staff found responses received from transmission-owning LSEs in the April 1, 2005, transmission filings to contain minimal corridor information. The majority of responses consisted of either 10-year Resource Plans or statements indicating that no transmission projects were planned. There was no evidence to indicate that transmission-owning LSEs considered staff's additional request to numerically prioritize the short- and long-term transmission projects identified in their filings and provide additional project details if known. Energy Commission staff sees considerable value in collecting additional project information, if known, to assist in identification of potential corridor needs and priorities. However, Energy Commission staff acknowledges that the request for additional information in early March was not timely considering transmission-owning LSEs were already in the process of preparing their April 1 filings and this was the first Energy Report cycle to address transmission-owning LSE corridor needs.

A Corridor Study Group

Energy Commission staff proposes establishment of a collaborative corridor study group or groups as part of an *Energy Report* Corridor Identification Process. A corridor study group would be comprised of interested stakeholders, federal, state, and local agencies, California Native American governments, landowners, and the public. This study group would assist the Energy Commission by identifying potentially affected agencies and the major institutional and other issues and constraints associated with potential corridors identified by transmission-owning LSEs, as well as agency or other actions that may be necessary to resolve these issues. Staff believes that identification of a study group with a specific, defined role will provide a more efficient process to identify parties and issues associated with needed corridors than the current workshop process. The workshop process would vet the results of the study group's efforts.

The California Biodiversity Council (CBC) was identified during the August 23, 2004, Energy Report Transmission Workshop by State Parks, as a potential forum where the Energy Commission could work with a range of federal, state, regional and local agencies to identify issues associated with potential transmission corridors.[25] The CBC is an existing organization formed to "…discuss, coordinate, and assist in developing strategies and complementary policies for conserving biodiversity."[26] Because the CBC is an existing forum, Energy Commission staff believes that potential corridors could be reviewed, vetted, and ultimately benefit from the CBC's existing public process.

Energy Commission staff briefed the CBC Executive Committee on March 30, 2005, to solicit their participation as part of a corridor study group and request future assistance with review of potential transmission corridors. The CBC was generally supportive and encouraged the Energy Commission's corridor planning activities, and agreed to assist noticing of staff's May 19, 2005, workshop via its electronic list server. The CBC agreed to hear further discussion of transmission corridors at future meetings. However, it is staff's opinion that because the CBC meets only a few times each year and has a standing list of important topics to consider, it is unlikely the CBC can provide formal assistance to the Energy Commission within the rigorous timeframes of an *Energy Report* cycle. State Parks noted at the May 19, 2005, workshop that the CBC's structure may not be the best approach to corridor planning assistance in the long run. "I think it's a good idea to keep the Biodiversity Council in mind, but don't use that as the day-to-day avenue toward working with state agencies interested in land use and regulatory impacts."[27] Staff believes the

Energy Commission should continue to engage the CBC and keep them apprised of ongoing corridor planning activities. In doing so, Energy Commission staff can continue to build important agency relationships crucial to resolving corridor issues in the future.

Several participants at the May 19, 2005, workshop supported the need to work with stakeholders in a collaborative process:

- SDG&E stated that: collaboration is needed between federal, state, and local jurisdictions; community outreach and local support are critical to building new transmission; statewide support and coordination are vital; and, the Energy Commission has a vital role in evaluating and adopting strategies this year for transmission planning.[28]

- SDG&E also stated:

  > "I think a collaborative approach is the only approach. I don't think you should consider anything else. But a collaborative approach has to end in some result. And whatever that result is, somebody is going to have to make the tough decisions that you're suggesting. And I think that role is probably best left with the state. They probably have the easiest time of making that decision."[29]

- SCE stated:

  > "…it is somewhat problematic if the developers, themselves, are not engaged in the process early on so that you can articulate with more clarity what the corridor ought to look like.[30]…I think there needs to be a lot of involvement and a lot of participation to try and satisfy everybody's requirements. And it's a long list of everybody."[31]

- The BLM noted :

  > "…what we're getting is this multitude of efforts going on out there. You have workshops like this; you have the study groups; you have BLM meeting with the industry; you have BLM meeting with DOD and BLM meeting with everything.[32] …. So I think I would really encourage a statewide effort. And BLM, at least, is very interested in being on-board with that."[33]

Energy Commission staff welcomes comments regarding a proposed corridor study group (or groups) that could assist the Energy Commission in future *Energy Report* cycles. Information developed by the study group would allow the public, agencies, stakeholders, and the Energy Commission to understand the feasibility of potential corridors identified by transmission-owning LSEs. After review of the Tehachapi Study Group's recommendations for future collaborative study groups,[34] staff believes that participation in the proposed corridor study group should be voluntary, and suggests that the study group vet its review activities through a series of *Energy Report* workshops held at the Energy Commission. In this way, the proposed study group would provide functional input to the Energy Commission within the timelines of the *Energy Report* cycle, allowing the Energy Commission to determine appropriate corridor priorities and needs.

Part 2: Designation Authority and a Transmission Corridor Designation Process

Importance of Designating Corridors

In order for the *Energy Report* Corridor Identification Process to be effective, it is essential that corridor recommendations (and land use requirements) resulting from that process be set aside for future use. Therefore, the Energy Report Corridor Identification Process must be accompanied by the legal authority to designate a transmission corridor through the Transmission Corridor Designation Process. The *Energy Report* Corridor Identification Process, as well a Transmission Corridor Designation Process, must in turn be coordinated with local land use permitting activities to ensure that local planning is factored into the Corridor Planning Process so that incompatible land uses do not limit future use of planned and designated corridors.

Energy Commission staff also believes that the *Energy Report* Corridor Planning Process and the designation process should be separate from one another and have different procedural requirements since each process deals with different questions requiring different input. The *Energy Report* Corridor Identification Process would occur during the *Energy Report* cycle and result in a list of potential corridor recommendations for the Energy Commission to consider for inclusion in the Strategic Plan. The designation process would be a public process initiated by an applicant's filing or the Energy Commission's own motion, and would include an assessment of environmental impacts of a proposed corridor in accordance with the California Environmental Quality Act (CEQA). The process would also result in proposed corridor designation by the Energy Commission and be reflected in local general plans for future electric transmission line facilities.

The Proposed Designation Process

After needed corridors are identified in the Strategic Plan, filings by applicants in the Transmission Corridor Designation Process would have to be in conformance with the Strategic Plan. Thereafter, the designation process would address physical, environmental, and land use issues and constraints associated with the proposed corridors, in addition to alternative routes within the corridor. To address these issues, the Energy Commission would act as lead agency and prepare an environmental document pursuant to the CEQA (Public Resources Code section 21000 et seq.). Upon conclusion of public informational hearings and certification of the environmental document, the Energy Commission would designate a transmission corridor that is acceptable and consistent with the Strategic Plan. The designation would then serve as the mechanism by which property within the designated corridor would be reserved for future use by transmission infrastructure projects. In addition, to ensure that previously designated corridors are relevant, they would also be revisited periodically during the *Energy Report* Corridor Identification Process noted above.

Table 4 shows the relationship of the proposed *Energy Report* Corridor Identification Process with the proposed Corridor Designation Process, and the basic differences between the two.

Table 4: *Energy Report* Corridor Identification vs. Corridor Designation

***Energy Report* Corridor Identification Process**	**Corridor Designation Process**
Identifies future point to point transmission corridor needs.	Provides a process to bank identified transmission corridors related to corridor needs for future permitting.
Is conducted as part of the *Energy Report* process. Results in corridor recommendations to the Strategic Plan.	Process initiated by applicant filings or Energy Commission motion, and includes environmental analysis per CEQA.
Submits results to the Governor and the Legislature for policy actions.	Makes results available to utilities and local agencies for land use planning coordination.
Identifies agencies affected by transmission corridor needs and includes agencies in corridor assessments.	Includes affected agencies in process and provides results to agencies for incorporation in their land use plans.
Includes previously designated transmission corridors in subsequent strategic grid plans.	Conforms designated transmission corridors with the current Strategic Plan.

Several participants at the May 19 workshop commented on the designation of corridors:

- SCE suggested that a designated corridor not be "done on a short-term basis,"[35] but rather be established on a 10- to 20-year planning horizon in order for the "corridor to withstand the duration of time, so that it allows us the flexibility of using it when we do, in fact, need it."[36] SCE further suggested that state-designated corridors be compatible with federal corridors, that the use of designated corridors allow for expedited permitting of project infrastructure, and access to designated corridors be preserved to allow for future facility repair and maintenance.

- The League of California Cities suggested that, in designated areas:

> "…if the local government or property owner wants to proceed with a development that would be inconsistent with that future use, … and perhaps that project or individual development was three years after this corridor was designated, the Energy Commission might want to go back and reassess."[37]

State Actions

Senate Bill 1059 (Escutia and Morrow) was introduced as draft legislation on February 22, 2005. It was last amended in the Senate on May 27, 2005 and has moved to the Assembly as a two-year bill that will not be heard until the 2006 legislative session. The bill would authorize the Energy Commission to designate suitable transmission corridor zones for high-voltage electric transmission lines that are consistent with the Strategic Plan to ensure reliable and efficient electricity delivery. The designation of a transmission corridor zone could be proposed by the Energy Commission or by application to the Energy Commission from any person or entity planning to build an electric transmission line in the state. The bill would identify the Energy Commission as the lead agency responsible for preparing an environmental impact for each corridor designation. The bill would also require that cities and counties amend their general plans as needed to be consistent with the Energy Commission's designations. The Energy Commission would be required to work with cities and counties, federal agencies, and California Native American tribal governments to identify appropriate areas within their jurisdictions that could be suitable for a transmission corridor zone.

At the May 19, 2005, workshop, the League of California Cities took exception to the provisions of SB 1059.[38] The League of California Cities noted that all stakeholders need to be involved in the planning process, including landowners, and that more upfront work needs to be done. The League of California Cities noted that the state "can't simply impose or [place a] demand on local governments to put everything on hold or change their plans, their designated land use plans, for a maybe corridor that may or may not be viable."[39] In addition, the League of California Cities noted that SB 1059 does not specify how wide a corridor would be.

Part 3: Land Acquisition and Banking

Staff believes that the most efficient way to acquire land needed for future corridors is to rely upon the transmission-owning LSEs to do it. The CPUC has exclusive ratemaking authority for regulated IOUs. In order to ensure land is available within the transmission corridors identified and designated as a result of the proposed processes identified above, the CPUC needs to extend the length of time an IOU is allowed to keep the costs of land acquired for future needs in rate base. This issue was raised during the May 19, 2005, workshop by SCE:

> "The cost recovery for land acquisition and designated corridors should be provided. It would be difficult for anybody to go out and purchase land without assurance that they're going to get the money back from their investment."[40]

The length of time IOUs are allowed to keep land acquired for future needs in rate base is currently limited to five years. This length of time does not allow IOUs to consider and effectively plan for long-term transmission options. CPUC action would need to be taken extending the length of time utilities can keep land acquired for future needs in rate base beyond the current five-year limit.

Corridor Modeling and Public Education

The PACT Model

The Energy Commission's PIER Program is currently funding the development of a web-based transmission corridor modeling program intended to assess a number of corridor factors, including environmental concerns, health and safety issues, engineering issues, and economic considerations. An overview of the modeling program, known as Planning Alternative Corridors for Transmission (PACT), and a contract were presented at the May 19, 2005, workshop by Aspen Environmental Group. The goal of the program is to facilitate the identification of transmission corridors and allow the public and decision makers to understand the trade-offs between proposed and alternative transmission routes based on objective, comprehensive, consistent, and transparent analysis.[41]

The PACT modeling program will build on a previous modeling tool developed by SCE to review potential substation sites and local transmission projects. The PACT contract was approved by the Energy Commission on June 8, 2005. In the coming months, a policy advisory committee will be established to provide guidance and research direction for the development of the model, and technical advisory committees will be established to provide input for each technical area considered in the model. These advisory committees will be responsible for assessing the existing model, modifying the scope and attributes of the model, developing weighting criteria, defining data needs and output, and designing the model's user interface. The first test of the PACT model is anticipated in late 2005, and a final version is expected to be available in late 2007.

Need for Public Education

Workshop participants were supportive of the PACT model and the potential educational benefits it would offer to the public and stakeholders. Several participants also suggested the need for a statewide program to educate the public on the need for and benefits of transmission.

- SDG&E noted the public's lack of information about transmission:

  > "… there really is not very much information in the general public and at the local level about what requirements are needed for transmission lines.[42] …I think we have to engage in a very powerful education program. And that program has to talk about how infrastructure works. I think the general citizenry does not understand the electric grid, and they don't understand how power [is] moved from one place to another.[43] …. Don't just make suggestions, but educate people about why these things are important.[44]

- PG&E expressed support for an education program that would explain how electricity works, how it is delivered, and would get citizens engaged at the local level to understand that it is delivered to their communities. "The education portion of this is long overdue," PG&E stated.[45]

Energy Commission staff agrees that a statewide education program would be valuable to the public. Such a program could focus on the importance of the state's electrical grid, how it operates, why transmission facilities are critical, and why public participation in the planning and designation process is important.

Policy Options

California could realize substantial environmental and economic benefits from the planning of future transmission corridors. This chapter has proposed a state Transmission Corridor Planning Process consisting of three essential components required to ensure the success of transmission corridor planning efforts. The components are:

Part 1: An *Energy Report* Corridor Identification Process.
Part 2: Designation Authority and a Transmission Corridor Designation Process.
Part 3: Land Acquisition and Banking

See Chapter 6 for transmission corridor planning policy options.

Endnote

[1] California Energy Commission. 2003 Energy Report. December 2004, p. 20.

[2] California Energy Commission. Upgrading California's Electric Transmission System: Issues and Actions for 2004 and Beyond. July 2004, p. 2.

[3] California Energy Commission. 2004 Energy Report Update. November 2004, p. xv, xvii, 27.

[4] California Energy Commission. 2004 Energy Report Update. November 2004, p. xvii.

[5] Ibid., p. xvii

[6] Proposed Senate Bill 1059, which would authorize the Energy Commission to designate a transmission corridor zones, was formally opposed in Senate hearings by the League of California Cities, the Regional Council of Rural Counties, the California State Association of Counties, and Southern California Edison.

[7] League of California Cities. March 2005. Letter to Senator Martha Escutia noting opposition to Senate Bill 1059. Docketed May 3, 2005.

[8] California Energy Commission. Upgrading California's Electric Transmission System: Issues and Actions for 2004 and Beyond. July 2004, p. 1.

[9] California Energy Commission. *Background Paper for the Transmission Corridors and Strategic Plan Update Workshop.* Staff Report. Publication number 700-2005-001. May 2005. [http://www.energy.ca.gov/2005publications/CEC-700-2005-001/CEC-700-2005-001.PDF]

[10] California Energy Commission, Integrated Energy Policy Report Committee Workshop Docket Number 04-IEP-01, 2005 IEPR Update; Committee Workshop on Corridor and Strategic Transmission Planning Issues, Recorded Transcript, May 19, 2005, California Energy Commission, Sacramento, CA, Date on-line May 24, 2005, p. 81.

[11] Ibid., p. 11.

[12] Ibid., p.17.

[13] Ibid., p. 85.

[14] Ibid., p. 85.

[15] Ibid., p. 86.

[16] Ibid., p. 43.

[17] Ibid., p. 43.

[18] Ibid., p. 45.

[19] Ibid., p. 91.

[20] Southern California Edison. Southern California Edison Company's 2005 IEPR Transmission Submittal. April 2005, p. 22-23.

[21] San Diego Gas and Electric. SDG&E's Bulk Transmission Information Submittal for the CEC's 2005 Integrated Energy Policy Report. April, 2005, p. 14.

[22] City of Palo Alto. Letter to Robert Therkelsen, Executive Director, California Energy Commission. March 2005, p.1.

[23] California Energy Commission. 2004 Energy Report Update. November 2004, p. 35.

[24] Ibid., p. 35.

[25] California Energy Commission, Integrated Energy Policy Report Committee Workshop Docket Number 03-IEP-01, 2004 IEPR Update; Committee Workshop on Upgrading California's Transmission System, Recorded Transcript, August 23, 2004, California Energy Commission, Sacramento, CA, Date on-line August 31, 2004. [http://www.energy.ca.gov/2004_policy_update/documents/2004-08-23_workshop/2004-08-23_TRANSCRIPT.PDF]

[26] California Biodiversity Council Homepage. Accessed June 1, 2005. [http://ceres.ca.gov/biodiv/]

[27] California Energy Commission, Integrated Energy Policy Report Committee Workshop Docket Number 04-IEP-01, 2005 IEPR Update; Committee Workshop on Corridor and Strategic Transmission Planning Issues, Recorded Transcript, May 19, 2005, California Energy Commission, Sacramento, CA, Date on-line May 24, 2005, p. 82.

[28] San Diego Gas & Electric. Part I, 500 kV Transmission Line Project. Presentation by Laura McDonald at the May 19, 2005, Committee Workshop on Corridor and Strategic Transmission Planning Issues. [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#051905]

[29] Ibid., p. 107.

[30] Ibid., p. 101.

[31] California Energy Commission, Integrated Energy Policy Report Committee Workshop Docket Number 04-IEP-01, 2005 IEPR Update; Committee Workshop on Corridor and Strategic Transmission Planning Issues, Recorded Transcript, May 19, 2005, California Energy Commission, Sacramento, CA, Date on-line May 24, 2005, p. 101.

[32] Ibid., p. 57.

[33] Ibid., p. 58.

[34] California Public Utilities Commission. Report of the Tehachapi Collaborative Study Group. March 2005, p. 53-55.

[35] California Energy Commission, Integrated Energy Policy Report Committee Workshop Docket Number 04-IEP-01, 2005 IEPR Update; Committee Workshop on Corridor and Strategic Transmission Planning Issues, Recorded Transcript, May 19, 2005, California Energy Commission, Sacramento, CA, Date on-line May 24, 2005, p. 37.

[36] Ibid., p. 37.

[37] Ibid., p. 106.

[38] Ibid., p. 77.

[39] Ibid., p. 77.

[40] California Energy Commission, Integrated Energy Policy Report Committee Workshop Docket Number 04-IEP-01, 2005 IEPR Update; Committee Workshop on Corridor and Strategic Transmission Planning Issues, Recorded Transcript, May 19, 2005, California Energy Commission, Sacramento, CA, Date on-line May 24, 2005, p.38.

[41] California Energy Commission, PIER Program. Developing a Web-based Decision Tool for Siting Transmission Lines. Presentation by Susan Lee of Aspen Environmental Group at the May 19, 2005, Committee Workshop on Corridor and Strategic Transmission Planning Issues. [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#051905]

[42] California Energy Commission, Integrated Energy Policy Report Committee Workshop Docket Number 04-IEP-01, 2005 IEPR Update; Committee Workshop on Corridor and Strategic Transmission Planning Issues, Recorded Transcript, May 19, 2005, California Energy Commission, Sacramento, CA, Date on-line May 24, 2005, p.11-12.

[43] Ibid., p.14-15.

[44] Ibid., p.16.

[45] Ibid., p. 91.

CHAPTER 5: IMPACT OF TRANSMISSION ON RENEWABLES DEVELOPMENT

Background

Chapter 5 describes major transmission issues facing renewable development. This chapter draws from results of the Energy Commission's *Energy Report* workshops on February 3, 2005, and May 10, 2005, on operational issues with renewable integration, the April 11, 2005, workshop on geothermal issues, the May 9, 2005, workshop on renewable resource potential in California and interstate renewable resources, and related PIER work. The chapter concludes with options for follow-up on PIER funding and policy options for inclusion of this chapter's results in the *2005 Energy Report* and/or the 2005 *Strategic Plan*.

Transmission infrastructure bottlenecks and related policy solutions will greatly affect the state's ability to meet the EAP RPS goal of 20 percent renewable generation by 2010. The Energy Commission has recognized the importance of this issue in several recent documents and planning efforts. The Energy Commission's *2004 Energy Report Update* highlighted both general and specific transmission barriers to renewable development:

> "The acceleration of the state's RPS has highlighted the importance of transmission in developing renewable resources. The development of remote renewable resources requires substantial investments in new or upgraded transmission facilities. Transmission interconnection issues for renewable resources located in concentrated areas such as the Tehachapi wind resource areas and Imperial County's geothermal resource areas are complicated by the number of developers of renewable resources competing for limited transmission capacity and their limited ability to finance large transmission investments. [P]roviding for timely and adequate transmission projects will prove critical to meeting the state's ambitious renewable energy goals." [1]

The *2004 Energy Report Update* also recommends that the state establish a long-term transmission planning process "to identify needed transmission infrastructure investments, consider non-wires alternatives to transmission lines, and approve projects that provide benefits to California."[2] That recommendation was reflected in the Energy Commission and CPUC joint Draft EAP II: Implementation Road Map for Energy Policies, released on June 8, 2005. It notes that "[A]n expanded electric transmission system infrastructure is required to mitigate grid congestion and bring new renewable and conventional power plants on line. Transmission planning and permitting must provide a more [timely], seamless, and comprehensive statewide process for moving transmission projects through the planning phase and into construction." [3]

Operational and Policy Issues

Analysis in this chapter focuses on the effects of present transmission-related operational and policy constraints on the ability to reach RPS goals in the state. Several existing transmission issues already present potential barriers to meeting the RPS goals. These issues were not created by introduction of renewable resources, but rather have become more complicated because of them. Most of these issues are already limiting the flexibility of the overall grid in meeting reliability requirements, and efforts are underway to address many of them. However, these efforts will likely have to be accelerated in order to meet RPS goals.

Operational Issues

From an operational standpoint, integration of generation of renewable resources into the grid creates two major, inter-related challenges:

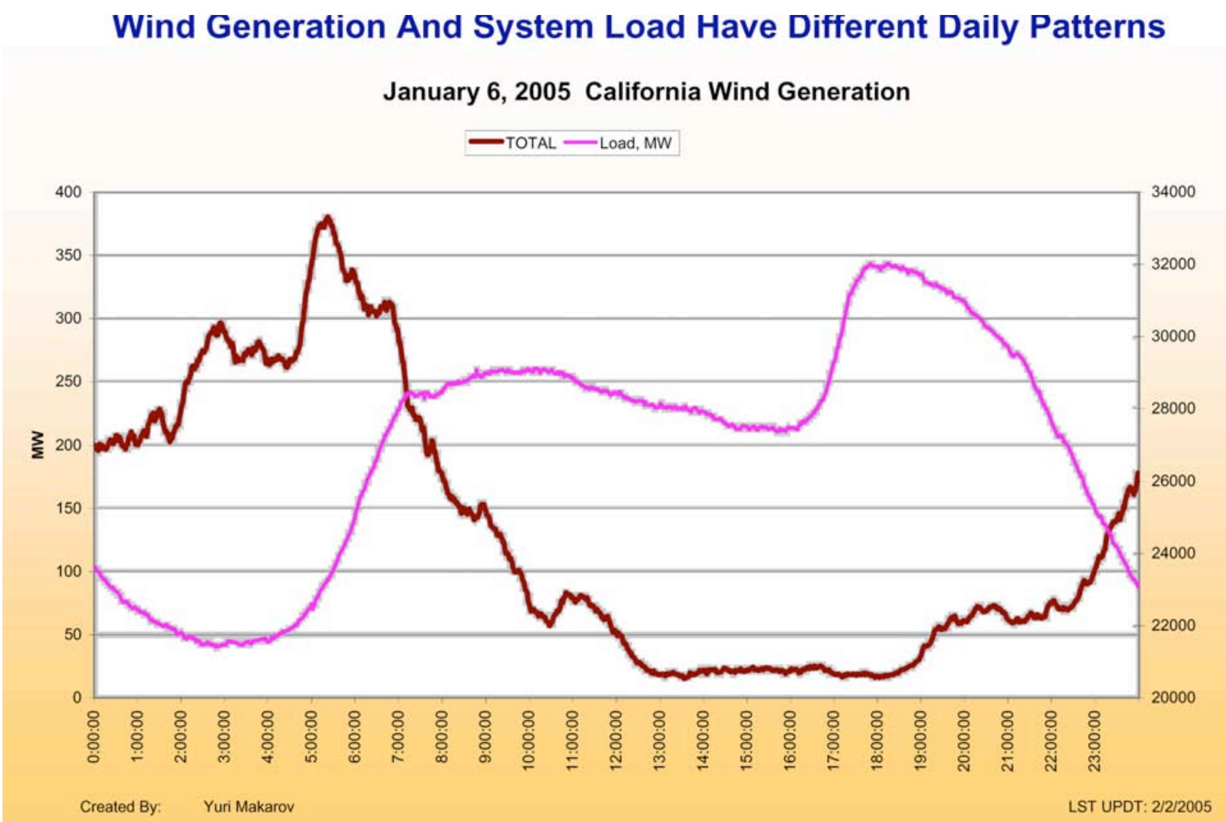
1. Accommodating intermittency in generation from wind farms and, to a lesser extent, solar facilities. Intermittency is an issue both with availability of specific facilities and production in different regions of the state. In other words, generation of a given wind project varies greatly over a given day, and the amount of windpower produced in each region of the state also varies significantly from day to day (see Figure 2, Hourly Wind Production in CA ISO).

2. Transmitting renewable generation, which is generated mostly in 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 also affect the transfer capability of that tie. Forecasting this variability, and allocating transmission capacity accordingly, will probably 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.

Figure 3: Hourly Wind Energy Production in CA ISO



Source: CA ISO, February 3, 2005 PowerPoint presentation entitled "Wind Generation Operating Issues: CAISO Perspective and Experience," slide no.13, [http://www.energy.ca.gov/2005_energypolicy/documents/2005-02-03_workshop/2005-02-03_CORRECTED_CAISO.PDF]. (July 20, 2005).

Though small hydroelectric, geothermal and biomass plants[4] can be dispatched to match load, availability of wind and solar power renewable generation is generally dictated by 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. Therefore, as power from renewable resources 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—most wind occurs at night, and full integration of wind energy requires turning down gas-fired generation below minimum load conditions. This is not a transmission issue *per se*, but is already an issue for many boiler plants,[5] but system transients could occur if unpredicted minimum load conditions cause gas plants to be tripped off suddenly.

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.[6]

Integrating small numbers of as-available or intermittent resources into the system could be accommodated with minor adjustments to the system. 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 electricity and transmission system.[7]

Siting multiple generators over large areas also reduces intermittency, as wind speed variability tends to cancel 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 in accommodating intermittency of any type 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 re-balancing. 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, areas with larger numbers of smaller control areas will experience greater difficulty in accommodating renewable intermittency than areas 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 negatively impact the transfer capability of the 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[8] 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.[9] 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.[10] CERTS's forecast of system operational changes needed to support the state's goal of 20 percent renewable 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 ramping capability to match system needs.

The CERTS study also found that control area operators may 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 to meet RPS goals is the effect of renewable resources, especially intermittent generation, on the ability to address grid frequency and voltage support reliability needs. This not only affects the relative capability of intermittent resources to provide such support, but also 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 integration would 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 (i.e., 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.[11]

The frequency response of generating resources is already a problem requiring corrective action before RPS goals can be met. 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.

Policy Issues

Federal and state policies concerning funding of transmission system development pose barriers to meeting the state's accelerated renewable energy goals, especially the rules for funding of transmission system development. Participants at the workshops held during preparation of the CERTS report acknowledged the need for additional transmission capacity in order 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) know 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 don't 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 funds 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.

The RPS statute requires the CPUC to promote transmission expansion needed to reach RPS goals. However, parties to this study consistently have expressed frustration with the speed of the transmission expansion approval process, slowed by both the mixed jurisdiction of the CPUC and FERC and with 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 would interconnect large concentrations of potential renewable generation resources located a reasonable distance from the existing grid. The costs of developing the new line could be recovered through general transmission rates.[13]

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. [14]

On April 14, 2005, the Energy Commission and the CPUC filed comments in support of SCE's petition.[15] The CPUC is supportive of the trunk line concept as a tool for statewide renewable energy development at the discretion of state regulatory agencies. As of April 15, 2005, more than 20 parties had filed comments on SCE's petition, some supporting and some protesting the proposal. The Energy Commission has consistently supported the notion that transmission projects with RPS requirements present a new kind of transmission project for the state.

SCE states that its proposed transmission capacity for the Antelope Transmission Project is based on forecasted renewable energy development instead of completed interconnection agreements. This approach exposes SCE to the risk that it could be left with sizeable quantities of unused transmission, in addition to liability for 50 percent of the associated "abandoned" costs.[16]

On July 1, 2005, the FERC disapproved SCE's application for the trunk line. Additional analysis and coordination is needed to address this issue.

CERTS performed an analysis comparing SCE's filing for the Antelope Transmission Project at FERC with their CPCN filing at the CPUC. The purpose of the analysis was to identify both inconsistencies between the two filings and operational integration issues. The CERTS study concluded that there were no inconsistencies between the two filings. In addition, the study reported that deliverability of new resources to other LSEs may require additional analysis and upgrades and that transmission planning and sizing, based on forecast resource development in the region, is appropriate. The CERTS study, "Review of SCE's FERC and CPUC Filings for the Antelope Transmission Project," is found in Appendix E.

Clustering

One way to address the problem of building transmission without the certainty of renewable generation is to build renewables near existing or planned transmission development, referred to as "clustering" generation projects. Clustering offers the advantage of evening out intermittency, since the intermittency of individual generators can cancel one another out when a sufficient number is connected. However, clustering renewable energy projects is not allowed under current CA ISO tariff and FERC interconnection policies. The Tehachapi Collaborative Study Group recommends regulatory changes to support clustered development of renewables, which would limit the risk of overbuilding transmission by "tying permitting and construction approvals closely to market demand."[17]

Line Losses

FERC is requiring the CA ISO to implement locational marginal prices (LMP) as part of its Standard Market Design, based upon the assumption that LMP will economically motivate power developers to build facilities as close to load as economically feasible. FERC also recognizes that some renewable resources, like wind, must be built in high wind areas and cannot relocate to reduce marginal losses; they are therefore penalized by a marginal loss component when it is part of locational marginal price. In response to this dilemma FERC has indicated that California and other states may develop their own approaches to address the marginal loss problem.

The Energy Commission staff is working with the CA ISO and the renewable community to promote awareness of the issue and present a proposed solution. The purpose of the approach is to identify the difference between marginal and average losses for designated renewable resources on a system-wide, bus-by-bus basis and determine the appropriate rebate owed individual grid users based on that difference. The Energy Commission anticipates holding workshops with interested representatives of the renewables community to exchange views on issues and solutions and agree to an approach to meet their needs.

Potential Solutions

Many options are under consideration for addressing technical and policy issues affecting the ability to meet RPS goals. The CPUC/Energy Commission joint EAP II recommends several key goals:

1. Develop and implement an integrated, comprehensive, statewide transmission planning process that eliminates bottlenecks, improves reliability, and accesses new renewable resources.
2. Establish a statewide transmission corridor planning process that creates and protects critical transmission corridors for potential future development.
3. Develop a streamlined methodology to expedite siting and certification review of proposed transmission projects.[18]

Both agencies have begun processes addressing these goals. One method of limiting the risk of overbuilding transmission is the interim “transmission cost adder” included in California’s RPS program, which would consider the indirect costs of transmission upgrades. After a “least-cost-best-fit” evaluation, bids would be clustered by interconnection location to determine the amount of generation that would trigger a transmission upgrade in each cluster. The costs would then be allocated to each proposal, with the cost estimate an adder to the bid price for renewable power.[19] The CPUC held a workshop in early 2005 to consider improvements to the interim methodology and developed several suggestions:

- Impose a curtailability standard.
- Coordinate deliverability requirements between the RPS and Resource Adequacy proceedings.
- Consider a new standard for transmission financing.[20]

Another option would be to allocate indirect transmission costs equally across all projects located near existing and anticipated renewable resource transmission upgrades, since their aggregate potential drives the need for transmission upgrades. For example, in the Antelope Transmission Plan the emphasis on the region's forecasted renewable energy potential is 4,000 MW, not on the individual projects in the interconnection queue.

On June 21, 2005, a proposed decision that would require the IOUs to allow bids with curtailability was released for comment in the CPUC's RPS rulemaking 04-04-026. On the same date, a related proposed decision was released in the CPUC's transmission proceeding (I.00-11-001) that would apply only limited modifications to the Transmission Ranking Cost Report methodology for the 2005 RPS solicitations.[21]

In the conclusion of the CERTS study, CERTS identified 10 solution sets and policy options for mitigating reliability and operational issues. These are summarized in Table 5.

Table 5: Summary of Solutions and Policy Options Addressing Transmission Concerns

	Issue / Solution Option & Action Required	Load Following	Minimum Loads	Reserves and Ramping	Load and Generation Forecast Variability	Storage	Frequency and Voltage Requirements	Resource Deliverability	Transmission Import Capability	Planning and Modeling
A	Establish requirements for controllable generation	x	x	x		x				
B	Enable load to participate in real time dispatch	x	x		x	x				
C	Renegotiate existing contracts for additional dispatchability and minimum load turndown (i.e. DWR and QFs)	x	x			x				
D	Modify CAISO AGC algorithm to make effective use of controllable hydro generation and controllable loads	x	x	x	x	x		x		
E	Modify WECC and CAISO interchange scheduling protocols, policies and procedures to enhance the use of renewable resources	x		x	x					
F	Ensure adequate generator performance standards are in place with clarity of implementation to ensure system performance						x			x
G	Actively manage generation output which exceeds planned levels, or when total generation exceeds load (e.g. during minimum loads)	x	x	x	x					
H	Improve transmission studies							x	x	x
I	Improve modeling of renewable generation							x	x	x
J	Improve production forecasting	x	x		x					

Source: Dyer, Jim et al., May 10, 2005 PowerPoint presentation entitled "Assessment of Reliability and Operational Issues for Integration of Renewable Generation," slide no. 13, [http://www.energy.ca.gov/2005_energypolicy/documents/2005-05-10_workshop/DYER_JIM_2005-05-10.PDF]. (July 12, 2005.)

CERTS studied solution options to integrate renewables without adverse impacts on reliability or operations. A list of solution options and actions was developed, including the relevance of each option to each issue. For each solution a matrix was developed identifying the proposed action, the likely owner(s), whether research was required, and the suggested metric that would be used.

CERTS also recommended several generic actions to address high-level policy issues. These are shown below in Table 6.

Table 6: High Priority Policy Options

High Priority Policy options

Define Attribute Requirements	▪ Define what is needed ▪ Develop appropriate metric ▪ Monitor performance
Reduce Uncertainty	▪ Reduce scheduling lead time ▪ Improve data availability ▪ Improve metering, monitoring and forecasting techniques
Resource Policies	▪ Appropriate resource mix ▪ Dispatch priority for both internal and imported resources ▪ Load participation ▪ Coordinated use of available storage
Improve Planning and Modeling	▪ Resource deliverability ▪ Import capability ▪ Improve models ▪ Perform off-peak contingency analysis ▪ Coordination with other WECC members and states

Source: Dyer, Jim et al., May 10, 2005 PowerPoint presentation entitled “Assessment of Reliability and Operational Issues for Integration of Renewable Generation,” slide no. 52, [http://www.energy.ca.gov/2005_energypolicy/documents/2005-05-10_workshop/DYER_JIM_2005-05-10.PDF]. (July 12, 2005.)

The Energy Commission could ensure that the operational integration work activities initially undertaken by staff are continued through a collaborative effort.

See Chapter 6 for policy options addressing transmission issues associated with renewable integration.

Endnotes

[1] California Energy Commission, November 2004, *Integrated Energy Policy Report 2004 Update*, p. 31, Sacramento, CA, P100-04-006CM, [http://www.energy.ca.gov/reports/CEC-100-2004-006/CEC-100-2004-006CMF.PDF].

[2] Ibid., p. 26.

[3] State of California, *Draft Energy Action Plan II: Implementation Road Map for Energy Policies*, p. 8, June 8, 2005, [http://www.energy.ca.gov/energy_action_plan/2005-06-08_ACTION_PLAN.PDF], (July 12, 2005).

[4] 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 Committee Workshop).

[5] California Energy Commission, August 2004, *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements*, Sacramento, CA, P100-04-005D, [http://www.energy.ca.gov/2004_policy_update/documents/2004-08-26_workshop/2004-08-04_100-04-005D.PDF].

[6] 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].

[7] KEMA-XENERGY, June 1, 2004, Intermittent Wind Generation: Summary Report of Impacts on Grid System Operations, Consultant Report, 500-04-091, [http://www.energy.ca.gov/pier/final_project_reports/CEC-500-2004-091.html]], accessed April 15, 2005. 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]], accessed 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.

[8] Inertia is a function of both the mass and speed of the rotating parts of any generator. Wind turbine generators are typically smaller than most generators connected to the grid, and they are usually induction (asynchronous) generators. Induction generators generally operate at lower speeds than synchronous generators, which use reduction gearing to match the high speed of the turbine to the lower speed of the generator. Therefore, because of their larger size and faster speeds, gas plants with synchronous generators have larger inertia ratings per installed MW.

[9] 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].

[10] Ibid., p. 38.

[11] Ibid., p. 38.

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

[13] United States 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], accessed April 30, 2005.

[14] SCE 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], accessed April 15, 2005.

[15] 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. [http://www.ferc.gov/docs-filing/elibrary.asp]], accessed April 19, 2005. 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. [http://www.ferc.gov/docs-filing/elibrary.asp]], accessed April 19, 2005.

[16] 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, [http://www.ferc.gov/docs-filing/elibrary.asp]], accessed April 15, 2005, see pp.18-19.

[17] CPUC, March 16, 2005, Docket I.00-11-001, Report of the Tehachapi Collaborative Study Group, [http://apps.pge.com/regulation/search.aspx?CaeName=Elec%20T-D%20OII%20AB970], accessed April 15, 2005.

[18] State of California, *Draft Energy Action Plan II: Implementation Road Map for Energy Policies*, p. 8, June 8, 2005, [http://www.energy.ca.gov/energy_action_plan/2005-06-08_ACTION_PLAN.PDF], (July 12, 2005).

[19] CPUC, June 9, 2004, "D0406013/I0011001 Adopted Methodology for Consideration of Transmission Costs in RPS Procurement," Proceeding: I0011001, [http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/37402.pdf]], accessed April 18, 2005. For an example of the interim method for applying a transmission cost adder in the 2004 round of RPS solicitations, see pp. A-13 and A-14.

[20] CPUC, March 17, 2005, "TerKeurst Ruling on Workshop Report Regarding Transmission Costs Used in Renewable Portfolio Standard Procurements - Attachment A," Proceeding: I0011001, [http://www.cpuc.ca.gov/WORD_PDF/ RULINGS/44759.pdf]], accessed April 18, 2005.

[21] CPUC, June 21, 2005, "Draft Decision of ALJ Simon: Opinion Approving Procurement Plans and Requests for Offers for 2005 RPS Solicitations," in Rulemaking 04-04-026, http://www.cpuc.ca.gov/PUBLISHED/COMMENT_DECISION/47288.htm. See also, CPUC, June 21, 2005, "Draft Decision of ALJ Terkeurst: Interim Opinion Regarding Transmission Costs in RPS Procurement," in I.00-11-001, http://www.cpuc.ca.gov/word_pdf/COMMENT_DECISION/47274.doc, accessed July 5, 2005.

CHAPTER 6: ENERGY COMMISSION OPTIONS FOR FURTHER ACTION

The *2003 Energy Report* recommended that the Energy Commission implement a fully collaborative state transmission planning process and consolidate the permitting process for new bulk transmission lines within the Energy Commission. The Energy Commission concluded that current approaches have suffered from fragmented and overlapping jurisdictional responsibilities, inconsistent environmental analyses, and a general failure to recognize the regional and statewide benefits of transmission projects. The *2004 Energy Report Update* further stressed the immediate need for critical infrastructure investments in order to reap the benefits of further development of renewable resources.

Improvements in transmission system planning, transmission corridor planning, and addressing transmission issues associated with renewables integration are needed to ensure that California's transmission system is expanded in an environmentally responsible, cost effective manner that considers public input, enhances reliability, and meets strategic statewide objectives, including effective integration of renewable generation. The Energy Commission staff recommends that the following policy options be considered.

Transmission Planning – Next Steps

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

Regional Planning

In January 2005 the WECC and the Committee on Regional Electric Power Cooperation formed the WAG to identify the major commercial issues affecting the Western Interconnection and evaluate whether the West has the necessary industry and regulatory institutions to effectively address and resolve these issues. The April 2005 draft WAG white paper identified transmission expansion planning as one of four critical issues. Most of the participants at the May 23, 2005 stakeholder meeting expressed preference to investigate whether the WECC would be the most appropriate organization to address both reliability issues and newly identified major commercial issues.

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

Statewide Planning

Recognizing the Energy Commission's interest in ensuring that long-term state objectives are met and the CA ISO's interest in ensuring that needed projects are identified and constructed in a timely manner, it is essential to recognize the strengths and expertise of each entity. Interactions between the Energy Commission's *Energy Report* work and the CA ISO's grid planning work could follow these principles:

- The LSEs would submit their load forecasts, resource plans, and price information to the *Energy Report* proceeding.
  - The Energy Commission could develop data requirements for future Energy *Report* proceedings in collaboration with the CA ISO and other parties to ensure that CA ISO information needs are met with respect to statewide transmission planning.
  - The Energy Commission could require that certain transmission planning information from transmission-owning load serving entities be provided annually so it could be used for developing staff forecasts and incorporated in grid planning by the CA ISO.
- The information would be analyzed and publicly reviewed in the *Energy Report* proceeding, resulting in adopted resource plans and scenarios.
  - The Energy Commission could develop formal agreements with transmission-owning load serving entities to ensure non investor-owned utility participation in the *Energy Report* transmission planning process.
  - The Energy Commission could work with the CA ISO and stakeholders to ensure that a disaggregated Energy Commission demand forecast is available for use in the CA ISO planning process during the next *Energy Report* cycle.
- Resource plans and scenarios, along with the municipal utility transmission plans, would be submitted to the CA ISO.
  - The Energy Commission could assist the CA ISO by providing publicly reviewed planning results for projects for inclusion in the California grid plan, including the identification of strategic benefits and consideration of comparative alternatives.
- The CA ISO would use that information -- along with the Energy Report load forecast information, participating transmission owner grid plans, and WECC plans -- to develop the California grid plan.
  - The Energy Commission could develop a Memorandum of Understanding with the CA ISO for a single electricity transmission planning process fully coordinating the individual processes and proceedings of the Energy Commission and the CA ISO, while recognizing the CA ISO as the transmission planning analysis entity for the state in preparing the California grid plan.

Transmission Corridor Planning – Next Steps

Corridor planning is essential to ensuring that California develops a healthy transmission system that will meet future electricity needs. Therefore, Energy Commission staff has developed, with input from stakeholders, a proposed state-led corridor planning process. This proposed process consists of the following three components:

- Part 1: An *Energy Report* Corridor Identification Process
  - Part 1 of the proposed process recommends collecting corridor information early in the *Energy Report* process. The Energy Commission could authorize staff to begin collecting corridor information so that adequate information is available.
  - Part 1 of the proposed process recommends developing collaborative Corridor Study Groups to review potential corridors. The Energy Commission could authorize staff to develop Corridor Study Groups in areas where a need has been identified.
- Part 2: Designation Authority and a Transmission Corridor Designation Process
  - The state should establish designation authority and a corridor designation process that sets land aside for future corridor use.
  - Future state corridors should be aligned with federally designated corridors when appropriate. The Energy Commission could authorize staff to work collaboratively with federal agencies, the public, local agencies, and other stakeholders to review the land uses along existing federally designated corridors and determine where complementary state designation would be beneficial.
- Part 3: Land Acquisition and Banking
  - Consistent with the *2004 Energy Report Update* recommendation for the development of a process to identify and bank utility corridors, the Energy Commission should encourage the CPUC to begin a proceeding on land banking to ensure that this issue moves forward. This corridor planning process can only be successful if the length of time IOU can keep land acquired for future needs in the rate base is extended beyond the current five-year limit.

The following additional corridor-related options complement staff's proposed state-led transmission corridor planning process described above. These options could serve as short-term alternatives to establish a foundation for future corridor planning efforts:

- Educating the general public about the fundamentals of the state's electrical grid and the need for additional transmission infrastructure would be beneficial. The Energy Commission could support development of a statewide education program, perhaps in coordination with the Public

Interest Environmental Research program's ongoing Planning Alternative Corridors for Transmission web-based modeling project.

- In the absence of state authority to designate transmission corridors, benefits could still be realized by identifying future corridors in areas where transmission infrastructure will be needed in the future. The Energy Commission could recommend in the Strategic Plan that utilities work with local agencies, stakeholders, and the public to identify a possible future corridor from the Imperial Valley into the San Diego region, a possible future corridor or corridors in the Tehachapi area that would complement projects already under consideration, and possible future corridors in other high priority areas.

Transmission and Renewables Development – Next Steps

Transmission infrastructure bottlenecks in California will greatly affect the state's ability to meet EAP RPS goals of 20 percent renewable generation by 2010.

- Federal and state policies pose significant barriers to meeting the RPS goals, especially those concerning rules for funding transmission system facilities.
  - The *2004 Energy Report Update* recommends investigating changes to the CA ISO tariff to encourage projects needed to commercialize renewable resources. To that end, SCE proposed the trunk line concept in an application to the FERC, and the Energy Commission and the CPUC supported that effort. However, on July 1, 2005, the FERC disapproved it. Additional analysis and coordination is needed to address this issue.
  - The Energy Commission could continue its collaboration with the CA ISO in developing mitigation of the negative cost effects that the FERC's marginal loss policy could have on siting renewable resources such as wind and geothermal. See Chapter 5 for additional information.
- From an operations perspective, integration of renewable generation into the grid offers major, inter-related challenges.
  - The Energy Commission could ensure that the operational integration work activities initially undertaken by staff continue through a collaborative effort.
  - To address the intermittent nature of wind resources and increase the effectiveness of existing energy storage facilities, the Energy Commission could promote coordination between system operators and storage owners. The Consortium for Electric Reliability Technology Solutions report notes, "…a more holistic strategy for the operation of all the pumped storage facilities in the state would yield a more efficient overall operation."[1]
  - Because minimum load issues may be exacerbated by intermittent resources, the Energy Commission could assist in the identification of viable locations for storage facilities that would complement intermittent renewable resources.

    - To reduce the uncertainty of resource availability, the Energy Commission could continue to promote research efforts to improve forecasts of intermittent resource availability. Reducing uncertainty in resource availability could reduce the need for costly reserve power that provides backup for intermittent renewable generators.
- Current transmission bottlenecks effectively limit the ability to transmit renewable generation from remote locations to major load centers.
    - The Energy Commission could continue to support the formation and implementation of stakeholder-based study groups to develop transmission plans allowing for the efficient movement of renewable energy to consumers.

Endnotes

[1] 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], p. 35.

GLOSSARY

Alternating Current (AC) – Electric current that reverses its direction at regular intervals or periods. Alternating current electricity flows in alternating directions due to the effect of a rotating magnetic field on electrons in a conductor. The single period in which AC flows in one direction and then reverses direction is called a cycle. The number of cycles per second is called the frequency (measured in Hertz, Hz) of the current. In North America, a frequency of 60 Hz is standard. Almost all electric utilities generate AC electricity because AC electricity can easily be transformed to higher or lower voltages. See also *Direct Current*.

Breaker – Circuit breaker, an automatic switch that stops the flow of electric current in a suddenly overloaded or otherwise abnormally stressed electric circuit.

Bus – Conductors that serve as a common connection for multiple transmission lines and circuit breakers.

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

Capacitor – An electric device used to store charge temporarily, generally consisting of two metallic plates separated by a dielectric. Capacitors produce reactive effects that can increase the capacity of long transmission lines.

Categorically Exempt – An exemption granted by the CPUC (or CEQA) from full environmental review and approval subject to a determination of no significant environmental or public impacts. Examples include adding or replacing circuit breakers in a substation and reconductoring an existing transmission line.

Certification of Public Convenience and Necessity (CPCN) – The approval (Decision) granted by the CPUC authorizing construction and operation of a transmission line or generating plant.

Circuit – A three-phase group of three conductors**.**

Congestion – The condition that exists when market participants seek to dispatch in a pattern which would result in power flows that cannot be physically accommodated by the system. Although the system will not normally be operated in an overloaded condition, it may be described as congested based on requested/desired schedules.

Congestion Management – Congestion management is a CA ISO scheduling protocol that is used to resolve congestion.

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

Contingency – An outage of a transmission circuit, transformer or other system element.

Corridor – For planning and corridor study purposes in the *Energy Report* corridor planning process, staff proposes that a transmission corridor be defined as a linear strip of land with width determined by land use, environmental, topographical factors, and study needs. The term corridor does not imply entitlement of use; environmental and regulatory review of the corridor is required prior to corridor use. The width of a corridor for corridor designation purposes is directly related to system needs determined during the IEPR process, and corridor use must be consistent with those needs as defined in the Strategic Plan.

Demand-Side Management – Measures taken by a utility or control area operator to influence the level or timing of customers' energy demand to optimize use of available resources.

Deliverability – A measure of a specific generating unit's ability to dispatch full power to the grid and/or the designated load area under normal albeit stressed system conditions. A generating unit that is required by the dispatch authority to limit requested unit dispatch due to reliability or security concerns is not fully deliverable. As an example, a generating unit which desires to dispatch its partial or full generation to Southern California but cannot because of congestion during normal system conditions is not fully deliverable. Deliverability of a generating unit is not assessed under contingency conditions.

Direct Current (DC) – Electric current that flows in a single direction and at a constant voltage. Almost all bulk electricity is generated as alternating current (AC) rather than DC because AC can be more easily transformed to any required voltage. DC electricity is typically used for specific applications, such as the transmission of electricity over very long distances. See also *Alternating Current.*

Double-Circuit Transmission Line – Two three-phase transmission circuits (a total of six conductors) supported by poles or towers.

Electric and Magnetic Fields – Energy fields that result from the existence and movement of electric charges. Electric and magnetic fields can both occur naturally and be man made. Electric fields are present wherever electric charge exists, and magnetic fields result from the movement of these electric charges. The voltage on a transmission line produces an electric field near the line. The flow of current on a transmission line produces a magnetic field near the line.

Import Capability – The magnitude of power that can be imported to an area while meeting reliability standards. The import capability is not the summation of line ratings connecting generation to an area.

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

Kilovolt (kV) – One thousand volts.

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

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

Megavolt Ampere (MVA) – One million volt-amperes. A volt-ampere, which is the product of the voltage (in volts) and the current (in amperes), is the basic measure of apparent power in an electric circuit. Apparent power includes both real power (measured in units of watts) and reactive power (measured in units of volt-ampere reactive, or var). See also V*ar* and *Watt.*

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

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

Mills/kWh – Mills per kilowatt-hour.

Normal Operation – When all customers receive the power they are entitled to without interruption and at steady voltage, and no element of the transmission system is loaded beyond its continuous rating.

Outage – The disconnection of a transmission component: for example, by a lightning strike or contact between two conductors**.**

Path Rating – The maximum amount of power that can be reliably transmitted over an electrical path (which may consist of multiple transmission lines) under the best set of conditions. Path ratings are defined and specified in the WECC Path Rating Catalog.

Publicly Owned Utility – A municipal utility, irrigation district, or federal power marketer. Examples include the Sacramento Municipal Utility District, the Imperial Irrigation District, and the Western Area Power Administration.

Reactive Support – Reactive power must be available at all load buses to prevent voltage collapse. Reactive power is provided by generating plants, capacitors, and static var compensators.

Reconductoring –.A construction technique where existing conductors on a transmission line are replaced with higher capacity conductors. Depending on the strength of existing towers or poles they may be modified or replaced. Additional towers and poles may also be installed.

Reliability – The degree of performance of the elements of the bulk electric system when electricity is delivered to customers within accepted standards and in the amounts desired. May be measured by the frequency, duration, and magnitude of adverse effects upon the electric supply.

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

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

Remedial Action Scheme – An automatic control that decreases a generating plant's output or trips a generating unit (see Special Protection System).

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

Series Capacitor – A static electrical device that is connected in-line with a transmission circuit that allows for higher power transfer capability by reducing the circuit's overall impedance.

Special Protection System – An automatic control that decreases a generating plant's output or trips a generating unit.

Strategic Plan – Senate Bill 1565, Chapter 692, Statutes of 2004, Bowen, which added section 25324 to the Public Resources Code, requires that the Energy Commission adopt a strategic transmission investment plan for the state's electric transmission grid in consultation with the CPUC, CA ISO, transmission owners, users, and consumers. The legislation requires that the Energy Commission include the Strategic Plan in its *2005 Energy Report*, to be adopted November 1, 2005.

Var – Volt-ampere reactive (var) is a measure of reactive power which is not capable of doing work but must be present in an alternative current circuit to operate certain types of equipment, especially electric motors.

Volt – A unit of electromotive force required to drive a steady current of one ampere through a resistance of one ohm. Power flows on a transmission line because there is a difference in voltage between the two ends of the line.

Voltage Collapse – The point at which the reactive demand at a substation bus exceeds the reactive supply at that bus. When the reactive demand is greater than the supply, the voltage at that point in the system will decrease. Eventually, the voltage will drop to a point at which it is no longer possible to serve load at that bus.

Voltage Limits – The established voltage minimum below which voltage collapse may occur.

Watt – The basic unit of measure of real electric power, or rate of doing electric work.

WECC – One of ten regional councils of the North American Electric Reliability Council. Its service territory includes the provinces of Alberta and British Columbia, the northern portion of Baja California, and all or portions of the 14 western states. It is responsible for coordinating and promoting electric system reliability in the Western Interconnection, as well as supporting efficient competitive power markets, assuring open and non-discriminatory transmission access among its members and providing a forum for resolving transmission access disputes and an environment for coordinating the operating and planning activities of its members.

ACRONYMS

AC – Alternating Current

AFC – Application For Certification

ALJ – Administrative Law Judge

BEP – Blythe Energy Project

BEP II – Blythe Energy Project II

BEPTL – Blythe Energy Project Transmission Line

BPA – Bonneville Power Administration

CA ISO – California Independent System Operator

CBC – California Biodiversity Council

CC – Combined Cycle

CEERT – Center for Energy Efficiency and Renewable Technologies

CEQA – California Environmental Quality Act

CERTS – Consortium of Electric Reliability Technology Solutions

CHP – Combined Heat and Power

CMTA – California Manufacturers and Technology Association

CPA – Consumer Power and Conservation Financing Authority

CPCN – Certificate of Public Convenience and Necessity

CPUC – California Public Utilities Commission

CSP – Concentrating Solar Power

CT – Combustion Turbine

DC – Direct Current

DG – Distributed Generation

DOE – U.S. Department of Energy

DSM – Demand-Side Management

DSW – Desert Southwest

DSWTP - Desert Southwest Transmission Project

DWR – California Department of Water Resources

EAP – Energy Action Plan

EHV – Extra High Voltage

EIPP – Eastern Integrated Phasor Project

EIS – Environmental Impact Statement

EIR – Environmental Impact Report

EMF – Electric and Magnetic Fields

EMS – Energy Management System

EPRI – Electric Power Research Institute

ER – Energy Report

FCL – Fault Current Limiter

FEIS – Final Environmental Impact Statement

FERC – Federal Energy Regulatory Commission

GIS – Geographic Information System

GO – General Order

IID – Imperial Irrigation District

IOU - Investor-owned Utility

kV – Kilovolt

kWh – Kilowatt-hour

LADWP – Los Angeles Department of Water and Power

LE – London Economics International LLC

LEAPS - Lake Elsinore Advanced Pumped Storage

LMP – Locational Marginal Price

LOLP – Loss of Load Probability

LRA – Local Reliability Area

LSPA – L.S. Power Associates

Mills/kWh – Mills per kilowatt-hour

MP – Mountain Pacific

MSW – Municipal Solid Waste

MW - Megawatt

MWh – Megawatt hour

NEPA – National Environmental Protection Act

NERC – North American Electric Reliability Council

OII – Order Instituting Investigation

OIR – Order Instituting Rulemaking

O&M – Operation and Maintenance

OMPPTP – Otay Mesa Power Plant Transmission Project

ORA – Office of Ratepayer Advocates

OTC – Operation Transfer Capability

PAC – Policy Advisory Committee

PACT – Planning Alternative Corridors for Transmission

PEER – Pacific Earthquake Engineering Research

PG&E – Pacific Gas and Electric

PIER – Public Interest Energy Research

PHFU – Plant Held for Future Use

PMU – Phasor Measurement Unit

PNW – Pacific Northwest

PTC – Permit To Construct

PRC – Public Resources Code

PV - Photovoltaic

PVD1 – Palo Verde-Devers 500 kV line

PVD2 – Palo Verde-Devers No. 2 500 kV line

PWG – Planning Work Group

R&D – Research and Development

RMATS – Rocky Mountain Area Transmission Study

RMR – Reliability Must Run

ROW – Right-of-Way

RPS – Renewables Portfolio Standard

RTO – Regional Transmission Organization

RTR – Real-time Ratings

RTSO – Real-time System Operations

SANDAG – San Diego Association of Governments

SB – Senate Bill

SCADA – Supervisory Control and Data Acquisition

SCE – Southern California Edison

SDG&E – San Diego Gas and Electric

SEC – Sutter Energy Center

SSG-WI – Seams Study Group – Western Interconnection

STEP – Southwest Transmission Expansion Plan

SVA – Strategic Value Analysis

SWIP – Southwest Intertie Project

TEAM – Transmission Economic Assessment Methodology

TRP – Transmission Research Program

UCAN – Utility Consumers' Action Network

WAG – Western Assessment Group

WECC – Western Electricity Coordinating Council

Western – Western Area Power Administration

WGA – Western Governors' Association

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APPENDIX A: PROPOSED CRITERIA FOR EVALUATION OF TRANSMISSION AND ALTERNATIVE RESOURCES

Executive Summary

Introduction

Developing and maintaining a highly reliable electric transmission infrastructure that promotes a competitive and efficient electricity market is critical for the state of California. Although significant new generation has been built in California during the last 20 years, considerably less new transmission capacity has been added.

Historically, transmission additions have been justified on the basis of reliability, or economic reasons, or both. Most of the transmission additions in California during the last 20 years have been justified using reliability as the basis. Of the 17 transmission projects approved by the CA ISO since the beginning of 2000, only five have been justified for economic reasons.[1] The concept of reliability upgrades is well understood, and standardized methods for assessing reliability needs and alternatives exist, and are well accepted.

Procedures for identifying and calculating economic benefits for transmission additions are not standardized, defined, or accepted as well as reliability benefits. New or improved transmission can result in benefits that are actually broader than just economic or least-cost criteria. They can include benefits outside the scope of the well-defined reliability needs established by regional and national reliability councils such as reducing risk and minimizing environmental impact.

The purpose of this report is to recommend resource evaluation criteria that can be used to evaluate potential transmission expansions and other resource alternatives.

Minimum Requirements

There are important resource criteria that have already been adopted as part of federal, state, and local, laws and policies. For purposes of this report, these criteria are considered “minimum requirements” and include resource requirements such as accepted reliability standards, minimum levels of energy efficiency and renewable energy, resource adequacy, and others. The concept of “environmental justice” is also considered a minimum requirement since it has been adopted at the federal, state, and local level. Resources additions that are included in portfolios to meet one or more of these minimum requirements are not considered optional and are, therefore, not modified as alternative resource portfolios are evaluated.

Stakeholder Criteria

There are numerous parties affected by the operation of the California electricity market. These parties have an interest in any decision that affects either the market structure or the composition of the underlying resource infrastructure. They are called stakeholders. In order to develop resource criteria that appropriately consider the priorities of these stakeholders, a diverse group of participants were surveyed. They included the following:

- Consumer groups
- CPUC, CA ISO
- Environmental groups
- Independent energy producers
- Investor-owned and municipal utilities
- Renewables groups
- Transmission owners

In total, 22 different groups and approximately 30 individuals were interviewed regarding their perspective on resource planning criteria. These groups are listed in Attachment 1. The criteria they suggested fell into one of the following four general categories:

- Reliability
- Least-Cost
- Environmental
- Risk

Reliability

The stakeholder-suggested reliability criteria are focused on those issues which are not already considered part of a reliability justification study or as a minimum requirement. These criteria include reducing the cost of energy-not-served in the market simulation study, reducing reliability-related payments to California generators, or increasing homeland security. The homeland security concern became much more significant after the September 11, 2001, New York City attack. It focuses on whether transmission facilities can be sited in such a way as to reduce the likelihood and impact of a potential terrorist attack to the electric grid.

Least-Cost

The least-cost criteria suggested by the various stakeholders are considerably more extensive than the reliability criteria. Suggested criteria ranged from traditional least-cost integrated resource planning to alternative perspectives of least-cost (e.g., generator profits from uncompetitive market conditions being excluded from consideration). Efficiency of the California electric market is considered an important criterion by some stakeholders. Market efficiency can be measured by evaluating the overall market prices compared to the underlying marginal costs or by comparing total magnitude of imports and exports as a measure of achievement of the goal of having seamless regional markets).

Other stakeholder-suggested criteria included in the least cost category that include a consideration of the impact on the capital budget for the next two, five, or ten years (from a rate stabilization perspective). Also, several least-cost criteria, such as market valuation and portfolio fit , were suggested for evaluating a single resource options, although they are less important in comparing extensive long-term resource portfolios.

Risk

The concept of measuring and comparing risk for resource alternatives or portfolios has been extensively developed in the 10 to 15 years. The criteria suggested by the stakeholders under the general classification of risk include financial portfolio concepts such as Value at Risk, Cash Flow at Risk, To Expiration Value at Risk, as well as others. More basic applications of portfolio risk include concepts such as "risk of extreme outcome" (i.e. the difference between the expected and average of a set of pre-specified worse cases). Several stakeholders with strong renewable or environmental preferences suggested a simple "pie chart" illustrating the fuel or resource type was a valuable indicator of potential risk.

Other stakeholder-suggested risk criteria focused on the risk caused by the possible occurrence of specific types of events such as CO_2 regulation, political feasibility of portfolio implementation, or impact of market paradigm changes. Other suggested criteria dealt with project feasibility including credit, cost overrun, and scheduling risks.

Environmental

The stakeholder-suggested environmental criteria demonstrated their priorities for cleaner air, greater amounts of renewable resources, less dependence on fossil fuels, a more efficient use of limited clean water sources, and a reduction in environmental and visual impacts of new transmission lines. In addition, some individuals indicated their strong desire for the federal and state government and local utilities to more fully comply with the provisions of "environmental justice laws" which protect minorities from an inequitable amount of pollution from electric facilities.

The specific resource evaluation criteria suggested by the 22 stakeholder groups are contained in Attachment 2.

Recommendations

There are six evaluation criteria believed important for resource evaluation purposes. The six recommended criteria are:

- Least-Cost
- Risk
- Reliability
- Market Efficiency
- Fuel Diversity
- Resource Flexibility

Many resource planners contend that the overall goal should be to develop a least-cost resource portfolio subject to a tolerable risk level. In other words, the two most important criteria are clearly least-cost and risk. Since many of the direct costs (e.g. environmental impacts, reliability payments, etc.) can now be considered in a comprehensive least-cost framework, it is necessary that the least-cost and risk criteria be included in some rational manner in evaluating resource strategies or extensive portfolios.

The least-cost analytical approach can be better specified by the planner performing an actual case study rather than applying a generic proscriptive formula developed without reference to the specifics of the case. The least-cost framework should identify the perspective(s) that will be considered (societal, state, consumer, generator, etc.) and be based on a present-value calculation of the benefits and costs over the assumed economic life of the project or portfolio.

The measurement of risk is also best left to the person performing the evaluation. The risk calculation can be statistically sophisticated and computationally demanding, or it may as simple as defining a standard risk index based on an "average worst case". The risk assessment needs to quantitatively consider those variables that can be defined and will have a substantial impact on the results. However, the risk assessment should also include a qualitative evaluation of those risk factors that cannot be easily quantified, such as the unknown impacts of a new market structure.

Beyond the least-cost and risk criteria, any of the other criteria that differ significantly between alternative resource strategies or portfolios should be considered. Since this approach would include almost all the stakeholder-suggested resource evaluation criteria, a few comprehensive "standard" criteria are recommended to be used for most evaluations. These other criteria include:

Reliability – Identify any significant reliability impacts that are not specifically required by existing reliability standards or easily quantified. For example, suppose two alternatives for transmission to San Francisco were being considered. One used the existing peninsula corridor, and the other was a type of trans-bay cable. The second corridor many not be required to meet existing reliability standards nor may it be quantified in traditional economic benefits analysis. However, since the alternative paths may provide differing levels of reliability, the reliability benefit of each should be identified and qualitatively considered.

Market Efficiency – Market power is a significant concern for the California consumer. The total benefit calculation of a proposed transmission or generation upgrade does not identify the "winners" and "losers". A proposed project that has high positive total benefits may not benefit the individual consumer in a manner desired by state policy makers. Therefore, a simple computation of market efficiency can be a valuable indicator of the relative advantage of one particular resource portfolio when compared to another.

Fuel Diversity – In a rigorous risk assessment that includes a full stochastic treatment of all fuels and related variables, a high-level summary of fuel diversity would not be necessary. However, since it is likely that this level of risk analysis is beyond the available capabilities and time of most entities engaged in resource planning, a simple, high-level summary comparison of fuels utilized to meet consumer load can be valuable in evaluating risk. Fuel diversity is an indicator of overall portfolio risk and can be used to identify future dependence on fossil fuels and associated amounts of airborne pollutants. For these reasons, it is recommended that a fuel diversity summary be prepared for each resource scenario.

Resource Flexibility – As a resource evaluation parameter, resource flexibility does not mean operational flexibility, but rather it examines the resource or portfolio's flexibility to vary the timing and amount of commitments of significant capital funds. For example, assume that two transmission alternatives have identical benefits and costs. However, one requires a full commitment of capital funds at the beginning of the permitting phase, and the other allows for some "stepping-off" milestones. Clearly, the second alternative would be preferred due to the flexibility in the timing of decision making. The "resource flexibility" evaluation criterion is used in this context in this report, and can be employed to qualitatively value the difference in commitment of capital funds.

In summary, the criteria recommended in this report for the evaluation of transmission, generation, and demand-side resource alternatives are not intended to be viewed as already established and inflexible. Rather, they are suggested as a standard that can be reduced or expanded upon depending on the judgment of the resource planner. The report is intended to provide the focus for a common starting point for all resource evaluation. The suggested approach is expected to evolve as better methodologies become available and practical in application. In the meantime, it is hoped that this set of resource evaluation criteria can be used to better plan for the critical changes in the generation and transmission infrastructure needed to ensure a robust and efficient California electricity market.

Introduction

The purpose of this report is to recommend a set of specific criteria to be used in evaluating generation, transmission and demand-side resource alternatives. Planning the best combination of resources to meet its customers' needs has traditionally been the task of the serving utility with oversight by state and local regulatory agencies. Often, all planning was accomplished by the same resource or power system planning department. The nature of this task changed significantly for many utilities when the FERC issued Order 888, requiring utilities to offer non-discriminatory transmission access. One practical result of FERC's ordering open access is that it generally required utilities to consider themselves as operating separate generation and transmission companies. This was followed by additional load and generation disaggregation fostered by the state's deregulation statute AB 1890. The CA ISO, merchant generation, trading companies and energy service providers were added to the planning mix.

Today, there is a lack of consistent integrated transmission and resource planning in the state of California. Each technical area has developed its own criteria, planning cycle, and process. The purpose of this study is to identify whether there are some basic criteria, acceptable to the full range of stakeholders, which can form the core criteria upon which all resource options are evaluated and compared.

The process for developing criteria to evaluate resource alternatives such as transmission, generation and demand-side programs on an equal basis included:

- Identifying a diverse group of stakeholders throughout California that are involved in, or directly affected by, the California electricity market.
- Surveying these stakeholders to identify their preferences for appropriate evaluation criteria.
- Determining what set of available criteria provide the best and most comprehensive information on which to base resource decisions, and recommending a set of specific criteria to use in all future evaluations.

The goal of this process is twofold: (a) to advance, improve and standardize the methodology for evaluating transmission and other resource alternatives; and, (b) increase the transparency and understandability of evaluation findings for the general public.

The paper first reviews minimum requirements which must be part of any California resource assessment. It then describes and assesses potential evaluation criteria, as suggested by the interviewed stakeholders. Finally, it recommends proposed broad-based criteria. More detail is contained in the Attachments.

Current Minimum Requirements

Various national, regional, state, and local authorities have made decisions and implemented policies establishing a minimum level of reliability for electric systems and the preferred resource types and amounts of each to be used in meeting customer demand. The resource standards that these authorities generally consider to be "minimum requirements" can be categorized as follows:

- Reliability
- Energy Efficiency
- Demand Response
- Renewable Resources
- Distributed Generation
- Qualifying Facilities
- Resource Adequacy

When planning additions or enhancements to an electrical system, these minimum requirements must be met regardless of the resource strategy or project being evaluated. Any new resource mix must also meet all environmental, public health and safety regulations and comply with applicable existing law. While these minimum requirements affect the evaluation, the planning process considers them as givens rather than variables. The usual practice is not to reevaluate these prior policies and reliability decisions in the assessment. Attempting to reevaluate and potentially recommend changes to existing policy is left to other forums.

A brief summary of these minimum requirements can help to describe one, of many sets, of constraints that affect the choices resource planners can make.

> ***Reliability –*** The North American Electric Reliability Council (NERC) has the mission to ensure that the bulk electric system in North America is "reliable, adequate, and secure".[2] NERC is divided into 10 reliability regions. California is in the WECC, which covers all fourteen of the western states, the Canadian provinces of Alberta and British Columbia, and the northern portion of Baja, Mexico. Throughout the NERC, utilities and other entities voluntarily enter into contracts to abide by reliability criteria. Violations can result in monetary penalties. NERC and WECC establish "reliability requirements" for the purpose of planning and operating the interconnected system during normal and defined-abnormal events.[3]
>
> In California, the CA ISO is also responsible for ensuring the "reliable operation of the transmission grid consistent with achievement of planning and operating reserve criteria…".[4] The CA ISO has established additional reliability criteria for the share of the California market under its control, specifically for local area reliability and reduction in transmission congestion.[5]
>
> Investor-owned or municipal utilities can also adopt additional reliability criteria for their utility service area or a particular local area within their

territory. As an example, the LADWP bases its long-term planning reserves requirements on the annual hourly peak with an 1-in-10-year expectation of occurrence, instead of the more common and less conservative 1-in-2-year expectation.[6]

These NERC, WECC, CA ISO, and utility reliability standards are considered "minimum requirements" for the purpose of this report.

Energy Efficiency – For many years, a top priority of the state of California has been to maximize the amount of participation in economic energy efficiency programs by energy consumers. For the IOUs, electric savings from energy efficiency programs are funded by ratepayers through a public goods charge (PGC) and through procurement rates. In a September 23, 2004 decision, the CPUC indicated that the IOUs are expected to capture 70 percent of the energy efficiency "economic potential" for the period 2004-2013. Between 2004 and 2013, these efforts are anticipated to meet almost 60 percent of the incremental electric energy needs.[7] This policy is reinforced in D.04-12-048 which requires the IOUs to meet or exceed the Commission's energy efficiency goals over the next ten years and specifically over the next energy efficiency program funding cycle (2006-2008). As the goals are updated, IOUs are to incorporate the most recently adopted goals into their resource planning efforts. In a similar manner, aggressive energy efficiency goals have been established and are being implemented by California municipals.

Demand Response – Demand response is used to reduce demand when energy prices are high or supplies are tight. The two general types of demand-response programs are "price-responsive" and "reliability-triggered" programs. In price-responsive programs, customers respond to the price of energy and implement load reductions when prices rise. In reliability-triggered programs, customers agree to reduce their load when directed by the IOU, municipal or by the CA ISO in exchange for an incentive. The CPUC initiated development of large-scale demand response programs in June 2003. For the IOUs, the 2005 goal was to meet 4 percent of the annual system peak load with demand-response programs in 2006, and 5 percent in 2007 and thereafter.[8] Deployment tests in 2004 have indicated that new program designs will be needed to meet these goals. In Decision 05-01-056, released in January 2005, the CPUC revised the definition to allow MWs "from any program that provides a day-ahead demand reduction signal, whether it is based on a price, temperature, or reliability forecast, to count towards meeting the utilities' price responsive demand program goals adopted in D.03-06-032 and D.04-12-048."[9] This most recent definition draws a line between day-of and day-ahead demand response. Its reasoning is that the purpose of day-of demand response is to support immediate system reliability. For procurement purposes, such demand response is accounted for separately.

Renewable Resources – RPS are state policies mandating that a specific percentage of the total generation mix come from resources that are defined as "renewable". This definition includes solar, wind, geothermal, biomass, and small hydro. California's RPS requires that the load-serving entities increase their renewable energy amount by at least 1 percent per year, achieving 20 percent by 2017 at the latest.[10] California's IOUs have committed to meeting the state standard more rapidly, achieving 20 percent by 2010. California municipal utilities have set similar renewable portfolio standards. As an example, the Sacramento Municipal Utility District (SMUD) has set a goal of achieving the 20 percent target by 2011.

***Distributed Generation* –** Distributed energy resources are small-scale power plants (usually in the range of 3 to 10,000 kW) that are located close to where the electricity is used. Distributed generation can provide incremental capacity to the electric grid. In some instances, it can avoid or reduce the cost of transmission and distribution upgrades.[11] One of the California EAP's goals is to "promote customer and utility owned distributed generation".[12] At this point, the plan contains no specific goals for the utilities regarding the amount and timing of distributed generation. It is possible that these goals could be established in the future.

***Qualifying Facilities* –** Qualifying Facilities (QFs) are independent co-generators or power producers that often generate from renewable or alternative resources. By federal law, a qualifying facility that meets specific operating, efficiency, and fuel-use standards, has the right to sell to the IOUs under long-term contracts at avoided-cost rates.[13] The Energy Commission estimated that there is approximately 5,567 MW of Qualifying Facility dependable capacity in California in 2005.[14] Long-term policy for expiring QF contracts, including pricing terms, is currently under consideration at the CPUC, with a decision expected in late 2005.

***Resource Adequacy* –** Resource adequacy is often considered a part of the planning reliability requirements briefly described on the previous page. The purpose of resource adequacy is to ensure that sufficient resources exist to meet defined contingencies such as generator or transmission outages or load forecast uncertainty. The CPUC has adopted a planning reserve margin of 15 to 17 percent of load for the IOUs. It is in the process of developing the implementation rules. The planning reserve margin is expected to be fully implemented by 2006. Of this capacity reserve, 90 percent must be acquired one year in advance.[15]

There are other resource standards or "minimum requirements" that exist today that are not summarized above. There will undoubtedly be additional minimum requirements established in the future. The purpose of this section of the report is, not to provide a comprehensive list of all current and future resource standards, but to illustrate the concept of “minimum requirements” and provide examples of criteria that fit into that category. For purposes of future strategic resource planning, these resource standards are considered established. All resource strategies proposed will be structured to meet these minimum requirements.

Stakeholder-Suggested Criteria

There are many parties that are impacted by the operation of the California electricity market. These parties have an interest in any decision that affects how the market is structured or the underlying resource infrastructure. They are called stakeholders. In order to develop resource criteria that appropriately considers the priorities of these stakeholders, we have surveyed a diverse group of participants including the following:

- Investor-owned and municipal utilities
- CPUC, CA ISO
- Environmental groups
- Renewable groups
- Independent energy producers
- Transmission owners
- Consumer groups

Attachment 1 presents a list of these participants. In total, 22 different groups or organizations were interviewed and asked what criteria they considered appropriate. The stakeholders suggested criteria that ranged from the traditional (least-cost), to more recent concepts (e.g., portfolio fit). We found that the stakeholder-suggested resource evaluation criteria could be classified into the following four general categories:

- Reliability
- Least-Cost
- Environmental
- Risk

There are two requirements for a resource evaluation criterion. First, the criterion needs to be applicable to state-wide resource planning. Although all of the information received from the stakeholders was interesting, not all of the feedback pertained specifically to criteria suitable for state-wide resource evaluation. That information was recorded, but not included in this report.

Second, the criterion is most valuable if it can be used to measure or assess the impact of a resource decision in some consistent standard way. These measurements can be quantitative in nature using a specific mathematical methodology. On the other hand, the measurements may be qualitative (if quantitative measurements are not applicable, or developed sufficiently, such as perceived “public acceptance” of a particular resource strategy). In some cases, a stakeholder suggested a criterion that, when applied, would provide valuable information. However, because it could not be used to evaluate all alternative resource plans in a standard, objective manner, that criterion did not prove valuable for our current purpose and therefore was not included in the list.

In this section of the report, we summarize and review the suggested evaluation criteria based on the four categories listed above. In the following section, we make recommendations regarding the evaluation criteria.

Reliability

Reliability is a critical consideration for any resource strategy. It can be measured in a variety of ways in an electric system.

Un-served Energy

In a chronological market simulation model, one measurement of reliability is the amount of energy that cannot be delivered to the customer due to generation or transmission limitations or outages. This amount is referred to as “un-served energy”.

One way to compare the overall reliability of alternative resource portfolios is to compute and compare the un-served energy for each scenario. This criterion is a traditional measurement of reliability and was suggested by several stakeholders. Another stakeholder suggested that the persistence of un-served energy within a zone or location would also be a valuable indicator of reliability.

There are several arguments, however, against using un-served energy as a reliability criterion. First, some will contend that, if an appropriately high unit cost for un-served energy is used in the market simulation, ($/MWh), the total cost of un-served energy (millions of $) is really a part of the direct cost of energy that is already being calculated by the simulation model. Computing a separate cost of un-served energy in the simulation and considering it as a reliability criterion, would be, in essence, double-counting its impact.

Second, in most simulations, if the resources and load are in approximate balance, there is very little or no un-served energy calculated. In the CA ISO market simulations demonstrating their Transmission Economic Assessment Methodology (TEAM), the model calculated no un-served energy except for two areas in Canada where hydro generation had not been completely optimized. This same phenomenon occurred in the CA ISO’s Palo Verde-Devers No. 2 feasibility study. There was no un-served energy except in Canada. Therefore, if the criterion is conceptually valuable, but simulations do not produce results that allow significant differentiation among alternative resource plans, some stakeholders have suggested that the criterion is not valuable for comparative evaluation.

Consumers' experience, however, has been that un-served energy does occur and results in a high cost to them. Thus, one might contend, the measurement of un-served energy is not truly reflective of outages the consumer might experience. This seems to be an accurate assessment. There are several reasons for this situation. First, the calculation of un-served energy often does not take into account distribution outages, perhaps the largest cause of consumer outages. A market simulation model includes specific logic dealing with generation and transmission operation. It does not specifically model the distribution system due to the overwhelming complexity of detail such a model would require. Second, many simulation models do not include transmission outages, either due to the lack of available input data, or simply the program's ability to model such outages. Third, the critical interrelationship between multiple transmission and generation outages has not explicitly been solved. And fourth, most models assume a "perfect foresight" with respect to future loads. This sometimes overstates a system's actual ability to respond to weather and load fluctuations.

Reduction in Reliability Payments

The CA ISO makes significant operational payments to ensure that an acceptable level of reliability is achieved. These reliability payments include the following:

- Minimum Load Cost Compensation (MLCC) – Payments to generators that are kept at their minimum capacity in order to protect against major generation and transmission outages. In 2004, the total MLCC payments were $290 million.[16]

- Reliability Must Run (RMR) – Payments to generators to ensure their availability for reliability purposes when the CA ISO calls upon them. The total RMR payments in 2004 were $650 million.[17]

Although the above-listed costs are significant, a goal or criterion of minimizing these and other reliability payments by themselves would not be appropriate since they are only part of the total system costs. These and other relevant reliability costs should be included in the overall objective of minimizing total system costs. This is true whether the reliability costs are directly computed in the simulation, or are derived separately and included as a post-processing operation.

Minimize Potential Terrorist Consequences

Since September 11, 2001, minimizing the likelihood and consequences of terrorist attacks on the national electric grid has been a high priority. The NERC has been tasked by the federal government to coordinate critical infrastructure protection from physical and cyber attacks. The NERC has the responsibility to "develop a plan to reduce electric system vulnerabilities."[18]

NERC has developed security guidelines to assist each utility in developing a comprehensive "Vulnerability and Risk Assessment". The guidelines are contained in a document providing a structured risk assessment methodology prepared by subject matter experts. The methodology includes:[19]

- Identification of assets and loss impacts.
- Identification and analysis of vulnerabilities.
- Assessment of risk and the determination of priorities for the protection of critical assets.
- Identification of countermeasures, their costs and trade-offs.

A similar type of vulnerability and risk assessment could theoretically be developed at the appropriate state or regional level to subjectively evaluate alternative resources or portfolios. The criterion of minimizing potential terrorist consequences could then be measured by using an appropriate risk assessment methodology.

Qualitative assessments of differences in reliability levels can currently be made for those reliability impacts that are not mandated by reliability criteria or included as a portion of the un-served energy costs. Further research into modeling transmission and generation outages in a statistically-relevant manner is also warranted.

Least Cost

A traditional methodology for evaluating resource alternatives or portfolios is comparing resource options based on direct costs. Direct costs can be defined in a number of ways: total system cost, revenue requirements, average consumer bill, or average system rate. These "least-cost" definitions can be used to evaluate transmission, energy efficiency, demand-response programs, renewable resources, distributed generation, and central-station thermal generation alternatives.

The direct costs calculated must be comprehensive enough to include all cost components that may change between resource scenarios. These "least-cost" definitions are traditional measurements that have been well-established in industry literature and in regulatory proceedings. Since the traditional least-cost evaluation criteria are so well-known and accepted, this report does not define the criteria in greater detail. (For further information, see the CPUC definitions of cost components.)

In addition to the multiple ways that least cost can be defined, there are also different perspectives on how to interpret it. These perspectives answer the question of "least cost to whom". Traditional perspectives include those based on geography (societal, sub-region, state, local area, or utility), or type of market participant (generator, transmission owner, and consumer, or a combination). Thus, when a least-cost methodology is used as a criterion to evaluate a resource portfolio, three parameters should be used to establish its application: (a) least-cost definition; (b) geography; and, (c) market participant.

There have been several "enhancements" to the traditional least-cost methodology over the years. One enhancement is the inclusion of bidding strategies instead of simply using marginal costs to forecast energy prices. Another update is the computation of an “expected value” based on many alternative cases, instead of a single base case.

Several additional enhancements to the least-cost methodology or criteria have been suggested by various stakeholders during the survey portion of this assignment. They are summarized below.

> ***“Modified” Tests –*** The CA ISO evaluates the economic feasibility of potential transmission upgrades by computing the benefits of the upgrade from three perspectives – WECC, CA ISO ratepayer, and CA ISO participant. All three of these perspectives are termed as “modified”, in that generator benefit derived from monopoly profits (non-competitive prices) is excluded from the benefits calculation. This methodology appears to be unique to the CA ISO, since other stakeholders surveyed do not exclude any generator profits from the project benefits.[20]
>
> From the CA ISO’s perspective, if the consumer and producer benefits are equally weighted, then the transfer of monopoly profits from the generator to the consumer nets to zero, since the total benefits remain the same. According to the CA ISO:[21]
>
> > “To the extent that policy makers believe there is value in transferring supplier monopoly profits to consumer surplus, the modified societal perspective will be a more appropriate measure of a transmission upgrade than the pure societal test.”
>
> The CA ISO concludes that not all economists agree with this approach. However, the CA ISO provides both the unmodified as well as the modified tests so that policy makers can decide the more appropriate methodology to consider on a case-by-case basis.[22]
>
> ***Market Valuation*** – A common approach for measuring economic viability is determining the value of a resource by comparing its benefits (determined by using market prices) against its projected costs. Market value is based on valuing the resource’s energy, capacity, and ancillary service capabilities against a forward market curve or forecast of market prices. The market price forecast needs to extend throughout the assumed economic life of the resource. This could be 20 years or more. PG&E and SCE are relying on “market valuation” as one of their primary evaluation criteria in their “Long Term Request For Offers” released earlier this year.[23]
>
> One potential limitation of the market valuation approach is that it is more suited for a single resource or small resource portfolio than a major generation station or transmission line. The larger the size of the project or portfolio of projects, the more likely it will affect market prices, thus limiting the

validity of a static market price forecast calculated independently of the proposed resource additions.

Portfolio Fit – The value of a resource is affectec by its ability to complement or fit into the existing resource portfolio. If a particular resource portfolio is already surplus with must-run resources or must-take contracts, the value of additional energy is less valuable than it would be to a portfolio where resource constraints result in an energy-deficit period. The concept of portfolio fit is expected to be used in both SCE's and PG&E's current long-term power procurements. Portfolio fit applies to energy, capacity, and ancillary services and has both a temporal (time) and locational aspect. According to the PG&E Request For Offer (RFO):[24]

> "Portfolio fit thereby weighs a (resource's) costs and benefits in the context of (the system's) portfolio needs. In contrast, the market valuation component considers a (resource's) costs and benefits without taking into account (the system's) portfolio needs."

Portfolio fit is a valuable tool for company-specific, short- and mid-term resource evaluation. At a state-wide level, and for the evaluation of 20-plus year resources, the portfolio fit measurement may have some limitations. For example, from a state-wide perspective, the long-term portfolios may require significant new resources. Hence, there is much greater freedom in terms of acquiring and fitting new preferred resources in the long-run, and at a state level, than there may be in the short- to mid-term at the company level.

Infrastructure Investments – Some energy resources may be economically attractive, but have high initial capital costs (such as a central-station base-load generation station or a major transmission line). These capital intensive projects, with front-loaded cash flows, can result in higher rates for the first few years compared to other alternatives. For most utilities, and particularly for many of the state's municipally owned utilities, rate increases can be highly undesirable. Thus, load-serving entities may have restrictions on the amount of capital they are willing to invest in infrastructure over a 1, 5, or 10 year period. They evaluate alternative resource plans based on several factors including the associated capital requirements. A resource plan with a relatively high capital budget may be viewed as less preferable than one with equivalent lifecycle costs and risk, but with lower initial capital requirements.

Market Competition – Part of the mission of the CA ISO is to ensure that there is a competitive market for electricity in California.[25] It is important to the CA ISO and other stakeholders that resource futures be evaluated with respect to their anticipated potential for allowing the exercise of market power (i.e., when a market participant has the ability to affect market prices and cause them to be significantly greater than the competitive energy price level).

One method of understanding this potential for market power is to compare the forecast market prices to the underlying marginal costs. This approach is only valid if the market prices provide a reasonable picture of the bid strategies potentially employed by generators to maximize their profit. The bid strategies in the market simulation model must be designed so they are generator-owner specific and are "dynamic" (i.e. the bid strategies can change hourly depending on system conditions and perceived market power).

A major transmission upgrade can be very beneficial in this regard. A transmission expansion can allow a host of new, potential suppliers to compete for additional sales. On the other hand, a major generation project may not add significant new competition if the project is owned by one of the largest existing suppliers. And although the market prices do not generally have a significant impact on the societal benefits, the prices can have a major impact on benefits and costs to market participants including California consumers.[26]

Seamless Markets – The creation of an electricity market that is "seamless" with respect to trading and operating practices across the WECC is an important goal for the region. As a result of utility interest, the Seams Steering Group – Western Interconnection (SSG-WI) was founded with the mission of "facilitating the creation of a Seamless Western Market and for proposing resolutions for issues associated with differences in RTO (Regional Transmission Organization) practices and procedures."[27] For the CA ISO and other stakeholders, achieving a more seamless market is important to sustain a competitive and efficient California electric market.

Environmental

Generation and transmission resources can have a significant environmental impact. These impacts have been recognized for many years. In response to these environmental and other concerns, the state has developed policies for energy efficiency, renewable resources, and best available control technology. The current issues are not whether environmental impacts should factor prominently in the development of future resource plans, but which impacts can be quantitatively or qualitatively compared, and which ones are of the greatest concern to Californians.

This section presents and discusses stakeholder-suggested environmental evaluation criteria. Many of these "environmental" criteria cross over into the other evaluation criteria categories such as least cost and risk. They are discussed here since their primary impact is environmental.

Airborne Pollutants

Many stakeholders would likely agree with the Natural Resources Defense Council (NRDC) position on clean air and energy: "No element of the natural world is more essential to life than air, and no environmental task more critical than keeping it clean." According to the NRDC, electric generating plants are a major "source of air pollution and its myriad effects from lung damage to acid rain to global warming".[28]

In California, airborne emissions from generation plants that are of concern include:

- Carbon dioxide (CO_2)
- Carbon monoxide (CO)
- Nitrogen oxides (NO_x)
- Sulfur dioxide (SO_2)
- Particulates (PM_x)

These airborne emissions can be directly modeled in a detailed market simulation analysis provided reasonable data are available. The data required include emission rates for individual generation units (or composite rates for stations), and a cost (or range of costs) for each emission (generally specified in terms such as dollars per ton of emission emitted). The challenge is finding and acquiring the appropriate data. This is particularly true for CO_2 and other emissions which are of regional concern; for them, the outputs of all generation sources in WECC should be considered.

Aside from the difficulties inherent in modeling emissions and costs, some stakeholders have suggested that emissions, by themselves, do not represent evaluation criteria. Rather, emissions have a cost associated with them that should be considered directly in the least-cost and risk criteria. Minimizing emissions beyond the point of recognizing their true societal costs, according to these stakeholders, is a form of double-counting and is not necessary or appropriate.

Water Cooling

According to the California Energy Commission, water use for power plant cooling can cause significant impacts on local water supplies. Since 1996, an increasing amount of new power plants have been sited in areas with limited fresh water supplies. Use of fresh water for power plant cooling is increasing significantly. Fresh water use can be reduced by the use of recycled water or degraded groundwater, alternative cooling technologies, and closed cooling systems. These alternatives to fresh, high-quality water used for "once-through cooling" are considered technically feasible and practical.[29]

Therefore, comparing the amount of fresh water required for plant cooling could be an important criterion for alternative statewide resource strategies. This calculation would most likely be a post-processing method where fresh water use per plant was estimated and summed with all other plants by local region and state.

Transmission Impact

Some of the most heated siting discussions in the last ten years have been regarding new transmission rights-of-way. As a result of public sensitivities, one large municipal utility has formally adopted a policy stating that they will maximize the use of their existing rights-of-way, before seeking to obtain new transmission rights-of-way.[30] In addition to public concerns about transmission line visual impacts, there are environmental concerns as well, such as migrating birds colliding with the towers and supporting wires.[31] Therefore, according to several stakeholders, the impact of a resource scenario involving new transmission lines should be evaluated and compared against alternative scenarios.

Amount of Renewable Resources

Most California utilities have already adopted specific RPS (see Section 2, Minimum Requirements, Renewable Resources). However, to the extent that a particular state-wide resource plan includes a greater level of renewable resources by a certain date than others could be an important distinguishing factor according to several stakeholders. As an example, the Energy Commission has asked the utilities as part of the *2005 Integrated Energy Policy Report* process to provide an "Accelerated Renewable Scenario" that has a longer-term goal of having 33 percent of their energy provided by renewable energy sources in 2020.[32] Some of the benefits of an increased level of renewable resources will be directly reflected in the least-cost and risk criteria (e.g., reduction in emission costs and greater fuel diversity). But not all benefits are captured in the modeling of direct costs (e.g., the use of greater level of "sustainable" fuels). If studies were completed to demonstrate the net costs and benefits of various fuel types, subsequent resource plans might be able to employ the resulting recommended percent of energy over the current renewable target as an important factor.

Fossil Fuel Dependency

The California League of Women Voters and other stakeholders have voiced a concern about reliance on fossil fuels, particularly oil and gas.[33] Their concern is that a continued dependence on fossil fuels increases airborne emissions, global warming, and rapid depletion of irreplaceable natural resources among other reasons. The Natural Resources Defense Council recommends that a simple pie chart showing California's annual energy requirement by production fuel type would be a valuable indicator of fossil-fuel dependency and fuel diversity.[34]

Environmental Justice

The concept of "environmental justice is that all people – regardless of color, income, national origin or race are able to enjoy an equal amount of environmental protection".[35] The United States instituted a federal environmental justice program in 1994.[36] The state of California adopted a similar environmental justice policy in 1999.[37]

The Bayview-Hunters Point neighborhood in San Francisco is a pertinent example of some of the issues regarding environmental justice. There are approximately 1,100 households living within one mile of PG&E's Hunters Point generating facility. Two-thirds of this population lives in low-income public housing. Of the 1,100 households, approximately 70 percent are African American, 15 percent Asian (primarily Chinese and South Pacific Islanders), and the remainder Hispanic or Caucasian.[38]

Since Hunters Point is expected to be completely retired by March 2006, the remaining units have not been retrofitted with the most effective airborne emission abatement equipment and are currently out of compliance for NOx.[39] In 2003, the average NOx emission rate was .0394 pounds per million Btu (lbs/mmbtu), about 10-20 times higher than in plants using best available control technology. The total NOx emissions in 2003 were about 60 tons.[40]

According to residents of Bayview-Hunters Point, "this low-income community of color" shoulders the burden of most of San Francisco's pollution. Over the years the health of local residents "has been heavily and disproportionately impacted by the cumulative impact of pollution from PG&E Hunters Point Power Plant" and other facilities. The residents conclude that this "small community has suffered more than fifty years of apathy, neglect, and environmental racism".[41] Thus, an evaluation criteria for alternative resource plans that measures either qualitatively or quantitatively how well the policy of "environmental justice" is being achieved, is an important consideration.

Risk

Perhaps the one area of resource planning that has evolved the most in the last 10 to 15 years is assessing the risk associated with alternative resource portfolios. In the early 1990s, a risk assessment typically consisted of developing a few discrete scenarios that would illustrate the impact of adverse outcomes (e.g. high load growth, high gas prices, low hydro, or individual segments of transmission lines being out of service for extended periods of time). In the early to mid-1990s, as utilities started to turn to the evolving wholesale energy market for their resource needs, more sophisticated and rigorous portfolio assessments (which had been used for years by commodity trading institutions) were implemented with various degrees of success.

Many traditional, and more recently-developed, ways of evaluating risk criteria were provided by the stakeholders interviewed for this report. These resource evaluation criteria and methodologies are summarized and described in this section.

Quantitative Portfolio Analysis

Portfolio analysis is generally used by financial traders to create robust portfolios that are "efficient" – that is, they maximize the expected return for any given level of risk. With respect to resource evaluation, portfolio-based techniques can be used to help compare and evaluate the relative cost and risk of alternative resource plans.[42]

In the mid 1990s, energy companies began to measure their risk by computing various risk measurements such as "Value at Risk" or VaR. Value at Risk is based on the probability distribution for a portfolio's market value. VaR indicates the maximum probable loss given a specified confidence factor. For example, if a portfolio has a one-year 90% VaR of $260 million, it can expect to lose less than $260 million 90 percent of the time.[43]

However, VaR is oriented towards active trading operations and values the portfolio at current market prices without regard to long-term price or operational risks. For longer-term resource portfolios that cannot be instantly liquidated, other risk management approaches such as “Cash Flow at Risk” (CFaR) or “Profit at Risk” (PaR) are often considered to be a better tool for measuring long-term risks. CFar and PaR have an advantage over VaR in that they incorporate energy price volatility and volume risks (i.e. amount of retail sales 10 years in the future).[44]

The CPUC has recommended that California utilities use “TeVaR (To Expiration Value At Risk), a type of VaR model, to measure and report risk . . . “.[45] Specifically, they recommend using TeVaR measured on a 12-month rolling basis, at a 99 percent confidence level, and state that the “risk reporting could cover a longer period if the if the utility entered (into) longer term transactions within the quarter”.[46]

These risk management techniques have significant value in that they systematically capture and measure many of the risk elements for a resource portfolio. The approaches, however, also have the limitation that they can be difficult to compute, data intensive, and do not represent all the risks that affect the value of a portfolio (e.g. changes in a wholesale market structure). For a more complete discussion of the application of portfolio theory to energy portfolios, please refer to Attachment 3.

Several stakeholders suggested that a VAR, CFaR, PaR, or TeVaR type of portfolio analysis would be the best way to evaluate the risk component of an energy portfolio. Others suggested that the computational and data requirements for such an intensive approach would be infeasible for most planning organizations, and suggested a more simplified approach.

This simpler approach treats selected variables stochastically (same as above) and derives a distribution of system costs, profits, etc. Then, it averages the lower 10 percent of the cases to derive an “average worse value” and computes the difference between the expected value or mean, and the average worse value. The greater this difference, the greater the risk. Alternative resource portfolios can be measured and compared on this basis. If hydro-produced energy is the largest variable, a company can simulate 100 years of hydrological conditions, average the worst 10 cases, and then subtract that value from the mean. This technique is popular in the Pacific Northwest where hydro energy is such a large part of the energy mix. If a gas price uncertainty statistic is available, then both hydro and gas prices are treated stochastically with the appropriate correlation indices. For this second group of stakeholders, this approach is easier to compute and to explain to their public.

Qualitative Portfolio Risk Evaluation

The stakeholders also suggested a number of methods to evaluate the risk of resource portfolio from a qualitative perspective. These suggestions included the following:

- Resource diversity
- Energy autonomy
- Portfolio or project flexibility
- Market risks
- Political feasibility

Resource diversity is similar to fuel diversity – it helps the decision maker to quickly recognize the level of generation diversity in the resource mix. It can also indicate overall dependency on fossil fuels and relative increases or decreases in airborne emissions. A resource diversity summary table is also a valuable tool to help the public understand significant differences between alternative resource portfolios or strategies.

Energy autonomy is another risk assessment that can be provided in a summary table or pie chart for various alternative portfolios. Based on the input from one stakeholder, energy autonomy is an important consideration in that it demonstrates the state of California's ability to meet its energy needs with its own resources. This criterion is opposite to another suggested criterion – facilitating seamless markets in which the magnitude of imports and exports are considered.

Portfolio or project flexibility refers to the ability of a resource to be modified to respond to unexpected events. For example, a transmission upgrade may have several "stepping-off" points where changes to the project (including modification or cancellation) could be made without the full commitment of capital funds. For instance, the full commitment to capital funds for a transmission project can be withheld until all the permitting and right-of-way are properly secured. Flexibility is a valuable consideration for decision makers and is frequently not considered directly in the economic evaluation.

Several stakeholders also proposed some review of the feasibility of a proposed resource portfolio considering potential market risk. If the economic viability of a proposed transmission upgrade is dependent on the assumption that the entire WECC will be operating under a Locational Marginal Price (LMP) market, it may be prudent to at least qualitatively consider the economic impact on the project if part of the WECC remains with a "contract-path" market. These considerations are generally too difficult to consider in a quantitative fashion, but should at least be thought through and qualitatively assessed.

One stakeholder thought that "political risk" should be considered. In other words, what is the likelihood that a resource portfolio will receive full approval and funding? If a proposed resource portfolio involves significant infrastructure investment, can this plan receive the approvals required, or will "political" considerations cause the plan to be compromised to the point that it no longer provides a significant portion of the benefits of the original resource portfolio.

Other areas of stakeholder-suggested risk assessments included CO_2 regulatory risk and project viability. The CPUC found that the investor-owned-utilities should use a Greenhouse Gas (GHG) adder when evaluating new resources (CPUC D.04-12-048). The range of reasonable adders is considered to be $8 to $25 per ton.[47] Translated into $/MWh, the adders range from 4 to 15 $/MWh.[48] From this perspective, the risk associated with the unknown cost of $C0_2$ emissions can be considered a major source of risk.

Project viability risk concepts have been reasonably well-defined in the in the recent Request For Offers (RFO) released by the three IOUs. These risk assessments include project credit, viability, transmission impact, debt equivalence, and qualifications.[49] These concepts are valuable for the evaluation of individual transmission or generation projects, but are less informative when applied to a diverse, long-term resource portfolio or strategy.

Recommended Criteria

The first step in integrating transmission, generation and demand-side alternatives in resource planning is to agree on evaluation criteria that are objective, transparent, and properly reflect the long-term priorities of the California energy market participants.

This section presents recommended criteria. These recommendations are not intended to be a conclusive and final statement about what evaluation criteria should be uniformly used for California transmission and resource planning. Rather, the recommendations are intended as "food for thought". The hope is that this report will help demonstrate the need for clear, comprehensive, and understandable evaluation criteria that can be utilized by those wishing to understand the economic benefits of transmission and other resources.

There are six evaluation criteria believed important for resource evaluation purposes. While other stakeholder-suggested criteria are considered valuable, they were not selected because they may be: (a) more difficult to measure; (b) less comprehensive in scope; or, (c) should be included in the "minimum requirements" set by state policy.

The six recommended criteria are:

- Least-Cost
- Reliability
- Risk
- Market Efficiency

- Fuel Diversity
- Resource Flexibility

Least-Cost

Least-cost can be interpreted from different perspectives and calculated in many different ways. It is inappropriate to dictate what specific formulae should be used. Rather, it is left to the evaluator to determine the appropriate least-cost methodology depending on the purpose of the study. However, some consistent type of least-cost methodology needs to be employed. The least-cost methodology should be comprehensive enough to calculate all the quantifiable direct and indirect costs. The costs should include:

- Un-served energy
- Fixed payments to reliability units and those dispatched out-of-order
- Airborne pollutants
- Environmental, cultural, and social mitigation

Some of these costs can be incorporated into the market simulation (i.e. cost of airborne emissions), and others may need to be computed separately (mitigation costs).

Reliability

For the most part, reliability requirements are already incorporated into any examination of alternative resource portfolios. The sophisticated modeling tools used to produce case results take into account NERC, WECC, CA ISO, and utility criteria in their simulations. Thus, they are considered minimum requirements and do not change between scenarios. The market simulation values any differences in un-served energy between the alternative scenarios and includes them in total system cost comparisons. Therefore, it does not need to be a specifically evaluated criterion. And, for the most part, the amount of un-served energy calculated in a market simulation is usually so small as to be an insignificant part of the total costs.

The reliability criterion that can change from one portfolio to another, and thus be considered a legitimate evaluation criterion, is the qualitative consideration of extreme reliability events that would be better mitigated by one resource portfolio versus another. For example, assume one of the options for San Francisco is to increase the capacity of an existing transmission line bringing power northward along the peninsula. Assume the other option was to build a trans-bay cable. If both alternatives met the same NERC, WECC, and CA ISO reliability criteria, and the "un-served energy" for each of the two alternatives is directly calculated in the market simulation, no additional reliability benefits would be noted in the analysis. However, in the extreme event of a fire, earthquake, or terrorist act eliminating the peninsula transmission capability, the trans-bay cable option would have the additional advantage of providing another corridor of power. Thus, the differential reliability benefits not mandated or captured in the market simulation, should be qualitatively described, evaluated, and considered.

Risk

There are several comprehensive risk computational methods based on portfolio theory. Often, these calculations are too data and computationally intensive to be available for routine use in most planning departments.

On the other hand, risk is much too important to ignore simply because of its potential complexity. After least-cost, many would consider risk to be the second most important evaluation criteria. It is essential that risk be considered in some manner which can be calculated on a routine basis and used for comparative purposes.

Since understanding risk is very important in analyzing alternative resource strategies, a reasonable alternative would be to consider it in some type of standard way. This would be superior to either ignoring it or adopting a rigorous, inflexible definition of portfolio risk that is beyond the scope and capability of many planning groups to produce. Besides, because the calculation of portfolio risk is rigorous and complex, it often gives a false sense of knowing the exact bounds of uncertainty in a given portfolio. This sense of having established bounds on risk can prove deceptive when perhaps the largest risk factors are those which cannot be readily considered in a quantitative manner (e.g. change in market paradigm, manipulation of market rules, etc.).

Many entities derive a distribution of potential costs, compute the expected cost, and then calculate an "average worse case". This can be a single case, or it can be the average of the worst 5 to 10 percent of cases. The difference between the expected cost and the "average worst case" is then computed and used as a measurement of risk. So, either a formal calculation of a risk index such as cash-flow-at-risk or a less rigorous calculation of the difference between expected and average worst case, could be an acceptable way of assessing risk. If any of these calculations are established as evaluation criteria, they can be helpful provided they are used consistently in routine decision making.

Market Efficiency

If the energy market is "efficient," competitive prices exist, and adequate generation resources can be built and funded through revenue from sales of energy, capacity, and ancillary services. If the market simulation model employs bidding strategies that are dynamic (i.e., can change hourly based on system and market conditions), the resulting simulated market-clearing prices can be compared to the underlying competitive prices (i.e., marginal costs of the resources used in the simulation), and a market efficiency index derived. If a marginal cost market is modeled, or static bid strategies employed (bids are static or unchanged for a period of time independent of system and market conditions), the market efficiency calculation will be of little or no value. However, currently computed, the market efficiency evaluation criterion can be a valuable indicator of how well the markets are operating and providing energy to consumers at competitive prices.

Fuel Diversity

Fuel diversity is partially considered in the least-cost and risk criteria. If there is a significant amount of fuel diversity (e.g., renewables), airborne emission costs are reduced and that reduction is reflected in the least-cost comparison. The fuel diversity also becomes apparent in the risk criterion, since fuel diversity reduces risk and helps to mitigate the impact from adverse outcomes.

Another way to approach risk is to use a method suggested by the NRDC. They suggest that a simple pie chart of fuels used for a given resource strategy is an effective way to understand fuel diversity. Because there are a number of identified benefits associated with fuel diversity that are not necessarily captured by the least-cost and risk criteria, fuel diversity is recommended as one of preferred evaluation criteria. For example, reducing fossil fuel dependence is an important goal of many California market participants. Additionally, not all airborne emissions can be quantified in the least-cost evaluation and not all risk impacts from choice of a fuel mix can be fully recognized in a standard risk analysis.

Resource Flexibility

Resource alternatives and plans that have flexibility in terms of timing and commitment of capital funds, and the ability to respond to changes in expected conditions, are more valuable than those having no flexibility and requiring substantial expenditures early in the project lifecycle.

Unfortunately, inherent flexibility is sometimes traded away in the contract negotiations. For example, merchant transmission projects may have significant advantages in terms of keeping capital and operating costs down and reducing the risk of completion. However, if a contractual commitment to the use of the transmission line is required before the permitting and licensing activities are initiated, some resource flexibility has been lost. Typically, one can complete the permitting and licensing of a transmission project and spend less than 10 percent of the total capital costs. For a decision maker, this spending schedule is valuable, in that the decision to commit significant amounts of capital funds can be delayed for two to three years when more information is available and any right-of-way and environmental risks are more fully understood.

Therefore, it is important to at least qualitatively consider the comparative benefits of resource flexibility when evaluating alternatives.

Criteria Not Selected

The Summary section below, notes that many suggested criteria were not selected as the recommended evaluation criteria. In some cases, the criteria were deemed more appropriate for a single resource or small portfolio comparison than for evaluating alternative resource plans and strategies at a state-wide level. These criteria included market valuation and portfolio fit.

In other cases, the criteria were thought to be "minimum requirements" rather than parameters that should be optimized. An example is environmental justice. Treating people fairly is a basic mandate and should be a given for all resource alternatives, not a variable to be fine-tuned or tweaked until the appropriate result is achieved.

Finally, some criteria were thought best left to the judgment of the group doing the evaluation as to whether they needed to be included in something like an "other" category. Evaluation criteria such as once-through water requirements, cultural and visual issues, project viability, political feasibility, and third-party credit worthiness are examples of issues that can be used for comparison if there are significant and relevant differences in those categories between resource alternatives. Otherwise, if the differences in these areas are not particularly different between alternatives, these criteria would not be added to the standard evaluation list.

Summary

Clearly, all of the stakeholder-provided resource evaluation criteria are important or they would not have been suggested. However, not all of the criteria can be included if one to is formulate a standard set of criteria than can be used by planning departments without requiring an infeasible level of staffing, software models, and data collection. The six criteria selected were considered to provide the best balance between the need for pertinent and comprehensive evaluation criteria, and an organization's ability to perform this work in a timely manner.

Table A-1 summarizes the recommended criteria.

Table A-1 Recommended Evaluation Criteria

Evaluation Criterion	Measurement Description	Criterion Derivation
Least-Cost	Compute present value of costs for appropriate perspective	Computed
Reliability	Summarize reliability improvements not required or quantified	Subjective

Risk	Determine difference between expected and average worse case	Computed
Market Efficiency	Compare market prices to competitive costs	Computed
Fuel Diversity	Summarize energy consumed by originating fuel source	Subjective
Resource Flexibility	Describe capital fund flexibility for resource commitments	Subjective

To evaluate the least-cost among alternatives, an entity should perform one or more of the least-cost calculations. Least-cost can be viewed from the perspective that is most relevant to the planning group (societal, California, CA ISO, utility, consumer, generator, transmission owner, etc.) and be defined in a way most meaningful to the evaluating group (e.g. total or modified benefits). An evaluation of reliability would consider only those factors that are not considered requirements, or already included as un-served energy costs.

Risk can be computed in a number of acceptable ways. Some indication of the maximum credible risk should be developed for those variables that are quantifiable, and a qualitative assessment provided for those critical variables that cannot be quantified or measured. Market efficiency should be considered provided the underlying market simulation allowed for a reasonable modeling of changing bid strategies and an examination of any resulting market power. The market efficiency index should not be calculated using more basic market simulation models in which the conclusions regarding market efficiency could be misleading.

Fuel diversity can effectively be represented by a simple “pie chart” showing the fuels used to produce the energy consumed. Resource flexibility is a qualitative measurement that can be used when there are significant advantages or disadvantages with respect to the commitment and use of capital funds.

In summary, two of the suggested criteria are considered mandatory in all cases – least-cost and reliability. Both are computed from underlying data in a quantitative manner. The remaining indices should be used as appropriate – when there are large differences between alternative resource strategies and when these differences can be recognized. Three of the remaining suggested criteria – reliability, fuel diversity, and resource flexibility – need to be qualitatively evaluated and compared. The fourth remaining criterion -- market efficiency – can be directly calculated when appropriate.

Endnotes

[1] "Palo Verde-Devers Board Report", CA ISO, February 16, 2005, p. 17.,

[2] See NERC's website at http://www.nerc.com/ .

[3] Ibid.

[4] CPUC Decision 04-07-028, "Interim Opinion Regarding Electric Reliability Issues", July 8, 2004, p. 3.

[5] CPUC Decision 04-07-028, p. 5.

[6] Discussion with Mohammed Beshir, Manager of Resource Planning and Development, LADWP, April 14, 2005.

[7] CPUC Decision 04-09-60, "Interim Opinion: Energy Savings Goals for Program Year 2006 and Beyond", September 23, 2004, pp. 2-3.

[8] California Energy Commission, "Proposed Electricity Resource and Bulk Transmission Data Requests", December, 2004, p. 4.

[9] CPUC, "Opinion Approving 2005 Demand Response Goals, Programs and Budgets."

[10] California Energy Commission "Renewable Resources Development Report", November, 2003, p. 1.

[11] California Energy Commission "Distributed Generation Resource Guide", see http://www.energy.ca.gov/distgen/.

[12] "California Energy Action Plan", p. 2, [http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF].

[13] California Energy Commission Energy Glossary.

[14] California Energy Commission, "Summer 2005 Electricity Supply and Demand Outlook", CEC-700-2005-006-SD, p. 8.

[15] CPUC "Procurement and Resource Adequacy Issues", PowerPoint presentation by Stephen St. Marie, Regulatory Analyst, November 3, 2004.

[16] "2004 Annual Report on Market Issues and Performance", CA ISO, July, 2005, p. 6-5.

[17] Ibid., p. 6-11.

[18] "Security Guidelines for the Electricity Sector", Critical Infrastructure Protection Committee", North American Electricity Reliability Council, p. 1, see NERC website: http://www.nerc.com/~filez/cip.html .

[19] NERC Security Guidelines, p. 3/5.

[20] CA ISO TEAM Report, pp. ES-6 and ES-20.

[21] Ibid., p. 2-18.

[22] Ibid., p. 2-18.

[23] For example, see PG&E's "2004 Long Term Request For Offers Power Purchase", March 18, 2005. p. 8 (see website: http://www.pge.com/suppliers_purchasing/wholesale_electric_supplier_solicitation/ltpp_rfo2004.html).

[24] PG&E Request For Offers, p. 8.

[25] CA ISO Mission Statement (see website: http://www.caiso.com/surveillance/overview/Mission.html).

[26] By definition, the societal benefits of any resource addition is the difference in production and capital costs for two cases -- one "with" the project, and one "without". This production and capital cost difference, is often only slightly impacted by market prices, since the market prices can cause a distortion to the least-cost generation commitment and dispatch.

[27] "Our Mission", Seams Steering Group – Western Interconnection (see website: http://www.ssg-wi.org/).

[28] "Clean Air and Energy", Natural Resources Defense Fund (NRDC), (see website: http://www.nrdc.org/air/default.asp).

[29] "Electricity and Natural Gas Assessment Report", California Energy Commission, December, 2003, pp. 135-138, (see website; http://www.energy.ca.gov:8765/query.html?col=energy&qt=water+cooling+concern&charset=iso-8859-1&si=0).

[30] Interview with Dr. Mohammed Beshir, Manager of Resource Planning and Development, Los Angeles Department of Water and Power (LADWP), April 14, 2005.

[31] Interview with Dr. Richard Ferguson, Director of Research, Center for Energy Efficiency and Renewable Technologies (CEERT), May 4, 2005.

[32] "Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal", California Energy Commission, March, 2005, p. 7 (see website: http://www.energy.ca.gov/2005_energypolicy/electricity_forms/index.html).

[33] "Energy – Position in Brief", League of Women Voters of California, (see website: http://ca.lwv.org/lwvc/issues/natres/energy.html).

[34] Interview with Sheryl Carter, Director Western Energy Programs, March 28, 2005.

[35] "Environmental Justice, Frequently Asked Questions", California Energy Commission, (see website: http://www.energy.ca.gov/public_adviser/environmental_justice_faq.html).

[36] Executive Order #12898 and EPA's 1998 Environmental Justice Guidance

[37] Senate Bill 115 (Chapter 690, Statutes of 1999) authored by Senate Member Hilda Solis (D El Monte), see website: http://www.calepa.ca.gov/EnvJustice/Legislation/#Senate)

[38] "Pollution, Health, Environmental Racism and Injustice: A Toxic Inventory of Bayview Hunters Point, San Francisco", Bayview Hunters Point Mothers Environmental Health and Justice Committee, Huntersview Tenants Association, Greenaction for Health and Environmental Justice, September, 2004, p. 5.

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[42] "Applying Portfolio Theory to EU Electricity Planning and Policy-Making", International Energy Agency, Report Number EET/2003/03, Shimon Awerbuch and Martin Berger, Paris, February, 2003, p. 4.

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[45] "Walwyn Agenda Dec. on Electric Procurement Planning", California Public Utility Commission, December 12, 2003 (see website: http://search.cpuc.ca.gov/query_portal.html?col=adocs&col=agda&col=cdecs&col=cpuc&col=cres&col=dcals&col=fdocs&col=gos&col=ora&col=pres&col=proc&col=rep&col=rul&ht=0&qp=&qt=TeVAR&qs=&qc=&pw=100%25&ws=0&qm=0&st=1&nh=10&lk=1&rf=0&rq=0&si=1 .

[46] Ibid.

[47] "PG&E Electric Resource Supply and Transmission Plan", April 1, 2005, p. 19 (CPUC D.04-12-048).

[48] "Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, p. 26.

[49] "2004 Long-Term Request For Offers, Power Purchase", Pacific Gas and Electric Company, p. 12.

Attachment 1
Organizations Participating in the Stakeholder Survey

1. California ISO (CA ISO)
2. California Public Utilities Commission (CPUC)
3. California Utilities Employees
4. California Wind Energy Association (CWEA)
5. Center for Energy Efficiency and Renewable Technologies (CEERT)
6. Constellation NewEnergy
7. Environmental Law and Justice Clinic, Golden Gate University
8. FPL Energy
9. Independent Energy Producers Association (IEP)
10. League of California Cities
11. Los Angeles Department of Water & Power (LADWP)
12. Mirant California LLC
13. Natural Resources Defense Council (NRDC)
14. Northern California Power Agency (NCPA)
15. Pacific Gas and Electric Company (PG&E)
16. Pasadena Water and Power
17. Sacramento Municipal Utility District (SMUD)
18. San Diego Gas & Electric (SDG&E)
19. Southern California Edison (SCE)
20. The Utility Reform Network (TURN)
21. Trans-Elect, Inc.
22. Utility Consumers' Action Network (UCAN)

Attachment 2
Summary of Stakeholder-Suggested Criteria

Category	Minimum Requirements	Proposed Criterion	Possible Measurement	Suggested by Stakeholder(s)
Reliability	NERC, WECC, and CAISO	Un-served energy	reflected in direct cost by using an appropriate value for un-served energy	many
		reduction in reliability-must-run (RMR) contracts and minimum load cost compensation (MLCC) costs	goal is to properly include RMR and MLCC costs in market simulation by modeling generation commitment accurately	CA ISO, generators
		minimize likelihood and consequences of terrorist attacks to power system	NERC-defined "Vulnerability and Risk Assessment"	many
Least-Cost	none specified	ratepayer total cost	present value (PV) of CA cost-to-load (CTL), net of utility-owned generation and transmission net revenue	many
		ratepayer rate	estimate rate impact due to increase in CTL	municipals, others
		societal cost	PV of WECC total production and fixed costs	many
		modified ratepayer cost	PV of CA modified CTL (excludes gen. profit from uncompetitive conditions), net of utility generation and transmission net revenue	CAISO
		modified participants cost	PV of CA modified CTL (excludes gen. profit from uncompetitive conditions), net of CA market generation and transmission net revenue	CAISO
		market valuation	NPV of project benefits compared to costs	utilities
		portfolio fit	reflected in ratepayer, participant, or societal cost (or market valuation)	utilities
		market competitiveness	CA weighted avg. price / cost mark-up	CAISO
		Seamless markets	average annual volume of imports and exports	CAISO
		Infrastructure investments	total capital requirements for next 5 and 10 years	utilities

Category	Minimum Requirements	Proposed Criterion	Possible Measurement	Suggested by Stakeholder(s)
Risk	none specified	CO2 regulatory risk	include CO2 cost in market simulation, consider as uncertain variable	many
		resource diversity	energy % from different resource categories in CA (DSM, DG, solar, natural gas, etc.)	NRDC, others
		project viability	qualitative evaluation regarding whether project will be built and perform according to expectations	utilities
		risk of extreme outcome	compute difference between expected cost, and average of worse 10 percent of cases	many
		insurance value	impact of extreme cases on overall expected value is already considered, risk premium could be quantified by estimating cost of obtaining equivalent coverage through other market instruments	CPUC, others
		payoff tables	information could be summarized into tables that indicate when decision is beneficial (or not); possible simplification is histogram	CPUC
		political feasibility	qualitative evaluation regarding risk relative to public and political support for project or resource scenario	CPUC
		cost overruns	qualitative assessment of ratepayer risk of incurring additional costs in the future due to cost overruns	IEPA
		project flexibility	qualitative assessment of how flexible resource decision and capital fund commitment is to changes in external factors	CPUC
		no additional infrastructure	risk should be measured against a base case of "doing nothing"	IEPA
		market changes	qualitative assessment of sensitivity of resource decisions to changes in market rules in CA and elsewhere	generators, CPUC
		counter-party, credit, debt equivalence	currently undefined	muni's
		energy autonomy	amount of out-of-state annual imports	consumer groups

Category	Minimum Requirements	Proposed Criterion	Possible Measurement	Suggested by Stakeholder(s)
Environmental	CPUC RPS, DSM, DG goals	amount of airborne pollutants	include CO_2, NO_x, SO_2, and particulate costs in market simulation	many
		amount of renewable energy beyond RPS requirements	percent of energy met by renewables in excess of RPS goal for that year	CEERT, others
		transmission impact	number of miles of new right-of-way, visual and environmental impact	utilities
		environmental justice	compare MW's of new projects built in low- versus higher-income zip codes; also consider population	consultant, others
		fossil fuel dependency	percent of energy needs met by fossil fuel	NRDC
		once-through water cooling impacts and thermal pollution	annual water requirements, thermal impact	CEERT, CEC

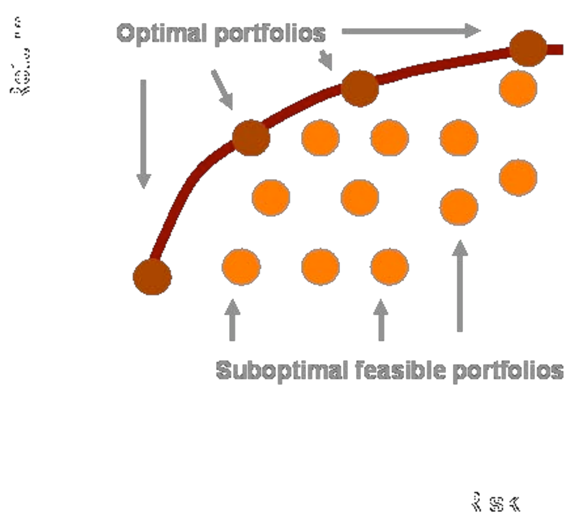
Attachment 3

Risk, Portfolio Theory, and Transmission Planning

Modern finance theory is well developed, with its tools increasingly being used in the electric power industry. In electricity planning exercises, it is commonly appreciated that risk is an important consideration.[1] A natural question that arises is, how well can the risk management methods of finance be applied to transmission planning? We explore this question below. First, however, we begin with some "high-level" background.

Portfolio theory generally refers to the collection of financial models that describe how an investor might balance risk and reward in constructing portfolios. It answers the question: Among the feasible portfolios, how do I identify the best ones?[2] Classical portfolio selection consists of identifying the portfolios that maximize return for a given level of risk or, equivalently, that minimize risk for each given return.[3] The set of optimal portfolios form the widely recognized *efficient frontier*. When plotted with risk on one axis and return on the other, the efficient frontier identifies the optimal portfolios.

Figure 1
Portfolio Efficient Frontier



In Figure 1, the feasible portfolios are indicated with solid dark circles. The thick convex line indicates the efficient frontier, along which fall the set of optimal portfolios. In order to increase the return of a portfolio on the efficient frontier, one would have to increase risk. This is in contrast to the suboptimal portfolios which lie to the right and below the efficient frontier: in these, portfolio expected return can be increased by rearranging the asset mix without increasing portfolio risk.

A key insight of portfolio theory is called the portfolio effect: the addition of a low-risk, low-return asset to the portfolio that is not highly correlated to the existing assets in the portfolio will produce higher risk reduction relative to the return reduction from adding the asset to the portfolio. In other words, portfolio diversification lowers risk and/or increases returns.

Beyond providing important insights, portfolio theory is widely used in finance and other fields for a practical reason: computational ease. Its computational ease, however, derives from several key assumptions, one of which is that the standard deviation (the measure of spread in a distribution) represents risk.

There are several concerns with the use of standard deviation as a measure of risk. One is simply that two very different distributions can have the same mean and standard deviation. Yet the use of standard deviation as risk measure is unable to tell us anything about those differences. It ignores potentially valuable information about risk.

As a result of the shortcomings of the use of the standard deviation as risk measure, alternative measures have been developed, the most common of which are the “at risk” variety, such as Value at Risk (VaR) and the closely related Cash Flow at Risk (CFaR).

VaR measures the possible change in value of a portfolio over a specified period, with a certain level of probability, caused by changes in quantifiable market risk factors. It answers the question: what is the maximum portfolio loss (or other performance measure) at a specified confidence level? The appeal of the VaR – and the “at risk” family of measures in general – is that risk is boiled down to one number (i.e. summary statistic) that is conceptually easy to understand and to compare to alternative portfolios.[4]

A variation on VaR is CFaR, which better deals with assets that cannot be marked to market or whose position cannot be closed at any time (e.g. on the forward market).[5] Fixed assets or illiquid forward markets generally suggest the use of CFaR rather than VaR.

The academic literature has recently turned its attention to the development of additional measures of risk. The fruit of this effort is a measure of risk called conditional Value at Risk (CVAR), also known as Expected Tail Loss or Expected Shortfall.[6] CVaR is surprisingly easy to understand: it is simply the average (expected value) of the tail, i.e., the distribution beyond VaR.

The CPUC has recommended that California utilities use “TeVaR (To Expiration Value at Risk), a type of VaR model, to measure and report risk . . . “.[7] Specifically, they recommend using TeVaR measured on a 12-month rolling basis, at a 99 percent confidence level, and state that the “risk reporting could cover a longer period if the if the utility entered (into) longer term transactions within the quarter”.[8]

We briefly return to the portfolio selection problem. Once defined, the VaR (CFaR) or CVar (ECFaR) can be defined as a constraint in the portfolio optimization problem, thereby forcing the feasible set of portfolios to respect the defined risk measure.

The use of portfolio theory for electricity planning and policy analysis is rapidly gaining favor. Work by the Northwest Power and Conservation Council (NPCC) provides an illustrative large-scale resource planning applications.

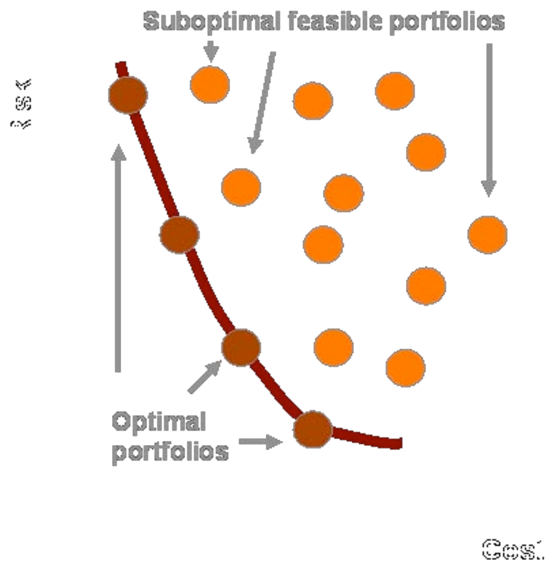
The Northwest Power and Conservation Council’s 5th Power Plan is an impressive application of portfolio theory and risk measures. Their “risk-constrained least-cost planning approach” considers a multitude of possible futures (“combinations of sources of uncertainty, usually specified over the entire … study”) for each plan (“actions and policies over which the decision maker has control that will affect the outcome of decisions”). In total, the analysis considers 750 futures over some 1000 alternative plans. The performance measure is the net present value of total system cost associated with each plan.

Replacing portfolio return with total system costs, and portfolio with resource plan, one can quickly see this analysis as an application of portfolio theory. It should come as no surprise, then, that an efficient frontier can be obtained describing the optimal (i.e., least cost) plans for different levels of risk. Risk, as defined in this study, is defined as the average of the total system cost outcomes above the 90 percent threshold (90th percentile) or, equivalently, the 10 percent worse outcomes in each plan.

In order to prevent the problem from exploding (due to dimensionality), however, various simplifying assumptions were made, including:
- aggregation of similar generating units
- inter-temporal aggregation of generation capacity factors and costs over one or more months
- quarterly hydro generation profiles (on and off peak)
- no inter- or intra-transmission constraint modeling (although regional imports and exports limited to 6,000 MW)

Figure 2 represents the efficient frontier in the context of total system cost, where now system cost is being traded off with risk.

Figure 2
The "Plan" Efficient Frontier



In a footnote of its Power Plan, the NPCC cites a simulation time estimate had they used Aurora, a production cost simulation model: 85 years. That estimate would likely assume the simplest modelling of transmission (i.e. in transport mode). For utility or regional resource planning, it may be reasonable to abstract from detailed modelling (or any modelling, for that matter) of transmission. But, transmission planning without modeling some spatial element appears to be a contradiction in terms.

Considering spatial elements, however, increases the breadth of the problem. How much spatial or network detail is required to identify the "need" for a transmission upgrade? The answer to this question will probably speak to the plausibility of using portfolio theory for the purposes of transmission planning.

Attachment 3 Endnotes

[1] For the purposes of this discussion, we take the formal economic definition of risk as the condition under which it is possible both to define a broad set of possible outcomes and to be able to assign probabilities to those outcomes. We use this narrower definition of the term in order to guide the discussion and frame our conclusions.

[2] Best here refers to the normative criterion used in economics, namely Pareto optimality. An allocation of resources is Pareto optimal if it is impossible to change the allocation in a way that would make someone better off without at the same time making someone else worse off.

[3] More specifically, the optimization seeks to identify the vectors of asset shares that satisfy constraints, and providing minimum total variance and total maximum return.

[4] This attribute is particularly important for senior managers.

[5] Earnings at Risk are sometimes identified separate from CFaR in the financial industry. We abstract from any difference between these measures for the purposes of this discussion.

[6] Analogously, Extreme Cash Flow at Risk measures have been developed to resolve the same issues with CFaR.

[7] "Walwyn Agenda Dec. on Electric Procurement Planning", California Public Utilities Commission, December 12, 2003.

[8] Ibid.

APPENDIX B: EVALUATION OF CA ISO ECONOMIC ANALYSIS OF PALO VERDE-DEVERS NO. 2 PROJECT

Review of CAISO's Economic Evaluation Methodology for the Palo Verde Devers Line No.2 (PVD2)

Energy Commission Committee Workshop Presentation

2005 Integrated Energy Policy Report

Sacramento, California

May 19, 2005

Presented by:

Joe Eto

Consortium for Electric Reliability Technology Solutions

Prepared by:
Electric Power Group

Electric Power Group CERTS

Background

Consortium for Electric Reliability Technology Solutions/Electric Power Group (CERTS/EPG) has carried out the following studies for the California Energy Commission:

1. Planning for California's Future Transmission Grid – Review of Transmission System, Strategic Benefits, Planning Issues and Policy Recommendations, October 2003.
2. California Electricity Generation and Transmission Interconnection Needs Under Alternative Scenarios, November 2003.
3. Economic Evaluation of Transmission Interconnection in a Restructured Market, June 2004.

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Strategic Value of Transmission

Strategic benefits identified in CERTS/EPG report includes:

- Price stability and decreased market power for existing generators.
- Potential for increased reserve sharing and firm capacity purchases.
- Insurance against contingencies during abnormal system conditions.
- Environmental benefits.
- Reduction in construction of additional infrastructure such as gas pipelines.

Scope of Review of CAISO's Economic Evaluation for Palo Verde Devers No. 2[1]

- Review of CAISO Board Report on economic evaluation of PVD2
- Review of strategic benefits included in CAISO evaluation[2]
- Comparison of strategic benefits identified in CAISO evaluation with the ones recommended in a report prepared for CEC by EPG/CERTS
- Impact of using a social rate of discount on benefit-to-cost ratio

[1] A similar review will be carried out by CERTS/EPG on SCE's CPUC Filing for PVD2

[2] CERTS/EPG did not carryout any quantitative analysis to verify the magnitude of energy and other benefits reported in the CAISO report.

PVD2 Project Description

- 230 mile 500kV transmission line from Palo Verde area to Devers
- Rebuilding four 230kV transmission lines from Devers into Los Angeles Area
- Additional voltage support
- Projected on -line date: 2009
- Estimated capital costs: $620 Million
- Ability to import an additional 1,200 MW of power from Arizona

CAISO's Quantified Economic Benefits

- Energy cost savings
  - The difference between electricity production costs to serve the load with and without PVD2
- Operational benefit
  - Operational savings not captured in the production simulation model, such as generation unit commitment costs, minimum load cost compensation, re-dispatch of units to address real-time congestion
- Capacity benefit
  - Cost of capacity in Arizona lower than in California
- Loss Savings
  - Transmission losses to be lower as a result of PVD2. These losses are not captured in the DC Power Flow Model
- Emissions
  - Airborne emissions are not directly modeled in the production simulation model. However, there will be a reduction in NOx emissions due to PVD2

CAISO's Benefit Criteria

CAISO evaluated the benefit based on the following four perspect ives:

1. **Societal** – the total WECC benefit including benefits to the consumers, producers, and transmission owners
2. **Modified Societal** – benefits to the producers from uncompetitive market conditions are excluded
3. **CAISO Ratepayer** (LMP only) – savings to CAISO ratepayers and assuming LMP throughout the WECC
4. **CAISO Ratepayer** (LMP + Contract Path) LMP market modified by the utilization of selected contractual paths between CAISO and Southwest region

CAISO Estimated Annual Energy Benefits for PVD2

(2008 Million $)

Perspective	2008		2013	
	Expected Value	Range	Expected Value	Range
Societal	$41	$4 - $200	$54	$20 - $200
Modified Societal	$61	$6 - $400	$81	$20 - $600
CAISO Ratepayer (LMP Only)	$39	($3) - $300	$56	($3) - $400
CAISO Ratepayer (LMP + Contract Path)	$110	$10 - $600	$200	$50 - $1,000

Benefit-to-Cost Ratios for PVD2

(2008 Millions $)

	Societal	Modified Societal	CA ISO Ratepayer (LMP Only)	CA ISO Ratepayer (LMP + Contract Path)
Levelized Benefits [1]	$91	$119	$84	$225
Levelized Capital & O&M Costs [2]	$71	$71	$71	$71
B/C Ratio	1.3	1.7	1.2	3.2

(1) A discount rate of 7.16% is used for calculation of levelized benefits.
(2) Energy benefit is based on production simulation for 2008 and 2013 with the assumption that it is linearly increased from 2008 to 2013, and 1% annual escalation after 2013.

Comparison of Strategic Values

	CEC Report [1]	Original CA ISO [2]	CA ISO Board Report [3]
Price Stability Market Power	√	√	√
Potential for Increased Sharing and Firm Capacity Purchase	√		√
Insurance Against Contingencies During Abnormal System Conditions	√	√	√
Environmental Benefits	√		√ (NOx)
Reduction in Construction of Additional Infrastructure	√		

(1) Economic Evaluation of Transmission Interconnection in a Restructured Market prepared for CEC by EPG/CERTS June 2004.
(2) Presentations made by CAISO TEAM staff in April 2004.
(3) Board Report: Economic Evaluation of the PVD2 Line 2 prepared by CA ISO Department of Market Analysis & Grid Planning Feb. 2005.

Recommendations on Strategic Values of PVD2

- There is need to refine the capacity value estimation and to capture the interaction between transmission and generation expansion
- Using the expected value for energy benefits, the insurance value of transmission expansion during abnormal system conditions is not fully captured
- Environmental benefits should include other benefits besides NOx reduction
- Decreasing California's need for additional infrastructure such as gas pipelines should be considered in estimating strategic values

Evaluation of PVD2 Using a Social Rate of Discount and Cost of Capital

- CAISO has evaluated the PVD2 benefits under both societal and CAISO ratepayer perspectives
- Under a societal perspective the social rate of discount should be used to calculate the present worth of benefits which is then compared with the capital cost of the project
- Under CAISO ratepayer perspective the discount rate based on weighted cost of capital should be used to calculate the annual levelized benefit which is then compared to the annual levelized cost. Real economic carrying charge could be used to convert capital cost to an equivalent stream of annual revenue requirement

Benefit -to-Cost Ratio for Societal and CAISO Ratepayer Perspective

(2008 Million $)

	Present Worth Using Social Rate of Discount [1]		Annual Levelized Using Cost of Capital and Carrying Charge [2]	
	Societal	Modified Societal	CA ISO Ratepayer (LMP Only)	CA ISO Ratepayer (LMP + Contract Path)
Energy Benefits	$1,072	$1,607	$57	$198
Other Benefits	$670	$670	$27	$27
Total Benefits	$1,742	$2,277	$84	$225
Capital and O&M Costs [3]	$721	$721	$71	$71
Benefit-to-Cost Ratio	2.42	3.16	1.2	3.2

(1) Social rate of discount is set to 5%.
(2) Discount rate for levelized benefits at 7.16% and carrying charg e for levelized capital cost at 10.43%.
(3) Present worth of O&M is calculated at 0.25 of capital cost escal ating at 3% and than discounted at social rate of discount.

Summary Results

- Based on the magnitude of the benefits calculated by CAISO, the benefit -to-cost ratio of PVD2 is higher than 1.0 under all four perspectives
- Some of the strategic value such as insurance value during abnormal system conditions, environmental benefits besides NOx reduction and decrease in California's need for additional infrastructure such as gas pipelines are not fully captured in CAISO report
- The use of a social rate of discount to calculate the present wo rth of PVD2 benefits under societal perspective will more than doubl e the benefit -to-cost ratio of the project compared to using weighted cost of capital to discount the future benefits

APPENDIX C: REVIEW OF SCE'S ECONOMIC EVALUATION METHODOLOGY FOR THE DEVERS PALO VERDE LINE NO. 2 PROJECT

Review of SCE's Economic Evaluation Methodology for the Devers Palo Verde Line No.2 (DPV2)

Prepared for:

California Energy Commission Presentation

2005 Integrated Energy Policy Report

Sacramento, California
July 28, 2005

Prepared by:

**Consortium for Electric Reliability Technology Solutions/
Electric Power Group**

Electric Power Group

CERTS

Background

Consortium for Electric Reliability Technology Solutions/Electric Power Group (CERTS/EPG) have carried out the following studies for the California Energy Commission:

1. Planning for California's Future Transmission Grid – Review of Transmission System, Strategic Benefits, Planning Issues and Policy Recommendations, October 2003.
2. California Electricity Generation and Transmission Interconnection Needs Under Alternative Scenarios, November 2003.
3. Economic Evaluation of Transmission Interconnection in a Restructured Market, June 2004.
4. Review of CAISO's Economic Evaluation Methodology for the Devers Palo Verde Line No. 2, May 2005

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Strategic Value of Transmission

Strategic benefits identified in CERTS/EPG report includes:

- Price stability and decreased market power for existing generators.
- Potential for increased reserve sharing and firm capacity purchases.
- Insurance against contingencies during abnormal system conditions.
- Environmental benefits.
- Reduction in construction of additional infrastructure such as gas pipelines.

Scope of CERTS/ EPG's Review of SCE's Economic Evaluation for Devers Palo Verde No. 2 [1]

- Review of SCE's Chapter 2 of DPV2 Proponent's Environmental Assessment filed April 5, 2005, covering purpose and need for this project
- Review of SCE's DPV2 Cost-Effectiveness Report prepared April 7, 2004 and its update, March 17, 2005
- Review of benefits included in SCE evaluation
- Review of additional benefits not quantified by SCE
- Impact of using a social rate of discount on benefit-to-cost ratio

[1] CERTS/EPG did not carryout any quantitative analysis to verify the magnitude of energy and other benefits reported in the SCE reports.

SCE's Objectives for Building DPV No. 2

- Increase California's access to low-cost energy from the Southwest
- Enhance competition among generating companies supplying energy to California
- Provide additional transmission infrastructure to support and provide an incentive for the development of future energy suppliers selling energy into the California market
- Provide increased reliability of supply, insurance value against extreme events, and flexibility in operating California's transmission grid

Economic Benefits Quantified by SCE for DPV2

- Energy Cost Savings
  - Construction of DPV2 will decrease electricity prices in California.
  - SCE's analysis shows that California prices will fall by about 2% with the addition of DPV2.
  - This is the main component of economic benefits.
- Third Party Transmission Revenue
  - Increased revenue to SCE from certain ETCs
  - Increased CAISO wheeling through or out of the CAISO grid

Benefits for DPV2 Identified, But Not Quantified by SCE

- New Generation Development -- developing the DPV2 could attract new generation development east of Devers Substation
- Market Power – DPV2 may provide benefits by reducing the potential for generators to exercise market power
- Emergency Value – DPV2 could provide benefits during an emergency outage of a major import line and/or a large generating facility

The above benefits are not captured in SCE's production simulation modeling assessment used for evaluation of DPV2 project.

Other Non-Quantifiable Benefits for DPV2

SCE's evaluation does not mention operational benefit, assumes there will be no capacity benefit, and SCE believes its estimate of transmission losses using a production simulation is inconclusive.

In contrast, CAISO has quantified the following benefits for DPV2:

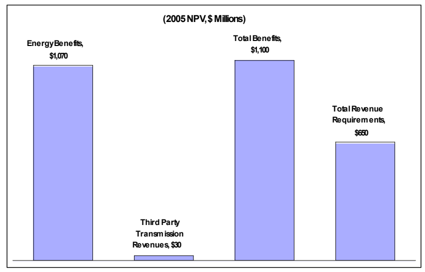
- *Operational Benefit* – savings not captured in the production simulation model – such as generation unit commitment costs, minimum load cost compensation, redispatch of units to address real-time congestion.
- *Capacity Benefit* – utilizing some of the surplus capacity in Arizona
- *Loss Savings* – reduction in transmission losses as a result of DPV2 operation, which were not captured in the DC Power Flow Model used by CAISO in the economic evaluation of DPV2
- *Emissions Reduction* – the emission reduction were not directly modeled in the production simulation model

In the CAISO evaluation, the above benefits are significant portion of the total benefits. For instance, in CAISO Ratepayer (LMP only) perspective 32% of the total benefits are attributed to the above benefits [(1)]

(1) Economic Evaluation of the DPV2 prepared by CAISO Department of Market Analysis and Grid Planning, Feb. 2005

DPV2 Projected Life Cycle Benefits

- SCE provides benefit -cost ratio for DPV2 in 2005 dollars
- It uses nominal 10.5% discount rate per annum
- The quantified benefits are: Energy benefits (due to electricity price reduction of around 2% due to operation of DPV2) and third party transmission revenues (around $3.0 million/year)



- Based on SCE's evaluation, the B -C ratio for DPV2 is 1.7
- Energy benefits are based on production simulation for 2009 -2015 and then escalated at GDP price index (around 2.28% per year)

WECC-Wide Benefit From DPV2

- At the request of CAISO, SCE has provided energy production cost for WECC for the years 2009 through 2014 with and without DPV2
- Net benefits for WECC (Real $ 2004 in millions) is the difference between total production cost with and without DPV2:

	2009	2010	2011	2012	2013	2014
Net Benefits	11	21	21	21	26	25

- Assuming the net benefits remain at $25 million after 2014 [1], and a social discount rate of 5%, the NPV of energy benefits for WECC region for the period 2009 -2055 will be $435 million (in $ 2005)
- Assuming an annual third party transmission revenue of $3 million, the PV of this benefit using 5% discount rage will be $55 million (in $ 2005).

(1) Project benefits beyond 2014 hold at the 2014 level with a zero real growth for the remainder of the project's life (2015 -2055) since we are using a social discount rate

Benefit-to-Cost Ratio for WECC Region and for CAISO Ratepayers Perspective (2005 $ Million)

	WECC Region (Social Discount of 5%)	CAISO Ratepayers (Discount Rate of 10.5%)
Net Energy Benefits	435	1070
Third Party Transmission Revenue	55	30
Total Benefits	490	1100
Capital Cost (1)	650	650
Benefit-to-Cost Ratio	0.75	1.7

(1) Capital cost is $680 million in nominal $, which includes $60 million AFUDC. Using GDP index and an assumed profile for annual capital expenditure, the Capital cost in 2005 $ is estimated to be $650 million.

Summary Results

- Based on the magnitude of the energy benefits calculated by SCE, the benefit-to-cost ratio of DPV2 is higher than 1.0 for CAISO ratepayers' perspective
- From the WECC regional perspective, using the numbers provided by SCE, even with a 5% social discount rate, the quantified benefits from energy and third party transmission revenue are not sufficient to create B-C ratio of larger than one.
- The WECC regional benefit is low, in part, because strategic values such as insurance value during abnormal system conditions, reduction in generators market power, potential for development of new generation outside of California, operational benefits, environmental benefits beside NOx reduction and finally decrease in California's need for additional infrastructures such as gas pipelines are not quantified in WECC regional benefit calculation.

Recommendations on Strategic Values of DPV2

A comprehensive assessment of WECC region-wide benefits and costs requires consideration of the following benefits, in addition to energy benefits:

1. The capacity benefits and the interaction between transmission and generation expansion
2. The insurance value of transmission expansion during abnormal system conditions
3. The environmental benefits besides NOx reduction
4. Impact on the need for additional infrastructures, such as gas pipelines
5. The operational benefits, including increased operational flexibility due to transmission expansion

It is essential that a comprehensive B-C analysis consider all significant expected impacts of DPV2. Failure to consider some of the strategic benefits we have identified leads to an incomplete assessment of the B-C ratio for this project (in this case, suggesting that it would be less than 1)

APPENDIX D: PUBLIC INTEREST ENERGY RESEARCH TRANSMISSION PROGRAM

Technology Availability and the PIER Transmission Research Program

Most PIER transmission research is conducted both 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 into productive use, a Policy Advisory Committee (PAC) provides strategic guidance and enhances technology transfer and adoption. It is composed of high-level management from: California investor-owned utilities (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.

Delivering more power through existing transmission corridors usually creates higher current flows, which in turn cause additional heating of conductor lines. Operating a line at too high a temperature can damage the line or cause it to stretch and sag too close to the ground, violating safety codes and leading potentially to power disruptions. HTLS conductor technologies use new materials and/or designs that withstand higher temperatures than conventional conductor materials, without damage or excessive sagging. Since the HTLS conductors are of similar weight and strength as conventional conductors, original lines can be replaced by HTLS conductors without significantly modifying or replacing existing towers.

Before rushing to replace existing lines with the HTLS conductors, however, transmission owners must consider a number of factors. For one thing, these new technologies are largely untested in actual use over time. Research field tests help utilities discover - under controlled testing conditions - installation, operational, and durability anomalies before widespread adoption. Costs are another factor. HTLS conductors are more expensive than conventional conductors. Since higher current flows mean higher energy losses, there are also economic and environmental consequences. The use of HTLS conductors must be evaluated in both the context of performance and the economic and environmental trade offs among alternative options.

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 re-conductored with a new conductor. SDG&E identified an appropriate transmission line for a test bed and the appropriate HTLS conductor technology, and performs both the engineering work and installation. Data is collected and analyzed in accordance with consortium protocols. The conductor supplier assists 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 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 both 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 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.

Expected applications of RTR to the transmission system are could include, but not be limited to:

- Contingency Management – Use of RTR to modify or improve protection and remedial action schemes. This could allow either higher pre-contingency power transfers or less severe remedial actions like load dropping, generation ramp-down or tripping.
- Congestion Management – When access to, or economic dispatch of, generation is frustrated because of static rating transmission line constraints, RTR can ease congestion under favorable ambient circumstances. Benefits include reduced reliability-must-run (RMR) requirements and avoided congestion costs (payments to generators not allowed to run).
- Economic Generation Dispatch – Use of RTR on lines that limit output of generation plants could increase plant availability and operational efficiency, or gain access to available economic energy from other regions.
- Clearance Management – Use of RTR technology could monitor or estimate the sag or clearance of transmission line spans and maintain positive safety margins while ensuring reliable operation.
- System Reliability – The CA ISO can use real-time data from transmission owners to manage overall reliability of the California transmission system.
- Static Uprating of Equipment – Analysis of actual system operations data could enable system planners to re-evaluate the static ratings of equipment by assessing acceptable levels of risk inherent in static ratings. The result could be greater asset utilization of existing lines and corridors and deferred capital investment in new transmission facilities. On the other hand, tests have shown that sometimes lines operating within their static ratings are actually operating too hot, so RTR has the added benefit of finding and correcting faulty static ratings, assuring the design lifetime of the conductor.

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 numerous 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. Some factors requiring consideration are:

- Cost: not just direct monetary requirements (capital and operating expenses), but the total ownership cost of the RTR technology when compared with the cost of standard utility alternatives on a common, apples-to-apples financial basis.

- Complexity of technologies of installation, operation, calibration, and maintenance.
- Technological difficulties: integration of technology with existing transmission system communications systems, operator interfaces, and utility computer systems.
- Actual or perceived risk of failure of the technology itself (reliability), liability from damages caused by failures when operating outside traditional engineering margins, or failure to achieve hoped-for benefits.
- Regulatory disincentives or lack of clear regulatory treatment.
- Uncertain benefits, including who receives benefits.
- Institutional inertia: unfamiliarity with new technology and resistance to new solutions.
- Personnel resource limitations, training issues and requirements.

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 with this technology. 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. Its goals are:

- Evaluate the accuracy and reliability of the auxiliary data server system’s functions: integrating data from multiple monitoring systems, performing requisite calculations, and providing processed real-time line data and alarm indicators to system operators.
- Determine the cost effectiveness of this approach, compared with the alternative of implementing software and hardware upgrades to PG&E’s EMS to accomplish the same functionality.
- Develop operator displays to integrate existing EMS/supervisory control and data acquisition (SCADA) operations tools and establish data protocols and communications interfaces with the CA ISO.

The second project, hosted by PG&E, the Western Area Power Administration (Western), and the Sacramento Municipal Utility District (SMUD), 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 area around Sacramento, one of the fastest-growing and complex transmission regions in California, will be the focus of the project. The area's largest transmission owners, SMUD and Western, have identified several lines expected to overload in the near future. These lines will be monitored and their data assessed to: determine the cost/benefit of the use of real-time ratings for large areas under normal conditions, develop and test methods for mitigating combined thermal and voltage constraints, and evaluate transmission capability forecasting methods. Preliminary results indicate potential for significantly reducing curtailments and increasing import capability into the region.

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. SDG&E will install monitoring equipment on key lines near the Miguel substation and collect real-time data for 18 months, including line loading and environmental conditions. The data will be analyzed to evaluate how often, and under what conditions, real-time ratings allow higher line loadings than static ratings, and to estimate scheduling implications and economic benefits. These benefits include avoided costs for RMR contracts and avoided payments to generators that would otherwise be curtailed.

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. Both technologies will be evaluated according to relative cost, installation considerations, ease of integration with operating systems, and overall accuracy when compared with actual clearance spot measurements.

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. We unfortunately had recent proof in this country of how a seemingly inconsequential local event, a high-voltage line sagging into a tree in Idaho, can quickly cascade, darkening the West Coast from Canada to Mexico and costing billions of dollars to millions of consumers in three countries. There is growing uncertainty in the grid operation environment.

One way to reduce uncertainty is to gather simultaneous and comparable information, convert it quickly to action, and do it 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,” or 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 him/her to handle unexpected distant events.

So much data, however, can overwhelm a human operator. Computer algorithms and models need to be developed that will quickly analyze data and convert them into actionable information. Computer visualization techniques designed around human factors will help. In many unexpected events, a human operator simply can’t observe, understand and react fast enough to prevent failures.

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 by some accountings, 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.

CA ISO and utilities are working together to deploy Phasors technology and provide communication integration so that real-time Phasor information will be available to utilities and CA ISO to run predictive modeling studies allowing dispatchers to securely operate. It is particularly important to develop these tools so that dispatchers know how close to the edge they are operating in a tight power situation in today’s competitive generation market without the tight central control of the pre-deregulation days of vertically integrated utilities.

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 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 their 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 an enhanced transfer capability at the Miguel Substation, improving a significant congestion problem. This congestion issue is also addressed by research work related to real-time system ratings.

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 U.S. 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.

Other Related Areas of Research for Transmission Systems

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

SCE is taking the lead in developing PIER research related 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, including:

- Initial savings from the purchase of competitively priced and industry-qualified equipment.
- The avoided costs of unnecessary retrofit and mitigation.

- Reduced uncertainty in building and equipment design demand parameters and savings due to reduced maintenance costs and loss avoidance.
- Savings from not replacing damaged components following earthquakes.
- Indirect benefits realized by both customers and utility companies from reduced outage times during earthquake response and recovery.

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 additionally 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.

APPENDIX E: REVIEW OF SCE FERC AND CPUC FILINGS FOR THE ANTELOPE TRANSMISSION PROJECT

SCE has filed an application with FERC and CPUC for the construction of the Antelope Transmission Project to integrate future Tehachapi wind generation development. CERTS/EPG was asked to review these two filings and develop a summary comparison, identifying any inconsistencies between the two filings and also identify any operational integration issues.

FERC

Purpose of filing

Requests FERC to issue a Declaratory Order that provides assurance about cost recovery and grants the following:

1. Rolled-in rate treatment for project costs incurred.
2. Recovery of reasonable project costs regardless of full increment of forecast generation.
3. Cost recovery in spite of FERC's abandoned plant policy.
4. Clarify that project trunk-line transmission facilities are eligible to be placed under the CAISO's operational control

CPUC

SCE has made two (2) filings related to this project (Segment 1 and Segment 2-3) BOTH conditionally request a Certificate of Public Convenience and Necessity (CPCN) to permit them to construct the Antelope Transmission Project.

Conditions on the filing:

- The establishment of a clear cost recovery mechanism and assurances by FERC and the CPUC in advance of construction
  SCE's request of the CPUC
- The CPUC participate in the declaratory order proceedings before FERC and advocate to FERC the need and recovery through general transmission rates.
- A finding from the CPUC that FERC's rulings issued at the conclusion of SCE's declaratory order proceeding satisfy the requirements of P.U. Code Section 399.25 (cost recovery)

Project Need

The project is needed to interconnect and integrate potential alternate energy projects

The project is needed to interconnect and integrate potential alternate energy projects

CEC Forecast of Wind Development

The CEC's forecast of wind development in the Tehachapi area, as stated by SCE, is in excess of 4,000 MW

Proposed facilities were designed to accommodate 4.400 MW

Description of the Project

The complete project consists of three (3) segments:

1. Segment 1 – The Antelope to Pardee Transmission Project, consists of 25.6 miles of transmission line between the two substations that is built for operation at 500 kV, but to be initially operated at 220 kV and the associated substation interconnection equipment at each facility. (see Figure 1) The in service date for the project is December 2006, enabling the interconnection of 201 MW of potential wind generation.

   - CAISO has approved this project
   - Project facility can be fully integrated with the transmission network
   - No generation interconnection agreements currently exist
   - Project justification – ordering paragraphs of CPUC Decision 04-06-010

Segment 1 – Same as FERC, with a little more detail about changes in the substations and field (i.e. tower requirements, right-of-way and spur road requirements) and also includes information technology facility requirements

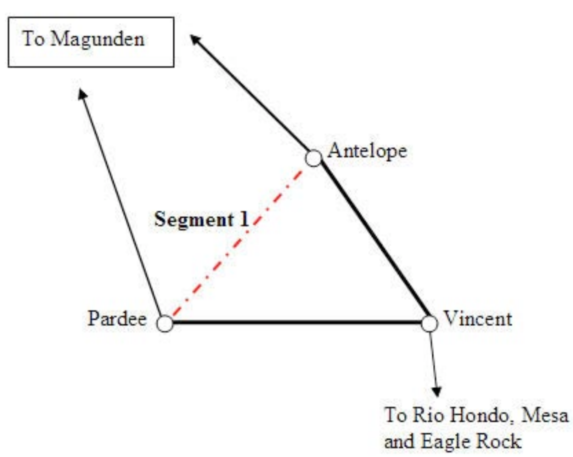


Figure 1 – Segment 1

2. Segment 2 – Antelope to Vincent Transmission

Project consists of 17.8 miles of transmission line between the two substations that is built for operation at 500 kV, but to be initially operated at 220 kV and the associated substation interconnection equipment at each facility. (see Figure 2)

- The in service date – currently some future unknown date.
- Project need – Interconnect and integrate potential alternate energy projects
- CAISO has approved this project
- Project facility can be fully integrated with the transmission network
- No generation interconnection agreements currently exist
- Project justification – ordering paragraphs of CPUC Decision 04-06-010

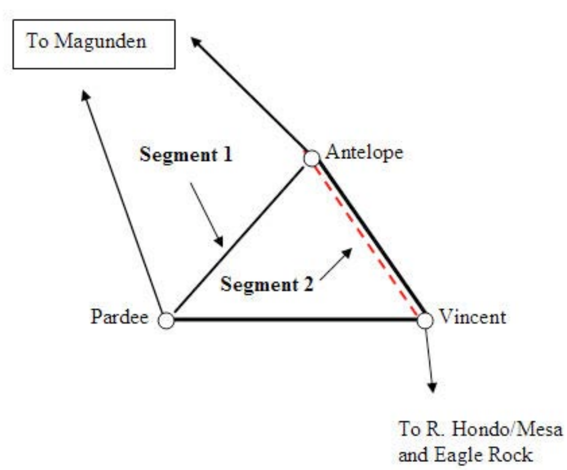


Figure 2 – Segment 2

3. Segment 3 – High Voltage Transmission Lines from Antelope Substation to New Substation #1 and from New Substation #1 to New Substation #2 Transmission Project. The project has four (4) elements (see Figure 3):
   1) Substation #1 a new 500/220/66 kV substation.
   2) Substation #2 a new 220/66 kV substation.
   3) An approximately 25 mile 500 kV transmission line between Antelope and Substation #1, operated initially at 220 kV.
   4) A 9.4 mile 220 kV transmission line between Substation #1 and Substation #2.

Segment 2 – Same as FERC, with a little more detail about changes in the substations and field (i.e. tower requirements, right-of-way and spur road requirements) and also includes information technology facility requirements

- Appendix C contains some additional information line and substation construction requirements.

- The in service date – currently some future unknown date.
- CAISO staff believes this segment is appropriate and reasonable
- Project facilities are built radial of the network and can not be fully integrated with the transmission network
- No generation interconnection agreements currently exist
- Project justification – ordering paragraphs of CPUC Decision 04-06-010

Segment 3 – Same as FERC, with a little more detail about changes in the substations and field (i.e. tower requirements, right-of-way and spur road requirements) and also includes information technology facility requirements.

- The CPUC filing states the 500 kV transmission line between Antelope and Substation #1 is 26.1 miles in length, operated initially at 220 kV.
- Appendix C contains some additional information line and substation construction requirements.

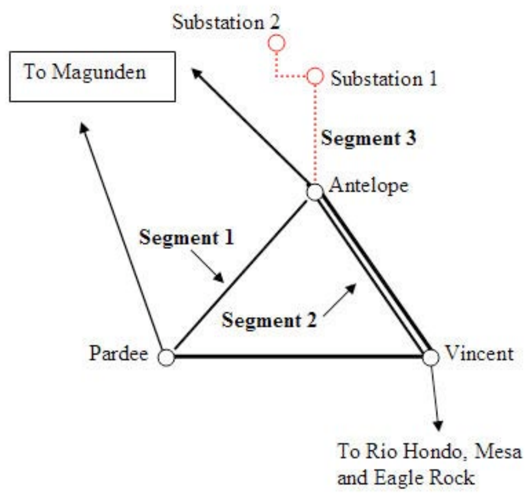


Figure 3 – Segment 3

Project Justification

Ordering paragraphs of CPUC Decision 04-06-010 (see attached).

Order Paragraph No. 8 of CPUC Decision 04-06-010 (see attached).

Discussion - Rolled in Rate Treatment

Project Segments 1 and 2:

- The lines and upgrades associated with these segments are clearly network facilities and will be under the CAISO's operational control.
- Justification for construction of segments 1 and 2 is unknown because no interconnection agreements have been signed.
- Certain entities in California have challenged the inclusion in the CAISO High Voltage TAC rate the costs of network transmission facilities that are primarily for the benefit of particular generators.

Project Segment 3:

- To address a perceived barrier to renewables, SCE has proposed that another narrow and specific category of transmission facilities be added to the present network and generation-tie categories. Eligibility requirements:

- Large concentration of renewables
- Located in a limited geographic area and reasonable distance from existing grid
- Is consistent with a stat's policy requiring procurement of renewables and
- The regulatory authority or ISO have determined upgrades are necessary and meet policy objectives

SCE is requesting a declaratory order to:

- Confirm that Segments 1 and 2 may be reflected in rolled-in rates even without interconnection agreements in place or filed with FERC and
- Clarifying that it is entitled roll-in Segment 3 (trunk-line transmission facility) costs into its FERC jurisdictional TRR and recovered through the CAISO's High Voltage TAC

Discussion - Recovery of Reasonable Costs
The CPUC is ordering a phased expansion plan for the Tehachapi wind area that is based the magnitude of the wind resource identified by the CEC, and other considerations such as engineering, cost, statewide transmission needs and benefits associated with transmission upgrades (CPUC Decision 04-06-010).

- SCE has proposed he Antelope Transmission Project to the CPUC
- SCE has no generation interconnection agreements
- SCE cannot predict the next steps in the process and cannot know if the project will be justified

SCE is requesting a declaratory order to:
Assurance they will be permitted to recover the prudent costs of the project (Segments 1, 2 and 3) regardless of whether a full increment of forecast generation justifying the upgrades commences commercial operation.
Discussion – Project Cost Recovery Even if the Upgrades are Cancelled for Reasons Outside SCE's Control
Provide SCE assurance they will be permitted

to recover 100% and not just 50% of the prudent project costs incurred in the potential generation does not develop as forecast and any of the projects are abandoned or cancelled	
Project Estimated Costs	
No information provided	➢ Segment 1 - $80,300,000 ➢ Segment 2-3 - $127,000,000 and a cost of $204,800,000 if the build out cost of Substation 1 and 2 are included
Application Schedule	
None Provided	SCE provided a detailed proposed schedule for the application proceedings. . ➢ Segment 1 – They are suggesting a final decision by February 2006 ➢ Segment 2-3 – September 2006

APPENDIX F: MAJOR TRANSMISSION PROJECTS

Local Reliability Transmission Projects - Northern California

Project #1: Jefferson-Martin 230 kV line

1. **System value:** The Jefferson-Martin 230 kV Project will allow San Francisco and the Northern Peninsula to continue to reliably serve loads through 2011 while allowing the shutdown of Hunters Point and possibly other aging power plants in the city.
2. **Description:** The Jefferson-Martin 230 kV is an approximate 27-mile transmission line running from the Jefferson Substation in San Mateo County, near San Carlos, to the Martin Substation in Brisbane. The project will be about 50 percent overhead line and 50 percent underground cable and will cost an estimated $212 million.[1]
3. **Status:** The CPUC granted a CPCN in August 2004. The transmission line is expected to be built and operational by the first or second quarter 2006.
4. **Issues:** The CPUC issued the permit for this project based on a record including discussions on reliability implications, alternatives, and strategic benefits.
5. **Planning and Permitting Process:** The planning that resulted in development of the Jefferson-Martin line (and the cable projects inside San Francisco) began in 2000.
6. **Project Benefits:** The CPUC determined that the project was needed for reliability in 2007 but that the strategic, environmental and economic benefits made the project beneficial in 2005.
7. **Consequences of Delays:** Any delays in construction of this project will result in increasing reliance on old fossil plants in San Francisco and a decrease in system reliability. Delays would also require PG&E to delay shutdown of the Hunters Point Power Plant.[2] The thin reliability margin in San Francisco will exacerbate the difficulty of maintaining existing facilities; combined with growing demand in San Francisco a delay will increase the likelihood of power outages

Project #2: San Francisco/Peninsula Long-Term (2011+) Upgrades

1. **System value:** The San Francisco Long-Term Upgrades are designed to eliminate the need for RMR contracts at the Hunters Point and Potrero power plants in San Francisco, while ensuring that reliability is maintained beyond 2011.[3] The upgrades would improve reliability and improve air quality in San Francisco.

2. **Description:** The CA ISO and stakeholders have identified six long-term options:[4]

    1. Do nothing.
    2. Conservation, renewable generation and distributed generation.
    3. Upgrade and replace existing transmission facilities - $114 million.
    4. Trans-Bay DC Cable Project - $275 million.
    5. Moraga-Potrero 230 kV line - $274 million.
    6. Tesla-Potrero 230 kV line - $457 million.

3. **Status:** The Long-Term upgrades are still under study. The stakeholder group has compared alternatives and further studies will be completed on the most promising.[5]
4. **Issues:** Most of the transmission alternatives could have significant permitting hurdles both due to costs and because most of them run through highly populated portions of the Bay Area.
5. **Planning and Permitting:** The San Francisco Peninsula Stakeholder group has been meeting for several years. They studied long-term options, including both transmission and non-transmission alternatives. If a transmission alternative is preferred, both CA ISO board approval and a CPCN will be required (except for the Trans-Bay DC Cable Project, where CPUC jurisdiction remains unresolved).
6. **Project Benefits:** Project benefits will depend on the alternative chosen. All of the alternatives are designed to eliminate the need for RMR contracts with the Potrero Power Plant while maintaining reliability in San Francisco and the Peninsula through at least 2015.
7. **Consequences of Delays:** Some improvements in the San Francisco/Peninsula transmission network will be required for the area to meet reliability standards after 2011. The CA ISO will also need to continue RMR contracts with the Potrero Power Plant.

Project #3: Trans-Bay DC Cable Project

1. **System value:** The Trans-Bay DC Cable Project proposed by Trans Bay Cable LLC (TBC), a subsidiary of Babcock and Brown, and the City of Pittsburg, could eliminate the need for RMR contracts at the Hunters Point and Potrero power plants while ensuring electricity reliability beyond 2011. The upgrades would also improve air quality in San Francisco.
2. **Description:** The Trans-Bay DC Cable Project is an approximate 50-mile cable that would connect the Pittsburg Substation in the East Bay to the Potrero Substation in San Francisco via an underwater DC cable.[6]
3. **Status:** TBC filed at the FERC for the approval of tariff proposals on May 19, 2005. Both SCE and SDG&E have argued that the proposal should not be approved[7]. TBC asked the FERC for a decision by July 1, 2005, but as of

July 6 no decision had been issued. The DC Cable Project is being analyzed as an alternative in the CA ISO's San Francisco/Peninsula Long Term Study.

4. **Issues:** Based on the CA ISO study, the Trans-Bay DC Cable may not be the most efficient alternative for long-term reliability in the San Francisco/Peninsula area. Without CA ISO endorsement the project may not be viable.
5. **Planning and Permitting:** The San Francisco Peninsula Stakeholder Group has been meeting several years. The long-term options have included both transmission and non-transmission alternatives. If the Trans-Bay DC Cable alternative is preferred then CA ISO board approval would be required. The proponent of the project, Babcock and Brown, estimates it could permit and install the cable by 2008.[8]
6. **Project Benefits:** The project would be designed to allow the CA ISO to discontinue RMR contracts with the Potrero Power Plant while maintaining reliability in San Francisco and the Peninsula through at least 2015.
7. **Consequences of Delays:** Improvements in the San Francisco/Peninsula transmission network will be required or the area may not meet reliability standards after 2011. The CA ISO will also need to continue RMR contracts with the Potrero Power Plant if the Trans-Bay cable or one of the other options is not operational.

Project #4: Metcalf-Moss Landing 230 kV Reinforcement Project

1. **System value:** The Metcalf-Moss Landing 230 kV Reinforcement Project is designed to increase the amount of power imported into the San Francisco Bay Area from new power plants in California's Central Valley, Moss Landing, and Morro Bay.
2. **Project Description:** The Metcalf-Moss Landing 230 kV Reinforcement Project would reconductor two 230 kV lines. Each line is approximately 35 miles long and the total project will cost between $29 and $40 million. It is expected to be operating in June 2006.[9]
3. **Status:** The CA ISO approved this project in May 2004 and PG&E is currently developing the application for a CPUC permit.
4. **Issues:** The two transmission lines pass through environmentally sensitive areas. While reconductoring projects are usually categorically exempted from major environmental permitting because of their limited impacts, this project may require a more thorough analysis, which could extend the permitting time.
5. **Planning and Permitting Process:** PG&E determined the need for the Metcalf-Moss Landing Reinforcement Project in its 2003 Electric Transmission Grid Expansion Plan. Two transmission alternatives were considered but generation and conservation alternatives were not considered. The primary goal of the project, in conjunction with the Tesla-Newark 230 kV upgrade, is to increase the network's ability to serve loads in the San Francisco Bay Area.[10]
6. **Project Benefits:** The project would increase the network's ability to serve load in the San Francisco Bay Area.[11]

7. **Consequences of Delays:** If this project is not completed by 2007, the transmission system in the area will continue to reduce delivery of generation from Moss Landing when certain transmission facilities are out of service. This could result in reduced electricity supplies and potential shortages if the outages occur during critical hours.

Project #5: Greater Fresno Area Projects

1. **System value:** Two projects, the Gregg-Henrietta 230 kV Line Reconductoring Project, and the Gates-Gregg 230 kV Double-Circuit Transmission Line, are key projects in the Greater Fresno area. These projects were first identified to serve growing loads in the Fresno area and to allow for greater use of the Helms Pumped Storage Power Plant, which would increase availability of summer peaking power.
2. **Project Description:** The Gregg-Henrietta 230 kV Line is a 45-mile section of the existing Gates-Gregg 230 kV Line. It would be upgraded by reconductoring the existing line and cost approximately $25 million. The Gates-Gregg 230 kV Line would be approximately 60 miles of new double circuit transmission line between the Gates and Gregg substations and would significantly improve the system's ability to deliver power to the greater Fresno area.[12]
3. **Status:** These projects are still in the planning stage. The Gregg-Henrietta 230 kV Reconductoring Project has received CA ISO staff approval but needs approval from the CA ISO board and the CPUC.
4. **Issues:** Both projects are planned and issues will not be identified until the permitting stage. Because the costs are greater than $20 million, both projects will require CA ISO board approval.
5. **Planning and Permitting Process:** The Gregg-Henrietta project will probably be considered 'exempt' in the CPUC permitting process because reconductoring projects generally have few environmental impacts. The Gates-Gregg 230 kV double-circuit transmission line will require a CPCN; but, since it is not needed until 2012, permitting is not yet an issue.
6. **Project Benefits:** Both projects would improve reliability in the Greater Fresno area and improve the use of the Helms Pumped Storage Power Plant.
7. **Consequences of Delays:** Without these projects reliability in the Greater Fresno area may not meet reliability standards beginning in 2012 and the Helms Pumped Storage Power Plant will not be used to its fullest capacity.

Project #6: Sacramento Area Voltage Support Project

1. **System value:** The Sacramento Area Voltage Support Project may be needed to ensure that loads in the Sacramento area are reliably met.[13] The project would also eliminate the need to reduce the output at Sutter Energy Center Power Plant.
2. **Project Description:** This project is the first step in developing a long-term transmission plan for the Greater Sacramento area, assuming no generation is added near the Sacramento load area. This project includes construction

of a new double circuit 230 kV line between the Elverta and O'Banion substations and includes conversion of the existing Sutter-O'Banion line to two separate circuits. Conversion of the Sutter-O'Banion line, was planned as a part of Calpine's Sutter Energy Center (SEC) interconnection, and could be easily accomplished by installing breakers at both ends. The new line would follow the existing line between the Elverta and O'Banion substations; a new corridor is not required. The cost of the project is an estimated $30 to $50 million, including necessary mitigation.

3. **Status:** The Final Environmental Impact Statement (FEIS) for this project was completed and a Record of Decision was issued in January 2004 by the Western Area Power Administration, essentially approving the project and selecting a "proposed action" from the alternatives assessed in the FEIS.[14] The project currently has no funding and will not progress without funding.
4. **Issues:** No major environmental or permitting issues would prevent construction of the Sacramento Voltage Support Project. Efforts to secure funding for the project have been unsuccessful however, though the project would benefit Calpine's Sutter Energy Center generating plant,[15] SMUD, PG&E, the Western Area Power Administration, and the public. Consultation with federal and state agencies is required prior to construction and may result in minor project modifications.
5. **Planning and Permitting Process:** Western is a federal agency and prepared the project's Environmental Impact Statement (EIS) under the National Environmental Policy Act. Planning for the project began in 1996 and permitting began in 2000. An EPA Notice of Availability for the Draft EIS was published in November 2002. Three public hearings were held and guided selection of the preferred alternative. Five transmission alternatives were considered in the EIS, as were local generation and the No Action Alternative. As described above, Transmission Alternative Option A was selected to be the Proposed Action.[16] Western would implement the proposed action under authority of the *Central Valley Project Ac*t.
6. **Project Benefits:** Construction and operation of the project would reduce anticipated curtailments in generation from the Sutter Energy Center and eliminate the need for pre-emptive shedding of 250-400 MW (depending on operating conditions) to prevent voltage collapse. The Sutter Energy Center generating unit may have to be curtailed beginning in summer 2005. This limitation in output will likely be exacerbated in time and could result in reduced electricity supplies and potential shortages if outages occur during critical hours.
7. **Consequences of Delays:** Without the Sacramento Voltage Support Project certain conditions could require load shedding in the Sacramento area to prevent voltage collapse. Generation curtailments from the Sutter Energy Center would also continue, thus limiting available generation in Northern California.

Local Reliability Transmission Projects- San Diego

Project #7: San Diego 500 kV Project

1. **System value:** The SDG&E 500 kV Project would provide a variety of benefits including improved reliability, reduced congestion and increased access to renewable energy sources. The project could also play a key role in California's overall grid plan.
2. **Project Description:** The STEP working group initially selected six potential alternatives for assessment, each containing two and four sub-options, for a total of 18 different alternatives.[17] The screening study performed by the working group reduced the list to four of 18 initial alternatives, and ranked them based upon a composite of reliability, economic, and renewable scores. The four final options under consideration by SDG&E are:
    1. The Imperial Valley substation to the Central substation to the Serrano or Valley substation in the SCE area.
    2. The Imperial Valley to Central substation with two 230 kV lines to the Sycamore Canyon substation.
    3. Imperial Valley to the Miguel substation.
    4. A northern interconnection to the Serrano or Valley substations.

   SDG&E anticipates completing additional studies and selecting a final from among the four alternatives by the end of 2005.
3. **Status:** SDG&E's 500 kV Project is still in the planning stage. The next steps include completing additional reliability and economic studies and selecting one of the four final alternatives. Other steps include CA ISO approval, CPUC approval and WECC path rating approval.
4. **Issues:** There are potential routing and permitting problems. The two highest rated options, Imperial Valley to Central and Imperial Valley to Central to Valley/Serrano, could both run through Anza Borrego Desert State Park, northwest of Imperial Valley, which could cause routing and permitting problems. There are also issues related to the 230 kV Mexicali to Tijuana option because supporters of that project claim that congestion problems limiting imports into San Diego are artificially created by Sempra.[18]
5. **Planning and Permitting Process:** SDG&E has been actively involved in planning for a new 500kv transmission line for at least the past six years.[19] Its most recent work included the Valley to Rainbow 500 kV Project, which was rejected by the CPUC. SDG&E then initiated another effort in October 2004 to identify and evaluate 500kV options to reinforce its 500kV system and meet its reliability, economic, and renewable access goals.[20] SDG&E also formed a working group made up of utility planners, regulators, and interested parties to identify needs, propose transmission options to meet needs and design an approach to evaluate alternative proposals. SDG&E presented its most recent findings from its 500 kV comparison study at the April 27, 2005 STEP meeting.[21]

6. **Project Benefits:** Reliability and economic assessments as well as assessment of specific renewable resources are not completed at this time. It is reasonable to assume, based on previous STEP reliability and economic assessments, that the project would be cost effective for both SDG&E and the CA ISO, and would improve area grid reliability while allowing SDG&E to economically meet RPS goals by 2010 (SDG&E CFM Filing).
7. **Consequences of Delays:** If a new project is not completed by 2010 SDG&E would not be able to meet its resource and planning objectives for reliability, meet state renewable objectives, reduce RMR and congestion costs, and strengthen the regional grid.

Project #8: Lake Elsinore Advanced Pumped Storage Hydro Project (LEAPS)

1. **System value:** The transmission facilities associated with the LEAPS Project would be similar to those of the northern portion of the SDG&E 500 kV Project. This project would improve reliability in San Diego and reduce the cost of serving area loads.
2. **Project Description:** The proposed LEAPS Hydro and Transmission Project is a combined generation/transmission project, located at Lake Elsinore in Riverside County. The LEAPS transmission facility is a proposed 29-mile, 500 kV line with a design capacity of 1,600 MW. The line would connect SCE's Valley-Serrano 500 kV transmission line, north of Lake Elsinore, to a new substation in the northern portion of SDG&E's service area. The project route would be roughly parallel to - but west of - the rejected Valley-Rainbow Project. The LEAPS transmission project cost is estimated at $170 million, not including SDG&E and SCE transmission upgrades.
3. **Status:** Both the hydro and transmission projects are still in the planning stage. Utility Systems Integration Inc. completed a Phase I transmission system study in January 2005.[22] Additional system and economic studies remain. Project sponsors submitted a Notice of Intent to prepare an EIS to the FERC in August 2004. (Federal Register: Aug 13 2004).[23] Sponsors also submitted an application to FERC for a license for the Lake Elsinore Project in November 2004.[24] Project financing is unclear at this point.
4. **Issues:** Permitting for this project may be an issue as a large portion would cross public lands.
5. **Planning and Permitting Process:** Both the generation and transmission components of the project are still in the planning stage and additional technical and economic studies are required for both. The hydroelectric generation component of the project must meet FERC licensing requirements. Since 90 percent of the proposed transmission line would be located on public lands, it would also be subject to requirements of the U.S. Forest Service, the Environmental Protection Agency (EPA), and the Bureau of Land Management (BLM). SDG&E and SCE transmission upgrades required to interconnect LEAPS would be regulated by the CPUC.
6. **Project Benefits:** Project proponents cite a number of grid and public benefits from the project.[25] Technical and economic studies for the project

are still in the early stages and there is no concrete information in this area yet.

7. **Consequences of Delays:** Until technical and economic studies are completed the potential cost of delays is not known.

Project #9: Otay Mesa Power Plant Transmission Project

1. **System value:** The Otay Mesa Power Plant Transmission Project (OMPPTP) would allow delivery of the full output of the Otay Mesa Power Plant to San Diego loads. Because SDG&E signed a long-term (10-year) power purchase agreement with the Otay Mesa Power Plant, this transmission project would reduce RMR costs in San Diego.
2. **Project Description:** The project consists of two new 230 kV circuits to the local San Diego area. One proposed circuit is a 28-mile 230 kV line from the Miguel area north to the Sycamore Valley Substation. The second circuit is a 14-mile 230 kV line running from the Miguel area to the Old Town Substation north of downtown San Diego (the route would include three miles of underground cable in the Chula Vista area and seven miles of undergrounding in downtown San Diego). Each of the circuits would be routed through, but not directly connected to the Miguel Substation and would have switching capability that could be used under some operating conditions. The estimated cost of the proposed project is $209 million.
3. **Status:** SDG&E submitted an application to the CPUC for a CPCN for the project in March 2004, the CA ISO Board of Governors approved the project on May 6, 2005. The CPUC approved the project on June 30, 2005.
4. **Issues:** The Office of Ratepayer Advocates (ORA) raised four issues in the permitting process:
    1. The lack of alternatives analyzed,
    2. The lack of CA ISO board approval,
    3. The piecemeal approach to transmission planning in the SDG&E area and,
    4. The transmission upgrade's potential to substantially increase the cost of the power from the purchase agreement with the Otay Mesa Power Plant.
5. **Project Benefits:** The CPCN Decision rejected the ORA's arguments and determined both that the Otay Mesa Power Purchase Agreement required deliverability of the Otay Mesa Power Plant output to meet SDG&E needs and that the proposed OMPPTP is an appropriate project to fully dispatch resources from the generator into the San Diego area to meet load, address RMR problems, meet reliability requirements, reduce congestion, and help meet increasing load.
6. **Consequences of Delays:** Without the Otay Mesa Power Plant Transmission Project SDG&E will be unable to reduce RMR contracts, congestion costs will continue, and reliability could be compromised.

Project #10: Miguel-Mission No. 2 230 kV Project

1. **System value:** The Miguel-Mission No. 2 230 kV Project would significantly reduce congestion in the San Diego area and could improve the transmission network's ability to deliver renewable resources from the Imperial Valley region.
2. **Project Description:** The Miguel-Mission No. 2 230 kV Project includes a new 35-mile line and improvements to the Miguel Substation.
3. **Status:** On July 8, 2004, the CPUC granted SDG&E a CPCN for the Miguel-Mission No. 2 230 kV Project. The first phase, the Miguel Substation improvement, was completed in October 2004. Phase 2 is on schedule and should be completed by June 2006. An interim upgrade was completed in June 2005 to ensure higher levels of reliability during summer 2005, prior to completion of Phase 2 of the project.
4. **Issues:** There are no remaining issues for this project.
5. **Project Benefits:** The CPUC decision found that the project would save ratepayers approximately $4 million per month in congestion costs.
6. **Consequences of Delays:** Since this project will reduce transmission congestion in the San Diego area, delays would cause congestion costs to continue to rise.

Local Reliability Transmission Project: SCE Area

Project #11: South of Lugo Congestion Mitigation (Vincent – Mira Loma 500 kV Transmission Line)

1. **System value:** The Vincent Substation to Mira Loma Substation 500 kV line may be needed by 2009 or 2010 to reliably serve growing loads in Southern California.
2. **Project Description:** The proposed Vincent-Mira Loma 500 kV Line is an approximate 77-mile single circuit 500 kV transmission line. The need for the line was identified in the CA ISO Controlled SCE Transmission Expansion Plan 2005-2014.
3. **Status:** The project is still in the planning stage and will require both CA ISO board approval and a CPCN from the CPUC.
4. **Issues:** It is still too early to identify significant issues associated with the planning, permitting and construction of this project.
5. **Planning and Permitting:** The Vincent-Mira Loma 500 kV Project was identified in the SCE 2014 Transmission System Long Range Plan (CA ISO Controlled Transmission Expansion Plan). The line would help deliver generation from the Tehachapi region and would need to be upgraded to support Tehachapi wind development.
6. **Project Benefits:** The Vincent-Mira Loma 500 kV Project will allow SCE to reliably serve growing loads in Southern California through 2014.
7. **Consequences of Delays:** Any delays in the planning and permitting could mean that the Vincent to Mira Loma 500 kV line could not operate in time to prevent violation of reliability standards south of Lugo.

Congestion-related Projects

Project #12: Path 26 Upgrades

1. **System value:** Path 26 is the main path limiting the delivery of power into Southern California from Central and Northern California. Upgrading Path 26 will improve summer resource adequacy concerns in Southern California.
2. **Project Description:** Starting on June 23, 2005, the rating on Path 26 increased from 3,700 MW to 4,000 MW.[26] The rating increase was achieved by improving remedial action schemes protecting the transmission system during disturbances by automatically reducing output from key generators. Major upgrades to Path 26 are being discussed as part of a northern interconnection for renewable generation in the Tehachapi region.
3. **Status:** The upgrade requires WECC approval and is far enough along in the approval process to allow for the increased rating.
4. **Issues:** There are no remaining issues.
5. **Planning and Permitting:** The planning and permitting for this project are complete.
6. **Project Benefits:** Increasing the transmission system's ability to move power from north to south into Southern California will help mitigate Southern California resource adequacy issues.

Project #13: Blythe Area Transmission Proposals

1. **System value:** The Blythe area is located near the California/Arizona border, far from load centers in Southern California. Power plants in the Blythe area could, therefore, supply lower-cost energy - like that produced in Arizona and other parts of the Southwest - to California if adequate, long-term transmission capacity from Blythe to the CA ISO grid is available. Tying the proposed Blythe-area generators to the PVD1 and No. 2 lines through the proposed Midpoint Substation would allow generators to deliver their power to Southern California.
2. **Project Description:** A 520 MW natural gas-fired power plant, Blythe Energy Project (BEP), interconnected to Western's Buck Blvd. Substation and currently operates in the Blythe area. However, the plant cannot deliver its full power output to the CA ISO grid due to limited firm transmission capacity. A second proposed 520 MW natural gas-fired plant, the Blythe Energy Project II (BEP II), is under permit review at the Energy Commission. The transmission proposals allowing delivery of some or all of the generation from the above plants to the load centers of the Southern California CA ISO grid area are:
   a. The Blythe Energy Project Transmission Line (BEPTL) modification plan, consisting of two transmission lines from Western's Buck Blvd. Substation; one would be a 67.4-mile single circuit 230 kV line to SCE's Julian Hinds Substation and the other a 6.7-mile 230 kV single circuit line to a new Midpoint Substation that would loop to the existing PVD 500 kV line (PVD1) and possibly to the proposed PVD2 500 kV

line. The plan includes upgrades and modifications at the Buck Blvd. and Julian Hinds substations. The BEPTL would provide adequate firm transmission capacity for delivery of the full power output of the BEP plant to the CA ISO grid. As the project sponsor, Blythe Energy is willing to fund the entire cost of the construction and operation of the new transmission lines.

b. The proposed Desert Southwest Transmission Project (DSWTP), sponsored by Desert Southwest Power, LLC, is a 118-mile 500 kV line from Western's Buck Blvd. Substation to SCE's Devers Substation. The DSWTP would, among other objectives, provide adequate transmission capacity for the proposed BEP II Plant in order to deliver power to the CA ISO grid.

3. **Status:** The BEPTL modification plan is a petition to amend the Blythe Energy Project, and is under review at the Energy Commission. A decision could be made by early 2006. The Draft Environmental Impact Statement/Environmental Impact Report (EIS/EIR) for the DSWTP is complete but the final report has not yet been published by BLM and the project sponsors. In order to integrate the DSWTP and PVD2 line projects as a single line project, Desert Southwest Power, LLC, and SCE are discussing a "Midpoint Substation" at Blythe which would provide an intermediate termination point for both the PVD1 and PVD2 lines and eliminate the need for a separate DSWTP line between Blythe and Devers.
4. **Issues:** No significant issues have been raised for either transmission proposal.
5. **Planning and Permitting:** The BEPTL modification plan requires an amendment to the existing Energy Commission permit. The amended permit is expected by December 2005. The DSWTP line itself may not move forward until the Energy Commission decision on the BEP II plant permit, which is dependant upon both its transmission option and upon receipt of system studies by Western and SCE, and CA ISO approval. WECC Path rating review will also be required. However, if the DSWTP is integrated into the PVD2 line, no separate approval will be required.
6. **Project Benefits:** The full output from the newly-built BEP plant and the proposed BEP II plant could not be delivered to load centers in Southern California on a firm and economic basis without either the above BEPTL and the DSWTP transmission projects or similar projects like the PVD2 line from the Blythe area to Southern California. The transmission proposals have the following benefits:
   - Provide cost effective energy to the California market.
   - Increase necessary generating capacity and reserve margins in California.
   - Provide energy to California with fewer transmission losses than power generated in the Southwest.
   - Relieve transmission congestion at a bottleneck in Southern California currently at issue.

7. **Consequences of Delays:** Any delays in building additional transmission lines from the Blythe area to Southern California will prevent the energy from newly-built efficient plants to reach the California market on a firm and economic basis.

Project #14: Short-term STEP Upgrades[27]

1. **System value:** The Short-Term STEP Upgrades would give Southern California greater access to low-cost generation in Arizona and other portions of the Desert Southwest.
2. **Project Description:** The Short-Term STEP Upgrades incorporate six separate improvements at various substations in Southern California and the Southwest. The CA ISO portion of these upgrades will cost approximately $148 million and would increase the import capability from Arizona to California by 500 MW.
3. **Status:** On June 24, 2004, the CA ISO approved the Short-Term STEP Upgrades. SCE and SDG&E are expected to have these upgrades operating by June 2006.
4. **Issues:** There are no identified issues for this project.
5. **Planning and Permitting:** The Short-Term Upgrades were identified in the STEP process. Most of the upgrades are exempt from major permitting.
6. **Project Benefits:** The CA ISO estimates annual savings to participants at $62 million compared with an annual cost of $26 million.[28]
7. **Consequences of Delays:** If this project is delayed the estimated annual net savings of approximately $36 million will not be realized.

Project #15: PVD2 500 kV Transmission Project

1. **System value:** The PVD2 Project significantly reduces congestion on transmission facilities linking California to Arizona. The project will increase California's ability to import less costly power.
2. **Project Description:** The PVD2 500 kV Transmission Project proposed by SCE is a major new transmission line connecting Southern California to Arizona and the Desert Southwest. The project would be located in the existing corridor used by the PVD1 500 kV transmission line and is scheduled to be completed by summer 2009. The project consists of a new 500 kV transmission line from the Harquahala Substation in the Palo Verde area in Arizona to the Devers Substation in Southern California. Several other system improvements, including the upgrade of four 230 kV transmission lines west of the Devers Substation, are part of the PVD2 Project. The project is expected to cost $680 million in 2009 dollars.
3. **Status:** SCE received approval for the project from the CA ISO on February 24, 2005. SCE filed a CPCN application for the PVD2 Project on April 12, 2005, and a decision is expected 12 to 18 months from the application date. Several other environmental consultations and approvals will be required. On May 15, 2005, LADWP filed a written demand requesting that SCE remove

its application for the PVD2 project because LADWP was exercising its option to pursue the project.[29]

4. **Issues:** At this time there are no major environmental or permitting issues, other than the CPCN process at the CPUC, which would prevent construction of the PVD2 Project. Other issues could delay or modify the project:
    a. LADWP has decided to exercise its option to develop the PVD2 Project, which could delay the permitting and planning. The exact implications of this development are currently unknown.
    b. The PVD2 Project will cost an estimated $608 million in 2009 dollars. Without an approved methodology for analyzing potential benefits, the CPUC view of the project's cost effectiveness is uncertain.
    c. The transmission interconnection of generation projects in the Blythe area may result in changes to the PVD2 Project.

5. **Planning and Permitting:** A consortium of utilities, generators and other stakeholders in California and the Southwestern United States developed the STEP. The plan was driven by generation development in the Southwest, which could benefit California ratepayers if the transmission paths connecting California and the Southwest are improved. Both the need for the project and potential environmental impacts will be issues in the permitting process.
6. **Project Benefits:** The primary benefit of the PVD2 Project is to increase California's access to new generation in Arizona and the Desert Southwest. Both the CA ISO and SCE estimate that electricity generated in Arizona will remain less expensive than generation in California, both because of land use and environmental issues and because of natural gas costs.

    a. SCE estimates the PVD2 net benefits to CA ISO participants at $419 million over the life of project, which is a 1.7:1 benefit-cost ratio[30].
    b. The CA ISO studied the PVD2 Project under a number of scenarios and estimated the annual benefit to cost from 1.2 to 3.2 to 1.
    c. Because of increased load growth in Arizona and Southwest Nevada, SCE does not believe the PVD2 Project will relieve summer supply adequacy concerns[31].

7. **Consequences of Delays:** Delaying the PVD2 Project will slow the accrual of savings to CA ISO participants.

Transmission for Renewable Energy Projects

Project #16: Tehachapi Area Renewable Interconnection

1. **System value:** The Tehachapi area is critical to development of renewable wind resources in California. Significant new transmission facilities are required to deliver any new Tehachapi generation to loads in California.

2. **Project Description:** The conceptual transmission plan is a three-phase development that would be gradually upgraded depending on the quantity and location of new wind generation. All three phases would accommodate 3,700 MW of new Tehachapi wind generation.
    a. Phase 1 would accommodate 700 MW of new generation at an estimated cost of $200 million. Phase 1 consists of three parts:

        1. A 500 kV line between the Antelope and Pardee substations.

        2. A 500 kV line connecting the Antelope Valley Substation to the Vincent Substation, with a second 500 kV line from Antelope Valley to the Tehachapi Substation.

        3. A 230 kV collector system near the Tehachapi Substation.
    b. Phase 2 is the upgrade of the Antelope – Mesa 230 kV transmission line, which would accommodate an additional 900 MW at an estimated cost of $281 million.
    c. Phase 3 consists of the Tehachapi-Vincent 500 kV line and not-yet-defined interconnections north to the PG&E transmission network. The Tehachapi-Vincent 500 kV line would serve an additional 750 MW of new generation and cost $66 million. The PG&E interconnection is still being studied.
    d. Phase 4 is still being studied and would consist of a stronger interconnection to the PG&E system.
3. **Status:** SCE has applied for a CPCN at the CPUC for the first stage of Phase 1. If SCE is able to maintain the current schedule, this phase should be completed by June 2007. The current schedule projects completion of all three stages of Phase 1 by June 2008. Phase 2 is scheduled for completion by June 2009. The Phase 3 Tehachapi-Vincent 500 kV line is scheduled for completion by January 2010. The PG&E upgrades are still being studied.
4. **Issues:** The Tehachapi upgrades provide a new concept in transmission and generation planning called the renewable trunk line, which is needed to deliver power from multiple remote generators to load centers. If the trunk line (or lines) is constructed and the generation never materializes, it could result in a stranded transmission resource. The significant number of new transmission lines and substations in potentially sensitive environmental areas could have significant environmental impacts.
5. **Project Benefits:** The Tehachapi 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 standards by 2010.
6. **Consequences of Delays:** Any delays in the planning and permitting for the Tehachapi area would reduce competition in renewable resource solicitations used by utilities to access the renewable generation needed to meet RPS targets. In the worst case, if transmission is not developed in the Tehachapi area, some California utilities may not be able to meet their RPS targets by 2010.

Project #17: Imperial Valley Transmission Upgrades

1. **System value:** Developers estimate that an additional 1,350 to 1,950 MW of geothermal potential in the Imperial Valley area could be developed over the next 15 years. Geothermal generation in the Imperial Valley would provide a significant source of renewable energy needed by California utilities to meet their RPS goals. The Imperial Valley area will require both a collector system and transmission facilities similar to the SDG&E 500 kV transmission project discussed earlier in this chapter.
2. **Project Description:** The Imperial working group initially identified seven transmission alternatives for study, based on proposals from group participants. All of the alternatives assumed 230 kV interconnections from geothermal generation facilities south of the Salton Sea to the Banister and Midway substations. 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. All of these cases assume a new SDG&E 500 kV line from Imperial to a new San Felipe Substation and then to either SDG&E's Central or Northern substations[32].
3. **Status:** The transmission component of the Imperial Valley Geothermal Project is still in the planning stage. As noted above, technical studies have been used to assess seven transmission alternatives, five of which were rejected by the study group. Additional technical studies are underway and the CA ISO will conduct an economic analysis of the project once these are refined.
4. **Issues:** The work group has identified several potential permitting and land use issues. BLM policies could be a major impediment to permitting since BLM's desert conservation plan does not include the Imperial Irrigation District's (IID's) proposed transmission corridors. (February 18, 2005 study group minutes.)
5. **Planning and Permitting:** The Imperial Valley Work Group is forming a permitting work group to both consolidate permitting of the overall generation and transmission development project and to notify and involve concerned state, county and federal agencies.[33]
6. **Project Benefits:** Coordinating additional geothermal development and transmission expansion work should be beneficial.. It should provide a predictable schedule that will enable developers to coordinate resource development, transmission expansion, and project permitting, and should also enable utilities to include predictable amounts of geothermal electricity in their resource portfolios. Finally, it should provide an additional 1,300 to 2,200 MW of geothermal energy to meet WECC loads.
7. **Consequences of Delays:** At this time there is no fixed development schedule, although a 2014 date is a "soft target." Nevertheless, the consequences of delaying development of the project could delay inclusion of renewable resources in utility portfolios.

Regional Transmission Projects

Project #18: The Frontier Project

1. **System value:** The Frontier Project would improve the transmission network in the western United States. The project would connect potential wind and coal generation in Wyoming and Montana to loads in other parts of the West, which would in turn reduce dependence on natural gas for electricity generation.
2. **Project Description:** The proposed Frontier Project is a multifaceted generation and transmission project. It would develop coal and wind resources in the Rocky Mountain area and transport power from those sources to other Western states. Tentative plans for the Frontier Project include two phases:
    A. Phase 1 calls for the development of 3,900 MW of new coal and wind generating resources in the Wyoming-Montana area for distribution within the Rocky Mountain footprint – Utah, Idaho, and Colorado. Phase 1 also calls for the addition of new transmission facilities and reinforcement of existing facilities to distribute power from these sources to Rocky Mountain area load centers.34 Phase I transmission upgrades within the Rocky Mountain area are estimated to cost $970 million and include:[35]

        i. The Montana System Upgrade.
        ii. The Bridger Expansion Project.
        iii. The Wyoming to Colorado Project.

    B. Phase 2 anticipates development of another 3,900 MW of coal and wind generation for export to Nevada, Arizona, and California load centers. This phase would also require upgrading existing transmission facilities and adding new transmission capacity to access other Western markets and would cost an estimated $4.6 billion.36 The proposed facilities include:

        i. A 500 kV AC transmission project connecting coal and wind resources in Montana and Wyoming to load centers in Arizona, Nevada, and either Northern or Southern California.
        ii. Upgrading the Intermountain Power Project-Adelanto DC line.
        iii. Additional transmission upgrades within the Rocky Mountain area to facilitate export to other Western load centers.

3. **Project Status:** The Frontier Project is in the pre-feasibility stage and proponents are taking steps to move the project forward. Proponents are securing participation by affected state political leaders, involving the business community in supporting the project, and obtaining participation and

coordination with state and regional planning organizations. Specific actions include:[37]

A. Agreement on a Memorandum of Understanding (MOU) by the Governors of California, Nevada, Utah and Wyoming to endorse the project and commit resources for a project task force to further assess issues, needs, and potential project benefits.
B. Formation of a Coordination Committee by MOU signatory states to perform further studies concerning the feasibility of the Frontier Project.
C. Briefings of key government officials and agencies in the affected states, at FERC, and congressional representatives from participating states.
D. Assessment of business models for project financing and promotion of business participation in the project.
E. Formation of the Wyoming Infrastructure Authority, with $1 billion in bonding authority to facilitate major transmission expansions in the area (completed in June 2004).
F. Securing the agreement of CA ISO management to provide technical support for the project.

4. **Project Issues:** The Frontier Line raises numerous regulatory and permitting problems associated with multi-state transmission projects financed and permitted by different state entities with potentially different rules for determining project need and different environmental and land use regulations governing transmission siting.
5. **Planning and Permitting Process:** The project is based on transmission studies performed by the Rocky Mountain Area Transmission Study Group (RMATS).[38] RMATS relies on regional planning studies performed by the Seams Steering Group (SSG-WI) and the modeling approaches and study assumptions used by that group to develop its west-wide congestion and resource assessment studies in 2003.[39] At this point no integrated transmission planning procedure is proposed for the Frontier Project. The proposed project is based on planning and analytical work performed by the RMATS group and is in the "pre-feasibility" stage. Sub-regional transmission studies are also underway separately by the CA ISO for California and STEP for integrating Southwestern and California power markets. Work to coordinate interstate transmission permitting procedures is underway but in an early stage.
6. **Project Benefits:** Project benefits identified in the RMATS study include greater fuel diversity, the capability of coal and wind generated resources to hedge against fuel price volatility from gas fired generation, and increased Western access to new wind generation resources to help meet renewable portfolio requirements. The RMATS studies estimate energy savings for both phases of the Frontier project.[40]

- Phase 1 focused on Rocky Mountain area savings, and estimates production cost savings (benefits) between $290 million and $1.1 billion per year for a 2013 test year.
- Phase 2, the export case, estimates production costs savings between $325 and $399 million a year for California and significantly lower savings for Nevada and Arizona.

7. **Consequences of Delays:** Proponents of the Frontier Transmission Project claim that the consequences of delaying or not developing the Frontier Project will increase reliance on gas-fired generation throughout the West, cause failure to take advantage of viable renewable wind resources, and result in increased costs to consumers in the Rocky Mountain area, California and other Western states.

Project #19: Northern Lights Transmission Project

1. **System value:** The Northern Lights Project would improve the transmission network in the Western United States. The project would both connect potential cogeneration developed in conjunction with Oil Sands development in Northern Alberta, Canada, and provide power to California and the rest of the Western United States.
2. **Project Description:** Northern Lights Transmission proposes two 500 kV DC transmission lines that would run from Alberta, Canada, to sites in the Western United States. One line, the Celilo Project, would extend 1,100 miles from Southern Alberta to Celilo, and The Dalles, in Oregon, and connect to the Pacific Northwest Intertie. The Inland Project would be a 1,700-mile project extending from the Fort McMurray area in Eastern Alberta to sites in Montana, Idaho, and Las Vegas. The Inland Project could also transmit coal and wind energy produced in the Rocky Mountain area to these sites and be compatible with the Frontier Project. Each line would be able to transmit between 2,000 and 3,000 MW of power and would cost a combined $2.8 to $3.4 billion.[41]
3. **Project Status:** Transmission planning appears to be at a very conceptual stage at this time. No transmission studies have been performed to identify potential reliability or congestion issues related to connection to the Western Interconnection grid.
4. **Project Issues:** The project appears to be too early in the development stage to identify issues that might be associated with its planning, permitting, financing, cost recovery, or other areas. One potential issue is the apparent overlap between the proposed Northern Lights Transmission Project and some aspects of the Frontier Project.
5. **Planning and Permitting Process:** Project planning and permitting for the Northern Lights Project would require coordination both with utilities and sub-regional planning groups in affected states, and with state and local regulators responsible for permitting transmission projects.
6. **Project Benefits:** No information on project benefits to California is available.

7. **Consequences of Delays:** Without transmission to deliver potential generation from the Oil Sands region of Alberta, developers could choose to forgo the cogeneration opportunity and a significant source of generation in North America could be lost.

Project #20: Southwest Intertie Project (SWIP)

1. **System value:** The SWIP in conjunction with proposed coal generation would serve loads in the Desert Southwest and increase the energy available for import into California.
2. **Project Description:** The SWIP was initially proposed by the Idaho Power Company in 1989 as a 500 kV, 520-mile transmission project from Midpoint Idaho to Dry Lake Valley, Nevada, near Las Vegas. The purpose of the project was to enable seasonal power exchanges between the Pacific Northwest and the Desert Southwest. Project proponent L.S. Power Associates (LSPA) plans to build the SWIP in conjunction with a 600-1,600 MW coal-powered plant. In 2000 the cost of the SWIP was an estimated $350 million.[42]
3. **Project Status:** An EIS for the project was completed by the BLM in 1994 and a Record of Decision was issued on December 14, 1994. The Record of Decision permitted granting of a public land right-of-way to Idaho Power for the construction, operation, and maintenance of the 500kV, 520 mile SWIP.[43] The project was subsequently put on indefinite hold until market conditions improved. In April 2005 LSPA announced its intention to move forward with the SWIP Project.
4. **Project Issues:** As noted above, LSPA and Idaho Power have recently signed an agreement enabling LSPA to acquire the transmission and right-of-way rights to the SWIP. Significant environmental work has been completed.
5. **Planning and Permitting Process:** Most of the permitting for the project has been completed.

Project #21: East of River 9000+ Project

1. **System value:** The East of River (EOR) 9000+ Project could increase EOR transfer capability from 8,055 MW to 9,300 MW and increase economic transfers between the Desert Southwest and California. The project complements SCE's PVD2 Project[44].

2. **Project Description:** The EOR 9000+ Project includes the upgrade of three 500 kV transmission lines between Nevada and Arizona, adding as much as an additional 1,245 MW to the EOR transfer capability and increasing the EOR path rating from 8,055 to 9,300 MW. The project is sponsored by the Salt River Project and LADWP, among others. It was also discussed and assessed in the STEP process. The project is estimated to cost between $24 million and $85 million, depending upon how it is configured.

3. **Project Status:** The EOR 9000+ project is currently under review in the WECC Path Rating Process.

4. **Project Issues:** No issues have been identified for the EOR 9000+ Project.

Endnotes

[1] Transmission Project Watch List, May 03, 2005.

[2] California Public Utilities Commission, *Opinion Granting a Certificate of Public Convenience and Necessity, Jefferson – Martin 230 kV Transmission Project*, August 2004).

[3] CA ISO, April 1, 2004, *San Francisco Peninsula Long-Term Transmission Planning Study Phase 2 Study Plan,* Folsom, CA, page 6.

[4] Pacific Gas and Electric, March 9, 2005, *San Francisco Phase II Study, Preliminary Cost Estimates and Discussion of Routes, Permitting and Schedules, Draft*, San Francisco, CA , page 2.

[5] Ibid., pages 3-10.

[6] Ibid., page 10

[7] Electric Utility Week, June 20, 2005, California Section, Page 19.

[8]Pacific Gas and Electric, March 9, 2005, *San Francisco Phase II Study, Preliminary Cost Estimates and Discussion of Routes, Permitting and Schedules, Draft*, San Francisco, CA, page 10.

[9] Pacific Gas and Electric, December 17, 2004*, PG&E's 2004 Electric Transmission Grid Expansion Plan, Final*, San Francisco, CA, Page 2-70.

[10] Pacific Gas and Electric, *Bay Area Bulk Transmission Reliability Improvement Project*, Jun 23, 2003, San Francisco, CA, Pages 11-13.

[11] Ibid, Pages 11-13.

[12] Pacific Gas and Electric, *PG&E's 2003 Electric Transmission Grid Expansion Plan*, San Francisco, CA, pages 1-226 to 1-228.

13 Western Area Power Administration, *Sacramento Area Voltage Support Final Environmental Impact Statement*, September, 2003. Pages ES-2 and ES 3

[14] Federal Register, Volume 69, No. 7, Monday, January 12, 2004/Notices. Page 1721, Sacramento Area Voltage Support Record of Decision.

[15] The SEC is a 500 MW project located 30 Miles north of Sacramento and began commercial operation in 2001.

[16] Western Area Power Administration, *Sacramento Area Voltage Support Final Environmental Impact Statement*, September, 2003, Sacramento, CA

[17] Ibid. p. 16.

[18] Utility Consumers' Action Network, Shames, Michael*,* April 21, 2005
Letter to Armie Perez, CAISO, reference "Artificial Creation of Transmission Congestion by Sempra to Generate Congestion Mitigation Payments and Justify New 500kV line, San Diego, CA.

[19] SDG&E is considered as a "local reliability area" which is characterized by limited internal generation resources and by limited transmission access to imports from outside the area. Due to these circumstances it has been subject to frequent reliability problems and to market power abuses in the past. It also experiences high congestion and RMR costs because of these conditions.

[20] San Diego Gas & Electric, April 27, 2005, *Study Plan for SDG&E's Transmission Comparison Study, October 2004 and SDG&E Transmission Comparison Study*, p. 4.

[21] Ibid., p. 4.

[22] Ibid., p. 4.

[23] Federal Energy Regulatory Commission. ; January 25, 2005, *Elsinore Municipal Water District and The Nevada Hydro Company, Inc., Notice of Application Accepted for filing and Soliciting Motions to Intervene, Project No 11858-002.*

[24] Federal Energy Regulatory Commission, January 25, 2005, "*Notice of Application Accepted for filing and Soliciting Motions to Intervene;" Project No 11858-002*.

[25] Ibid., Sponsor Presentation.

[26] Western Electric Coordinating Council, May 9, 2005, *Approved 2005 Summer OTC Limits*, Vancouver, WA, page 4.

[27] CA ISO, March 8, 2004, *Southwest Transmission Expansion Plan 2003 Status Report*, Folsom, CA, Pages 20-23. http://www1.caiso.com/docs/2004/03/08/2004030814004810105.doc

[28] CA ISO, June 24, 2004, *Board of Governors, 6-24-2004, STEP Transmission Upgrades*, Folsom, CA http://www.caiso.com/docs/09003a6080/31/ac/09003a608031ac4d.pdf.

[29] Los Angeles Department of Water and Power, May 16, 2005, Protest of the City of Los Angeles Department of Water and Power, California Public Utilities Commission Application No. 05-04-015, Los Angeles, CA.

[30] Southern California Edison, April 11, 2005, Proponent's Environmental Assessment- Devers- Palo Verde No. 2 Transmission Line Project (Volume I), Rosemead, CA, Page 3.

[31] Ibid., page 4.

[32] David L. Barajas, P.E., February 10, 2005, Imperial Valley Study Group, "Study Alternatives."

[33] Imperial Valley Study Group 4/12/05 meeting minutes.

[34] Rocky Mountain Area Transmission Study, September 2004, Rocky Mountain Area Transmission Study, Connecting the Region Today for the Needs of the Future, pp 3-5. http://psc.state.wy.us/htdocs/subregional/FinalReport/reportcover.pdf

[35] Ibid., page 2.

[36] Ibid., page 56.

[37] The Frontier Line: A transmission project for the American West; Press Release http://psc.state.wy.us/htdocs/subregional/Frontierline040105.pdf

[38] The Frontier Line: A transmission project for the American West; Press Release http://psc.state.wy.us/htdocs/subregional/Frontierline040105.pdf

[39] Seams Steering Group- Western Interconnection, October, 2003, *Framework for Expansion of the Western Interconnection Transmission System, October, 2003.* http://www.ssgwi.com

[40] Ibid., chap 3, pp 7-9.

[41] The Northern Light Transmission Website contains materials summarizing various aspects of the project with links describing the transmission project, cogeneration oil extraction methodologies, and oil and electricity development potential. (www.northernlighttransmission.)

[42] Western Interconnection Biennial Transmission Plan, July 2002, pp 103-104.

[43] Ibid., BLM Record of Decision.

[44] CA ISO Department of Market Analysis & Grid Planning, February 24, 2005, *Board Report-Economic Evaluation of the Palo Verde-Devers Line No. 2*, Folsom, CA.