Attachment 8
California Energy Commission Transmission Planning Report

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PLANNING FOR CALIFORNIA'S FUTURE TRANSMISSION GRID

REVIEW OF TRANSMISSION SYSTEM, STRATEGIC BENEFITS, PLANNING ISSUES, AND POLICY RECOMMENDATIONS

CONSULTANT REPORT

Prepared For:
California Energy Commission

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Consortium of Electric Reliability Technology Solutions

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FOREWORD

Electric Power Group, LLC (EPG), prepared this report under the auspices of the Consortium of Electric Reliability Technology Solutions (CERTS)[1]. The CERTS Program Manager is Joseph Eto, Lawrence Berkeley National Laboratory. The project was funded by California Energy Commission, Don Kondoleon, Project Manager.

[1] CERTS is currently conducting research with funding from the U.S. Department of Energy (DOE) Transmission Reliability Program and the California Energy Commission. CERTS is working with electric power industry organizations, including ISOs, RTOs, NERC, and utilities. CERTS members include Electric Power Group, Lawrence Berkeley National Laboratory, Oak Ridge National Laboratory, Pacific Northwest National Laboratory, National Science Foundation, Power Systems Engineering Research Center (PSERC), and Sandia National Laboratories.

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EXECUTIVE SUMMARY

California's investments in its transmission grid and interconnections to neighboring states have produced substantial reliability, economic, environmental, and fuel diversity benefits. Since the late 1960s, the investments in interconnections have totaled approximately $4.1 billion. These investments have produced substantial benefits as summarized below:

- Import capability of 18,170 MW. The equivalent amount of peaking capacity from power plants would require an investment of approximately $10 billion.
- Access to hydro, coal, geothermal, wind, and nuclear power from outside of California.
- Import of California utility-owned or -contracted generation totaling nearly 6,000 MW from the Desert Southwest (DSW) and Utah.
- Reduction in required planning reserves of 1,500 to 2,500 MW with an associated present value savings of $750 million to $1.3 billion.
- Savings from energy imports totaling $7.2 billion from the Pacific Northwest (PNW) and $5.7 billion from the DSW.

The California Independent System Operator's (CAISO) authorized Transmission Access Charge (TAC) for 2003 is approximately $390 million and equates to a cost of approximately 0.2¢/kWh or $2/MWh. If the State of California took a proactive role and invested $3 billion in strategic transmission interconnections over the next two decades, the rate impact would be equivalent to the current CAISO transmission access charge and represent approximately a 0.2¢/kWh or $2/MWh increase, or less than 2% increase in residential rates. The issue for policy makers is whether or not the benefits associated with strategic transmission assets justify the minor rate impact over time. The benefits associated with California's strategic transmission assets are:

- Reliability
- Access to markets
- Fuel diversity
- Environmental
- Insurance against contingencies
- Replacement for aging power plants

California needs to resume its leadership in the Western Interconnection to develop strategic interconnections, invest in technologies to improve utilization of existing transmission infrastructure, and develop new approaches to planning and valuing transmission investments. A summary of the specific recommendations for California transmission is outlined below:

- Develop a long-term strategic vision and plan for California’s Grid of the Future.
- Simplify regulatory review/approval processes and provide greater certainty associated with cost recovery and cost allocation.
- Work with Western states to develop a coordinated approach to regional resource and transmission development.
- Formulate a policy on the appropriate level of investment for strategic transmission interconnections as insurance against contingencies and market disruptions.
- Review planning and project evaluation methodologies to incorporate strategic benefits of transmission in planning and regulatory approval process.
- Develop plans to access developing markets in the Western Interconnection and achieve cost-effective fuel diversity.
- Develop a technology plan to maximize existing transmission infrastructure utilization and create the future transmission grid.
- Identify actions that can be taken in the short term that will enhance and expedite California’s long-term strategic development and expansion of the Extra High Voltage (EHV) system.

INTRODUCTION

Reliable electricity at affordable prices is critical to support California's growing population and economy. California's transmission grid and interconnections with other states and regions in the Western Interconnection (14 states, 2 Canadian provinces, and Mexico) are critical to meeting reliability, environmental, and economic goals. California's transmission grid is designed to reliably move power within the state and deliver it to consumers. California's interconnections to other regions total over 18,000 MW or approximately one-third of its peak load requirements. Much of this system was developed in the 1970s and 1980s. New transmission developments and investments have lagged behind load and population growth due to regulatory uncertainty, local opposition, industry restructuring, long development lead times, uncertain and changing approval processes, concerns about inadequate returns on investment, and other factors.

Transmission deficiencies greatly exacerbated the problems experienced by Californians during the 2000 and 2001 market dysfunction. This period was plagued by outages in San Francisco; constrained transmission serving San Diego, Silicon Valley, and other load pockets; bottlenecks limiting power transfers from Southern California to Northern California; and excessive costs to consumers estimated to be in the range of $25 to $30 billion. While additional transmission may not have prevented these problems due to rampant market gaming, it could have substantially mitigated the impact on California consumers.

CALIFORNIA'S TRANSMISSION SYSTEM

Starting in the late 1960s, California utilities built major EHV transmission lines. These interconnections enabled California utilities to access power in the PNW, Arizona, New Mexico, Utah, and other parts of the Western Interconnection. Utilities also built the intra-state transmission grid to move power within the state and to the major load centers in San Francisco, the Los Angeles region, and San Diego. California interconnections to neighboring states are summarized in **Table 1**.

Table 1 – California Transmission Interconnections (MW)

Region	Import Capability (MW)
Pacific Northwest	
▪ AC Intertie	4,800
▪ DC Intertie	3,100
Utah	1,920
Desert Southwest	
▪ Northern System	4,727
▪ Southern System	2,823
Mexico – Baja Region	800
	18,170

Starting with approximately 4,000 MW of interconnections in the early 1970s, California increased its interconnections to 18,170 MW by the mid-1990s, an average increase of approximately 600 MW per year. Notably, transmission interconnection capacity has been essentially unchanged since the mid-1990s. In addition, most of the transmission interconnection capacity increases since the late 1980s have come through the efforts of municipal utilities. California investor-owned utilities (IOUs) have not added major interconnections in the last 20 years -- since the addition of the Palo Verde-Devers, Palo Verde-Miguel, and Pacific DC Intertie (PDCI) upgrades, all of which were in the mid-1980s.

A summary of California's import capability over time is provided in **Figure 1**.

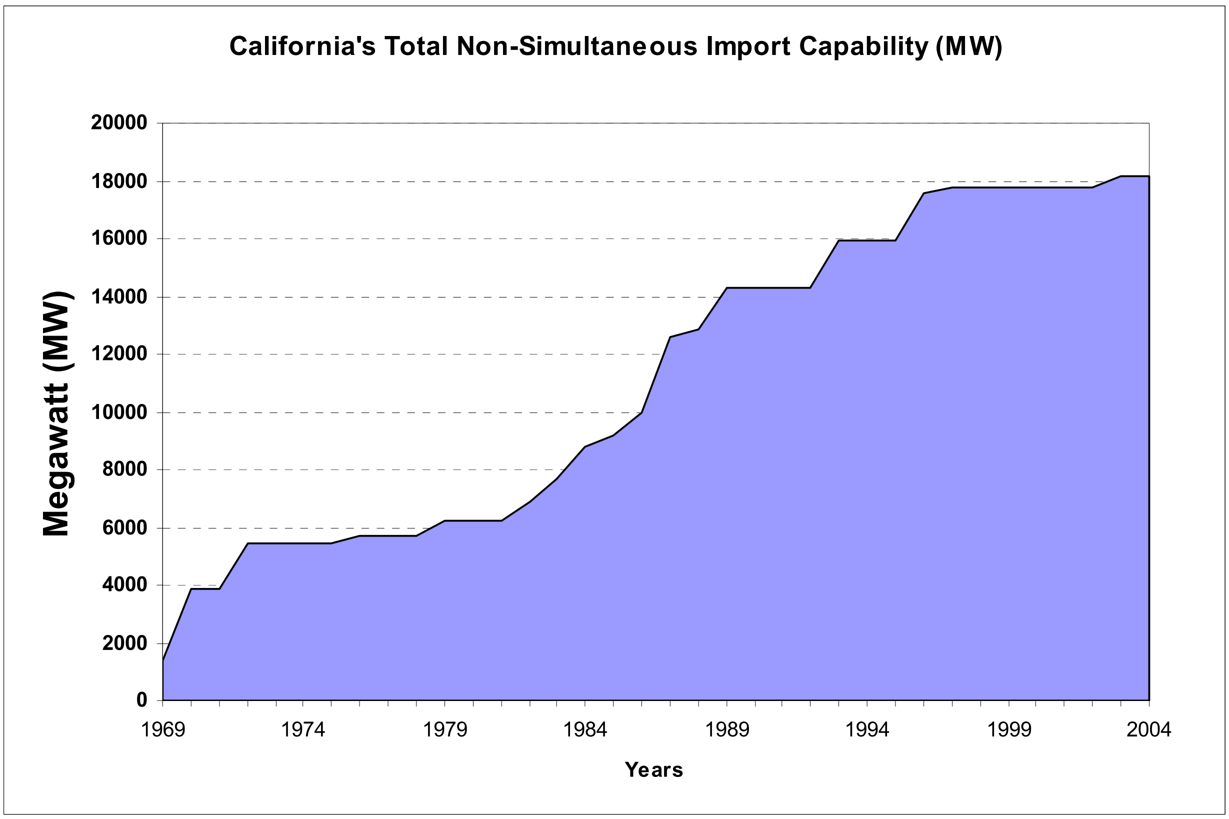

Figure 1 – California's Non-Simultaneous Import Capability

DEVELOPMENT OF INTERCONNECTIONS AND STRATEGIC VALUE

California's transmission interconnections were developed to obtain strategic benefits. California utilities pursued these projects for:

- Reliability
- Load diversity
- Fuel diversity
- Access to power plants
- Firm purchases
- Economy energy and surplus hydro purchases
- Power exchanges
- Reserve sharing

These projects required support and cooperation from utilities at opposite ends of the transmission interconnections, and all involved parties benefited from the expansion of the grid. A review of the interconnection to major market regions in the Western Interconnection is summarized below.

Pacific Northwest

In August 1964 the proposed Pacific AC Intertie (PACI) project to link California to the PNW was approved. The transmission lines associated with the project resulted in linking together the electric systems, both public and private, from as far away as Vancouver, B.C., and Seattle to Los Angeles and Phoenix. The project facilities consisted of both AC and DC transmission lines. The PACI project, with 800 MW of initial transfer capability, became operational in late 1968, and the rating was increased to 1,400 MW in 1969. In 1970, the PDCI project with 1,440 MW transfer capability started its operation. Transfer capabilities of these transmission lines increased over time to 3,200 MW and 3,100 MW, respectively. In 1993, a third 500 kV AC line, the California-Oregon Transmission Project (COTP) was built by Northern California Municipalities and increased the transfer capability between California and the PNW to 7,900 MW, an increase of 1,600 MW. A summary of the projects is presented in **Table 2**.

Table 2 - California-PNW Interconnection Capacity

Year	PACI	PDCI	COTP	Total
	2-500 kV Lines	1-1000 kV DC Line	Third AC Line	Transfer Capability
1969	1400 MW			1400 MW
1970	1400 MW	1440 MW @ 800 kV		2840 MW
Early 1970s	2000 MW	1440 MW @ 800 kV		3440 MW
Early 1980s	2500 MW	1600 MW @ 800 kV		4100 MW
1987	2800 MW	2000 MW @ 1000 kV		4800 MW
1989	3200 MW	3100 MW @ 1000 kV		6300 MW
1993	3200 MW	3100 MW @ 1000 kV	1600 MW	7900 MW

Desert Southwest

The first interconnection to the Nevada-Arizona region was built in the 1930s to bring the output of the Hoover power plant to Southern California. In the mid-1960s, the desire for fuel diversity resulted in the Southern California utilities looking at additional power sources outside California. This led to the development of three major coal-fired plants in the DSW in which California utilities were major participants. Along with the development of the power plants, the utilities built the necessary transmission infrastructure to transfer power from the power plants to Southern California. The transmission lines were completed in the late 1960s and early 1970s with 2,000 MW of transfer capability.

In the late 1970s and early 1980s, due to environmental constraints associated with burning oil and the Federal "Fuel Use Act," the California utilities participated in the Palo Verde nuclear plant in Arizona and built two additional 500 kV transmission lines to the DSW to connect Southern California, including the San Diego area, to Palo Verde. By 1988, the maximum transfer capability from the DSW was increased to 5,700 MW.

In 1996, the Southern California Municipalities, with participation from Arizona utilities, built the Mead-Phoenix 500 kV and Mead-Adelanto 500 kV Transmission Projects. These projects provided the municipalities with ownership in a firm transmission path that would support their future long-term resource needs. The transfer capability between California and the DSW increased to 7,550 MW by 1997.

The interconnections to the DSW enable import of over 4,500 MW of generation from Hoover, Navajo, Four Corners, Mojave, and Palo Verde power plants owned by or under contract to California utilities. A summary of these projects is presented in **Table 3**.

Table 3 – Historical California DSW Maximum Transfer Capability (AKA East of the Colorado River Transmission System)

YEAR	TRANSMISSION SYSTEM ADDITION(S)	MAXIMUM TRANSFER CAPABILITY
1969-74	Moenkopi-Eldorado 500 kV Line	Approx. 2000 MW
	Navajo-McCullough 500 kV Line	
	Liberty-Mead 345 kV Line	
1976	Navajo - 3 Units	2250 MW
1979	Series Compensation (70%) Added to 500 kV Lines	2790 MW
1983	Devers-Palo Verde 500 kV Line	3600 MW
1984	Palo Verde-Miguel 500 kV Line	4300 MW
1985	Palo Verde Unit #1	4650 MW
1986	50% Series Compensation added to the Palo Verde-Devers	5500 MW
	Palo Verde-Miguel Lines	
	Palo Verde Unit #2	
	Devers-Valley-Serrano 500 kV Line	
	Palo Verde-Westwing #2 Line	
1988	Palo Verde Unit #3	5700 MW
1996 (1-Q)	Mead-Phoenix 500 kV Line	7000 MW
1996 (2-Q)	Series comp upgrades in Moenkopi-Eldorado and	7365 MW
	Devers-Palo Verde Lines	
1997	New Study Methodology	7550 MW

Mexico - Baja California

The Comisión Federal de Electricidad (CFE) initially developed the Cerro Prieto Geothermal field to meet future energy demand in northern Baja, Mexico. The plant, however, had excess capacity and that led to construction of two transmission lines interconnecting the CFE electrical system to the Western Interconnection. In 1984, two 230 kV lines were built between San Diego Gas and Electric (SDG&E) and CFE, with a total transfer capability of 408 MW (south to north).

In 2003, as a result of independent power producer's development in Baja California using natural gas, CFE and SDG&E reinforced the transmission system between their two systems. On July 17, 2003, the transfer capability was increased to 800 MW (south to north).

Utah

The representatives from 23 Utah municipalities, six Utah cooperatives, Utah Power & Light Company, and six Southern California Municipalities developed the concept for the Intermountain Power Project (IPP) and the Northern and Southern Transmission Systems (NTS, STS). The project includes the construction of two coal fired power plants in Utah totaling approximately 1,600 MW, and necessary transmission to the existing Utah/Nevada transmission system, as well as a 490 mile 1,000 kV DC transmission line to California. Construction of the IPP was completed in 1987. The transfer capability of the STS to

California is 1,920 MW. This enables import of the generation owned by the Southern California Municipalities, which is approximately 75% of the total output.

Figure 2 below shows the map of California and adjacent states with the associated transmission interconnections.

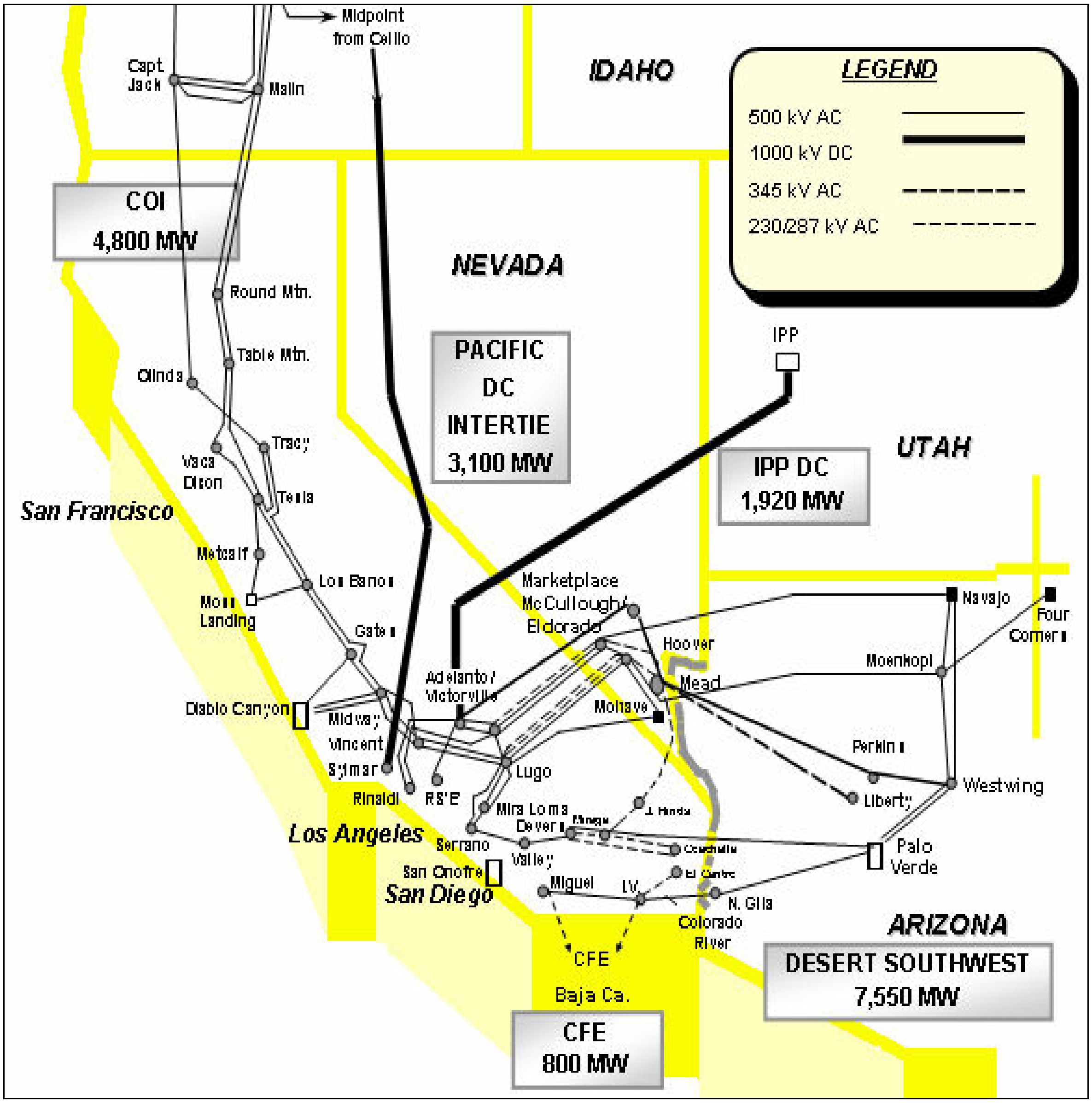

Figure 2 – California's 18,170 MW of EHV Transmission Interconnections

BENEFITS AND VALUE OF TRANSMISSION

Reliability

Power system planners and operators have to account for many uncertainties in their resource plans to provide adequate levels of reliability to consumers. Major uncertainties that can impact the power system include:

- Power plant and transmission line outages
- Fuel supply disruptions
- Droughts impacting production from hydro projects
- Heat storms resulting in high peak loads
- Economic and population growth impacting load

Utilities have utilized probabilistic simulation models to evaluate reliability. These studies generally conclude that planning reserve margins of 18 to 20% are required. With the development of strong interconnections to neighboring utilities and the demand diversity within the Western Interconnection, the planning reserves were reduced to a target level of around 15%. Hence, transmission interconnections enabled California to reduce installed generation capacity by 1,500 W to 2,500 MW (3% to 5% reserve margin on a 50,000 MW system peak), with an associated present value savings of $750 million to $1.3 billion.

Access to Regional Markets and Resource Diversity

Since natural gas has been California's marginal fuel source for electric production since the early 1980s, transmission access to diverse markets within the Western Interconnection has provided substantial value in enabling California to improve its fuel diversity, minimize its power production costs, and reduce emissions.

In the mid-1980s, as a result of the significant EHV infrastructure into and out of California, some of the California utilities took a leadership role in the development of the Western Systems Power Pool (WSPP). The WSPP was a Feder Energy Regulatory Commission (FERC)-approved umbrella agreement that allowed participants to enter into a wide variety of energy, capacity and transmission transactions. WSPP transactions provided annual savings/revenue in the tens of millions of dollars for some California utilities.

The PNW, dominated by renewable hydro generation, has historically had extremely low marginal costs of production. The DSW, dominated by coal generation, has had marginal production cost in the $5 to $15/MWh range. California's marginal generation since the 1970s has been fuel oil and natural gas. These fuel sources have exhibited the highest prices and are subject to significant price volatility. In January 2001, California's city gate price for natural gas averaged $12.32/MMBTU[2] and market prices spiked to over $300/MWh.

Transmission access within the Western Interconnection enables regional power transfers, creating a more competitive market place for the interconnected system. During 1998 and 1999, California imported approximately 48,000 GWh or 18% of its total energy requirements. This declined to approximately 16,700 GWh or 6.3% during the market dysfunction and drought conditions of 2001. In 2002, CAISO's total costs of energy and ancillary services were down by over $16 billion compared to 2001[3]. This was attributed to improved market fundamentals, including the State's energy imports more than doubling compared to 2001 (a discussion on the dysfunctional market is provided in Section VIII). In 2002, natural gas costs increased 120 percent from $2.25/MMBTU in January, to $5/MMBTU by the end of the year. Natural gas prices exhibit a lot of volatility. Significant fuel diversity, environmental, reliability, and price stability benefits are derived by importing lower cost hydro and coal generation, which offset otherwise higher cost California gas fired generation.

Environmental Benefits

The PACI and PDCI were constructed for bi-directional benefits. In the 1980s and 1990s both the PNW and California received significant environmental benefits associated with "environmental energy exchanges." The environmental benefits to California were in the form of reduced NOx pollution. The PNW entities would deliver the environmental energy during the daily on-peak periods in the spring and summer, avoiding a higher level of NO_x production from some of the older California fossil fuel plants. The energy would be returned during the spring/summer off-peak hours or during the winter months when the level of NO_x production would be low.

The environmental benefit for the PNW was in the ability to maintain a constant flow on the many rivers, with no increased hydro spill, during the critical fish flush and fish migration periods. In absence of the environmental exchange agreements, the PNW entities would have had to spill valuable water over the dams, without producing electricity, and replace the lost energy in the winter months with energy from fossil resources.

One of the interests expressed by the California legislature in AB 1890 (Chap. 854, Stats. of 1996) was the environmental performance of the electricity industry and systems in California. As California and its demand for electricity grow, competition for air offsets and water resources becomes more acute and impacts from the operation of the electricity generating system become more severe. EHV transmission system expansion offers strategic environmental benefits that may help to reduce overall electricity system impacts and make progress toward improved environmental performance of the system while meeting the demand for electricity.

[2] Energy Information Administration, file reference: ngm20vmall.xls, $12.64/mCF and 1,026 BTU/CF.
[3] CAISO 2002 Annual Report on Market Issues and Performance, Figure E.8.

From an environmental perspective, the transmission system expansion option may be preferred over generation additions in certain regions or locations within California. The California Energy Commission's *2003 Environmental Performance Report* states, "Energy imported from outside California's borders means less impact to California's natural resources and positive effects for the economies of other states and countries." Transmission system expansions as alternatives to generation system additions offer several characteristics that may be beneficial to certain regions of the state, some of which include:

- Additional capacity without local air emissions.
- Local air offsets needed for generation are available for other new industries with higher employment, providing economic advantages.
- Additional capacity with no water used for power plant cooling, avoiding impacts to local water and natural gas supplies.
- Additional capacity without impacts associated with waste disposal.

Benefits During Abnormal System Conditions and Insurance Against Contingencies

History has shown that although the majority of benefits for transmission investments in both intra- and inter-state transmission facilities accrue over a rather long period of time, significant benefits can accrue over a relatively brief period (6 to 12 months), as a result of abnormal system conditions and contingencies that were generally unforeseen in the planning process. The net benefits from these events tend to fully offset EHV transmission investment costs. These benefits can be in the form of greatly reduced energy costs or substantially improved reliability. Examples of economic and reliability benefits of transmission during abnormal system conditions include:

- The 1970s oil embargo when California was able to save over $100 million per month in differential fuel cost.
- Imports to offset loss of the Mohave generating station (1,200 MW to California) in 1985 for approximately four months due to reheat steam piping failure.
- Imports to offset the Palo Verde Nuclear Plant outage in mid 1980s, which was ordered by the Nuclear Regulatory Commission due to steam generator issues. The plant outage represented a loss of approximately 3,600 MW of generating capacity to the DSW area and California (1,000 MW to California).

- Above average attractively priced imports from the PNW during wet periods resulting in substantial energy cost saving. For example, California saved over $900 million in 1984 alone, which was more than the total investment in the Pacific Intertie.

The evaluation process of future long-term transmission projects needs to be factored into the assessment of the insurance value that an EHV transmission line provides. The process should include sensitivity analysis for low-probability high-risk events and how they would be mitigated with available transmission capacity. The benefits resulting from this sensitivity analysis would be in addition to the other benefits derived from the proposed project.

The sensitivity analysis could include an event, such as a 3-to-6 month outage of a California base load nuclear plant (e.g., 2,200 MW). The benefits derived from the use of available transmission capacity to mitigate the impact of the outage could include:

- Lower cost for the replacement of the lost energy and capacity.

- Contribution to reducing the loss-of-load probability (LOLP) with its associated public safety and economic benefits.

- Smaller and reduced number of market price spikes due to acute supply and demand imbalances.

Hence, transmission can provide much needed insurance to capture benefits and protect against contingencies. These low probability events produce benefits in a short period that may exceed the total investment in transmission.

California's Secondary Benefits from Extra High Voltage Infrastructure

A key benefit associated with the development of the PACI transmission system was that it allowed for other beneficial uses and projects.

- A parallel effort to the Pacific Intertie planning during the 1960s was the development of the California Power Pool (CPP). The CPP was an agreement between the three California IOUs in close coordination with the City of Los Angles Department of Water and Power (LADWP). The agreement addressed the necessary planning and coordination required to enhance their reliability and economic operation.

- In the development of the California aqueduct system, the state utilized the Pacific Intertie to provide the transmission infrastructure to which the many generators and pumping facilitates of the California aqueduct could interconnect. This supported the movement of large amounts of power required for pumping the water through the California aqueduct.

SAVINGS FROM TRANSMISSION INTERCONNECTION INVESTMENTS

Pacific Northwest Imports

Since commercial operation of the early EHV system to the PNW, capacity and energy imports from that region have economically displaced otherwise higher cost fossil fuel generation in California. Transmission access to surplus capacity, largely due to load diversity, and surplus energy supplies have provided substantial economic value to California.

The interconnections to the PNW totaling 7,900 MW, as indicated earlier in **Table 2**, were built for an investment of $1.6 billion. Over the 30-plus years of operation, the annual benefits are shown in **Figure 3** and total $7.2 billion. This is based on the actual amount of energy imported times the difference between California's marginal cost of generation and the cost of imports from the PNW. Any savings related to capacity benefits that were associated with California utilities entering into firm power transactions with PNW entities would be in addition to the $7.2 billion.

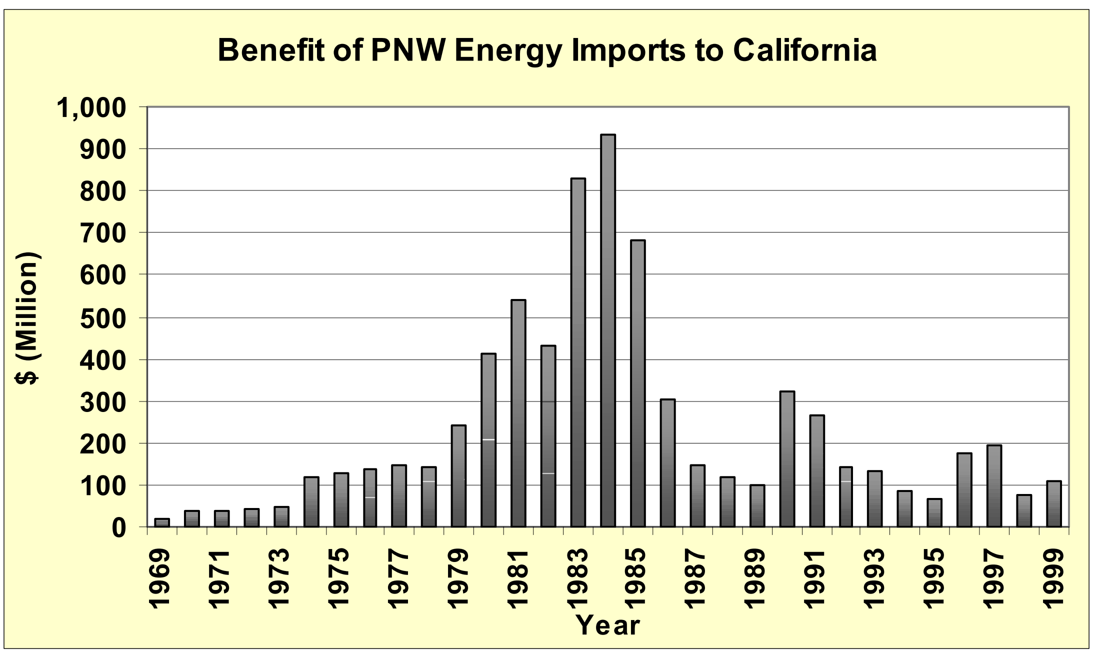

Figure 3 - Benefits of Pacific Northwest Energy Imports to California

This EHV system to the PNW is expected to continue to provide benefits for its remaining life, which is likely to be well in excess of the assumed 50-year project life in planning studies.

Desert Southwest Imports

DSW transmission is used to import both firm utility-owned generation and surplus regional capacity and energy. Surplus energy imports, principally from coal resources, economically displaced higher cost oil and natural gas fired generation in California. Transmission access to surplus capacity and surplus energy supplies from this region provided substantial economic value to California.

The benefit of importing DSW surplus energy from 1971 through 1999 is estimated at approximately $5.7 billion, nearly a five-fold benefit, compared to an investment of $1.3 billion. The annual benefits are shown below in **Figure 4**.

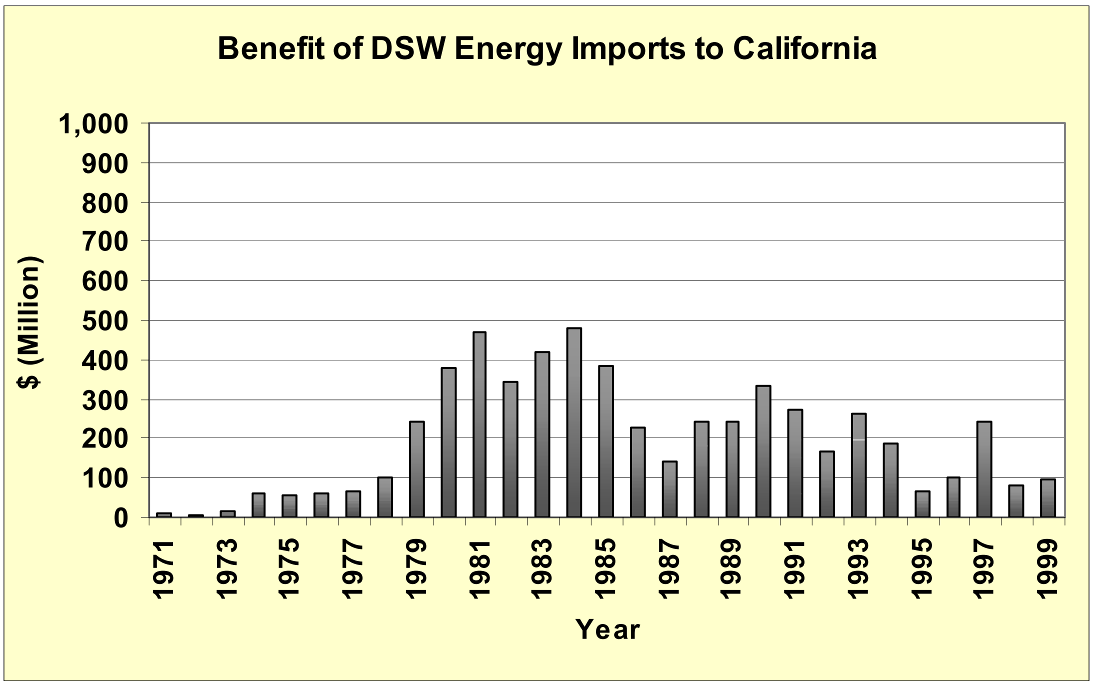

Figure 4 - Benefits of DSW Energy Imports to California

Utah Imports

The transmission system associated with the IPP, the STS, was built at a cost of approximately $1.23 billion. The primary purpose of the transmission line was to enable the Southern California Municipalities to access their ownership rights in the two 800 MW coal fired units at IPP. The two units at IPP, as a result of different boiler design and construction, have historically out-performed all of the other coal-fired generators of California utilities that have participated in the DSW. The IPP's high capacity factor and outstanding performance have represented a significant fuel savings for the Southern California Municipalities compared to the volatility of the price of gas.

CALIFORNIA'S TRACK RECORD IN PURSUING NEW TRANSMISSION PROJECTS

Since the late 1980s, California IOUs have been unsuccessful in gaining regulatory approvals to build major new projects. These include for example:

- Third Pacific AC Intertie
- Palo Verde-Devers No. 2
- Path 15
- Path 26
- Valley-Rainbow

These projects were denied for a variety of reasons including some of the following:

- Uncertainty about future benefits.
- Economic evaluation methodologies that do not recognize the strategic value of transmission.
- Present worth valuation that discounts the long term benefits of long life transmission assets.
- Utilization of average conditions in long term planning studies that discount the substantial insurance benefits that result during abnormal conditions and contingencies in any short periods.
- Preference for alternatives including generation and demand management.
- During this same time frame, however, the municipal utilities pursued transmission investments that are now delivering substantial benefits to their constituents.

PLANNING AND POLICY ISSUES

In March 2003, Department of Energy (DOE) completed the *Transmission Bottleneck Project Report* which looks at transmission bottlenecks within the nation's six Independent System Operators (ISOs), and the challenges of mitigating or resolving them. The following is a summary of the planning, policy issues and challenges faced by ISOs in obtaining regulatory approval for transmission projects that offer economic and strategic benefits:

- Lack of the necessary market models by the ISOs to adequately forecast and "prove" their need and develop necessary business cases justifying market-driven economic projects.

- Lack of established processes for reviewing and approving construction of transmission projects that facilitate competitive markets and large regional power transfers.

- Long and uncertain regulatory approval processes, especially for multi-state projects.

- Uncertainty about cost recovery and regulatory treatment provides a disincentive for Transmission Owners to propose anything more than reliability projects.

- Disconnect between who pays for new transmission vs. who benefits – the customers of the local Transmission Owner could be straddled with the costs of fixing bottlenecks while those benefiting may be located several states away.

- Lack of deliverability standard for connecting new generation.
  - The minimum interconnection standard for new generators does not ensure deliverability and as a result it creates congestion and stranded generation pockets; it does not address regional resource and transmission adequacy issues; and it puts the planning process in a reactionary mode.

- Shorter lead times for generation solutions than those for transmission projects and can provide a quicker fix to many bottlenecks.
  - Recent generation project cancellations around the nation are creating challenges for the grid planners and eventually customers.

- Limited data available on planned new generation projects to support ISO long term planning studies.

CALIFORNIA'S FUTURE TRANSMISSION GRID – POLICY ISSUES AND IMPEDIMENTS

The planning and policy issues identified in the DOE study are very relevant to California. Given California's dependence on transmission interconnections for over one-third of its energy, it is important to find solutions to address these issues. Investments in transmission offer substantial benefits for reliability, access to markets, resource diversity, and insurance against contingencies. Key policy issues and impediments must be addressed to build California's future transmission grid.

Long Planning Horizon

Transmission projects require an 8-to-10 year lead time. Many of the current interconnections being considered in California were first identified 20 to 30 years ago. Transmission projects have long lives. Hence, it is critical to address future transmission from a strategic long-term perspective. A good target for California's future transmission grid would be to look ahead 25 to 30 years. In that time window it is reasonable to assume that:

- Population will be higher.
- Economic activity will be higher.
- Electricity consumption will be higher.
- Many of the currently operating power plants will have been retired.

Traditional approaches to planning transmission are inadequate. For example, there are no definitive generation expansion plans extending 10 years or more that provide guidance for future transmission. Consequently, a strategic approach with a long-term time horizon is needed to plan regional interconnections to market hubs and resource-rich areas.

Planning Methodologies for Evaluating Transmission Projects

There is a critical need for innovation in planning methodologies to be used for evaluating transmission projects. Some factors to be considered include:

- Incorporating the strategic value of transmission for insurance against contingencies in project evaluations.
- Developing innovative economic approaches to evaluating transmission projects.
- Developing comparative analyses for assessing alternatives to transmission.
- California needs transmission for its strategic benefits and generation and demand management to cost effectively meet electricity needs.

New generation and demand management are often considered to be alternatives to transmission – however, these alternatives do not:

- Provide expanded access to developing markets.
- Maintain or enhance grid reliability.
- Expand regional fuel diversity with bi-directional access.
- Insurance against major contingencies.

Project Review Process and Cost Recovery

One of the biggest impediments to the development of new transmission projects in California is the overlapping and conflicting processes associated with project planning, assessment, licensing and approval. In pursuing transmission expansion, California needs clear, logical and orderly policies associated with transmission project review and approval processes. Enhancements to the processes could include improved coordination of existing state agencies, consolidation of licensing responsibilities, and coordination with adjacent regions. Changes to the current process are sorely needed.

Another impediment to the IOUs pursuing new transmission has been the concern regarding the recovery of costs associated with developing project plans and pursuing the certification of transmission facilities.

Asset Utilization During Market Dysfunction

California's energy imports for the first two years (1998 and 1999) of the California competitive market were 47,563 GWh and 49,487 GWh, respectively[4]. In 2000, the imports were approximately 50% of the previous year and during 2001 the imports were only one-third of the 1999 level. By 2002, imports had recovered to approximately 39,000 GWh or 79% of the 1999 import level. (See **Figure 5** below.) There were several contributing factors to the reduced level of imports:

- Market gaming

[4] Energy imports exclude output of California utility-owned shares of coal and nuclear plants outside of California and some firm contracts, consistent with California Energy Commission database.

- Credit issues associated with the IOUs

- Credit issues associated with California

- Poor hydro conditions in the PNW during 2001

- CAISO implementation of protocol changes that impacted Western Electricity Coordinating Council (WECC) suppliers

This underscores the fact that there needs to be a strong regulatory, policy, and business framework in place to obtain the full benefit of transmission interconnections.

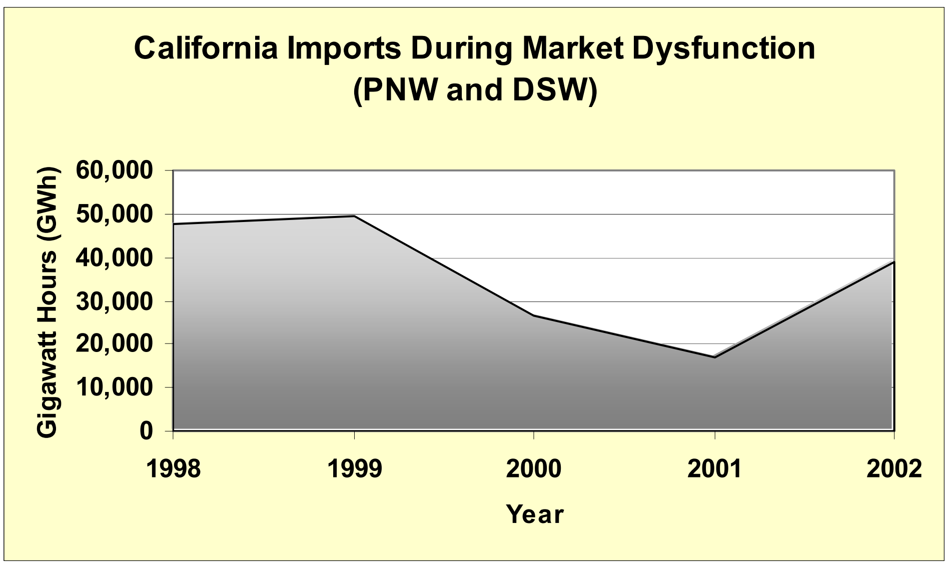

Figure 5 - California Imports During Market Dysfunction

STATUS OF CURRENT TRANSMISSION NEEDS AND FUTURE STRATEGIC INTERCONNECTIONS

Reliability and Market Operations

- Path 15 – Reinforcing Path 15 is necessary to mitigate the operational impacts and the high costs of congestion that have been associated with this path for many years. In addition, it will ensure the ability to effectively deploy the state's resources in meeting customer demand in either the northern or southern portions of the state. Although there has been a need to reinforce this path for almost 15 years, the application for a Certificate of Public Convenience and Necessity (CPCN) submitted by Pacific Gas &

Electric (PG&E) in 2001 was not acted upon by the California Public Utilities Commission (CPUC). In spite of the State's lack of action the necessary reinforcements are going forward under the direction of the DOE, with participation by the Western Area Power Administration (10% participant), PG&E (10% participant) and an independent transmission company (Trans-Elect, 80% participant). The expected operating date for the project is January 2005.

- Path 26 – Although this path, which consists of three 500 kV transmission lines, has not historically experienced high levels of congestion it is a strategic path that will become the next weak link once Path 15 is upgraded. On July 17, 2003, the WECC approved a Path 26 rating increase from 3,000 MW to 3,400 MW, north to south. As mentioned earlier in this report, Path 26 will eventually require a major reinforcement project.

- Valley-Rainbow – The project justification was based on SDG&E and CAISO studies that indicate the line is needed for local area reliability. In June 2003, the CPUC, for the third time, voted not to approve this project for various reasons. The CPUC's decision does not preclude SDG&E from re-filing at a later time. However, at this time, SDG&E has elected not to re-file the CPCN application and is evaluating alternatives.

Access to Markets

- Devers-Palo Verde No. 2 – In the recent CPUC long-term resource procurement proceedings, Southern California Edison (SCE) indicated its intention to build a second 500 kV line between the Devers Substation in the Palm Springs area and the Palo Verde Nuclear Plant, 50 miles west of Phoenix, Arizona. This second line will significantly increase the import capability (1,200 to 1,500 MW) from the DSW region and facilitate the delivery of additional generation supply from resources recently completed or currently under construction (6,000 MW of new generation by year 2007). SCE has indicated that it will file a CPCN application in the fourth quarter of 2003 or early 2004. The expected operating date for the line is 2008.

Access to Stranded Renewables

- Tehachapi - To meet California's objective of encouraging the development of renewable resources, SCE has proposed a project that would expand its transmission in the Tehachapi area. SCE has proposed the construction of a new 230 kV line from the Tehachapi area to their Pardee Substation, as well as the associated 66 kV lines to the wind developer's sites. The final solution of how best to reinforce the transmission system in and around the Tehachapi area will be worked out between SCE and the CAISO. The proposed project has an expected operating date of 2006.

Load Pockets

- San Francisco - PG&E has been working with stakeholders on the issue of maintaining the security and reliability to the critical load on the San Francisco Peninsula. PG&E has stated they are implementing substantial upgrades of its transmission system, with some construction in progress and a new Jefferson-Martin 230 kV line awaiting CPUC approval. This new line will add 400 MW of import capability into the peninsula and will not be on a common right-of-way with the other six source lines. The operating date for the new 230 kV line estimated as September 2005.

- Silicon Valley/San Jose – Year 2002 technical studies identified the need to reinforce the 115 kV transmission system of the southern portion of the Silicon Valley/San Jose area. PG&E has developed a plan to make the necessary reinforcements by mid-year 2006.

STRATEGIC INTERCONNECTIONS

California needs to think long-term, beyond the current 5-to-10 year time frame, to develop a plan for California's Grid of the Future. Key factors and issues to consider include:

- Transmission has an 8-to-10 year lead time – the 5-to-10 year planning horizon is not enough.

- California needs to plan new strategic interconnections to regional markets to ensure grid reliability, price stability, and resource diversity.

- California's transmission plan needs to recognize the strategic value of transmission for reliability, insurance, market efficiency, and security.

- California's long-term plan must integrate with regional efforts and initiatives.

Transmission planning in California faces many challenges. Many of the current projects have been in the planning pipeline since the mid-1980s and were designed to address known bottlenecks and reliability problems. Interconnections for California's future grid need to take into account:

- California's aging fleet of resources will result in plant retirements.

- Qualifying Facilities (QFs) will come to the end of contract terms.

- Economic recovery – returning load growth merchant suppliers – financial status – cancelled projects.

- Lead times for transmission projects.

- Planning is heavily data/model driven.

- Project economic justification for strategic transmission investments.

The Planning Group at the CAISO has taken a very proactive role in working with stakeholders interested in the development of strategic transmission interconnections, as indicated below:

- Southwest Transmission Expansion Plan (STEP) – The CAISO has initiated and continues to provide a forum for stakeholders in the development of transmission expansion plans to the DSW area. The group identified over 20 transmission expansion proposals which were reviewed and narrowed down to approximately five potential projects. The project list consists of both AC and DC transmission lines that will be further assessed and studied for possible project recommendations.

- Pacific Northwest Transmission Expansion Plan – In July 2003, the CAISO met with representatives from the PNW to determine if there are interested parties who would like to participate in expansion discussions and studies, similar to the ones currently underway in the DSW.

RECOMMENDATIONS

California's investments in its transmission grid and interconnections to neighboring states have produced substantial reliability, economic, environmental, and fuel diversity benefits. The investments in interconnections have totaled approximately $4.1 billion. These investments have produced substantial benefits as summarized below:

- Import capability of 18,170 MW. An equivalent amount of peaking capacity from power plants would require an investment of approximately $10 billion.

- Access to hydro, coal, geothermal, wind, and nuclear power from outside of California.

- Import of California utility owned or contracted generation totaling nearly 6,000 MW from the DSW and Utah regions.

- Reduction in required planning reserves of 1,500 to 2,500 MW with an associated present value savings of $750 million to $1.3 billion.

- Savings from economy energy imports totaling $7.2 billion from the PNW and $5.7 billion from the DSW.

The CAISO's authorized TAC for 2003 is approximately $390 million and equates to a cost of approximately 0.2¢/kWh or $2/MWh. If the State of California took a proactive role and invested $3 billion in strategic transmission interconnections, over the next two decades, the rate impact would be equivalent to the current CAISO TAC and would represent a 0.2¢/kWh or $2/MWh increase or less than 2% increase in residential rates. The issue for policy makers is whether or not the benefits associated with strategic transmission assets justify the minor rate impact over time. The benefits associated with California's strategic transmission assets would be:

- Reliability
- Access to markets
- Fuel diversity
- Environmental
- Insurance against contingencies
- Replacement for aging power plants

California needs to resume its leadership in the Western Interconnection to develop strategic interconnections, invest in technologies to improve utilization of existing transmission infrastructure, and develop new approaches to planning and valuing transmission investments. Specific recommendations for California transmission planning are outlined below:

- Develop a long-term strategic vision and plan for California's Grid of the Future.
- Simplify regulatory review and approval process.
  - Review all the involved processes associated with transmission projects and identify redundancies, gaps, and overlaps.
- Work with Western states to develop a coordinated approach to regional resource and transmission development.
- Formulate a policy on the appropriate level of investment for strategic transmission interconnections as insurance against contingencies and market disruptions.
- Review planning and project evaluation methodologies to incorporate strategic benefits of transmission in planning and regulatory approval process, including benefits of reliability, contingency insurance, efficient market operations, fuel diversity, and access to regional markets.
- Develop plans to achieve cost-effective fuel diversity.
- Develop plans to access new and developing markets in the Western Interconnection.
- Provide greater certainty to the issues associated with cost recovery and cost allocation.

- Promote greater operational and planning coordination of transmission assets between CAISO and municipalities, state and federal agencies.

- Identify actions that can be taken in the short term that will enhance and expedite California's long-term strategic development and expansion of the EHV system.

- Identify a desired level of import capability and maintain it through expansion projects. Current import capability is 35% of load demand level.

- Develop a technology plan to maximize existing transmission infrastructure utilization and create the future transmission grid.

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APPENDIX

SUMMARY DATA ON PNW AND DSW

TRANSMISSION RATINGS, ENERGY IMPORTS,

INVESTMENT COSTS,

AND ESTIMATED SAVINGS

Year	Pacific Northwest Data				Desert Southwest Data			
	Rating (MW)	Energy Imports[1] (GWh)	Investment Cost[2] ($ Millions)	Savings[3] ($ Millions)	Rating[4] (MW)	Energy Imports[1] (GWh)	Investment Cost[2] ($ Millions)	Savings[3] ($ Millions)
1969	1,400	6,598	296	20				
1970	2,840	13,384	304	40				
1971	2,840	13,384		40	2,000	8,358	365	8
1972	3,440	16,212	127*	41	2,000	8,358		5
1973	3,440	16,212		47	2,000	8,358		16
1974	3,440	16,212		118	2,000	8,358		61
1975	3,440	16,212		127	2,000	8,358		57
1976	3,440	16,212		137	2,250	9,403		60
1977	3,440	16,212		146	2,250	9,403		66
1978	3,440	16,212		142	2,250	9,403		101
1979	3,440	16,212		241	2,790	11,660	20	243
1980	3,440	16,212		414	2,790	11,660		379
1981	3,440	16,212		542	2,790	11,660		471
1982	4,100	19,322	142*	432	2,790	11,660		342
1983	4,100	38,375		831	3,600	17,755	140	420
1984	4,100	41,027		931	4,300	20,261	223	480
1985	4,100	37,146		683	4,650	19,863		385
1986	4,100	31,632		304	5,500	19,463	150	226
1987	4,800	24,977	152*	147	5,500	20,522		142
1988	4,800	19,893		119	5,700	27,018		243
1989	6,300	17,739	200	98	5,700	23,325		245
1990	6,300	31,665		325	5,700	30,294		333
1991	6,300	28,819		267	5,700	27,054		271
1992	6,300	19,600		141	5,700	18,104		167
1993	7,900	15,466	350	131	5,700	27,426		261
1994	7,900	15,315		87	5,700	28,040		188
1995	7,900	19,890		66	5,700	27,624		64
1996	7,900	29,529		174	7,365	20,167	434	99
1997	7,900	25,204		197	7,550	27,517	10	242
1998	7,900	19,428		74	7,550	28,135		79
1999	7,900	26,051		107	7,550	23,436		96
Total			**1,571**	**7,168**			**1,342**	**5,749**

Assumptions:
1. CEC Energy Imports: http://www.energy.ca.gov/electricity/index.html#generation, Electricity Generation/Production, 1983 to 2001, excludes energy associated with utility owned generation outside of California. Energy imports from 1969 through 1982 are derived and are equal to the yearly capacity rating times the historical region specific capacity factor for the period 1983 through 1999. These were 54% and 48% for the PNW and DSW, respectively.
2. Investment costs: Actual PACI investment costs used for the initial investment ($600 million), PDCI upgrade (1989), and COTP project (1993) costs. Other PACI upgrade costs, noted by an asterisk (*) were estimated using an average cost of $215k/MW. DSW transmission cost estimated from FERC Form 1 data, utility-specific project cost data, and EPG knowledge of some project related costs.
3. Methodology: Savings based on energy imported times the difference between California's marginal cost of production and the cost of energy imported. Capacity value of energy imports is not included and would increase the stated savings.
4. East-of-the-River Rating.
5. CA marginal generation assumed to be fuel oil 1969 to 1983, otherwise natural gas.
6. EIA data used for fuel oil and city gate natural gas prices.
7. Energy import cost based on EPG knowledge of and discussion with industry experts.

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