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The Honorable Arnold Schwarzenegger
Governor, State of California
State Capitol Building
Sacramento, California 95814

Dear Governor Schwarzenegger:

On behalf of the California Energy Commission, I am pleased to present the *2004 Integrated Energy Policy Report Update (Energy Report Update)*. The *Report*, approved by the Energy Commission on November 3, 2004, addresses three issues critical to meeting the challenges of ensuring adequate electricity supplies as early as next summer:

- Reliability issues with aging power plants
- Transmission planning
- Accelerated renewable energy development

Additionally, this report discusses actions taken to implement key recommendations from the *2003 Integrated Energy Policy Report.*

The *Energy Report Update* strongly recommends policies that will to improve demand response, make better use of the state's existing fleet of power plants, and move aggressively to bring new generation and transmission resources on-line. We believe that immediate action on these items will improve reserve margins and forestall impending energy shortages.

The Energy Commission is proud of what we have been able to accomplish with the *Energy Report Update*. We look forward to working with your office and the Legislature to implement workable energy programs that benefit all Californians.

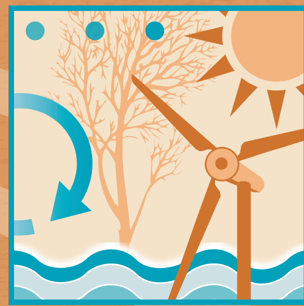
Sincerely,

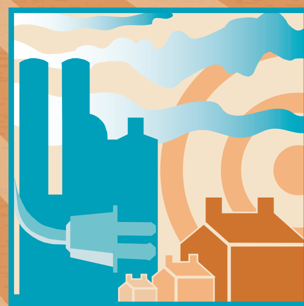
William J. Keese

WILLIAM J. KEESE
Chairman

INTEGRATED ENERGY POLICY REPORT

2004 Update





Governor
Arnold Schwarzenegger

CALIFORNIA ENERGY COMMISSION

NOVEMBER 2004

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CALIFORNIA ENERGY COMMISSION

INTEGRATED ENERGY POLICY REPORT

2004 Update

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INTEGRATED
ENERGY POLICY REPORT
2004 Update

ABSTRACT

The *2004 Integrated Energy Policy Report Update* provides additional analysis in three critical areas: reliability issues with aging power plants, transmission planning, and accelerated renewable energy development, along with a discussion on the California Energy Commission's progress in implementing the recommendations in the *2003 Integrated Energy Policy Report.*

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PREFACE

The *2004 Integrated Energy Policy Report Update* is required under Senate Bill 1389, (Chapter 568, 2002, Bowen), which requires the California Energy Commission to prepare a biennial integrated energy policy report for the Governor and Legislature, with an update due in even years. In 2003, the Energy Commission submitted the first *2003 Energy Report*. This report fulfills the update requirement for 2004.

INTEGRATED ENERGY POLICY REPORT

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EXECUTIVE *Summary*

Over the next several years, California faces significant challenges in ensuring adequate electricity supplies to keep California's lights on during critical peak demand periods. This challenge is especially evident in Southern California, which also faces regional and local reliability challenges. To address these, California must step up its efforts to achieve the goals already established for demand response programs, make better use of its existing fleet of power plants, and move aggressively to bring new resources on-line.

California consumers are up to the task ahead; they know how to conserve energy and reduce demand during times of short supplies. As recently as the 2000-2001 electricity crisis, Californians embraced energy efficiency and demand response programs, reducing state demand by approximately 6,000 megawatts, more than 10 percent of peak demand. To meet the coming challenge, however, consumers must be armed with the tools necessary to shift their energy use away from critical peak periods when supplies are especially tight.

California must also act now to ensure that its long-term energy strategy – the *Energy Action Plan's* loading order – is realized.[1] California's principal energy agencies have been meeting regularly to coordinate activities, programs, and proceedings in critical energy areas, and have made major strides to implement the loading order strategy.[2] But more must be done.

California's systematic under-investment in transmission has left the state's transmission lines congested, increasing the cost of electricity to consumers and reducing reliability. In addition, inadequate transmission presents a significant barrier to accessing renewable energy resources critical to diversifying fuel sources, which increases California's dependence on natural gas, and slows progress in meeting California's environmental goals. The state must significantly alter its approach to transmission planning, not only to keep the lights on and hold down energy costs, but also to advance critical state energy, environmental, and economic policy goals.

In 2003, the California Energy Commission adopted its first Integrated Energy Policy Report (*2003 Energy Report*), which provided an assessment of the major energy trends and issues facing California along with recommended energy policies. These recommendations were based on extensive technical assessments that were captured in three subsidiary volumes on electricity and natural gas; transportation fuels, technologies, and infrastructure; and public interest energy strategies.

In this 2004 update, the *Integrated Energy Policy Report* Committee focused on three areas:

- reliability issues with aging power plants
- transmission planning
- accelerated renewable energy development

In addition, the report also assesses the progress California has made on the *2003 Energy Report* recommendations.

> If significant numbers of aging power plants continue to retire between now and 2008, reserve margins in the state could become dangerously thin, primarily in Southern California.

Near-term Supply and Reliability Concerns

In the *2003 Energy Report*, the California Energy Commission concluded that under average weather conditions, California is likely to have adequate electricity supplies through 2009. However, if hot weather conditions occur in 2006 and beyond, then operating reserve margins could fall below the 7 percent needed to maintain system reliability.[3]

Additional analysis undertaken for this *2004 Energy Report Update* indicates that if significant numbers of aging power plants continue to retire between now and 2008, reserve margins in the state could become dangerously thin, primarily in Southern California.[4] Aging power plant owners may choose to retire these units because they are unable to recover fully their costs during the relatively few hours of the year that they can operate. Keeping this capacity available over the next few years will prove a daunting challenge, while California transitions away from reliance on electricity generated under Department of Water Resources (DWR) contracts to newly constructed plants.

This summer, California saw the emergence of regional reliability problems, especially in Southern California, associated with increasing congestion on the transmission system. Currently, aging power plants appear to be an important element in addressing congestion on the southern portions of the California Independent System Operator (CA ISO) system, and ensuring that supplies from outside the greater Los Angeles basin can be reliably delivered to load centers.

In the longer run, those aging plants that prove critical for local or regional reliability should be repowered, refurbished, or replaced, which may be beneficial in reducing local environmental impacts in highly populated load centers. However, each aging unit has a unique set of operating characteristics, each must meet different environmental rules and regulations, and each faces differing levels of public opposition or support. Thus, repowering, refurbishment, or replacement decisions must be assessed on a site-specific basis.

As many as 9,000 MW of aging power plants are considered to be at risk for retirement by 2008. While it is doubtful that all of these aging power plants will retire, because retiring just a portion of them would likely improve the financial prospects for those remaining on-line, additional steps must be taken to ensure that California has adequate supplies over the next few years. The consequences of not taking actions to address potential supply shortfalls from possible retirements would expose consumers and businesses to unacceptable risks.

2004 Update Proposed Recommendations

The Energy Commission believes that a combination of actions on the demand and supply sides are necessary to stave off another electricity crisis in the near term.

The state must accelerate its implementation of demand response programs that signal the actual price of electricity to customers during peak demand periods. Peak hours, while they occur for only 50 to 100 hours a year, pose one of California's most significant challenges to ensuring reliable electricity supplies. Rapidly deploying demand response programs in the state is the most effective approach to address peak demand for the summers of 2005-2008. The first order of business should be the adoption of dynamic pricing tariffs for large customers and the roll-out of advanced metering for small customers, ensuring that utilities attain the demand response program goals the California Public Utilities Commission (CPUC) and Energy Commission have already established.

Simultaneously, the state needs to shore up its electricity supplies for 2005 through 2008, including generation from aging power plants, to maintain adequate reserve margins for peak demand periods and provide regional and local reliability services. The Energy Commission recommends developing a capacity market in a phased fashion, which would provide flexibility for both utilities and generators in complying with the state's proposed resource adequacy requirements and deliverability standards.[5] In addition, California must maximize its ability to share resources, both inside the state between the investor-owned utilities (IOUs) and adjoining municipal utilities, and with out-of-state suppliers.

While pressing for short-term solutions, California must not lose sight of its long-term goals for planning transmission and developing renewable energy supplies.

Transmission upgrades and expansions are critical to ensuring a robust and reliable electricity system. The state must design a comprehensive transmission planning process that is based on a proactive expansion policy that recognizes the long useful life of transmission assets and their increasingly "public goods" nature. California must also establish a process to plan effectively for and designate transmission corridors well in advance of their need. This process will ensure that government land use plans identify land necessary for future transmission lines and allow utilities to acquire the necessary rights of way. Finally, to meet state policy goals, California's transmission planning process must address the need for transmission to access renewable resources.

California must develop and codify ambitious long-term renewable goals to continue the flow of investments in renewable resources in the state, drive down the costs and push for continued innovation in renewable technologies. Significant progress has been made to achieve the accelerated goal of meeting 20 percent of California's retail electricity sales with renewables by 2010. However, unless the state sets out longer-term renewables targets for 2020, important momentum could be lost in achieving the maximum fuel diversity and environmental benefits renewables offer.

In addition, solar photovoltaic (PV) systems hold promise to enable consumers to help address our peak demand challenges by combining PV with enhanced energy efficiency measures and price-responsive demand programs. The Governor plans to move forward with a "million solar roofs," providing California with a unique opportunity to leverage investments in PV for important economic, environmental, and fuel diversity goals.

The following summarizes the Energy Commission's recommendations, which are addressed in more detail in the remainder of the *2004 Energy Report Update*.

Attaining Demand Response Goals

All investor-owned and municipal utilities should work aggressively to implement demand response programs to attain the 2007 statewide goal of reducing peak demand by 5 percent. In this vein, to address supply adequacy concerns for the summer of 2005, the CPUC should immediately require dynamic pricing tariffs for large electricity customers who already have advanced metering capability. In addition, by January 2005, the CPUC should approve IOU proposals to modify the current tariff design that could expand program eligibility and attractiveness for the summer of 2005 and beyond.

While aggressively pursuing demand response goals, California must simultaneously shore up its electricty supplies.

The CPUC should also begin implementing a large-scale rollout of advanced metering systems for smaller customers, targeted first to areas of the state with the highest peak demand. Dynamic rate offerings and load control options should then be developed for customers as the metering systems become operational.

The Energy Commission should work with DWR, the CPUC, the CA ISO, and other water agencies to investigate and pursue all cost-effective load management and demand response programs on these water systems.

Shoring Up Electricity Supplies

While aggressively pursuing demand response goals, California must simultaneously shore up its electricity supplies. The Energy Commission should work with the CPUC and other parties to develop a capacity market to allow utilities and generators flexibility in meeting proposed resource adequacy requirements, including a capacity "tagging" mechanism and tradeable capacity rights or obligations.

California should also re-examine the link between the CA ISO transmission expansion process and local area reliability assessment to stimulate adequate investment in a more robust transmission system, allowing California to more rapidly transition away from dependence on reliability must-run contracts.

The CPUC should also support the pending petition to allow the utilities to enter into one- to five-year power purchase contracts, as long as they do not replace the long-term procurement necessary to construct new power plants already licensed.

The CPUC, the IOUs, and municipal utilities should consider allowing cold standby plants to contribute to reserve margins, providing insurance against low hydro conditions and system contingencies such as the extended outage of nuclear plants or transmission lines.

Enhancing Supply Management

California should also take steps to enhance its supply management. To this end, the Energy Commission, CPUC, and all utilities should:

- Establish more closely coordinated planning and reserve sharing among California's IOUs and municipal utility service areas, allowing greater sharing of generating resources.

- Pursue all cost-effective seasonal energy exchanges with the Pacific Northwest to satisfy California's summer peak demand, including needed transmission upgrades to take advantage of seasonal generation surpluses.

- Explore opportunities to use existing pumped-storage facilities more fully, which provide both a more stable base load for existing power plants and valuable peaking power generation during high demand.

Designing a Comprehensive Transmission Planning Process

The Energy Commission, pursuant to its new responsibility to develop a strategic transmission plan in its *2005 Energy Report* proceeding, should establish a comprehensive statewide transmission planning process with the CPUC, CA ISO, other key state and federal agencies, local and regional planning agencies, investor-owned and municipal utilities, generation owners and developers, stakeholders and interest groups, and the public. This statewide planning process should:

- Assess statewide transmission needs for reliability and economic projects as well as transmission to support Renewables Portfolio Standard (RPS) goals;

- Examine non-wires alternatives to transmission (demand response, energy efficiency, generation, etc.);

- Approve beneficial transmission infrastructure investments that can move into permitting;

- Examine the right-of-way needs for future transmission projects, designate and conduct environmental reviews of needed corridors, and allow utilities to set aside or bank necessary land for longer periods of time;

- Assess transmission costs and benefits that recognize the 30-50 year useful life of transmission assets, incorporate methods (quantitative and qualitative) to assess the long-term strategic benefits of transmission, and use an appropriate social discount rate.

To facilitate transmission for renewables projects, the Energy Commission should step up its participation in the Joint Transmission Study Group on the Tehachapi wind resources area, including initiating corridor planning to facilitate permitting of needed upgrades, and establish a Joint Transmission Study Group for the

Imperial County geothermal area. In addition, the Energy Commission, CPUC, and CA ISO should investigate whether changes to the CA ISO tariff are needed to encourage transmission projects necessary to commercialize renewable resources.

> **More ambitious renewable energy goals, supported by the Governor and a large majority of Californians, are needed to meet critical state policy goals.**

Achieving Ambitious Renewable Energy Goals

More ambitious renewable energy goals, supported by the Governor and a large majority of Californians, are needed to meet critical state policy goals. The state should enact legislation to require all retail suppliers of electricity, including large publicly-owned electric utilities, to meet the accelerated 20 percent eligible renewable goal by 2010 and a longer-term goal of 33 percent by 2020, using common definitions of eligible renewable energy. In addition, the state should enact legislation that allows the CPUC to require Southern California Edison (SCE) to purchase at least one percent of additional renewable energy per year between 2006 and 2020, reaching 25 percent by 2010, 30 percent by 2015, and 35 percent by 2020.

To help meet renewables goals, California's older wind sites should be repowered to harness wind resources more efficiently and reduce bird deaths; the CPUC should also require IOUs to facilitate such repowerings in its pending effort to develop renegotiated Qualifying Facilities contracts. Local permitting agencies for wind repowering projects should implement actions similar to those identified in the Energy Commission's recent study on wind energy and bird deaths.

In terms of the Governor's million solar roofs proposal, the Energy Commission recommends the following principles to guide its development:

- Establishing a comprehensive solar program that includes new and existing homes and businesses.
- Leveraging energy efficiency improvements for new and existing buildings.
- Addressing peak demand challenges by linking PV installations with price responsive tariffs and advanced metering.
- Targeting PV deployment to climate zones with high peak demands and where they can provide distribution system benefits.
- Providing long-term declining incentives to promote a sustainable, competitive PV market.
- Exploring a business role in PV deployment for utilities and developing a professional inspection capability.

Endnotes

[1] The Energy Commission, the California Public Utilities Commission and the California Consumer Power and Conservation Financing Authority, adopted the *Energy Action Plan* in the spring of 2003.

[2] The *2003 Energy Report* relied on the loading order in laying the foundation for energy policies and decisions affecting the state required under SB 1389 (Bowen and Sher, Statutes of 2002).

[3] *2003 Integrated Energy Policy Report*, California Energy Commission, Sacramento, CA, December 2003, p.8.

[4] See Chapter 2 and the Appendix to this report for more detail.

[5] A capacity market would allow buyers and sellers to bifurcate the payment stream associated with electricity between a capacity component (which represents the rated continuous load-carrying ability of generation expressed in megawatts) from the energy component (which represents the generation or use of electric power over a given time period, expressed in megawatt-hours). For example, a utility could purchase capacity necessary to meet a possible future peak need without having to purchase the underlying energy. In this way the utility can ensure that the generation capacity will be available if needed, but will not have to take delivery of the energy if the peak is lower than anticipated.

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CHAPTER ONE *Introduction*

In 2003, the California Energy Commission submitted the *2003 Energy Report* to the Governor, which addresses electricity, natural gas, transportation fuels, and environmental issues in California. In this report, the Energy Commission provides the Governor and Legislature with an update of the *2003 Energy Report,* continuing its focus on upgrading California's energy infrastructure with additional analyses and recommendations on reliability, transmission planning, and renewable energy development, as well as progress on 2003 recommendations.

Key State Agencies Collaborate

In 2003, the state's principal energy agencies developed a common policy vision widely referred to as "the loading order," as articulated in the *Energy Action Plan* and cemented in the *2003 Energy Report*. The loading order calls for optimizing energy efficiency and demand response, meeting new generation needs first by renewable energy resources and DG, then by clean fossil fuel generation, and improving the bulk electricity transmission grid and distribution infrastructure.[6] This loading order was expressly embraced by Governor Arnold Schwarzenegger in a letter to CPUC President Michael Peevey on April 28, 2004.

This vision is now being carried out through collaborative staff work between the CPUC and Energy Commission in several joint proceedings such as:

- Electricity resource procurement (CPUC R.01-10-024 and R.04-04-003);
- RPS proceeding (Energy Commission 02-REN-1038 and 03-RPS-1078 and CPUC R.01-10-024, and R.04-04-026);
- Energy efficiency and demand response proceeding (CPUC R.01-08-028);
- Distributed Generation policy development (Energy Commission 04-DIST-GEN-1 and CPUC R.04-03-017); and,
- Natural Gas Supply and Infrastructure (CPUC R.04-01-025).

Report Development Process and Public Review

This report was developed under the direction of the Energy Commission's 2004-2005 *Integrated Energy Policy Report* Committee. Beginning in late 2003, the Energy Commission staff began holding meetings with a wide range of stakeholders to gather input for the *2004 Energy Report Update*. Along with these numerous meetings, the Energy Commission held a series of public workshops to gather information and data. Altogether 19 workshops were held.

Through the process, stakeholder participation was extensive, beginning with various workshops on aging power plants, improving transmission planning, and accelerating renewable energy development. Transcripts were made of each workshop, and stakeholders were urged to submit comments for each workshop. All written comments have become part of the record: 229 written submittals have been docketed in Energy Commission Docket #03-IEP-1.

Drawing from the record, the staff drafted three staff white papers:

> *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements* [http://www.energy.ca.gov/2004_policy_update/documents/2004-08-26_workshop/2004-08-04_100-04-005D.PDF]
>
> *Upgrading California's Electric Transmission System: Issues and Actions for 2004 and Beyond* [http://www.energy.ca.gov/2004_policy_update/documents/2004-08-23_workshop/2004-07-30_100-04-004D.PDF]
>
> *Accelerated Renewable Energy Development* [http://www.energy.ca.gov/2004_policy_update/documents/2004-08-27_workshop/2004-07-30_100-04-003D.PDF]

These draft documents were released in the summer of 2004, followed by three Committee hearings to solicit comments on the draft staff white papers and ensure that the Energy Commission accurately captured public input to create a substantial record for the *2004 Energy Report Update*.

In drafting this report, the Committee considered public input carefully, sifting through the extensive record and reflecting on current conditions, to develop its various policy recommendations. The Committee's draft report and recommendations were vetted in a series of five Committee hearings throughout California. The Committee then revised the report to reflect public input before the California Energy Commission considers the report at its November 3, 2004, Business Meeting.

Report Structure

The remainder of this report is arranged into four chapters:

Chapter 2: Reliability Concerns with Aging Power Plants

Chapter 3: Transmission Planning

Chapter 4: Renewable Energy Development

Chapter 5: State Progress on 2003 Recommendations

Endnotes

[6] California Energy Commission, the CPUC, and CPA *Energy Action Plan*, Spring 2003, p. 4.

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CHAPTER TWO Reliability Concerns with Aging Power Plants

Introduction and Background

California depends upon a significant number of aging power plants that may be retired in the near-term because they operate infrequently and thus do not fully recover their on-going costs in the current market.[7] This chapter discusses the reliability concerns associated with these aging power plants, focusing on the years 2005 to 2008.

In the *2003 Energy Report*, the Energy Commission noted that the retirement of aging power plants can affect the state's reserve margins, with estimates of retirement ranging between 4,630 and 7,232 MW from the Energy Commission and CA ISO, respectively.[8] More starkly, merchant generators indicated 10,000 MW could be retired in the near-term.[9] While contributing this capacity toward reserve margins, some of these aging power plants also provide important local and regional reliability services.

Although the reliability implications are critical to address, these aging power plants also have implications for California's dependence on natural gas for electric generation. In recent years, natural gas prices have become increasingly volatile, heightening California's awareness of its growing dependence. In the *2003 Energy Report*, the Energy Commission noted that the state could help reduce natural gas consumption from electric generation by retiring older, less efficient natural gas-fired power plants and repowering, replacing, or refurbishing them with new, more efficient plants. In addition, the *2003 Energy Report* noted that the aging power plants are more polluting than modern power plants.

Appendix A contains detailed statewide supply/demand balance tables under a base case scenario and medium and high-risk retirement scenarios. The appendix also contains additional details for the following discussion.

Aging Power Plant Study

As part of the *2004 Energy Report Update*, the Energy Commission undertook a detailed study of aging power plants to:

- analyze the role that individual aging power plants play in maintaining reserve margins and providing local and regional reliability services
- assess the environmental and efficiency implications of continuing to rely on aging power plants, and
- examine in more detail the range of retirements that may occur over the next few years to better understand the implications of these potential retirements on system reliability.

This study identified 50 aging power plant units to include in an assessment of reliability impacts.[10] The study then focused on 32 aging units that have a medium-to-high risk of retiring between 2005 and 2008, because they lack a Reliability Must-Run (RMR) or other contract or other assured revenue source. Without either, these units have a limited ability to recover their operation and maintenance costs because they cannot compete effectively in the markets currently open to them during much of the year—primarily the CA ISO energy and ancillary services markets.[11]

Compared with newer combined-cycle plants, aging units have higher fuel costs because of their lower efficiencies. In addition, these units need more frequent maintenance and have higher operation and maintenance costs because they lack automated controls, meaning higher staffing requirements.

Table 1 shows the total amount of aging units at medium-to-high risk of retirement through 2008.

Table 1

Aging Power Plant Retirements
2005-2008 Medium and High Risk Retirement Scenario

	2005	2006	2007	2008	Cumulative MW
PG&E	1,046	1,016	0	990	3,052
SCE & SDGE	676	2,152	1,310	1,879	6,017
Three Utility Area Total	**1,722**	**3,168**	**1,310**	**2,869**	**9,069**

Source: *Resource, Reliability and Environmental Concerns with Aging Power Plants Operations and Retirements.*

Reliability and Reserve Margin Concerns

In assessing the role of aging power plants in California's electricity system, the Committee notes that the aging units under study play the following important roles:

- provide local reliability services in select areas of the state through the CA ISO's RMR contracts;
- contribute to regional and statewide reliability by acting as generating reserve margins during periods of peak load, primarily hot summer periods, and in system emergencies; and
- help alleviate transmission system congestion by offsetting regional transmission congestion, or intertie overloading, with generation at or near load.

Based on its study, the Energy Commission identified 9,000 MW of potential capacity losses from aging units with a medium-to-high risk of retiring by 2008. However, even without these retirements, and including all currently expected new power plant additions, generation reserve margins for the state during summer peaks between 2005 and 2008 may become very thin.

The Energy Commission identified 9,000 MW of potential capacity losses from aging units with a medium-to-high risk of retiring by 2008.

Looking at the historic data, the CA ISO identified critical periods when reserve margins may become thin as a range of 50-100 hours a year, when the system load is 90 percent or greater of the absolute peak for the year.[12]

It is unlikely that *all* aging units in the medium-to-high risk scenario will retire or shutdown. Since aging units compete with each other, retiring just a portion of the state's aging units would likely improve the financial viability of those remaining on-line. However, if a substantial number of aging units actually retire, electricity supplies could be adversely affected in the near-term.

The CA ISO is responsible for maintaining sufficient operating reserves to meet the Western Electricity Coordinating Council's reliability requirements. When operating reserves fall short, a series of CA ISO Staged Alerts is triggered, which is designed to keep the grid operating safely. A Stage 1 emergency is declared when the CA ISO determines that operating reserves will fall below seven percent, although customer services are not interrupted at this stage. A Stage 2 emergency reserve shortfall of less than five percent is imminent. At this point, service interruptions are required for some or all of selected customers, many of whom receive reduced rates as compensation for their agreement to be curtailed. The CA ISO declares a Stage 3 emergency when operating reserve is projected to fall below the critical 1.5 percent threshold, requiring involuntary curtailment of customers, also referred to as rotating outages, to keep the system from collapsing.[13]

Northern California Reserve Margins

Although the range of retirements remains uncertain, in Northern California, Pacific Gas & Electric (PG&E) should have adequate reserve margins under normal and hot weather conditions from 2005 though 2008 under the base case scenario, as shown in Figure 1. In addition, PG&E should have adequate reserve margins with normal weather conditions under the medium-to-high risk retirement scenario, although reserves become tight in 2008, as shown in Figure 2. However, in hot weather conditions under the medium-to-high risk retirement scenario, reserve margins are only slightly above seven percent in 2007, and rotating outages could become necessary in 2008.

Figure 1
Projected Reserve Margins for PG&E Area
2005-2008 Base Case Scenario

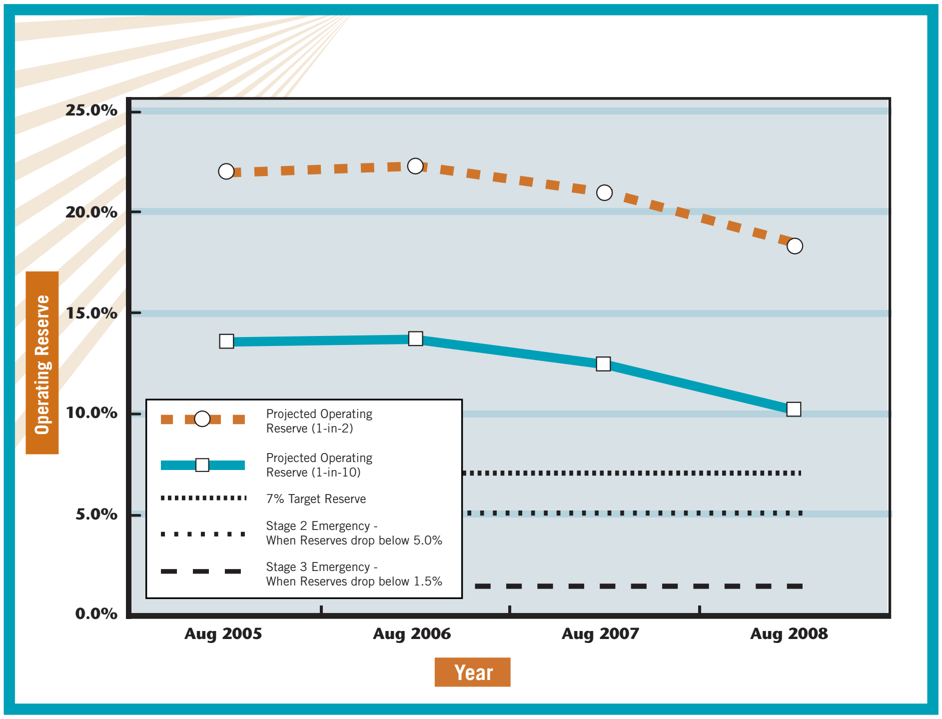
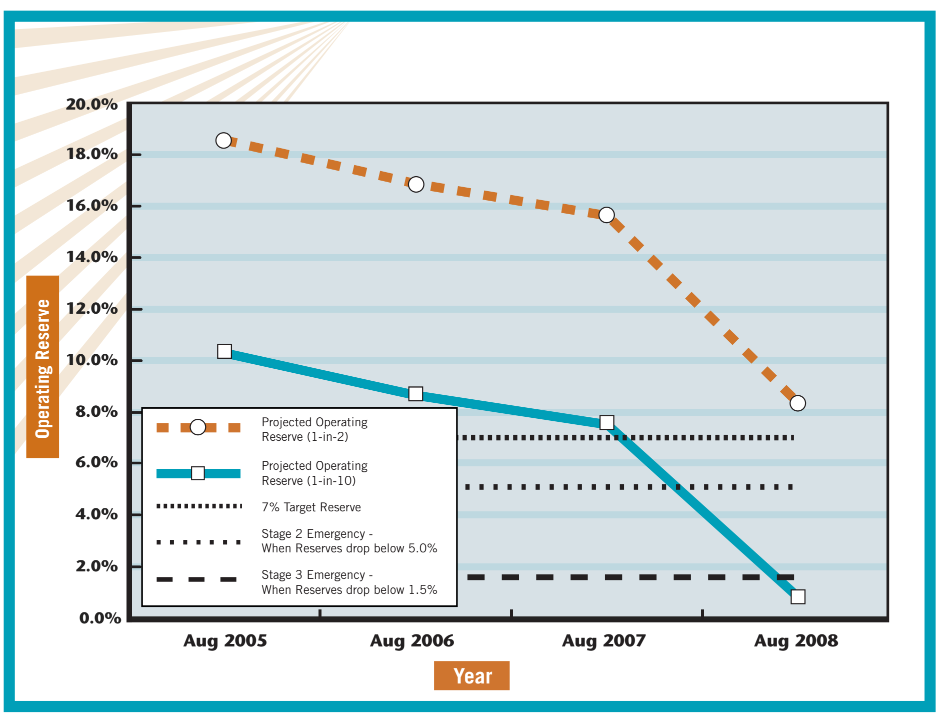


Figure 2
Projected Reserve Margins for PG&E Area
2005-2008 Medium-to-High Risk Retirement Scenario



The possible retirements in Southern California only exacerbate the already serious outlook for reserve margins.

Southern California Reserve Margins

However, the possible retirements in Southern California only exacerbate the already serious outlook for reserve margins. Figure 3 illustrates likely Stage 1 emergencies under normal weather conditions in the base case scenario and rotating outages under hot weather conditions. As Figure 4 shows, the medium-to-high risk retirement scenario compounds this problem.

In Southern California, these scenarios pinpoint the need to find options to bring in additional supplies in the near-term. As discussed below, it should be possible to reduce peak loads through demand response programs, share reserves among multiple utilities for peak periods, or even store some of California's off-peak power in either existing in-state pumped storage facilities or hydro facilities in the Pacific Northwest. In addition, transmission infrastructure additions and enhancements, like upgrades to Path 26, should be a high priority to facilitate greater transfers from Northern to Southern California.[14]

Figure 3

Projected Reserve Margins for SCE and SDG&E Areas
2005-2008 Base Case Scenario

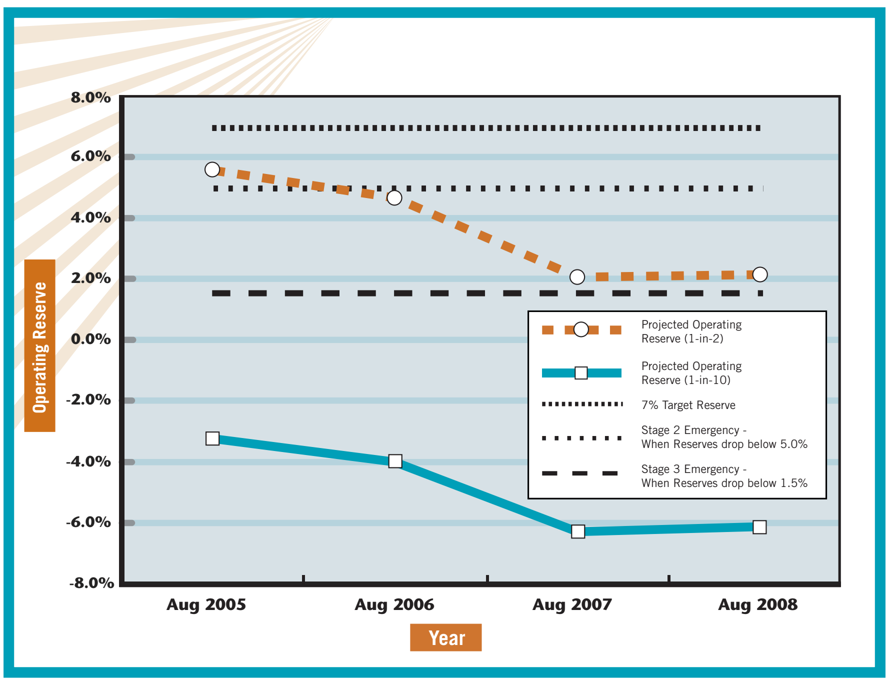
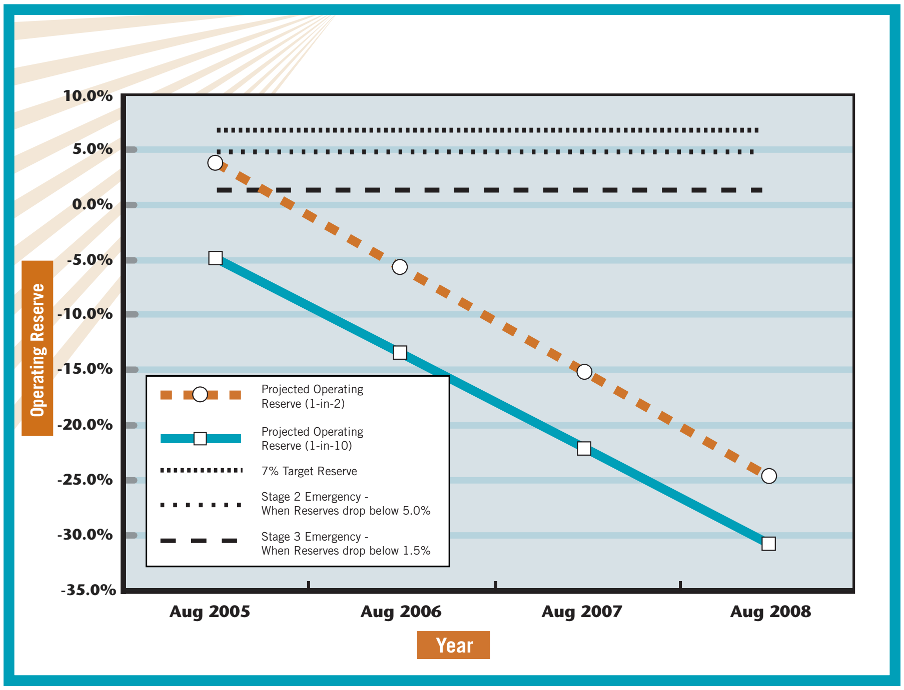


Figure 4
Projected Reserve Margins for SCE and SDG&E Areas 2005-2008 Medium-to-High Risk Retirement Scenario

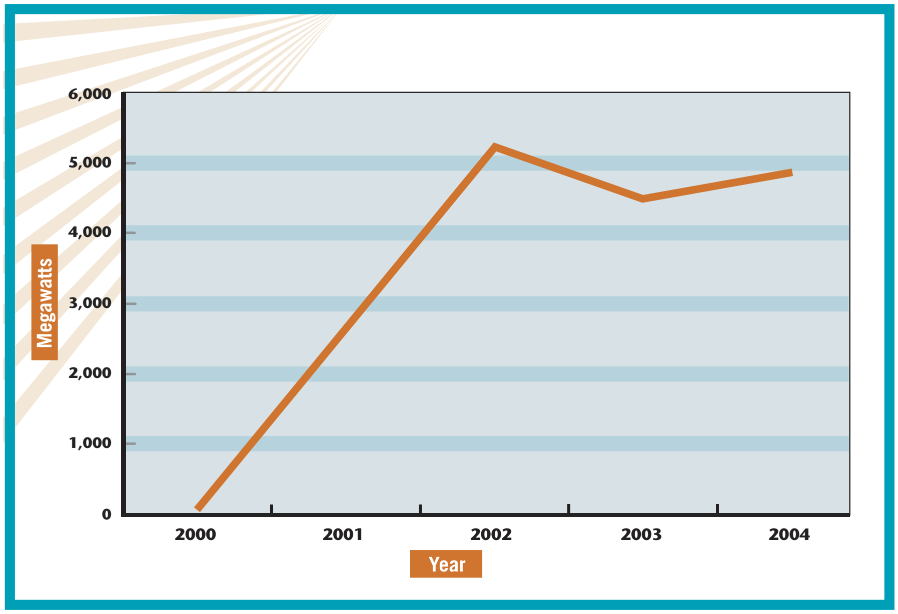


Source: *Resource, Reliability and Environmental Concerns Aging Power Plants.*

Although the Energy Commission has licensed over 18,700 MW of power plants since 2000, some 7,500 MW lack financing, and these power plants have not proceeded to construction. Figure 5 shows that although the pace of power plant additions rose dramatically between 2000 and 2002, it has slowed significantly in the last two years. While the near-term need for resources appears to be in Southern California, the vast majority of the plants that have been licensed, but not constructed, are in the northern part of the state.

Some of the reliability concerns could be mitigated if aging power plants are allowed to compete in the market. To this end, the CPUC's recent proposed decision on resource adequacy requirements could improve the prospects for aging power plants if they are able to successfully compete to meet short- and medium-term IOU needs as the DWR contracts begin to expire. The Committee believes that while the CPUC requirements may allow these aging plants to continue to operate, California will need additional policy initiatives to forestall reliability problems until replacement resources become available through long-term procurement.

Figure 5
2000-2004 Statewide Net Capacity Additions



Source: Energy Commission staff presentation, *Energy Action Plan Meeting*, September 8, 2004.

Efficiency and Environmental Concerns

Although the 2003 Energy Report raised both efficiency and environmental concerns associated with continued reliance on natural gas-fired aging power plants, the Energy Commission notes that it is important to examine the specific roles these aging power plants play in the electricity system, and to compare their efficiency and environmental impacts relative to the alternatives for each of these roles.

In general, the Energy Commission notes that many of the aging power plants (30 out of 50) have emission control technologies that are comparable to those of the new combined cycles.[15] Because similar emission control technology is used on the combined cycles and the aging plants' steam boilers, the difference in emissions reflects only the differences in the relative heat rates or efficiency of the two types of power plants.

During peak periods in California, aging power plants provide part of operating reserves, which must be available when needed. In this role, the aging power plant fleet acts in place of peaking resources such as combustion turbines, which are likely to be even less efficient and have even greater emissions.

The aging power plants also can be used to substitute for some of the energy lost from hydro generation in dry years or to replace generation from existing coal and nuclear power plants when those plants have forced outages. Although California's newer combined cycles can provide replacement power at lower cost and with fewer emissions than older technology, the aging units can be placed in cold standby for such contingencies.[16]

In addition, these aging power plants are generally well-suited to provide load-following capability to the grid. As discussed in the staff white paper, older technology steam boilers, like the aging power plants, have a relatively constant efficiency across broad operating ranges, while the efficiency of new combined cycle units, although high, drops off substantially at lower operating levels. With that decline in efficiency, emission rates of the newer plants increase.

Accelerate Demand Response Programs

Demand response programs are California's most immediate and cost-effective option to address reserve margin and reliability concerns.

A recent report of the Bay Area Economic Forum compared California's performance in demand response and load management programs relative to other states', ranking California 20th in the nation.[17] This is a significant under-performance when compared to our worldwide reputation in energy efficiency programs. The report further concluded that California could reduce its peak loads an additional 2,000 MW, if it only reduced its load by the same 3.5 percent, as the state of Florida has.

The Energy Commission believes that the state must aggressively implement much more comprehensive demand response programs immediately. Current efforts have failed to achieve existing benchmarks and appear unlikely to meet the modest goals established by the *Energy Action Plan* (EAP), the *2003 Energy Report*, and the collaborative effort between the Energy Commission and the CPUC.[18]

In the near-term, increases in demand response capability will have to come primarily from the larger customers who already have real-time meters.

In the near-term, increases in demand response capability will have to come primarily from the larger customers who already have real-time meters. During the 2000-2001 electricity crisis, the state general fund paid for the installation of about 20,000 real-time meters for customers with demand greater than 200 Kilowatts (kW). This effort greatly expanded the number of large customers who could nominally participate in demand response programs and dynamic pricing in addition to limited pilot tests for small customers. While some 500 MW of customer load is estimated to be potentially available from these voluntary programs, only 25 MW has been achieved to date. However, the Energy Commission and CPUC staff are continuing to work with utilities and customer groups to improve the dynamic pricing options and demand response from those rates and programs.

Proposed Demand Response Recommendations

The Energy Commission recommends that the CPUC ensure that its current proceeding on price responsive demand programs for 2005 takes full advantage of the taxpayer installed meters. To address concerns about the summer of 2005, the CPUC should immediately require dynamic pricing tariffs for large electricity customers with real-time pricing metering systems, which would significantly improve reliability of the electric system and reduce peak loads beginning in the summer of 2005.[19] This recommendation is particularly important for Southern California loads, predominately in the SCE service area, where such a mandatory tariff could create a dynamic pricing response capability of 400 to 1,600 MW. Further, these large customers already have real-time pricing metering systems installed,[20] so additional hardware expense or installation costs would not be required, although some customer education would be desirable.

Regulatory authority for dynamic pricing tariffs already exists and the IOUs are already required to reach demand response capability equivalent to three percent of system peak demand by July 2005, and 5 percent by 2007, using any combination of pricing incentives and command and control measures.[21] In addition, the CPUC required IOUs to file demand response plans for summer 2005 by October 15, 2004.[22] Although the CPUC plans to issue a final decision by January 2005 specifying required tariffs and programs to allow compliance, the comparable goals for summer 2004 were not achieved, and preliminary discussions with IOUs about their proposed summer 2005 plans raise concerns that they do not expect to achieve these targets. Instituting a mandatory tariff for large customers with real-time pricing metering systems would remedy the situation.

The Energy Commission also recommends that the CPUC begin aggressively rolling out advanced metering systems for smaller customers and developing dynamic rate offerings and load control options. Since demand response programs for smaller customers will be most cost-effective in areas with high air conditioning demand — such as the Central Valley, inland Southern California, and the desert portions of California — the rollout of advanced metering should target these areas first.

The Energy Commission and CPUC have collaborated in testing a range of demand response programs aimed at residential and small commercial customers less than 200 kW in size. Several thousand residential and small commercial customers have participated in the statewide pilot project, which is a large scale formal experiment testing several types of dynamic rates and load control technologies. The results show that customers who receive dynamic rates can and do respond by reducing their peak demand, and these rates are acceptable to them in terms of comfort and rate impact. About 80 percent of customers reduced their bills, and reduction in peak load (coincident) for residential customers averaged about 12 percent during a relatively cool summer for the experimental tariffs used in the pilot. Small commercial customers also showed substantial peak reductions.

In the next phase of the CPUC proceeding, the utilities will submit their "business cases" to implement advanced metering for customers with demand less than 200 kW. While the demand response effects from dynamic rates could be very large, the actual implementation process will probably take at least two years to achieve significant results.[23] Therefore, the short-term impacts will not reflect the large potential over the longer term.

Proposed Recommendation for Other Load Shifting

The Energy Commission recommends that it work with the DWR, the CPUC, the CA ISO, and other relevant water agencies and municipalities to identify opportunities to reduce electricity demand related to the water supply system during peak hours. While DWR is the largest single user of electricity in California because of its need to pump massive amounts of water over very long distances and elevations, DWR currently operates the State Water Project to maximize pumping during off-peak hours and minimize on-peak pumping based on power and transmission costs, contract delivery requirements, and operational or engineering constraints. DWR is also a major participant in the California Power Authority's (CPA's) Demand Reserves Partnership Program and regularly offers load into the CA ISO's "load drop" market.

While the short-term options for additional peak load reduction from the State Water Project may be limited, the Energy Commission and the CPUC should work with DWR and other water agencies to investigate and pursue additional cost-effective load management and demand response programs that may be possible in the longer-term. Some long-term options may require engineering and marketing assistance from the Energy Commission or the use of state bonding authority to install additional storage capacity to make them cost effective. In addition, the CPUC should consider rate design proposals that would encourage local and regional water agencies to participate in demand response programs.

> **A capacity market, in combination with resource adequacy requirments with local deliverability standards, should send proper signals to the market about the value of these generating units.**

Resolve Market Issues and Reduce Regulatory Risks

The Energy Commission should work with other parties in the CPUC's procurement proceeding, in particular the resource adequacy phase, to develop proposals for capacity markets and explore how these proposals could be used to meet short-term potential supply demand shortfalls, especially those from the potential retirement of aging power plants in the state.

Develop Capacity Markets

Developing a capacity market in California could provide an effective means of providing a price signal to power plant owners and developers of the value of capacity, reducing uncertainty about their ability to compete in the present and future electricity markets. Capacity markets can also provide a useful framework to help achieve resource adequacy goals in a cost-effective and flexible manner. Properly designed, a capacity market can compensate providers of needed capacity from a variety of resources, and ensure that the generator can meet any "qualifying" requirements established for resource adequacy. Tradeable capacity rights and/or obligations can help address uncertainties related to load and responsibility for meeting resource adequacy requirements, mitigating the "stranded asset" scenario that has played prominently in the core/non-core debate.

Ultimately, well-established capacity markets would allow aging power plants to compete with other existing generation and new power plant construction. Owners of aging plant maintain that the location of their facilities near load is of higher value than generation more remotely located. A capacity market, in combination with resource adequacy requirements with local deliverability standards, should send proper signals to the market about the value of these generating units.

The CPUC's draft decision on resource adequacy requirements, issued August 31, 2004, takes a significant step in stabilizing California's electricity market and providing adequate future supplies. The CPUC proposes to explore developing a capacity market in California, which the Energy Commission believes will be an important component of the overall resource adequacy framework. Capacity markets should be designed to provide an opportunity to meet resource adequacy requirements flexibly and cost-effectively. Establishing the core features of tradeable capacity obligations that satisfy resource adequacy requirements would be a useful next step. The duration of initial capacity markets could be for up to a year, and over time, they could evolve into multi-year products.

The CPUC also proposes to develop local deliverability requirements to ensure that resources acquired to satisfy adequacy requirements are available in the local areas where most needed. To the extent local deliverability requirements are successful at ensuring resources are available where they are needed, deliverability requirements can help diminish the need for the current system of RMR contracts in meeting local reliability requirements.

The Energy Commission believes that some form of "tagging" system to enhance the liquidity of capacity resources can help reduce the costs of forward commitment obligations proposed in resource adequacy requirements. (The proposed tagging concepts would standardize terms now defined uniquely in bilateral contracts between generator and utility or other load serving entity, such as an energy service provider or community choice aggregator, leading to a market trading standardized products and thus creating much greater liquidity.)

The Silicon Valley Manufacturing Group (SVMG) has taken a leadership role in developing such a capacity tagging proposal. Their current proposal is a good first step, but will need considerable refinement over time, particularly to accommodate deliverability and changing market design. The Energy Commission notes that numerous other useful ideas were presented at the CPUC capacity markets conference on October 4-5, 2004, in San Francisco, jointly sponsored with CA ISO and Electricity Oversight Board. While the conference provided useful lessons from Eastern ISOs, California must design capacity markets in a manner that integrates with the overall market design that exists here, and the unique conditions of California within the Western Interconnection.

Proposed Capacity Market Recommendations

The Energy Commission recommends that the CPUC and all stakeholders follow the broad policy principles below in developing a capacity market:

- Capacity markets should make compliance with resource adequacy requirements easier and less expensive, while supporting applicable local deliverability requirements.

- Initial steps should be targeted to meeting near-term capacity requirements. All qualifying capacity should be eligible to participate in a capacity market. The Energy Commission staff white paper suggested that some aging plants could compete quite effectively in such a market.[24]

- Tradeable capacity obligations should use standardized contractual terms and conditions, and should include provisions to ensure that they are actually available to the system operators as needed. These obligations should facilitate the resource adequacy requirement migrating with the load, making it easier to implement a core/non-core market structure. A capacity "tagging" mechanism building on the approach suggested by the SVMG is one way of accomplishing this.

- Establishing standardized contract terms and conditions, including an availability commitment provision that can be traded in bilateral contracts and can be the foundation for a broader capacity market that will grow over time.

Proposed Recommendations on Multi-Year Utility Contracts

Multi-year contracts could provide additional assurance that the investor-owned utilities can secure reserve requirements and reliability resources as the supply demand situation tightens in the next few years. Such multi-year contracts could include aging power plants, to the extent they supply reliability services and provide cost-effective capacity resources, as a bridge to bringing on new generation.

The CPUC limited the IOUs' ability to enter into mid-term contracts in the short-term procurement decision to plants that could come on line by 2004. PG&E and SCE have requested authority for additional mid-term contracts in the long-term procurement proceeding, which the CPUC expects to decide on by the end of 2004. In addition, PG&E and SCE have filed petitions that would allow them to immediately execute mid-term commitments of up to five years.[25]

In support of the utility petitions, PG&E, The Utility Reform Network (TURN), and the CA ISO sent a letter on August 16, 2004, requesting the CPUC to provide utilities with the flexibility to procure power now to meet their customer demands through mid-term contracts. These entities were concerned that current limitations hinder a utility's ability to manage long-term market risk and expose ratepayers to the risk of rising prices. They further concluded that such arrangements may provide generation owners with enough revenue certainty to forestall a shut-down of marginal, but necessary, generation facilities. While the Energy Commission also wants to forestall such shut-downs, it does not want these commitments to replace long-term commitments to new resources, particularly projects already licensed and ready to construct.

The Energy Commission recommends that the CPUC support the pending petitions to allow the utilities to enter into limited numbers of one- to five- year power purchase contracts as long as these commitments act as a bridge rather than a substitute for long-term procurement of additional new resources.

Proposed Recommendations on Cold-Standby Plants as Contingency Reserves

Cold standby plants, when used as contingency reserves, are one possible method to reduce costs of maintaining reserve margins. Aging power plants may be good candidates for placing in cold-standby status. These plants would remain shut down but fully staffed during most of the year, so that they could be called upon to start up with advance notice, typically six weeks to three months, to provide capacity during known times of shortages. By reducing maintenance and operating costs to minimal levels while in cold-standby, these plants could provide a cost-effective alternative to maintaining plants that run, even though they are seldom used except in the rare supply emergency.

Planners and control area operators are generally aware months in advance of low-hydro conditions, and cold-standby plants could be called upon to startup during late spring and early summer, to be available during the peak summer periods. Similarly, when a nuclear unit is scheduled for refueling or steam generator replacement, a cold-standby plant could be restarted to substitute for the unavailable nuclear generation.

The Energy Commission encourages the CPUC, CA ISO, IOUs, and municipal utilities to consider using cold standby plants to provide contingency reserves. These plants can remain dormant through much of the year at minimal cost and restart with as little as six to eight weeks' notice when planners know a generation shortage may occur.

Transition Away From Reliability Must Run Contracts

The CA ISO and California's utilities perform extensive annual studies to determine the power plants needed to meet reliability criteria, while considering their locations near load centers and the reliability services the power plants can provide. Those individual power plants most critical for local reliability are awarded RMR contracts. When multiple units could meet these reliability requirements, an open bidding process is used to identify the most cost-effective set of resources to meet those minimum generation requirements. In some cases, however, only a limited number of resources can meet these reliability needs, and cost-based contracts are signed with these specific generators.

For example, the City and County of San Francisco is located on a peninsula with limited transmission interconnections to the rest of the California grid. As a result, the existing power plants at Hunters Point and Potrero are both currently designated as RMR units. These plants must continue to operate until the CA ISO determines that they are no longer necessary for local area reliability. The RMR contracts provide revenue assurances to the plant owners, but also tend to limit their ability to participate in other energy markets where they may be able to secure higher prices for generation. While Hunters Point is scheduled to shut down once transmission upgrades are complete, other plants necessary for local reliability in San Francisco may not be able to continue operating without additional opportunities to recover their costs going forward.

The Federal Energy Regulatory Commission (FERC) and the CPUC have encouraged the utilities to pursue alternatives and reduce the need for RMR contracts, which are considered an expensive, inflexible, and temporary local reliability measure. In some cases, IOUs can reduce the need for RMR contracts by upgrading their transmission systems, thereby reducing RMR payments. Once the transmission investment occurs, some units likely will lose their RMR contracts and no longer be required for local reliability.

Over the last several years, SCE has pursued a variety of transmission upgrades to reduce the number of RMR contracts in Southern California. PG&E also is pursuing transmission upgrades to reduce RMR requirements.

However, delays in getting transmission upgrades on-line may create or worsen local reliability problems. Earlier this summer, the CA ISO entered into an RMR contract with Reliant to return the Etiwanda units to service. Last fall, Reliant, pursuant to settlement agreements, held an auction offering the capacity from its Etiwanda facility, but no one submitted a bid. Then, after an SCE transmission upgrade was delayed, the CA ISO found that power flows in the Los Angeles Basin were being unnecessarily constrained by congestion without the Etiwanda facility or transmission upgrade.[26]

Congestion has been an ongoing issue on the CA ISO grid. The Path 15 interconnection between Northern and Southern California is perhaps the most visible example, as exemplified in the 2000-2001 power system failures. These system failures were exacerbated by the inability to move power to Northern from Southern California. In another example, when the CA ISO examined the need for additional transmission in the San Diego Gas & Electric (SDG&E) area, the utilities in the Southern California transmission zone (SP15) were estimated to have incurred nearly $35 million in congestion-related costs over a nine-month period in 2003-2004. The extent to which congestion continues to occur on the Southern California system was graphically illustrated in evidence provided by the CA ISO to the Energy Commission during the August 26, 2004, workshop.

This summer, the CA ISO has raised issues about worsening transmission congestion in the Southern California region, especially on the transmission lines feeding the Los Angeles Basin. In a June letter to the CPUC, the CA ISO raised major concerns that SCE's procurement practices were not adequately considering local reliability needs, and that the utility was procuring an excessive amount of power that could not be delivered into Southern California because of congestion.

The Energy Commission continues to be concerned that California is systematically under-investing in transmission infrastructure.

On July 8, the CPUC adopted a reliability decision, which addressed the CA ISO concerns about a "relative disconnection between the resources that are scheduled and the ones required to serve load in the SP 15 area."[27]

The CPUC directed the utilities in general to consider local reliability needs in their procurement plans rather than relying upon the CA ISO and/or RMR contracts. While the CA ISO noted that congestion may exist on the grid in the near future, including areas in Northern California, the CPUC did not directly apply its decision beyond Southern California at this time.[28] However, the CPUC directed all IOUs to minimize total costs, including reliability and all known and reasonably anticipated CA ISO-related costs (including congestion, re-dispatch, and must-offer costs).

The CA ISO and SCE are adopting protocols to implement the CPUC decision, which will require the CA ISO to publish information on both known and reasonable congestion, and the cost of procurement options.[29] The CPUC plans to revisit protocols and the cost impacts later this year to evaluate SCE's performance this past summer. SCE has raised concerns about the compatibility of the CPUC's reliability decision with the long-term procurement requirements in Assembly Bill (AB) 57.[30] Under this law, the CPUC must reduce the regulatory risks associated with utility procurement decisions by replacing after-the-fact reasonableness reviews with an upfront review and approval process. The Energy Commission believes that harmonizing the CPUC reliability decision with the AB 57 requirements, including FERC's policies requiring open, non-discriminatory access to the bulk transmission grid, will be challenging.

Proposed Recommendations to Transition Away From Reliability Must Run Contracts

The CPUC has enunciated a goal to transition away from the RMR contracts to a long-term procurement framework that considers local reliability needs combined with a viable deliverability component. The Energy Commission believes that, given the critical reliability role of the RMR units, this transition needs to be carefully and smoothly executed over the next few years.

Given this goal, the Committee recommends that California re-examine the link between the CA ISO transmission expansion process and the Local Area Reliability

Study (LARS) and RMR efforts. Although the CPUC has approved over $2.34 billion in transmission investments over the last several years, the Energy Commission is concerned that congestion appears to be a persistent and growing problem on the CA ISO grid.[31] In the face of increasing congestion, the question remains why more transmission fixes have not emerged from the transmission expansion and LARS efforts. Given this, the Energy Commission continues to be concerned that California is systematically under-investing in transmission infrastructure.

Enhanced Supply Management

Over the next several years, transmission upgrades and other options could greatly reduce the state's potential supply shortfall, increasing the flexibility of the existing generating resource base.

California's operational history shows that peak demand seldom simultaneously hits all areas of the state. More typically, one region hits very high peaks, stressing the available generation in that area, while nearby areas have relatively milder weather and generation surpluses.[32] For example, between 1993 and 2002, the sum of the non-coincidental peaks of the utilities in the CA ISO control area was between 800 MW to 2,800 MW greater than the highest annual peak load on the CA ISO system as a whole.[33]

While California needs reliable supply even when very hot weather is experienced in the entire Western region, there is considerable value in enhancing the ability to transfer power from areas with surplus to areas in need of generation during the times when hot temperatures do not coincide. However, because of transmission congestion, control area operators are very limited in their ability to import more power, and therefore must rely on local generation to meet the peaks.

Transmission bottlenecks typically occur at the seams between the CA ISO control area and these public utility control areas—the Sacramento Municipal Utility District (SMUD), Los Angeles Department of Water and Power (LADWP), and Imperial Irrigation District (IID). For example, the transmission systems of SCE and LADWP could be more fully interconnected to allow additional reserve sharing. LADWP has indicated that a transmission expansion between its service territory and SCE's is currently underway.[34]

However, preliminary transmission system analysis shows that retirements within the Los Angeles Basin sub-region could further reduce the capability of importing power into the area, as well as potentially reducing generating reserve margins to unacceptable levels.[35] Reliability concerns in this sub region could be reduced by a greater ability to rely upon LADWP's resources in a system emergency.

While supplies are tight during peak periods, the state has more than adequate amounts of power in the low load periods, especially at night. California utilities and generators have some options for shifting power supplies from off-peak to on-peak periods through the use of pumped-storage facilities. While limited, these options would not only reduce the number of power plants needed to meet day-time peaks, but could also increase the overall efficiency of the generating sector by increasing baseload operations and decreasing load-following and peaking operations. This would reduce natural gas use and air emissions as well.

In the past, California utilities contracted with Pacific Northwest utilities for significant amounts of capacity exchange, benefiting both regions. Throughout the 1980s and early 1990s, policy makers in the Western region nurtured these relationships. With deregulation, though, California utilities began to reorient their procurement to very short-run transactions through the Power Exchange, straining relations with the Pacific Northwest. The relationship was further strained during the California electricity crisis when California's price spikes rolled throughout the regional supply markets, and the Pacific Northwest attempted to erect a "fire wall" between itself and California. Many of the exchange contracts dissolved in the ensuing litigation.

Proposed Supply Management Recommendations

The Energy Commission recommends that it work with utilities, the CPUC, and other agencies to identify cost-effective projects that would increase transfer capability between the transmission system in the CA ISO control area and the three other California control areas. This increased connectivity would provide flexibility to control area operators in matching generation to load, and could reduce the number of power plants needed to meet total system-wide demand. With increased connectivity, control area operators would have greater flexibility to import power from cooler regions that have generation surpluses.

The Energy Commission recommends that it work with the CA ISO, CPUC, and other California control area operators to identify and alleviate transmission barriers to the sharing of generation reserves, eliminating bottlenecks that constrain the use of these resources for reliability purposes.

The Energy Commission also recommends that California establish a joint planning effort to take full advantage of the complementary utility systems in California and the Pacific Northwest. The Energy Commission recommends that the California energy agencies identify broad regional policies to guide the IOUs and others to develop exchange contracts with Pacific Northwest entities.

In addition, the Energy Commission recommends that California establish a joint planning effort to use existing pumped-storage facilities in the state more fully.

Endnotes

[7] Utilization rates for the fleet of aging plants under study declined from 48 percent in 2001 to 26 percent in 2002 and 18 percent in 2003. *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements*, p.23.

[8] *2003 Integrated Energy Policy Report*, California Energy Commission, December 2003, p. 8.

[9] Ibid.

[10] The majority of the aging power plants have several units that operate independently of each other. Depending on the system conditions, one or all of the units could be operating. Energy Commission staff initially selected 66 aging power plants totaling 17,126 MW of generating capacity of steam boiler units that were representative of units most likely to retire during the study period of 2005 through 2008. Of these, 16 were removed from the study group for the staff's reliability analysis because 14 plants are owned by municipal utilities that have no plans to retire them before 2008. The additional plants are owned by PG&E, which plans to operate Humboldt units through 2008 and retire Hunters Point as soon as possible.

[11] *Resource, Reliability and Environmental Concerns of Aging Power Plant*, p. 5.

[12] See Appendix B of the CPUC Workshop report on Resource Adequacy issued on June 15, 2004.

[13] CA ISO website.

[14] There are two potential upgrades being considered for Path 26. Expanding the existing special protection systems (or non-hardware fixes) could increase transfer capability from 3,400 to 3,700 MW by 2005. Transfer capability could be increased to 4,400 MW with reconductoring of 500 kV lines, upgrade of 500 kV capacitors and installation of voltage support equipment.

[15] Selective Catalytic Reduction technology is used on both new combined cycles and aging plants' steam boilers.

[16] It would be economically inefficient to build new combined cycles for such standby service.

[17] *Lightning Strikes Twice: California Faces the Real Risk of a Second Power Crisis*, Bay Area Economic Forum, August, 2004, pp. 13, 14, 15.

[18] The feasibility of implementing dynamic pricing in California and activities being pursued is described in detail in: Feasibility of Implementing Dynamic Pricing in California, California Energy Commission, 400.03.020F, October 2003. A plan for increasing demand response in California is presented in: *(An Action Plan to Develop More Demand Response in California's Electricity Markets)*, Energy Commission, P400.02.016F, July 2002.

[19] In the Energy Commission report, *Feasibility of Implementing Dynamic Pricing in California*, Appendix Table A-2, October 2003, the staff estimated that the short-run elasticity demand for industrial as well as large and medium commercial customers is 0.1 to 0.4. Applying the range of elasticity to the estimated peak loads of >200kW customers for SCE, approximately 60,000 GWh at 65 percent load factor, suggests potential peak reductions on the order of 400 MW to 1,600 MW.

[20] Real-time Pricing (RTP) metering systems typically include interval meter, electronic data uploading, and daily access to usage data. Funding for installation of these metering systems, which began in spring 2001, was provided by AB29.

[21] CPUC Decision 03-06-032.

[22] CPUC Rulemaking 02-06-001.

[23] Implementation would entail CPUC approval of meters and dynamic rates, installation of meters, and customer education.

[24] *Resource Reliability and Environmental Concerns*, p.36.

[25] Mid-term contracts would be pursuant to PG&E and SCE's adopted short term procurement plans.

[26] The components for the transmission upgrade were diverted to repair damage from the Southern California wildfires last year.

[27] P. 5 of Decision 04-07-028 of the CPUC (July 8, 2004).

[28] P. 17 of Decision 04-07-028 of the CPUC (July 8, 2004).

Endnotes (continued)

[29] See Resolution E-3888 adopted by the CPUC on August 19, 2004.

[30] AB 57, Chapter 835, Statutes of 2002, Wright.

[31] *Electricity and Natural Gas Assessment*, California Energy Commission, December 2003, Sacramento, CA, p 5.

[32] However, it should be noted that during the summer of 2004, we experienced some simultaneous peaks. North of Path 26 peaked on Sept. 8th, but dropped considerably by the date of the South of Path 26 peak on Sept.10th. This is a rare event; PG&E has only peaked in September one other time since 1980. SMUD peaked on Aug. 11th, while LADWP control area peaked on Sept. 8th.

[33] See Table 3-3 and the discussion on pages 3-9 and 3-10 of PG&E's testimony in the Rulemaking 04-04-003.

[34] LADWP is currently installing a third bus-tie transformer at its Sylmar Switching Station that will increase the interchange capability there from 1200 MW to 1600 MW.

[35] *Resource, Reliability and Environmental Concerns of Aging Power Plant and Retirements,* California Energy Commission, August 2004.

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CHAPTER THREE *Transmission Planning*

Introduction

The *2003 Energy Report* identified the need to reform California's transmission planning and permitting process. While the *2003 Energy Report* focused primarily on structural inadequacies in the permitting process, it recommended that the 2004 Update concentrate on systemic problems in the planning process.

As part of the *2004 Energy Report Update*, the Energy Commission engaged the CA ISO, CPUC, utilities, and other stakeholders in a series of workshops to address planning issues. By bringing together this diverse group in dialogue, the Energy Commission identified a number of long-term needs and strategies to improve transmission planning in the state.

In particular, stakeholders emphasized the need for early public participation in the planning process. In fact, the success of a state-wide transmission planning effort will depend to a significant extent on our ability to engage the active participation of local government, public interest groups, and the residents who live in areas where these infrastructure investments are being considered. Other state and federal agencies affected by or involved with transmission land use planning and permitting will also need to participate actively.

Despite progress, California currently lacks a systematic, statewide approach to transmission planning that would help address critical energy and environmental policies. Recent legislation directs the Energy Commission to develop a statewide, strategic plan for transmission, establishing the Energy Commission's *Energy Report* proceeding as the appropriate forum for the state to conduct transmission planning.[36]

This chapter discusses the Energy Commission's recommendations for improving the state's long-term transmission planning process.

Background

Before electricity restructuring, the IOUs and municipal utilities that did transmission planning could integrate electricity generation and transmission investments so that both were timed and brought on-line to ensure a reliable electricity system. As vertically-integrated utilities, the CPUC regulated transmission investments and rate recovery for IOU projects.

Since restructuring, FERC has sole jurisdiction over the financial regulation of IOU investments within the CA ISO-controlled transmission network. In early September, a California appellate court unanimously agreed with SCE that FERC has pre-empted the regulation of interconnection to the bulk transmission grid. The decision nullified a CPUC order to SCE that it finance transmission network upgrades near Tehachapi rather than look to wind developers to pay for network improvements.[37] Although presently under appeal and with full ramifications still unclear, the decision is an abrupt reminder of the desirability of harmonizing state and federal transmission policies.

In the restructured electricity market, the CA ISO operates the IOU transmission lines in California and conducts transmission system planning with the IOUs under a FERC approved tariff. This process begins when the IOUs submit their annual plans to the CA ISO. The CA ISO conducts a stakeholder process to consider load growth and constrained transmission paths before recommending projects for the CA ISO Board of Governors to approve. The CA ISO and IOUs then submit projects to the CPUC for regulatory approval.

Currently, though, the CA ISO transmission planning process covers only the transmission systems of the state's IOUs, accounting for about 80 percent of the transmission system.[38] In 2002, Senate Bill 1389 gave the Energy Commission responsibility to conduct a comprehensive assessment of the electricity and natural gas system, including transmission.

Recently the Governor signed Senate Bill (SB) 1565 that elevates the Energy Commission's formal role in transmission planning, requiring the Energy Commission to adopt a strategic plan for the state's electric transmission grid beginning with the *2005 Energy Report* cycle.[39] This plan must identify and recommend actions necessary to implement investments needed to ensure reliability, relieve congestion, and meet future growth in load and generation, including renewable resources.

Collaborative Long-term Transmission Planning

Several basic shortcomings beset transmission planning in California. One of the principal deficiencies is that the state lacks a comprehensive statewide transmission planning process that is forward-looking and involves all of the relevant utilities, market participants, and stakeholders, including the 20 percent of the transmission grid not subject to the CA ISO process.

California also lacks a seamless process for moving transmission projects through the planning phase into permitting. One way to achieve this is to develop a state planning process to identify needed transmission infrastructure investments, consider the non-wires alternatives to transmission lines, and approve those projects that provide benefits to California. Projects deemed of benefit could then move directly into the permitting phase. This would allow the alternatives analysis required under California Environmental Quality Act (CEQA) in the permitting process to focus on alternative routes for transmission lines and mitigation measures. This framework could greatly reduce the redundancies in the current process, where alternatives are raised at multiple stages in planning and permitting for transmission.

Earlier this year, the CA ISO Market Surveillance Committee stressed the need for "a proactive and coordinated planning process," observing that:

> …the potential harm to consumers associated with under-investment in transmission is far greater than the potential harm associated with over-investment. As such, we recognize that even an imperfect transmission planning process that actually improves the network is better than a dysfunctional process that makes no investments at all.[40]

In addition, the planning process must be coordinated with all relevant state and federal policy and regulatory agencies, the CA ISO, investor-owned and municipal utility transmission owners, and the various power plant developers, stakeholders, and members of the public.

The Energy Commission proposes that the state, as part of the *2005 Energy Report* Process, initiate a comprehensive, statewide transmission planning process for the *Energy Report* designed to meet the following important objectives:

- Assess statewide transmission needs for reliability and economic projects as well as those necessary to achieve statewide policy goals such as the RPS.
- Approve beneficial transmission infrastructure investments that can move into permitting.
- Examine the statewide corridor needs for future transmission projects, designate and conduct environmental reviews of corridors, and allow the utilities to set aside necessary land costs in ratebase for future use.
- Examine transmission alternatives early in the planning phase, so that the environmental review in the permitting phase can more appropriately focus on routing alternatives and mitigation measures.

The state has no formal process to plan for transmission corridors well in advance of their need.

Establish a State Transmission Corridor Planning Process

The state has no formal process to plan for transmission corridors well in advance of their need so that land or easements necessary for future transmission lines can be acquired by utilities.

To facilitate corridor and right-of-way banking within the state, the Energy Commission recommends that it and CA ISO, in collaboration with the CPUC and stakeholders, develop a statewide process for transmission corridor planning. Stakeholders should include the California Department of Parks and Recreation, State Lands Commission, U.S. Forest Service, Bureau of Land Management, the Western Utility Group, military installations, investor-owned and publicly owned utilities, Native American tribes, the public, and city, county, and regional planning agencies. Corridor planning should require that state, regional, and local land use concerns and environmental assessments to be considered together in developing long-term strategic plans.

In addition, the Energy Commission recommends that the state develop a process to identify and bank multiple-use utility corridors and rights-of-way, including transmission, natural gas, or water pipelines.

To address transmission corridor needs of most immediate concern, the Energy Commission recommends that the state enact legislation authorizing the Energy Commission to designate needed transmission corridors as part of its transmission planning responsibilities. This authority should identify the Energy Commission as the lead agency to prepare programmatic environmental impact reports (EIRs) or other appropriate environmental documents that could be relied on for permitting or banking of utility corridors and rights-of-way. In addition, the Energy Commission and CPUC should eliminate current limitations on the utilities' ability to acquire and hold the cost of lands in their rate bases for longer periods of time.[41]

Non-Wires Alternatives to Transmission

An important element of a state transmission planning process is considering non-wires alternatives to transmission, including new generation, energy efficiency, and demand response. To date, non-transmission alternatives have not been considered early in the transmission planning process, but have been delayed until the permitting process, which has proven disruptive and inadequate. During the Energy Commission workshops for this report, regulatory authorities, industry, and the public agreed that waiting until the permitting process is too late to consider transmission alternatives fully or fairly. If non-wires alternatives were evaluated early, then all parties would have the most complete information. Further, if all affected stakeholders participated in the process, the best transmission or non-transmission alternatives would likely move forward to the permitting process.

> **The Energy Commission recommends that the benefits of transmission projects be accurately captured over their 30-50 year useful life.**

The Energy Commission recommends that it, in collaboration with the CA ISO, CPUC, and other stakeholders, explore workable options and identify, as part of the *2005 Energy Report*, the best approach for examining non-transmission alternatives in the statewide transmission planning process.

Improve Assessment of Transmission Costs and Benefits

Throughout this update process, the Energy Commission explored improvements needed to evaluate the costs and benefits of transmission investments to:

- Capture the long useful lives of transmission assets, which remain in service for 30 to 50 years or more.
- Explore various methods that quantitatively and qualitatively capture long-term strategic benefits, such as insurance against unexpected adverse events, price stability, mitigation of market power, and potential for increased sharing of electricity resources.
- Use an appropriate social discount rate to assess costs and benefits of transmission investments.

Transmission Assets Have Long Economic Lives

Transmission projects have very long economic lives, staying in service for 30 to 50 years and beyond. The timeframe for evaluating the costs and benefits associated with transmission investments must be longer than the ten years currently used in determining the need for transmission projects. While a ten-year timeframe may seem an improvement upon the five-year horizon used to disapprove the Valley-Rainbow project, it remains seriously inadequate to properly evaluate such long-lived public assets.

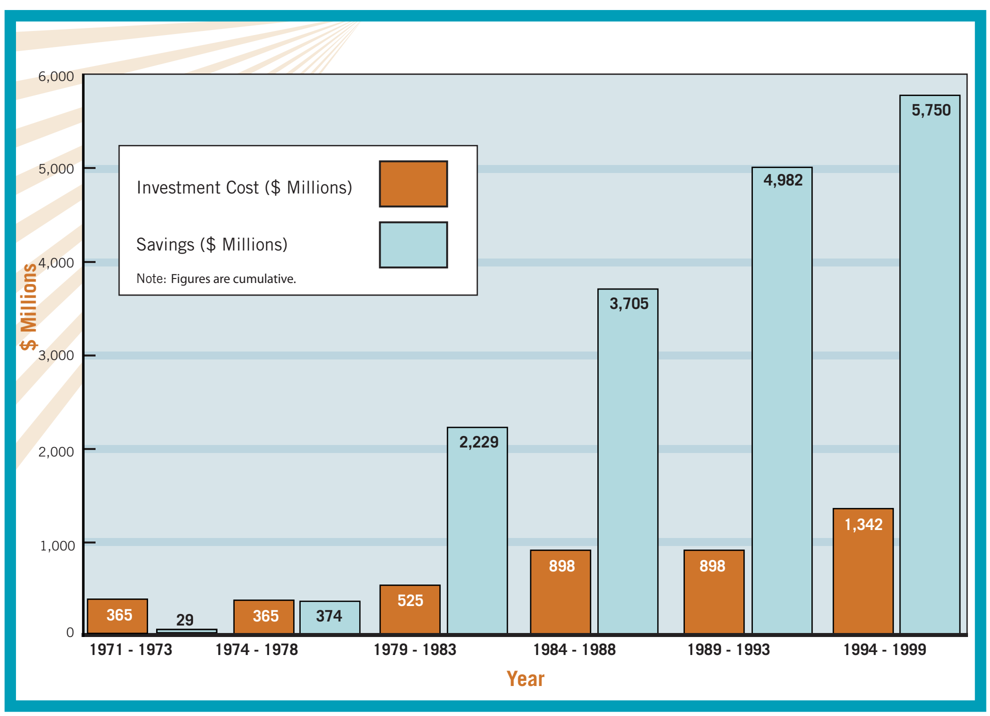
The Energy Commission recommends that the benefits of transmission projects be accurately captured over their 30- to 50-year useful life and fully represented in the analyses that determine which transmission investments best meet California's needs. The Energy Commission also recommends changes to Section 1003(d) of the Public Utilities Code to ensure that the full costs and benefits of projects, including difficult to quantify strategic benefits, are considered in a reformed planning and permitting process.

Strategic Benefits of Transmission Projects

Transmission planners now recognize that many existing bulk transmission projects provide strategic benefits that were not foreseen or were not evaluated either quantitatively or qualitatively in the planning and permitting processes. Some of these benefits include insurance against contingencies during abnormal system conditions, price stability, and mitigation of market power, the potential for increased reserve resource sharing, environmental benefits, reduction in generation infrastructure needs, and achievement of state energy policy objectives in commercializing renewable resources.

As shown in Figures 6 and 7, transmission interconnections to the Pacific Northwest and the Desert Southwest over the past 30 years have provided benefits well in excess of their costs. Many of these benefits were not calculated as part of the projects' economic evaluation when the projects were approved because they are difficult to measure and monetize, or in some cases predict. It is important to develop appropriate methodologies for quantifying as many of these strategic benefits as possible.

Figure 6
Long Term Benefits: Desert Southwest Transmission Expansion

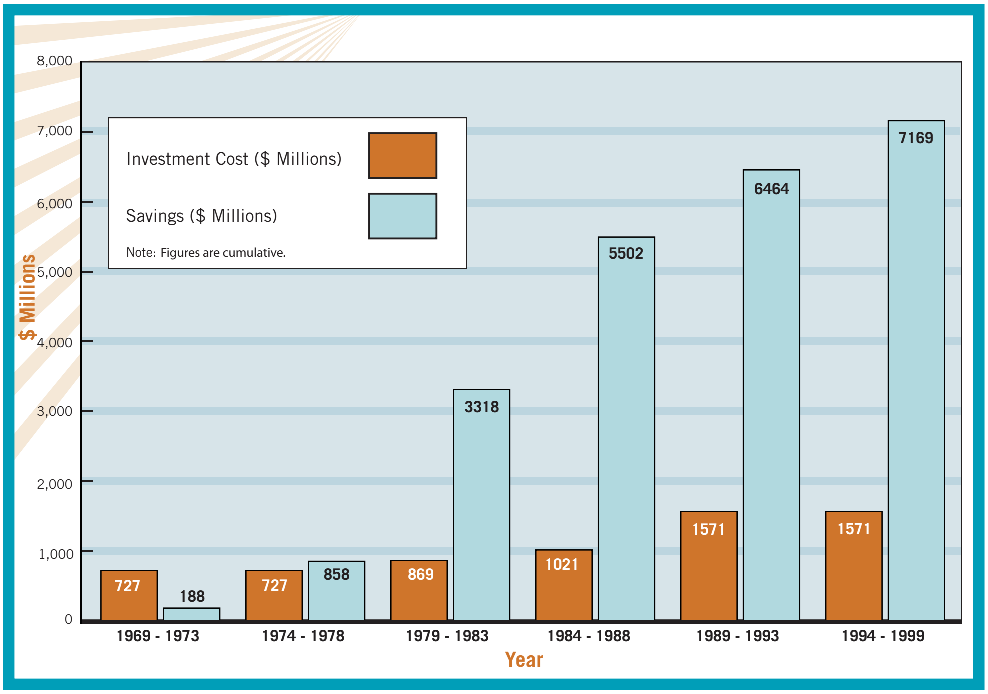


Source: *Planning for California's Future Transmission Grid*: Review of Transmission System, Strategic Benefits, Planning Issues, and Policy Recommendations.

In the past, imports from surrounding states have provided important insurance against contingencies. For example, in 1985, power imports offset the loss of 1,200 MW when a reheat steam piping failure kept the Mohave Generating Station off-line approximately four months. Also in the mid-1980s, power imports offset the Palo Verde Nuclear Plant's unplanned outage that resulted from a Nuclear Regulatory Commission order to address steam generator issues. This outage represented a loss of approximately 3,600 MW in generating capacity to the Desert Southwest area and 1,000 MW to California.

Figure 7

Long Term Benefits: Pacific Northwest Transmission Expansion



Source: *Planning for California's Future Transmission Grid*: Review of Transmission System, Strategic Benefits, Planning Issues, and Policy Recommendations.

Imports from out-of-state provided important benefits in stabilizing California electricity prices in the past. For example, during the 1970s oil embargo, California saved more than $100 million per month through shutting down in-state oil-fired plants and importing power from out-of-state non-oil-fired plants. In addition, above-average amounts of attractively priced hydro imports from the Pacific Northwest during periods of wet weather have resulted in substantial cost savings in the state. California saved over $900 million in 1984, which was more than the total investment in the Pacific Intertie up to that year.[42]

While some of the strategic benefits of projects cannot be easily quantified, there are qualitative aspects that should be recognized and presented to decision makers. Decision makers can use this information to make fully informed judgments about the expected present and future value of transmission projects. In the future, all strategic benefits (qualitative and quantitative) of transmission projects must be fully included when evaluating proposed projects, so that decision makers may correctly weigh a project's costs and benefits.

Social Discount Rate for Transmission Planning & Evaluation

The Energy Commission believes using a social discount rate is an appropriate approach for valuing the long useful life and the public goods nature of transmission projects. The costs and benefits of transmission lines under the restructured market are no longer limited to a sponsoring utility or its retail customers, as they were when utilities were vertically integrated. On the CA ISO grid, the costs of transmission upgrades are now spread among all users through transmission access charges. The benefits of these transmission investments cannot be denied to any retail customer or generation owner, and as a result, transmission lines have increasingly become a public good.[43]

However, the current discount rate used to evaluate transmission projects at the CA ISO and CPUC is based on the utility industry's opportunity cost of capital, which effectively shortens the period over which benefits accrue. Decision makers must weigh the costs and benefits to society over the full useful life of these capital-intensive projects. Doing otherwise biases the decision against investment.

Social discount rates are used to appraise the economics of public projects in other sectors such as transportation, water resource development, and land-use. For example, in its building standards, the Energy Commission uses a three percent discount rate for testing cost-effectiveness that reflects a real (inflation-adjusted), after-tax rate that is more reflective of a social discount rate.

The Energy Commission recommends using a social discount rate, comparable to that used for its buildings and appliance standards, for evaluating the costs and benefits of transmission investments in a properly focused state transmission planning process.

Transmission Needs to Meet Renewables Portfolio Standards

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. As discussed in the next chapter on renewable resources, providing for timely and adequate transmission projects will prove critical to meeting the state's ambitious renewable energy goals.

The Energy Commission proposes the following recommendations to facilitate the timely development of transmission to bring renewable projects on line:

- The Energy Commission should increase its participation in the work being done by the Study Group for Phased Tehachapi Transmission Development in CPUC proceeding I.00-11-001, Phase 6, led by SCE and the CA ISO.
- The Energy Commission should work with stakeholders to identify corridor or right-of-way studies to ensure effective and efficient permitting for the Tehachapi Wind Resource Area. Stakeholders who should be included in corridor planning for Tehachapi include the CA ISO, CPUC, SCE, LADWP, PG&E, renewable energy developers, military bases, local planning agencies, and interested public.
- The state should establish a Joint Transmission Study Group for Imperial County's geothermal resource areas with municipal and investor-owned utilities, renewable developers, California Department of Parks and Recreation, and local and regional planning agencies.

In addition, California policy makers are recognizing that RPS goals present a new kind of transmission project for the state, which the current CA ISO tariff does not cover.[44] Because the tariff does not explicitly contain a provision for projects that are needed to commercialize renewable resources, the Energy Commission recommends that it, CPUC, and CA ISO should investigate whether changes to the tariff are needed.

Endnotes

[36] SB 1565 (Bowen) Chapter 692, Statutes of 2004 was signed into law on September 22, 2004.

[37] In this court case there was no dispute about the developers' obligation to pay for lines to the first point of interconnection.

[38] The ISO controls approximately 80 percent of California's bulk transmission system based on the amount of circuit miles of transmission. *Upgrading California's Electric Transmission System: Issues and Actions,* p, 6; California Energy Commission, August 2003.

[39] SB 1565 (Bowen) Chapter 692, Statutes of 2004 was signed into law on September 22, 2004.

[40] *Opinion on Large Generator Interconnection Rule*. Market Surveillance Committee of the CA ISO, January 7, 2004.

[41] In Decision 87-12-066 and Decision 89-12-057, the CPUC upheld that SCE and PG&E, respectively, could only include transmission lines that are not related to new power plants in"plant held for future use" for a maximum of five years, thereby limiting the utilities' ability to hold such properties in their rate base to five years.

[42] Consortium of Electric Reliability Technology Solutions, *Planning for California's Future Transmission Grid: Review of Transmission System, Strategic Benefits, Planning Issues, and Policy Recommendations*. Consultant Report. Prepared for the California Energy Commission. Publication number 700-03-009, p. 28. October 2003.

[43] Consortium of Electric Reliability Technology Solutions, *Economic Evaluation of Transmission Interconnection in a Restructured Market.* Consultant Report. Prepared for the California Energy Commission. Publication Number 700-04-007, p. 28. June 2004.

[44] CA ISO Tariff Section 3.2.1.1 outlines the requirements for a need determination for economically driven projects, while Section 3.2.1.2 outlines the requirements for a need determination for reliability driven projects.

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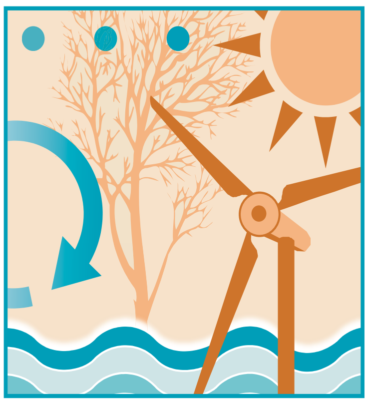
CHAPTER FOUR Renewable Energy

Introduction and Background

Renewable energy is an important priority in the state's loading order, and as noted in the *2003 Energy Report*, the RPS is the centerpiece of the state's strategy for diversifying the electricity system. The state's RPS program enjoys broad public support, with nearly nine in ten surveyed Californians supportive of doubling the use of renewables over the next 10 years.[45] This chapter discusses California's RPS, along with several recommendations for changing the program and accelerating renewable energy goals.



As originally specified in SB 1078, the RPS requires all IOUs to increase their portfolio of renewable resources by at least one percent of sales every year to reach the target of 20 percent renewable resources by 2017. The *Energy Action Plan* accelerated the 20 percent target to 2010. SB 1078 directs publicly owned utilities to develop RPS programs consistent with the Legislature's intent, taking costs and the goal of environmental improvement into account.[46] Although the IOUs can count wind, geothermal, small hydro, and other specified technologies as renewable resources, large hydro does not count toward the state-managed RPS. As outlined in the legislation, the CPUC and Energy Commission have complementary responsibilities, and as a result collaborate closely to administer the RPS.[47]

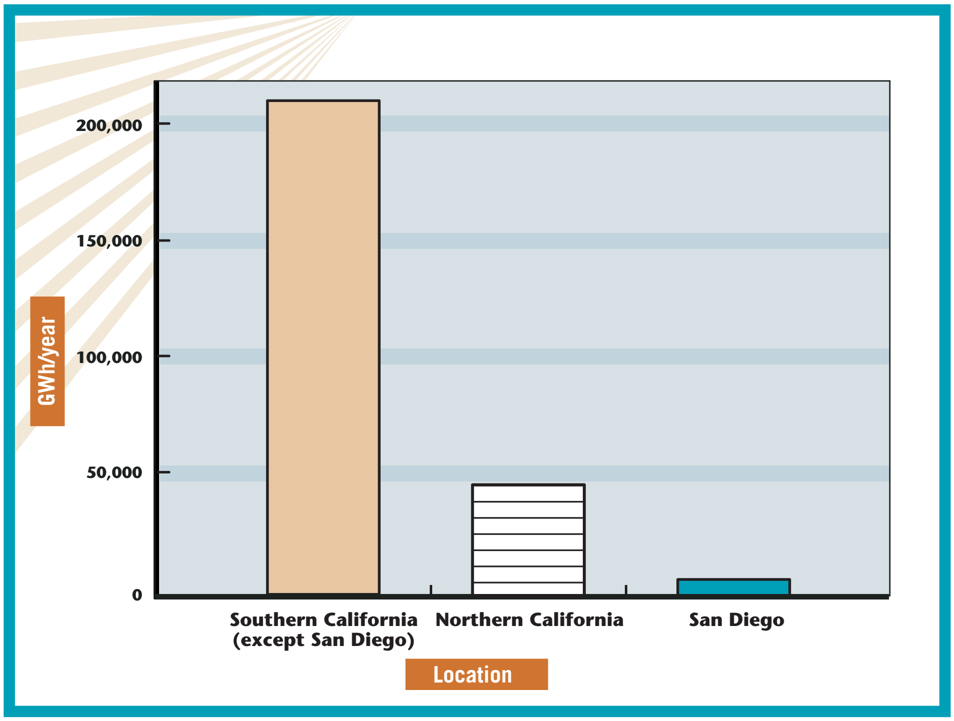
California enjoys abundant renewable resources, but they are unevenly distributed across the state, with over 80 percent of the resources located in Southern California, primarily in the Tehachapi Mountains and Imperial Valley. (See Figure 8, Renewable Resources: Technical Potential by Region.) Yet even though Southern California has significant potential, the transmission infrastructure is not available to deliver these renewable resources to other areas.[48]

The Energy Commission, CA ISO, CPUC, and other stakeholders are collaborating to address transmission constraints within California, as well as inter-state, with work to continue through 2005 and beyond. Presently, transmission projects necessary to access wind resources near the Tehachapi area and geothermal resources located in Imperial County appear to be the highest priority. The state needs to act now to make critical infrastructure investments so that these renewable resources develop in a timely manner to meet California's growing electricity needs.

Current Progress on Renewables Portfolio Standard

At the end of 2003, the IOUs appeared to be on track for meeting the state's accelerated RPS goals of 20 percent renewables by 2010. Since the end of 2001, the IOUs have held interim solicitations, increasing their procurement of renewables by about 4,000 gigawatt hours a year, or over two percentage points each, without using any RPS funds to pay for above market costs of renewables.[49] However, facility operators from several projects who have sold the IOUs energy under these interim contracts have received financial support from the Energy Commission's previous renewable incentive programs.

Figure 8
Renewable Resources: Technical Potential by Region



Source: California Energy Commission, *Renewable Resource Development Report*

Both PG&E and SDG&E have released their first formal RPS procurement solicitations. However, SCE will not hold a solicitation this year, because it expects to reach 20 percent renewables in 2004, six years ahead of schedule.[50]

Unlike the IOUs, the state's publicly owned electric utilities have adopted widely divergent renewable energy programs, with some counting large hydro as a renewable resource despite its exclusion in SB 1078. For example, LADWP has a renewable target of 20 percent by 2017, but has chosen to use a different size threshold in counting hydro for its target. Without large hydro, LADWP's renewables program is currently about 1.5 percent of its retail sales.

The Imperial Irrigation District (IID) has a renewable goal of 20 percent by 2007, but its program includes large hydropower. Without large hydro, the IID retail sales of renewables are 12 percent. IID has stated that it intends to reach its goal, 20 percent by 2007, by adding a geothermal plant by 2007.[51] On the other hand, SMUD's program has a 20 percent goal by 2011, excluding large hydro. Currently, without large hydro, SMUD's renewable resources are about seven percent of its current retail sales.

Some smaller utilities have indicated that they anticipate difficulty complying with the RPS because of their contractual obligations, small load, slow growth rates, and the lack of locally available renewable resources.

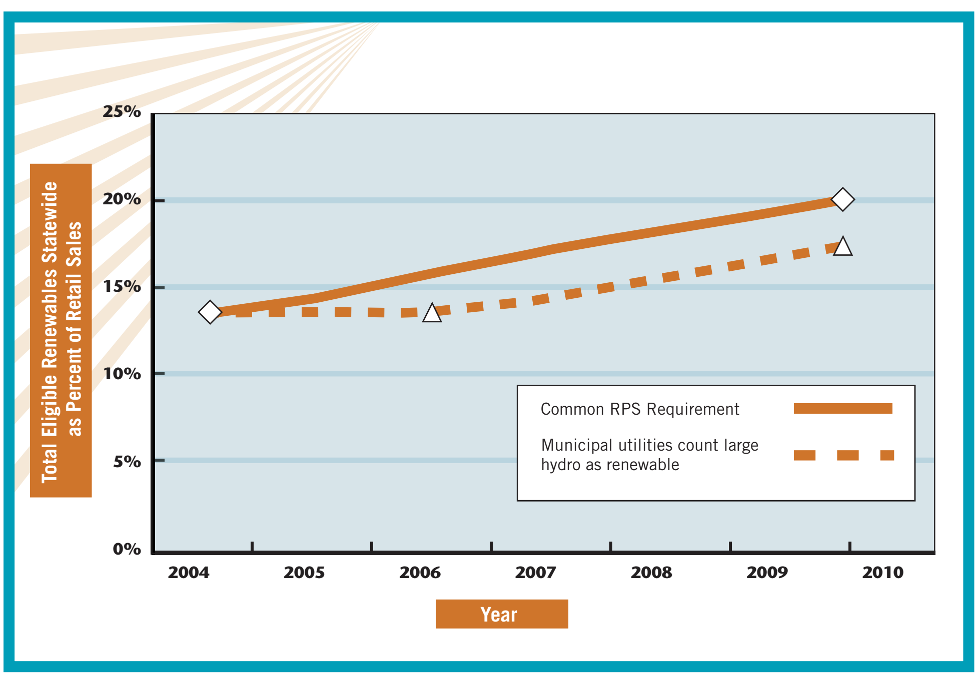
Develop Ambitious RPS Goals

The Energy Commission believes that it is important to set ambitious RPS goals for the post-2010 period to maintain the momentum for continued renewable energy development, expand investment and innovation in technology, and drive costs down for renewable energy. Governor Schwarzenegger has indicated strong support for accelerating the RPS goal to reach 20 percent renewables by 2010 and 33 percent by 2020, referring to renewables as the cornerstone of his energy and environmental action plans.[52] Given the degree to which California's earlier commitment to renewable energy was allowed to atrophy in the late 1980s and 1990s, the Energy Commission believes that it is imperative to codify the RPS goals.

While the IOUs are on track to meet the 20 percent goal in 2010, bringing the municipal utilities into the program, especially LADWP, will likely prove crucial to achieving the statewide goal. Given the breadth of the public support for the RPS, the Energy Commission expects most municipal utilities to ultimately be enthusiastic participants but believes consistent definitions between programs are important to maintain the public's confidence. For example, if large hydro were counted for IOUs under SB 1078, the corresponding statewide goal for 2010 would logically be 40 percent rather than 20 percent. The Energy Commission notes that LADWP has taken several actions in recent months that move it closer to embracing the statewide renewable goals, largely in response to the tide of public opinion in favor of renewables.[53]

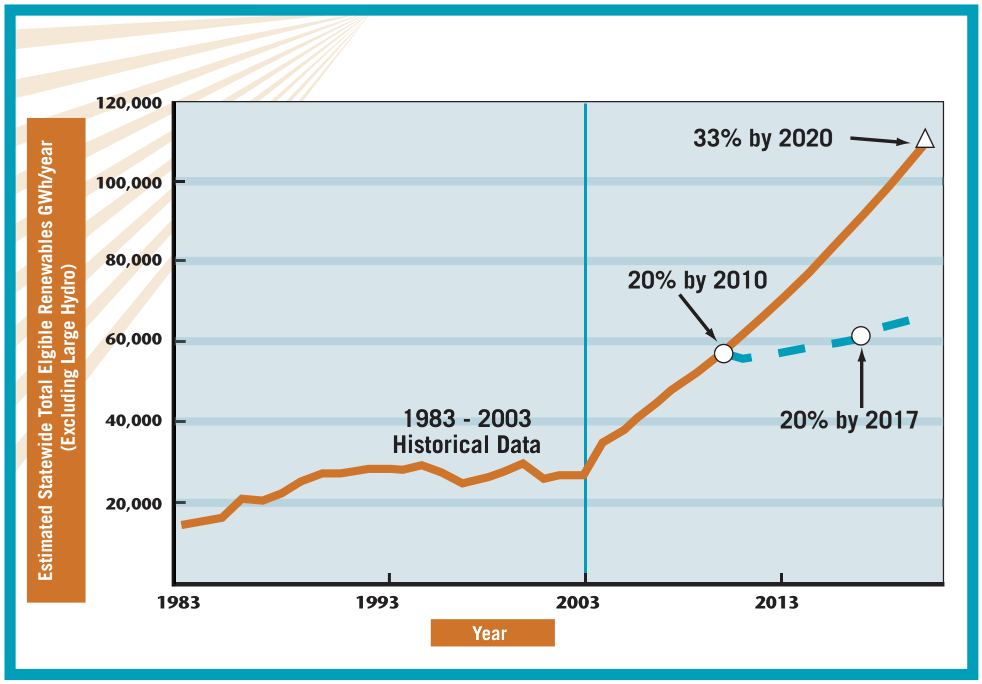
The two different scenarios in Figures 9 and 10 illuminate the need for a statewide program in which all retail sellers participate. The Energy Commission recognizes, though, that some small utilities may face significant challenges to comply with the RPS goals and recommends a variance process for such circumstances.

Figure 9
Renewable Energy Growth: Two Scenarios (as a percentage of total retail sales)



Source: *Accelerated Renewable Energy Development.*

Figure 10
California's Renewable Energy Goals: Two Scenarios 2010 - 2020



Source: *Accelerated Renewable Energy Development.*

In terms of expanding development beyond 2010, Figure 10 illuminates how little progress California will make in expanding future renewable energy development without more ambitious goals. Further, without more ambitious goals for 2010 and beyond, the utilities will have little incentive to continue their investments in renewable development, and the momentum necessary to reduce costs and push technological innovation would be lost.

More ambitious goals are needed because long-term goals with a sufficient funding source will encourage the long-term private investments in technology and other innovation, bringing them to commercial-scale application, and driving down the costs. The technology for low-speed wind turbines, for example, is not expected to be widely available until 2011 or 2012.

Embracing Governor Schwarzenegger's 2020 goal would correct this problem, and allow California to take advantage of the abundance of renewable resources in the west and further the state's goals to reduce our dependence on natural gas.

Individual Utility Targets

The Energy Commission recommends that the IOUs with the greatest renewable potential should have a higher RPS target beyond 20 percent by 2010. The focus of California's renewable energy program should be harnessing the best opportunities for commercial development rather than allocating a burden of public altruism.

With over three-fourths of renewables' technical potential within the SCE service area, SCE started the RPS with a base of 15 percent for 2001 and 17.56 percent in 2002.[54] For PG&E and SDG&E, which started the RPS with a base of 12.3 percent and 1.8 percent respectively, the Energy Commission believes that the 20 percent target by 2010 is reasonable and should not be adjusted at this time.

Without more ambitious goals for 2010 and beyond, the utilities will have little incentive to continue their investments in renewable development, and the momentum necessary to reduce costs and push technological innovation would be lost.

Through its first interim solicitation in 2002, SCE increased its retail sales from cost-effective renewables to 18.11 percent, without needing any additional RPS subsidy funds.[55] SCE held an additional interim solicitation in mid-2003, but has yet to bring forward contracts with winning bidders for the CPUC to approve, nor will SCE hold an RPS solicitation this year under the state's first formal RPS solicitation.[56] In fact, depending on the results of last year's interim solicitation, SCE may be able to maintain its 20 percent goal without having to issue any RPS solicitations for several years.

The Energy Commission believes that a new target for SCE will help accelerate renewable energy development statewide, and although SCE has raised concerns that a higher target will increase its ratepayers' costs, the current regulatory framework adequately insulates SCE's ratepayers from any above market costs through Public Goods Charge funds. In the past, SCE has shown strong leadership in this area and has taken pride in being the largest purchaser of renewable resources in the United States. The Energy Commission believes that SCE's continued leadership will be vital to achieving the state's long-term objectives to commercialize its renewable resources and to promote fuel diversity in the electricity sector.

To minimize the uncertainty regarding SCE's participation in accelerating California's RPS, the Energy Commission recommends state legislation to allow the CPUC to require SCE to purchase at least one percent of additional renewable energy per year between 2006 and 2020, reaching 25 percent by 2010, 30 percent by 2015, and 35 percent by 2020. SCE's new target should be implemented under the existing RPS structure. SCE's procurement plans, annual procurement targets, and least-cost-best-fit criteria should be revised to reflect at least one percent of additional renewable energy per year between 2006 and 2020 to reach the new target.

Barriers to Accelerated Renewable Resource Development

Transmission expansions will be needed in the Tehachapi and Imperial Valley areas to take advantage of some of the most promising sources of renewables. Currently, the transmission interconnection process for new generation is based on single location power plant development, which does not fit the characteristics of renewable resources in remote areas. The risk of planning transmission on a plant-by-plant basis is developing a suboptimal system. In contrast, the risk of planning for long-term renewable development provides for a more optimal transmission system, but assumes that multiple developers bring their plants into operation on a given schedule.

Because the results from the first formal RPS solicitations will not be final until the end of the year, it is unclear how many projects in the Tehachapi area or Imperial County will qualify for transmission upgrades in the near-term under the state's present transmission planning process. This problem is exacerbated by SCE's non-participation in the RPS solicitation process. Future solicitations will likely include bids from these areas, but there is substantial risk in waiting until the RPS solicitations are final and contracts signed to begin planning and approving the future transmission upgrades to accommodate additional winning contracts. A proactive approach to transmission planning for renewables development is necessary to avoid a classic chicken-and-egg dilemma. Phased development plans for transmission upgrades in remote areas like Tehachapi and the Imperial Valley must be developed and will be essential to meeting statewide RPS goals in a timely and cost-effective manner.

Unbundled Renewable Energy Certificates

Trading unbundled Renewable Energy Credits (RECs) may be an effective way to assist utilities that have fewer local renewable resources to meet the state's renewable energy goals in the future. Currently, unbundled RECs are not allowed in California's RPS program, and RECs procured for RPS compliance must remain bundled with the associated renewable electricity.[57]

A REC typically represents the environmental attributes of renewable energy as a separate commodity from the electricity. For this discussion, the term is used in its broadest definition to mean the "renewable attributes" of a given unit of renewable-based generation, as distinct from the underlying electrical energy.[58] A REC may be "bundled" and sold together with the underlying electricity, or a REC may be unbundled and the renewable attribute sold separately.

Senate Bill 1478 (Sher) would have required the Energy Commission, in consultation with the CPUC, to establish the definition of a REC to ensure compatibility with standard contract terms and conditions and protect the interests of ratepayers. However, the Governor vetoed the bill because he believed that it would create a renewable credit market with several onerous restrictions.[59]

Unbundled RECs represent a potential advantage for California because they could reduce the need to add transmission lines, relieve transmission congestion, and help meet renewable energy goals. Yet this potential advantage will depend on the location of the renewable resource and whether transmission lines are available to transfer the electricity. Although RECs can help utilities transfer "renewable attributes" between utilities, RECs cannot eliminate the need for transmission infrastructure to access renewable energy or meet RPS targets.

Even with these potential transmission constraints, unbundled RECs may be a reasonable means for electric service providers and community choice aggregators to use to comply with the RPS. Unlike the IOUs and municipal utilities, electric service providers and community choice aggregators are typically small entities, who may lack a guaranteed revenue stream or credit backing for long-term power purchase agreements. Electric service providers and community choice aggregators may of necessity have to enter into short-term electricity contracts, with relatively small financial commitments and the flexibility to respond to market changes. For these two groups, unbundled RECs may be an appropriate compliance option.[60]

The CPUC and other parties, however, have raised a possible disadvantage to this approach: whether allowing unbundled RECs would create environmental justice issues. For example, if an IOU procured unbundled RECs from a new wind facility outside its service territory, along with matching fossil fuel-based electricity generated locally, to serve its load, then the renewable energy would not result in local air quality benefits.

The CPUC also indicated that allowing unbundled RECs for the RPS could invite market manipulation, or double counting. If RECs were to become a feature of the RPS, the Energy Commission notes, then safeguards will be needed to ensure that a RPS contract for bundled renewable electricity is not stripped of its electricity. The Western Renewable Energy Generation Information System accounting system, currently under development, can help to prevent double counting.[61]

Through the ongoing RPS proceedings, the CPUC and Energy Commission collaborative staff will further investigate the advantages and disadvantages of incorporating unbundled RECs into the RPS for IOUs as well as for electric service providers and community choice aggregators.

Repowered Wind Facilities

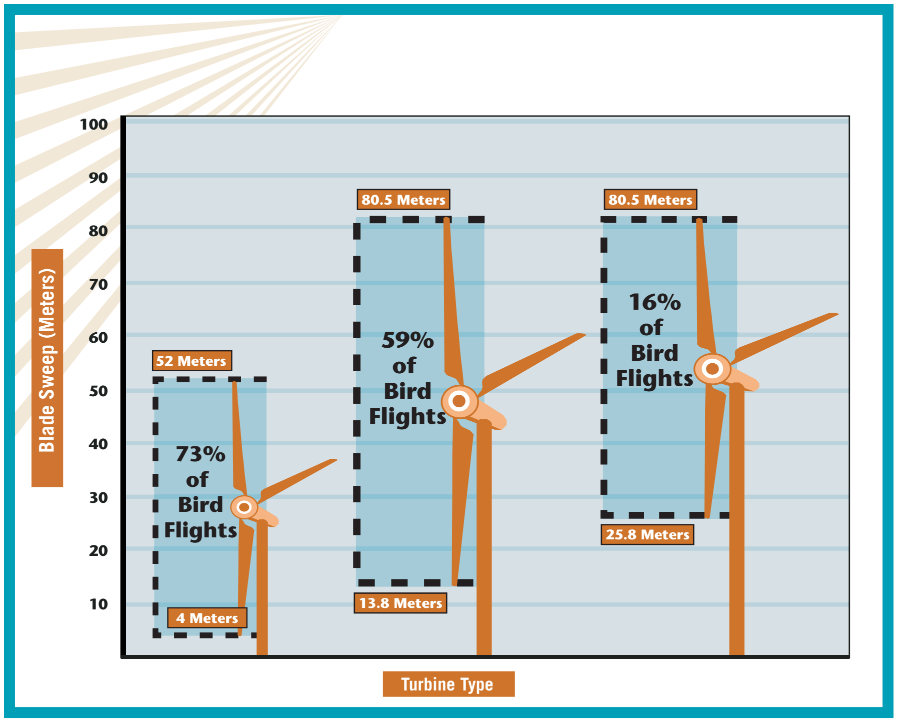
California has up to 1,000 MW of aging wind facilities that are candidates for repowering.[62] However, repowering these facilities has been hindered because of rising concerns in recent years about the need to reduce bird deaths associated with wind facilities, many of which use antiquated technology installed over 20 years ago. For example, in the Altamont area neither repowered nor new wind facilities will receive permits until planning officials are confident that steps have been taken to prevent bird mortality.

The Energy Commission funded a multi-year research project to better understand factors associated with bird fatalities in the Altamont Pass.[63] This report identified a series of mitigation measures designed to avoid, reduce, and offset impacts caused by existing and future wind turbines in the Altamont Pass Wind Resource Area. The research concluded that the most effective solution to reduce bird mortality may be to replace the currently numerous small turbines with fewer, larger turbines, especially if turbines are installed on towers that allow a blade clearance of 29 meters above ground to avoid bird flight paths. The precise effect that the repowering program will have on bird mortality is unknown and will require post-construction studies to document an actual reduction. However, these research results should aid the siting process of any new turbines, with the primary goal of installing new turbines in locations and arrangements that will result in fewer bird deaths than in the past, as show in Figure 11.

New wind developments and existing developments shown to have high bird fatalities could employ similar research methodology to determine high collision risk factors and avoid high collision risk locations. Doing so will likely reduce bird fatalities, improve public perception of wind technology, and encourage more wind energy capacity to be sited in California.

Another barrier to wind repowering is the current limitations on federal tax incentives for these projects. The Federal Production Tax Credit (PTC) could provide much needed financial incentives for repowering of wind; however, provisions in the U. S. Tax Code (Section 45) that prevent wind repowering projects from qualifying for the PTC have had a chilling effect on repowering decisions. In this

Figure 11
Percentage of Raptor Flights at Blade Sweep Heights in Altamont Pass



Source: *Developing Methods to Reduce Bird Mortality.*

provision, repowered facilities with an existing standard offer contract are only eligible for the PTC if the contract is "amended" so that any wind generation in excess of historical norms is either sold to the utility at its current avoided costs or else sold to a third party.[64] A CPUC June 2003 Decision endorsed a TURN goal to require IOUs to conduct "prompt negotiation to resolve…a stalemate around repowering of wind facilities."[65] Despite this decision, very little progress has been made. The PTC, which expired in December 2003, has been extended by Congress, but not yet signed by the President. Removal of the repowering clause in the U.S. Tax Code along with extension of the PTC funds would improve prospects for wind repowering and other renewable development.

The Energy Commission supports repowering wind turbines to harness wind resources more efficiently and mitigate or prevent bird deaths and recommends that the CPUC use its declared intent to develop renegotiated Qualifying Facility contracts to break the existing logjam that is impeding repowering.[66] The Energy Commission also recommends that local permitting agencies for wind projects implement the actions identified in the Energy Commission study to prevent and mitigate bird deaths from wind turbines.

The Role of Biomass

While biomass has been an important source of renewable electric generation, and has the potential to contribute toward meeting the state's RPS goals, biomass provides benefits far beyond electricity alone. For example, biomass addresses larger societal issues such as reducing the amount of solid waste that goes into landfills, using gasification in existing landfills to produce electricity, promoting forest management and fire prevention, eliminating air emissions from open field burning, and addressing other agricultural waste problems.

Currently, biomass technologies receive incentives for their generation from electric ratepayers. The state needs to develop a better strategy to commercialize biomass by allocating the external costs of biomass appropriately to those who benefit. This is not an easy task, and will take coordination among the various state agencies and stakeholders and is likely to rely on more forceful directives from air quality and waste management regulators. The task ahead is to find innovative ways to allocate electricity benefits to the ratepayers, while ensuring that electric ratepayers are not burdened with costs that should be paid by society as a whole or by the segments of society who directly receive the benefits from biomass.

> **The Energy Commission's PV incentive program, also known as the Emerging Renewables Program, is heavily oversubscribed... .**

California's Solar Programs

The Energy Commission's PV incentive program, also known as the Emerging Renewables Program, is heavily oversubscribed, straining administrative and financial resources.[67] The program has been extremely successful in bringing PV development to the state, supporting over 10,600 PV installations, and representing nearly 43 MW to date. Another 7,000 pending applications requesting funding will represent an additional 33 MW of PV installations.[68] However, more robust and long-term funding of PV programs is needed in the next year.

Without significant changes in program design or increased funding level, the Energy Commission's current incentive program in the IOU service territories cannot be sustained. In the last year and a half, the Energy Commission has encumbered almost five years' worth of funding for PV, as well as re-allocating funds from other Renewable Energy Program areas. Last year alone, the Energy Commission provided $50 million in rebates to customers to install PV systems.

In addition, the CPUC Self-Generation Incentive Program (SGIP) provides an additional $125 million per year in rebates for larger PV and other distributed generation systems.[69] In 2004, the demand for the SGIP rebates for PV system installations dramatically increased, with applicants reserving $228 million. Although the SGIP incentives have brought about 114 installations of large PV systems over the last several years, representing 21 MW of PV, the current oversubscription in this program also cannot be sustained.

Assembly Bill 135[70], which was signed by the Governor, addresses the immediate funding crisis for the Energy Commission's PV program. The bill authorizes the Energy Commission to spend up to $60 million of the Renewable Resources Trust Fund, to be collected between 2007 and 2012, for emerging renewable systems. At current program activity level, this bill provides "stop gap" funding for approximately six months.

The CPA and Department of General Services coordinated a solicitation for bids where private parties may own, finance, and install PV systems on state facilities, provided that the electricity is sold to the state at a price that does not exceed the price that would have been paid to a utility. Given current prices of PV systems relative to the price of electricity paid by the state, the private parties who bid in this solicitation would need to receive funding from the Emerging Renewables Program or the SGIP, and may take advantage of tax credits and depreciation.

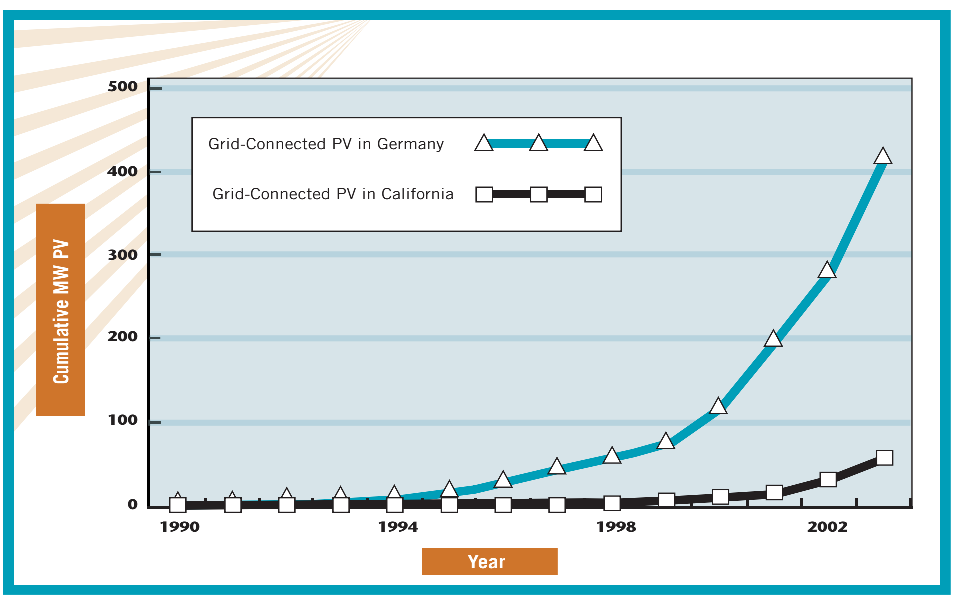
In addition to the problems of oversubscription, current rebate programs may not be the most effective way to ensure optimal design, placement, and maintenance of PV systems to maximize their output. The Energy Commission's Renewables Committee has directed staff to focus on developing a pilot performance-based incentive program by January 2005, using the results of the pilot test to help develop a long-term strategic plan for the Emerging Renewables Program. Also, the CPUC staff has proposed lowering the incentive level offered by the SGIP to better match Energy Commission incentive levels and is expected to issue a decision later this year.

Performance-Based Incentives

Current PV incentive programs in California provide an up-front buydown of capital costs. In contrast, performance-based incentives provide a payment for measured kilowatt-hours of production, which are tied directly to a system's performance. Performance-based incentives have the potential to provide greater insurance that systems will function well because PV owners are likely to put pressure on installers and marketers to ensure that their systems perform. This promotes greater cost-effectiveness of public goods charge incentives for distributed generation PV in terms of long-term energy generation per dollar of incentive support.

In Germany, performance-based incentive programs are very successful (see Figure 12). The German model uses a "feed-in" law that requires the utilities to purchase PV generation at rates that have led to the installation of a significant number of performance-based systems. Incentive programs can also mix funding tied to capacity with funding tied to energy performance. PV programs in Pennsylvania and Massachusetts are examples of a mixed capacity-and-performance model.

Figure 12
Grid-Connected PV: Germany Compared to California



Source: *Accelerated Renewable Energy Development.*

The Energy Commission supports performance-based incentive programs for PV. A workshop was held in September 2004 to discuss a number of questions and issues regarding the design and administration of a performance-based incentive program in California. These include what the proper incentive level should be, how best to collect performance data from each system, whether performance-based incentives result in better PV system performance, and the appropriate frequency and duration of performance payments to program participants.

Later in 2004, the Energy Commission will revise its Emerging Renewables Program guidebook and establish the rules for the pilot performance-based incentive program. Once underway, the results from the pilot will be used to evaluate and shape a performance-based incentive PV program going forward to achieve a sustainable PV market in California. To ensure consistency among the state's solar programs, the Energy Commission should work with the CPUC and stakeholders to move toward a consistent performance based approach to incentives for all solar programs, including the Emerging Renewables Program and the SGIP.

The Energy Commission shares the Governor's interest in stimulating large scale PV development.

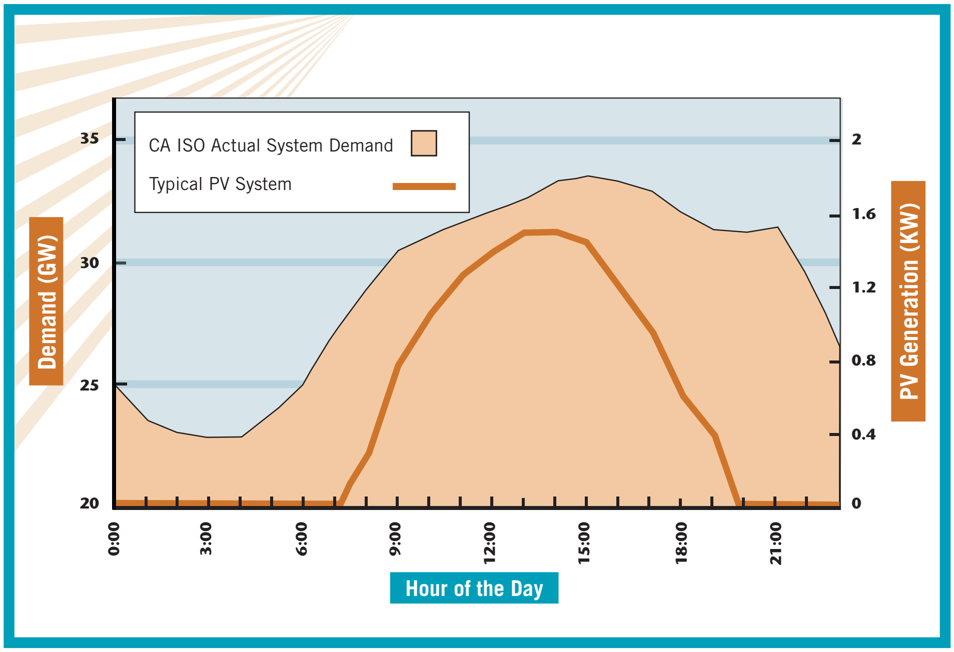
The Governor's Solar Initiative

Governor Schwarzenegger has indicated strong support to develop solar energy in California: the "million solar roofs" campaign, which calls for dramatically increasing the number of solar power systems in the state.[71] Recent surveys show overwhelming public support for increased use of solar energy in California homes and businesses, including 82 percent support for a mandatory goal of 15 percent of new homes starting in 2006.[72] The Energy Commission shares the Governor's interest in stimulating large scale PV development, and we will continue to explore options and help shape the program to help bring down installed costs.

PV offers California several benefits, especially since electricity production from PV generally aligns with peak demand (see Figure 13). In hot climate zones like the Central Valley and the inland Southern California, population is growing, resulting in corresponding increases in peak air conditioning demand. In these areas, new and existing houses and commercial buildings provide an excellent opportunity to deploy PV. In addition, all customers benefit when customer-owned PV generation reduces the peak demand on the electricity system. If the PV penetration grows at sufficient levels, the reduction in peak demand could help relieve pressures on the existing generation system and help diversify the fuel sources in California's electricity mix.

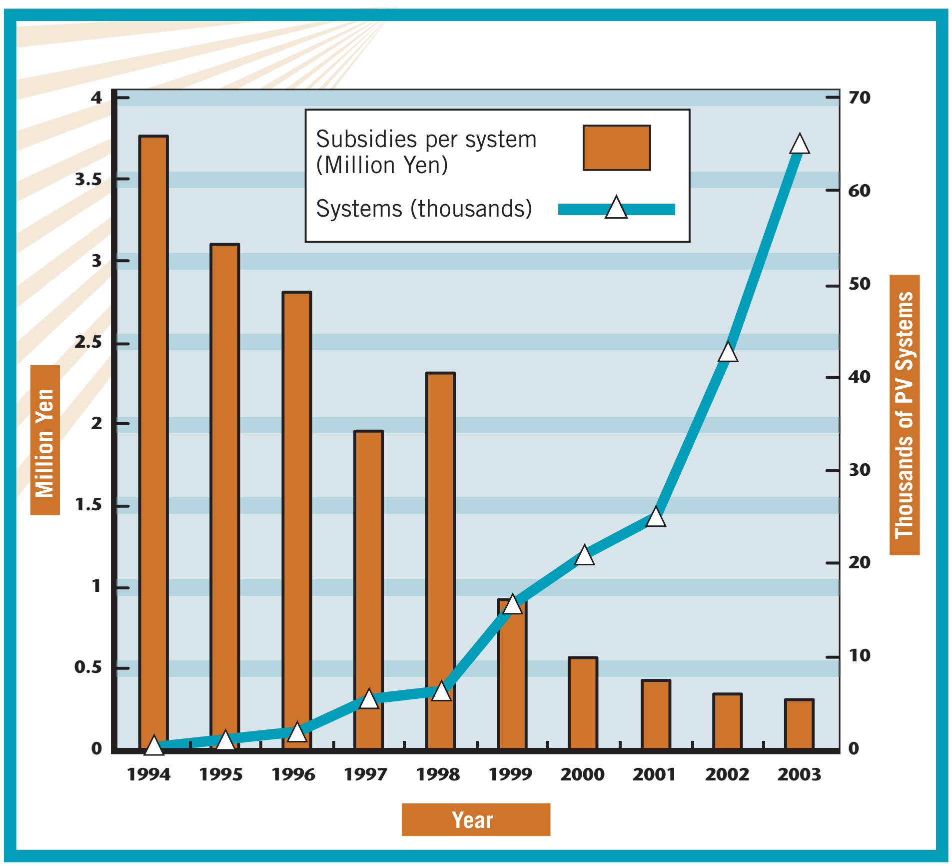
However, to achieve these benefits, the financial incentives for PV systems need to be carefully crafted to reduce the installed cost over time and create a sustainable, long-term market in California. As demand for PV increases, economies of scale in production, manufacturing, retailing, and installation should bring down costs. As this occurs, the financial incentives should be scaled down until they are no longer necessary (see Figure 14). This approach has been followed in Japan and Germany. In Japan, prices for PV dropped 35 percent from 1999 to 2003, with the level of subsidy for PV reduced to about $.75 per Watt by 2002. By the end of 2003, cumulative installed PV systems in Japan totaled 640 MW.[73] Similar cost reductions have been achieved in Germany's solar program, with an installed PV capacity increasing from 60 MW in 1999 to about 375 MW in 2003, accompanied by a 25 percent drop in installed price.[74]

Figure 13
PV Generation Typically Matches Peak Load Shape



Source: *Accelerated Renewable Energy Development.*

Figure 14
Roof-top PV in Japan: Additions and Subsidies



Source: *Accelerated Renewable Energy Development.*

The Energy Commission recommends several principles to guide the state in developing a successful PV program:

- Achieving the scale articulated by the Governor—a million solar roofs—means that all residential and commercial buildings, whether existing or new construction, should be considered as candidates in a comprehensive solar program. Limiting the program to new homes or new and existing homes would eliminate some of the most promising candidates for PV installation—commercial buildings.

- Leveraging energy efficiency improvements should be a primary consideration in deploying PV. To participate in the PV program, new homes should be required to exceed the current building standards, while existing buildings should be required to improve their efficiency by a set percentage. Combining energy efficiency measures with PV will ensure proper sizing of PV systems, contribute to meeting the state's efficiency goals, and provide maximum benefits to PV purchasers and electricity consumers.

- Linking PV installations to dynamic pricing tariffs and advanced metering will promote more effective use of the solar systems to meet peak load and provide customer and system benefit, which in turn will drive down electric system costs and lower electricity rates.

- Rational targeting of PV deployment to achieve the greatest cost benefit should be a central feature of a large-scale solar program. Solar installations should be targeted to climate zones with high peak demands for air conditioning, where solar systems provide the most benefit. In addition, distributed PV, if located properly on the electricity system, can provide additional benefits by deferring investments in distribution facilities. This approach will provide California the early successes necessary to ensure a long-term, robust solar program.

- Long-term declining incentives should be a center-piece of a solar program. The solar industry and others have suggested that declining rebates over a 10-year period are key to providing the volume and commitment necessary to drive manufacturing and other costs down. While the initial phase of the program may need to be based on rebates consistent with existing incentives, the program should transition away from an up-front buy-down to a performance-based incentive structure.

- The state should carefully explore viable business roles for utilities to ensure that it achieves the large scale solar expansion proposed. The volume of interaction with the electric grid that massive deployment will entail requires a willing partnership with the operators of the distribution system. In addition, the state should encourage the development of a professional inspection capability. Both of these principles can help to ensure high quality installation and performance of solar systems.

- The state should consider ways to increase installation of solar technologies, including solar thermal, as part of the 2008 building efficiency standards. While PV systems can shave peak electricity demand, solar thermal technologies can result in substantial natural gas savings through displacement.

Net Metering

Net metering has been an important element of California's efforts to expand the PV market. Net metering allows a customer's meter to spin backwards when the amount of energy generated by the system exceeds the amount consumed. Combined with time-of-use rates, net metering means that the utility credits the customer at a higher rate for excess electricity generated in the afternoon than the utility charges for electricity consumed in the evening. As a result, net metering can provide an important incentive for customers to install and maintain performance of PV systems.

Assembly Bill 58 expanded the individual project size and ensured the availability of net metering up to a cap of one-half of one percent of the utility's aggregate customer peak demand.[75] However, utilities are already nearing the overall cap for net metering, because of the growth of PV over the last few years. Once the overall cap is reached in a specific utility service territory, the utility could refuse to allow new PV owners to net meter.[76] At this time, it is unclear what individual utilities will do once the cap is reached. If utilities do prevent additional new PV owners from net metering, this would have a serious dampening effect on the PV market, including the use of PV in new homes.

The Energy Commission believes that a higher net metering cap is necessary to facilitate the orderly development of PV markets and other renewable DG. Because SDG&E faces the most immediate challenge, the Energy Commission recommends that the Legislature raise the net metering cap for SDG&E to five percent of peak demand to accommodate increased levels of PV and other renewable Distributed Generation in California.

Endnotes

[45] Mark Baldassare, July 2004, *PPIC Statewide Survey: Special Survey on Californians and the Environment, Public Policy Institute of California*, Sacramento, CA [http://www.ppic.org/main/pubs.asp], accessed July 24, 2004, p. 11.

[46] SB 1078, Chapter 516, Statutes of 2002, Sher.

[47] For details on the RPS, see the staff draft white paper *Accelerated Renewable Energy Development*, Appendix B, publication number,100-04-003.

[48] Out-of-state renewable energy is also eligible to participate in the RPS.

[49] *Accelerated Renewable Energy Development*, California Energy Commission, June 2004, p. 2.

[50] September 2003, A Letter from Southern California Edison to the Energy Action Plan Steering Committee.

[51] *Accelerated Renewable Energy Development*, p. 27 reported that the IID planned to reach its RPS goal, 20 percent by 2007, although it would not own the RECs associated with the electricity from the project. Updated information provided by IID in their written comments, filed October 13, 2004, states that an amended contract specifically conferring the rights o the RECs to IID was approved on September 21, 2004.

[52] Governor's veto message on SB 1478 (Sher).

[53] Consistent with its Integrated Resource Plan adopted in 2000, LADWP submitted written comments for the Energy Commission's August 27, 2004, workshop on renewables indicating that it would meet half of its load growth with conservation, energy efficiency, DG, and renewables. To support and build on these objectives, LADWP cancelled its participation in the Intermountain Power Project, a coal facility in Utah, embraced a local RPS program to reach 20 percent renewables by 2017, and excluded Hoover Dam large hydro generation from its RPS.

[54] *Accelerated Renewable Energy Development*, Appendix A, p. A-2, Row 24. Report to the California Public Utilities Commission: Utility Procurement of Renewable Energy in 2001 and 2002, Southern California Edison, October 20, 2003.

[55] Ibid, page 25, Chapter 3, endnote 2. 2002/2003 interim procurement (reported in D.04-06-014, Standard Contract and Terms decision, Appendix B, Calculation for SDG&E, SCE, PG&E's2004 RPS Annual Procurement Target.)

[56] *Accelerated Renewable Energy Development*, Appendix A, p A-2, Row 24, SCE increased renewables to 12,791.

[57] CPUC Decision 03-06-071, Order Initiating Implementation of the Senate Bill 1078 Renewables Portfolio Standard, June 19, 2003.

[58] A REC represents the renewable attributes associated with one megawatt hour (MWh) of renewable-based electricity that has been generated.

[59] Governor's veto message on SB 1478 (Sher).

[60] Through their collaborative work, the CPUC and Energy Commission will develop rules for both groups to comply with RPS goals in 2005.

[61] *Accelerated Renewable Energy Development*, California Energy Commission, June 2004.

[62] Letter from the California Wind Energy Association to CPUC President Michael Peevey regarding CPUC Position on Federal Wind Production Tax Credit Provisions on Repowers, July 21, 2003.

[63] The research findings on wind facilities are reported in the consultant report prepared for the Energy Commission on this topic, *Developing Methods to Reduce Bird Mortality in the Altamont Pass Wind Resource Area (500-04-052)*. The number of deaths of protected and endangered birds was 1.5 to 2.2 raptor fatalities/MW/year and 3.0 to 8.1 bird fatalities/MW/year.

[64] Standard offer contracts were instituted by the CPUC to establish prices, terms and conditions for investor-owned utility purchases from independent generators, including renewable generators, in the late 1970s and 1980s in response to the federal Public Utilities Regulatory Policy Act of 1978.

[65] California Public Utilities Commission, June 19, 2003, "Rulemaking 01-10-024, Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development."

Endnotes (continued)

[66] CPUC Decision 04-01-050, January 22, 2004, in Utility Procurement Proceeding R01-10-024.

[67] Currently, the Energy Commission's Emerging Renewables Program funds PV and small wind systems up to 30 kW in size, although solar thermal electric systems and fuel cells using renewable energy are also eligible.

[68] *Accelerated Renewable Energy Development*.

[69] The Self Generation Incentive Program funds systems of 30 kW to 1MW for PV, wind and other distributed generation technologies, including fuel cells, turbines, microturbines, and internal combustion engines using renewable or conventional fuel sources, except diesel.

[70] Assembly Bill 135 (AB 135, Reyes), Chapter 867, Statutes of 2004, [http://www.leginfo.ca.gov/pub/bill/asm/ab_0101-0150/ab_135_bill_20040929_chaptered.pdf], accessed October 18, 2004.

[71] "An Energy Plan for California's Future," Editorial by Governor Schwarzenegger, *San Diego Union-Tribune*, October 8, 2004.

[72] Mark Baldassare, July 2004 *PPIC Statewide Survey: Special Survey on Californians and the Environment*, Public Policy Institute of California, [http://www.ppic.org/main/pubs.asp], accessed July 24, 2004.

[73] *Accelerated Renewable Energy Development*, pages 76-77.

[74] Ibid.

[75] AB 58, Keeley, Chapter 836, Statutes of 2002.

[76] The net metering cap is a soft cap, meaning that a utility may allow net metering to go beyond the cap or they could deny additional net metering.

2004 Update

INTEGRATED ENERGY POLICY REPORT

2004 Update

CHAPTER FIVE State Progress on 2003 Recommendations

The energy report establishes a real-time, public forum for continuing dialogue on California's energy policies. The process allows the state to correct or re-direct energy policies at the end of the two-year report cycle and during the interim update. In the *2003 Energy Report,* the Energy Commission proposed policies in the following areas:

- Electricity
- Natural gas
- Transportation energy
- Environmental stewardship

This chapter examines the progress state government has made as a whole, including the energy agencies, the Governor's Office, and the Legislature in addressing the *2003 Energy Report* recommendations.

Progress on Electricity Policy

The *2003 Energy Report* contained recommendations to:

Progress of State Government	Significant	On Track	Needs Improvement
• Incorporate the *2003 Energy Report* findings and results to guide resource adequacy and procurement.	✓		
• Increase energy efficiency funding/Evaluate and monitor energy efficiency programs.	✓		
• Maximize energy efficiency of existing buildings.			✓
• Rapidly deploy advanced meters/Implement dynamic pricing tariffs.			✓
• Explore a core/noncore market structure.		✓	
• Accelerate the Renewables Portfolio Standard goals.		✓	
• Create a transparent distribution system planning process.		✓	
• Consolidate permitting for bulk electricity transmission.			✓

Guide Resource Adequacy and Procurement

The Energy Commission recommended that the state:

> Incorporate the forecasts, resources assessment, and policy preferences of the *2003 Energy Report* into an explicit resource adequacy requirement for all retail electricity suppliers to guide resource procurement.

The state has made significant progress in this area, with the CPUC's recent decision to link the Energy Commission's planning process and the CPUC's procurement rulemaking.[77] This critical step established that future CPUC procurement rulemakings will only come after the Energy Commission has published its Energy Report; the decision also required the IOUs use the results of the *2003 Energy Report* in their procurement filings for the summer 2004.[78] This decision ensures that energy planning guides resource procurement, guaranteeing that the state relies on its loading order for preferred resources.

The Energy Commission and CPUC staff have worked collaboratively to streamline and coordinate the planning and procurement processes. These efforts will reduce duplication among agencies, lessen the time and costs for stakeholders to participate in state planning, and ultimately ensure that California has a single framework for developing facts, setting policy, and procuring adequate resources.

Additionally, in a joint letter dated April 30, 2004, CPUC President Michael Peevey and Commissioner John Geesman, Presiding Member of the Energy Commission's Energy Report Committee, reiterated the two agencies' commitment to collaborate in adopting long-term resource plans and resource adequacy requirements for electric IOUs. Finally, on September 16, 2004, President Peevey issued a ruling that, beginning with the *2005 Energy Report,* future CPUC long-term resource procurement proceedings will rely on the Energy Commission's forecasts and resource assessments.[79]

Increase Energy Efficiency Funding/Evaluate and Monitor Energy Efficiency Programs

The Energy Commission recommended that the state:

- Ramp up public funding for cost-effective energy efficiency programs above current levels to achieve at least an additional 1,700 MW of peak electricity demand reduction and 6,000 Gigawatts (GWh) of electricity savings by 2008.

- Standardize and increase the evaluation and monitoring of energy efficiency programs to ensure that savings and benefits are being delivered.

The state has made significant progress in this area, with the CPUC's recent decision to adopt more aggressive goals for the IOUs than the *2003 Energy Report* recommended.[80] These new goals, based on collaborative staff work between the Energy Commission and CPUC, require peak electricity demand reductions of 2,205 MW by 2008, exceeding the *2003 Energy Report* goal by 505 MW, and energy consumption reductions of 10,489 GWh by 2008, exceeding the *2003 Energy Report* goal by 4,489 GWh. These new goals will require approximately $522 million in annual funding by 2008[81] compared to the annual spending level of $348 million for 2004 and 2005.[82]

Also, in another draft decision, the CPUC has proposed new administrative and evaluation structures.[83] The draft decision increases state oversight of efficiency program evaluation and implements new safeguards against conflicts of interest between program delivery and evaluation.

Maximize Energy Efficiency of Existing Buildings

The Energy Commission recommended that the state:

> Implement appropriate mandates, incentives, and funding to maximize the energy efficiency potential of existing buildings.

The state has made some progress in this area. Assembly Bill 549 directs the Energy Commission to "investigate options and develop a plan to decrease wasteful peak load energy consumption in existing residential and nonresidential buildings ... and report its findings to the Legislature."[84] The Energy Commission delivered an interim report to the Legislature in December 2003 that reported on the initial progress in investigating options for reducing energy consumption in California's existing buildings and the further work that the Energy Commission will complete.[85] The final report is due to the Legislature in October 2005.

Rapidly Deploy Advanced Meters and Implement Dynamic Pricing Tariffs

The Energy Commission recommended that the state:

- Rapidly deploy advanced metering systems if analyses show the results are favorable to the customer and will effectively decrease peak electricity use.

- Implement sufficient real-time and dynamic pricing tariffs to satisfy the goal of 5 percent of system peak load.

The state needs to accelerate its work in this area. Pilot tests in California and other states show that dynamic pricing tariffs and advanced metering effectively reduce peak demand.[86] Given the concern over declining reserve margins in the next few years, California should begin implementing these programs immediately. (See Chapter 2 for a thorough discussion of this recommendation.)

Explore a Core/Noncore Market

The Energy Commission recommended that the state:

> Explore through collaboration between the CPUC and the Energy Commission the implications of a core/noncore market structure for electricity, with the goal of making recommendations in 2004.

The state is on track in implementing this recommendation. In response to a legislative request, the CPUC staff issued a report defining a core/noncore market structure and recommending that certain larger customers be provided direct access.[87] CPUC President Peevey, in an alternative approach, proposed a more aggressive timetable for instituting customer choice, which the Energy Commission endorsed.[88] Notwithstanding this progress, though, implementing a core/noncore structure will require action by the Legislature, who debated the issue extensively in deliberations on AB 428 (Richman) in the 2004 session. While the bill did not pass, all parties recognized that this issue will likely re-emerge during the next session.[89]

Accelerate the Renewables Portfolio Standard Goals

The Energy Commission recommended that the state:

> Enact legislation to require that all retail suppliers of electricity meet the RPS goal of 20 percent of retail electricity sales and accelerate the target date for reaching the goal from 2017 to 2010.

The state is on track in implementing this recommendation. In fact, Governor Schwarzenegger not only supports this goal, but also supports a more aggressive statewide goal of 33 percent renewable energy by 2020, which includes municipal utilities.[90] (Chapter 4 provides a thorough discussion of this recommendation.)

Create a Transparent Distribution System Planning Process

The Energy Commission recommended that the state:

> Create a transparent electricity distribution system planning process that addresses the benefits of distributed generation, including cogeneration.

The state has made slow progress in this area, although the Energy Commission and CPUC are working to address this issue in their continuing collaboration on regulatory issues relating to DG. The Energy Commission is now prepared to address the issue in its current investigation into unresolved DG issues.[91] Phase 2 of this proceeding, which is scheduled to consider distribution system planning, will begin immediately once Phase 1 interconnection issues are completed in February 2005. The recommendations associated with this issue are expected to be a major component of the *2005 Energy Report* process.

Consolidate Permitting for Bulk Electricity Transmission

The Energy Commission 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.

Since the *2003 Energy Report* was adopted, the Governor has initiated a review of California government, the California Performance Review, which recommended that transmission permitting be placed in a single agency within an energy infrastructure permitting agency.[92] While this recommendation is a sign of progress, the state has not made progress in correcting structural deficiencies with transmission permitting. Thus, the Energy Commission remains convinced that its *2003 Energy Report* recommendation should be implemented immediately.

This conviction reflects the longstanding, continuing, and widespread criticism of California's transmission permitting process, the reason for the *2003 Energy Report* recommendation. While the CPUC reached favorable decisions on several important projects like Mission-Miguel and Jefferson-Martin, the problem with the illogical separation of generation siting from transmission siting has figured prominently in these proceedings.

As noted in the *2003 Energy Report* and reiterated in Chapter 3 of this update, the financial regulation of the bulk transmission system was federalized more than a decade ago. Despite this shift in authority, the CPUC retains jurisdiction for the IOUs even though the state's primary permitting interests have shifted to integrating the generating plants and land use/environmental concerns. This situation reflects the state's failure to adapt the regulatory design to changing needs.

Over the past year, despite the CPUC and CA ISO's good faith efforts to bridge this gap, the disconnect between the current permitting process and rational transmission planning has been exacerbated. The CA ISO and CPUC attempted to address this problem with a planning methodology that is well-intentioned, but the data needs and modeling complexity render it impractical, and the CA ISO Board declined to transmit it to the CPUC. More significantly, the experimental methodology fails to grapple with some of the more prominent issues raised in Chapter 3 of this report, such as a 30- to 50-year timeframe, an appropriate social discount rate, and difficult-to-quantify strategic benefits. In addition, the question of whether the CPUC could delegate its need determination under CEQA to the CA ISO is subject to legal dispute.[93]

Progress on Natural Gas Policy

The *2003 Energy Report* contained four recommendations to:

Progress of State Government	Significant	On Track	Needs Improvement
• Increase funding for natural gas efficiency programs.	✓		
• Encourage LNG facility construction on the West Coast.		✓	
• Ensure existing storage capacity is used appropriately.		✓	
• Initiate hearings to examine gas quality and gas gathering issues.			✓

Increase Funding for Natural Gas Efficiency Programs

The Energy Commission recommended that the state:

> Increase funding for natural gas efficiency programs to achieve an additional 100 million therms of reduction in natural gas demand by 2013.

The state has made significant progress in this area, with the CPUC recent decision to adopt a more aggressive goal than the *2003 Energy Report* recommended.[94] The new goal calls for natural gas savings of 154 million therms by 2008, exceeding the *2003 Energy Report* goal by 54 million therms. This new goal will require approximately $118 million in annual funding by 2008[95] compared to the annual spending level of $59 million for 2004 and 2005.[96]

This decision also re-affirms the loading order principles for electricity, which were identified in the *Energy Action Plan*: Increasing efficiency in all energy sectors is the highest priority for meeting demand. Developing renewable resources over fossil fuel is another high priority in the loading order. In this regard, the state should examine the potential of solar thermal systems to displace natural gas for water heating and other thermal applications.

In another recent decision, the CPUC established a natural gas research, development, and demonstration (RD&D) program at the Energy Commission to complement its electricity RD&D program.[97] Initial funding, set at $12 million dollars a year, will increase $3 million annually until an annual funding cap of $24 million is reached.

Encourage LNG Facility Construction on the West Coast

The Energy Commission recommended that the state:

> Encourage the construction of liquefied natural gas facilities and infrastructure and coordinate permit reviews with all entities to facilitate their development on the West Coast.

The state is on track in implementing this recommendation, with five liquefied natural gas (LNG) facilities proposed along the West Coast. The U.S. Coast Guard and California State Lands Commission will soon release a joint draft environmental review of an LNG facility off the California coast. This facility is one of the first proposed in over 30 years. Permit coordination has been effective and occurs through a statewide LNG Interagency Permitting Working Group, with representatives from various state, local, and federal agencies. The working group also provides technical support and background information to the Resources Agency, the Governor's Office, and the general public on LNG-related issues, including fact sheets, reports, and other materials on the Energy Commission website.

Also, the CPUC recently authorized the state's natural gas utilities to develop additional receipt points to accommodate LNG deliveries to their pipeline network.[98]

Ensure Existing Storage Capacity Is Used Appropriately

The Energy Commission recommended that the state:

> Ensure that existing natural gas storage capacity is appropriately used to provide adequate supplies and protect prices.

The state is on track in implementing this recommendation, with the Energy Commission and CPUC coordinating this issue in two forums. The CPUC initiated a proceeding to examine a number of gas issues, including storage, which will be addressed in 2005.[99] The Energy Commission is conducting a technical analysis on natural gas storage issues and will release a staff white paper in early 2005 as part of the *2005 Energy Report* process.

Initiate Hearings to Examine Gas Quality and Gas Gathering Issues

The Energy Commission recommended that the state:

> Initiate legislative hearings that will:
>
> 1) examine the issue of gas quality and gas gathering as it relates to California gas production and
>
> 2) determine whether additional legislative action is warranted to resolve the issues.

The state has made little progress in this area. At the time this recommendation was drafted for the *2003 Energy Report*, the various parties involved with California natural gas quality issues had reached an impasse. These parties include the Energy Commission, CPUC, California Air Resources Board (CARB), California Division of Oil, Gas, and Geothermal Resources (Division of Oil and Gas), local distribution companies, and California producers. Since then, SoCal Gas filed an application with the CPUC to begin natural gas production in California,[100] CARB is re-examining its existing fuel specifications for natural gas vehicles, and the CPUC is exploring this issue in three active proceedings.[101] Additionally, the Energy Commission, CARB, and CPUC are co-sponsoring a public workshop in December 2004 on natural gas quality issues. Depending on progress over the next few months, legislative action may not be needed.

Progress on Transportation Energy Policy

The *2003 Energy Report* contained five recommendations to:

Progress of State Government	Significant	On Track	Needs Improvement
• Reduce on-road gasoline and diesel demand.	☐	☐	☑
• Increase fuel economy.	☐	☐	☑
• Increase the use of non-petroleum fuels.	☐	☐	☑
• Improve petroleum infrastructure permitting.	☐	☐	☑
• Develop a public information program.	☐	☑	☐

Reduce On-road Gasoline and Diesel Demand

The Energy Commission recommended an overarching goal for the state to:

> Adopt a goal of reducing demand for on-road gasoline and diesel to 15 percent below 2003 levels by 2020 based on identified strategies that are achievable and cost-beneficial.

The state has failed to make substantial progress toward reducing demand; in fact, despite rising prices at the pump, demand is growing. This trend represents a significant challenge to policy makers. Legislation to establish a demand-reduction goal was defeated earlier in 2004.[102] To achieve the 2003 Energy Report goals, the state must demonstrate national leadership in increasing vehicle fuel economy while aggressively expanding the use of non-petroleum fuels in California.

Increase Vehicle Fuel Economy

The Energy Commission recommended that the state:

> Build a coalition with other states and stakeholders to influence Congress and the U.S. Department of Transportation to double the combined fuel economy of new passenger cars and light trucks by 2020. If the federal government fails to revise corporate average fuel economy standards, California must reassess its petroleum reduction strategy.

The state has made little progress in this area mainly because the federal government has the sole authority to raise Corporate Average Fuel Economy (CAFE) standards for the nation. Lacking this authority, the state must create a national debate to pressure the federal government to raise the CAFE standards significantly, yet the state has not taken any steps in this direction. The Western States Climate Change Initiative offers a model to build an effective coalition, which California should implement immediately.

For context, China, the world's fastest growing car market, recently adopted fuel economy standards that are more stringent than our own national CAFE standards. The Chinese standards take effect in two phases, 2005 and 2008. In contrast, only 79 percent of U.S. car sales and 27 percent of U.S. light-truck sales could meet China's 2005 requirements and only 19 percent of car sales and 14 percent of light-truck sales could meet the 2008 level.

In April 2004, the Energy Commission provided extensive comments on the National Highway Transportation Safety Administration's notice of proposed rulemaking to revise the structure of the CAFE standards for light trucks. While potentially correcting some deficiencies in current national regulations, this proceeding is limited to the light-truck category. Nevertheless, this proceeding allows California to engage the federal government formally on advancements in vehicle technology that are now available and would cost-effectively increase the fuel economy of a growing part of the new vehicle population.

Despite lack of progress at the national level, the Energy Commission and other state agencies have continued to work in this area. The Energy Commission has begun work on a fuel-efficient replacement tire program, with funding from the California Integrated Waste Management Board to test tires, while the California Department of General Services revised the state's vehicle procurement process to encourage agencies to purchase hybrid-electric vehicles.[103]

Expand the Use of Non-Petroleum Fuels

The Energy Commission recommended that the state:

> Increase the use of non-petroleum fuels to 20 percent of on-road fuel consumption by 2020 and 30 percent by 2030 based on identified strategies that are achievable and cost-beneficial.

The state has made little progress in this area. Yet for more than 20 years, the state has experimented with, promoted, and implemented alternative fuel programs with varying degrees of success. The most significant barrier to any sustained progress in this area has been the lack of sustained commitment by the state. With few resources, the state has made slow progress toward meeting the non-petroleum fuel goal.

The Energy Commission and representatives from the alternative fuels industry have established working groups (industry represented include ethanol, liquefied petroleum gas, gas-to-liquid (GTL) fuel, biodiesel, electric-drive-train/hydrogen, natural gas). On October 12, 2004, the Energy Commission held a conference with these groups so that each could present their initial results and seek common ground identifying key market barriers, prioritizing actions to address barriers, and estimating the market impact of such actions.

The California Department of Transportation also completed testing of GTL fuel in a portion of its Los Angeles fleet, demonstrating the emission-reduction value of the fuel.

On April 20, 2004, Governor Schwarzenegger announced his Hydrogen Highway Initiative: to develop a network of hydrogen fueling stations along the state's major highways so that every Californian has access to hydrogen fuel by 2010. The Initiative provides that a significant and increasing percentage of that hydrogen will be produced from clean, renewable sources.[104] The Governor will describe this vision of a network of hydrogen fueling stations in a Blueprint Plan due to be released by January 1, 2005.[105]

Improve Petroleum Infrastructure Permitting

The Energy Commission recommended that the state:

> Establish a one-stop licensing process for petroleum infrastructure, including refineries, import and storage facilities, and pipelines, that would expedite permits to increase supplies of transportation energy products available to California while maintaining environmental quality.

The state has made little progress in this area. The Energy Commission has consulted with stakeholders regarding the merits of this recommendation, and though several approaches are under discussion to expand California's petroleum infrastructure, these discussions have not produced a consensus on how to proceed.

On May 20, 2004, the Energy Commission adopted an Order Instituting Information (OII) to assess the nature and causes of permit delays, including the best permitting practices of local, regional, state, and federal agencies.[30] The Legislature has also explored concepts to implement a state-wide licensing program within the Energy Commission and evaluated best permitting practices; the Legislature has not approved any concepts.

The Energy Commission is also analyzing factors affecting the petroleum refining, importing, storage, and distribution infrastructure. This analysis, combined with new reporting regulations on petroleum products and pricing, will provide a more complete base of information to formulate future state policies.

Finally, the Energy Commission recently released a consultant report on market power in the petroleum wholesale sector and on October 12, 2004, convened a workshop to examine issues relating to competition in the wholesale and retail petroleum markets.

Develop a Public Information Program

The Energy Commission recommended that the state:

> Develop a public information program to inform consumers of the fuel savings benefits of efficient tires, proper tire inflation, and vehicle maintenance.

The state is on track in implementing this recommendation. On May 25, 2004, the Governor launched the "Flex Your Power...at the Pump" public education campaign to encourage Californians to use gasoline more efficiently.[107]

Progress on Environmental Stewardship Policy

The *2003 Energy Report* contained five recommendations to:

Progress of State Government	Signifi-cant	On Track	Needs Improvement
• Report greenhouse gas emissions from new plants.	☐	☑	☐
• Include greenhouse gas reductions in procurement decisions.	☐	☑	☐
• Include climate change strategies in state planning	☐	☑	☐
• Use sustainable building designs	☐	☐	☑
• Address California-Mexico energy and environmental issues.	☐	☑	☐

Greenhouse Gas Emissions and Climate Change Strategies

The Energy Commission recommended that the state:

- Require reporting of greenhouse gas emissions as a condition of state licensing of new electric generation facilities.
- Account for the cost of greenhouse gas reductions in utility resource procurement decisions.
- Require all state agencies to incorporate climate change mitigation and adaptation strategies in planning and policy documents.

The state is on track in implementing these recommendations. Regarding the reporting recommendation, in an Order Instituting Rulemaking, the Energy Commission will consider a requirement for applicants seeking licenses for new generation facilities to include information on the anticipated greenhouse gas emissions from the proposed facility in their filings. Also, in its recently released Preliminary Assessment of the Los Esteros Critical Energy Facility Phase 2 application, the Energy Commission staff is proposing a condition that would require the owner to report emissions of greenhouse gases from the power plant. This requirement could set a precedent for future siting cases.

Regarding the procurement recommendation, the CPUC is investigating a methodology to value greenhouse gases in its efficiency proceedings. This methodology would be used in determining the value of greenhouse gas reductions in procurement decisions.

In the area of state planning, the Energy Commission chairs the Joint Agency Climate Team, which coordinates climate change considerations among state agencies. In response to issues raised by this team, the Department of Water Resources and the California Department of Transportation (Cal Trans) have taken steps to address global climate change specifically in their policy and planning documents.

In the State Water Plan, DWR recognizes the long-term effects of changing climate on the quantity and timing of water availability and snowmelt. The Plan also encourages water planning agencies to monitor and model the hydrology effects of changing climate.

Cal Trans, in its most recent update of the State Transportation Plan, similarly encourages regional and local transportation plans to recognize the benefits and risks of climate change. The State Transportation Plan encourages state and local policies on transportation system efficiency, mode shifts, alternative fuels, and the fleet purchase of hybrid vehicles, which have important climate change co-benefits.

The Energy Commission initiated its Climate Change Virtual Research Center with the University of California and Scripps Oceanographic Institute to improve the state-of-science regarding climate change and its physical and economic impacts to California, and allow the state to develop sound mitigation and adaptation strategies. The Energy Commission also convened its first major conference on climate science.

The Energy Commission established its California Climate Change Advisory Committee, and is participating with the Cal/EPA in the Western States' Global Warming Initiative. Working groups have drafted five technical papers, and the three western Governors are expected to adopt recommendations from these papers next spring.

The California Climate Action Registry approved its first set of reporting protocols for the forest industry and, with technical support from the Energy Commission, is developing similar protocols for the electric generation and utility industry.

Sustainable Designs

The Energy Commission recommended that the state:

> Use sustainable energy and environmental designs in all state buildings.

The state has made little progress in this area. Although California leads the nation with the first green building, Sacramento's Department of Education building, and although other efforts are now underway, California has a long way to go before it reaps the benefits that an aggressive green building program offers.[108]

Steps are being taken to initiate a green building program. In his recent veto message of Assembly Bill 2311 (Jackson), Governor Schwarzenegger noted that the bill is largely identical to an executive order passed in the prior administration that is still in effect. The executive order directs the Cal/EPA to establish a working group to develop green building bank initiatives for both public and private buildings. Members of the working group include public sector decision makers, commercial real estate business owners and managers, energy experts, and financial managers. The group is currently developing recommendations for a comprehensive program to incorporate advanced energy conservation and other green building principles into commercial buildings.

Bi-national Energy and Environmental Issues

The Energy Commission recommended that the state:

> Conduct a Mexico Energy Program to fulfill joint declarations developed by the Border Governors' Conference Energy Worktable. The program should address energy and air quality issues on the California-Mexico border and stimulate energy technology exports for California energy.

The state is on track in implementing this recommendation, albeit slowly. California is a member state of the Border Governors Conference. In August 2004, the ten border Governors held their annual meeting in Santa Fe, New Mexico, at which Governor Schwarzenegger made a sweeping bi-national commitment to coordinate energy planning and development, dramatically increase energy efficiency, and expand the use of clean and renewable energy resources. Also, at the annual meeting, Governor Schwarzenegger's approved joint declarations incorporating tasks that directly support the Governors' three-point plan. The Energy Commission, actively involved in carrying out the energy declarations, has received funding from the U.S. Department of Energy to support these objectives and the use of American products and services in Mexico.

Endnotes

[77] CPUC Decision 04-01-050.

[78] Meetings were held between the CPUC, Energy Commission collaborative staff and the IOUs to ensure that the utilities followed this direction.

[79] Assigned Commissioner Ruling in Rulemaking 04-04-003.

[80] CPUC D.04-09-060, September 23, 2004.

[81] CPUC D.04-02-059, Attachment 9.

[82] CPUC D.04-02-059, February 26, 2004.

[83] I*nterim Opinion on the Administrative Structure for Energy Efficiency: Threshold Issues*, August 18, 2004.

[84] AB 549, Longville, Chapter 905, Statutes of 2001.

[85] http://www.energy.ca.gov/reports/2003-12-22_400-03-023F.PDF.

[86] Dynamic pricing programs create customer tariffs that reflect market prices as they change during the day.

[87] *A Core/Non-core Market Structure for Electricity in California*, Staff Report, March 15, 2004.

[88] Core/Non-core Electric Market Structure Discussion Proposal, April 8, 2004.

[89] AB 428 (Richman) died in the Senate Energy, Utilities and Communications Committee on June 22, 2004 on a 3-3 vote.

[90] The Governor's veto of SB 1478 (Sher, 2004), which among other things would have codified the accelerated RPS goals, was accompanied by a statement inviting the codification of the 2010-20 percent target and a new goal of 33 percent in 2020. [http://www.governor.ca.gov/govsite/pdf/vetoes/SB_1478_veto.pdf].]

[91] California Energy Commission, "Order Instituting Investigation," 04-DIST-GEN-1.

[92] Infrastructure Siting for Energy Facilities is Fractured and Inefficient, August 22, 2004. The Governor is reviewing the California Performance Review along with comments from public and state agencies.

[93] Comments of the City of Temecula, City of Hemet, City of Murietta, and Save Southwest Riverside County Opposing the Proposed Amendment to Commission General Order 131-D, filed April 6, 2004, R.04-01-026.

[94] CPUC D.04-09-060.

[95] CPUC D.04-09-060, Attachment 9.

[96] CPUC D.04-02-059, February 26, 2004.

[97] CPUC R. 02-10-001.

[98] D.04-09-022, September 2, 2004.

[99] CPUC OIR 02-10-001.

[100] These new circumstances include SoCalGas filing an application with the CPUC to begin natural gas production in California (Native Gas Proceeding A.04-01-034), the potential introduction of LNG to the California gas system, and the CPUC including this issue in its Natural Gas Policy Proceeding R.04-01-025. As a result of the SoCal filing, a stipulation was reached between SoCalGas and the California producers that required SoCal to file a subsequent application at the CPUC to specifically deal with the California produced natural gas quality issues. This application was filed in August of this year, Natural Gas Policy Proceeding R.04-01-025.

[101] Native Gas Proceeding A.04-01-034, Natural Gas Policy Proceeding R.04-01-025, and A.04-08-018.

[102] Assembly Bill 1468 (Kehoe, Status of 2004).

[103] This first step is part of a longer-term plan to establish a tire rating system and adopt minimum efficiency standards for after-market tires. The state vehicle procurement process now encourages state agencies to purchase hybrid-electric vehicles and limits their ability to purchase less fuel efficient vehicles, like larger sedans and sport utility vehicles.

Endnotes (continued)

[104] [http://www.hydrogenhighway.ca.gov/announce].

[105] Topic Teams are providing information and recommendations for the Blueprint Plan in the areas of roll out strategy, environment and health, business and investment, insurance, liability and codes and standards, and marketing, communication and education.

[106] Docket No. 04-SIT-1.

[107] http://www.fypower.org/save_gasoline/

[108] As the term suggests, a "green building"is one in which key resources like energy, water, material, and land are used more efficiently than buildings built to code. Green buildings are evaluated with Leadership in Energy and Environmental Design (LEED), a rating system produced by the U.S. Green Building Council. Because the LEED system is national, it does not necessarily ensure buildings meet California's more stringent building codes. As a result, California has developed a supplement to LEED to ensure that benefits exceed costs and buildings exceed codes. Recent studies have demonstrated that for little or no additional cost over standard state construction practices, state government buildings could achieve a LEED silver rating by following the California supplement to the LEED rating system. However, each new construction project continues to be evaluated on a case by case basis without a consistent policy that buildings should achieve more than minimum compliance with building codes.

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APPENDIX

Table A-1
Aging Power Plant Retirements for PG&E Area
2005-2008 Medium and High Risk Retirement Scenario

	2005	2006	2007	2008	Cumulative MW
High Risk					
Contra Costa 6		340	*	*	0
Morro Bay 1&2	326	*	*	*	326
Pittsburg 7	720	*	*	*	1046
Contra Costa 7				340	1386
Morro Bay 3&4		676	*	*	2062
Pittsburg 5&6				650	2712
Total PG&E Area	1046	1016	0	990	

Table A-2
Aging Power Plant Retirements for SCE and SDG&E Areas
2005-2008 Medium and High Risk Retirement Scenario

	2005	2006	2007	2008	Cumulative MW
High Risk					
Coolwater 1&2	146	*	*	*	146
Long Beach 8&9	530	*	*	*	676
Etiwanda 3&4			640	*	1316
South Bay 1-4				468	1784
Mandalay 1&2		430	*	*	2214
Ormond Beach 1&2		1500	*	*	3714
El Segundo 3&4			670	*	4384
Coolwater 3&4				482	4866
South Bay 4		222	*	*	5088
Encina 1-5				929	6017
Total SCE and SDG&E Areas	676	2152	1310	1879	

Table A-3
Supply/Demand Balance for PG&E Area
2005-2008 Base Case Scenario

Line		Aug 2005	Aug 2006	Aug 2007	Aug 2008
1	**Existing Generation**	25,858	25,710	25,935	26,088
2	**Retirements (Known)**		-219	0	0
3	**Retirements (Generic Assumption)**	-375	-625	0	0
4	**High Probability CA Additions**	227	1,069	153	0
5	**Forced Outages** [1]	-1,600	-1,600	-1,600	-1,600
6	**Zonal Transmission Limitation**[1]	-300	-300	-300	-300
7	**Net Interchange** [2]	2,500	2,750	2,750	2,750
8	**Total Supply (MW)**	26,310	26,785	26,938	26,938
9	**1-in-2 Summer Temperature Demand (Normal)**	22,017	22,410	22,748	23,180
10	**Projected Operating Reserve (1-in-2)***	22.0%	22.3%	20.9%	18.4%
11	**1-in-10 Summer Temperature Demand (Hot)**	23,469	23,888	24,249	24,709
12	**Projected Operating Reserve (1-in-10)***	13.5%	13.7%	12.5%	10.2%
13	**MW need to meet 7.0% Reserves in NP26**	-1,373	-1,417	-1,184	-692

14 Notes: *Does not reflect uncertainty for "Net Interchange" or "Forced Outages" which can result in significant variation in Operating Reserve.
[1] CAISO provided estimate.
2 2005 estimates based on CAISO provided levels of NW and SMUD interchange values during June-July 2004 and assuming flows are S-N on Path 26. The 2006 estimate assumes a decrease in exports to SMUD by 250 MW

Table A-4
Supply/Demand Balance for PG&E Area
2005-2008 Medium and High Risk Retirement Scenario

Line		Aug 2005	Aug 2006	Aug 2007	Aug 2008
1	**Existing Generation**	25,858	25,039	24,873	25,026
2	**Retirements (Known)**		-219	0	0
3	**Retirements (Medium and High Risk)**	-1,046	-1,016	0	-990
4	**High Probability CA Additions**	227	1,069	153	0
5	**Forced Outages** [1]	-1,600	-1,600	-1,600	-1,600
6	**Zonal Transmission Limitation**[1]	-300	-300	-300	-300
7	**Net Interchange** [2]	2,500	2,750	2,750	2,750
8	**Total Supply (MW)**	25,639	25,723	25,876	24,886
9	**1-in-2 Summer Temperature Demand (Normal)**	22,017	22,410	22,748	23,180
10	**Projected Operating Reserve (1-in-2)***	18.6%	16.9%	15.6%	8.4%
11	**1-in-10 Summer Temperature Demand (Hot)**	23,469	23,888	24,249	24,709
12	**Projected Operating Reserve (1-in-10)***	10.3%	8.7%	7.6%	0.8%
13	**MW need to meet 7.0% Reserves in NP26**	-702	-355	-122	1,360

14 Notes: *Does not reflect uncertainty for "Net Interchange" or "Forced Outages" which can result in significant variation in Operating Reserve.
[1] 2005 is CAISO estimate.
[2] 2005 estimates based on CAISO provided levels of NW and SMUD interchange values during June-July 2004 and assuming flows are S-N on Path 26. The 2006 estimate assumes a decrease in exports to SMUD by 250 MW

Table A-5
Supply/Demand Balance for SCE and SDG&E Areas
2005-2008 Base Case Scenario

Line		Aug 2005	Aug 2006	Aug 2007	Aug 2008
1	**Existing Generation[1]**	20,154	20,550	21,066	21,066
2	**Retirements (Known)**		-916	0	0
3	**Retirements (Generic Assumption)**	-375	-625	0	0
4	**High Probability CA Additions**	771	2,057	0	550
5	**Forced Outages [2]**	-2,000	-2,000	-2,000	-2,000
6	**Zonal Transmission Limitation[2]**	-500	-500	-500	-500
7	**Net Interchange [3]**	9,903	9,903	9,903	9,903
8	**Total Supply (MW)**	27,953	28,469	28,469	29,019
9	**1-in-2 Summer Temperature Demand (Normal)**	27,001	27,645	28,096	28,617
10	**Projected Operating Reserve (1-in-2)***	5.6%	4.6%	2.1%	2.1%
11	**1-in-10 Summer Temperature Demand (Hot)**	28,561	29,243	29,719	30,271
12	**Projected Operating Reserve (1 in 10)***	-3.3%	-4.0%	-6.3%	-6.1%
13	**MW need to meet 7.0% Reserves in SP26**	1,914	2,050	2,558	2,596

14 Notes: *Does not reflect uncertainty for "Net Interchange" or "Forced Outages" which can result in significant variation in Operating Reserve.
[1] Dependable capacity by station includes 1,080 MW of stations located South of Miguel
[2] CAISO provided estimate.
[3] Includes CAISO estimate for DC transfer capability 2,000 MW; Path 26 3,000 MW; South of Miguel by 400 MW; SW imports 2,500 MW; Dynamics 1,003 MW, plus CEC estimate of LADWP imports of 1,000 MW.

Table A-6
Supply/Demand Balance for SCE and SDG&E Areas
2005-2008 Medium and High Risk Retirement Scenario

Line		Aug 2005	Aug 2006	Aug 2007	Aug 2008
1	**Existing Generation[1]**	20,154	20,249	19,238	17,928
2	**Retirements (Known)**		-916	0	0
3	**Retirements (Medium and High Risk)**	-676	-2,152	-1,310	-1,879
4	**High Probability CA Additions**	771	2,057	0	550
5	**Forced Outages [2]**	-2,000	-2,000	-2,000	-2,000
6	**Zonal Transmission Limitation[2]**	-500	-500	-500	-500
7	**Net Interchange [3]**	9,903	9,903	9,903	9,903
8	**Total Supply (MW)**	27,652	26,641	25,331	24,002
9	**1-in-2 Summer Temperature Demand (Normal)**	27,001	27,645	28,096	28,617
10	**Projected Operating Reserve (1-in-2)***	3.8%	-5.7%	-15.2%	-24.7%
11	**1-in-10 Summer Temperature Demand (Hot)**	28,561	29,243	29,719	30,271
12	**Projected Operating Reserve (1 in 10)***	-4.9%	-13.5%	-22.1%	-30.8%
13	**MW need to meet 7.0% Reserves in SP26**	2,215	3,878	5,696	7,613

14 Notes: *Does not reflect uncertainty for "Net Interchange" or "Forced Outages" which can result in significant variation in Operating Reserve.
[1] Dependable capacity by station includes 1,080 MW of stations located South of Miguel
[2] CAISO Estimate
[3] Includes CAISO estimate for DC transfer capability 2,000 MW; Path 26 3,000 MW; South of Miguel by 400 MW; SW imports 2,500 MW; Dynamics 1,003 MW, plus CEC estimate of LADWP imports of 1,000 MW.

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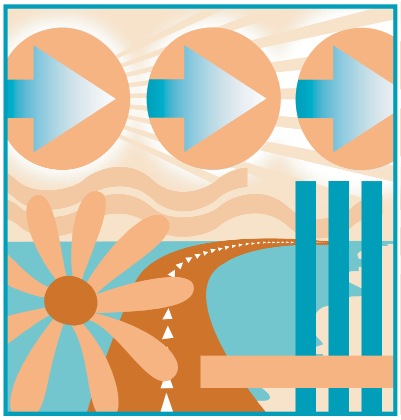

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