



Lightning Strikes Twice: California Faces the Real Risk of a Second Power Crisis

Taking the Right Steps to Ensure a Powerful Future

Bay Area Economic Forum
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EXECUTIVE SUMMARY

The average citizen may assume that the 2000-2001 power crisis was a fluke and that electricity will always be available at a flick of the switch. But the truth is different. California still faces the risk of another power shortfall and investors in a new generation still see no clear path forward.

California could face another energy shortage as soon as this summer or next if hot weather causes demand to spike and the economic recovery continues. The risk will grow even greater in 2006. The amount of generation capacity in the state has scarcely changed since the last power crisis, slowed by the lack of a clear public policy backing the construction of new capacity. More than 28,000 megawatts (MW)¹ of new capacity was announced for construction in California after the crisis, but a net increase of only 3,800 MW has been achieved, once retirements are taken into account.² Meanwhile, peak demand has continued to grow at 2.7% per year on average, amounting to more than 3,000 MW of demand growth. Moreover, the possibility that hot weather will strain supplies appears even more likely than expected. **As a result, the risk of a second power crisis is very real.**

If this happens, the price tag will be daunting. The earlier energy crisis left the state with nearly \$48 billion in long-term contracts for new capacity — more than \$3,500 per customer in California. Add in the cost to the state of lost investment, jobs, and growth potential, and the true costs were much higher.³ In a time of gradual market recovery, a second energy crisis would put the brakes on our economy — an impact we cannot afford. It is critical for Californians to come together to find an appropriate and speedy solution to the state's energy needs.

Part of the current problem lies in the slow response of California policy makers to put in place clear and effective market rules and regulations. They have not acted quickly enough to encourage new infrastructure investment by establishing a clear rate-setting process that provides adequate guarantees to investors. Indeed, although the Legislature passed AB57 in 2002 to lay down clearer rules for procuring new power supplies, its implementation is still under debate and the subject of potential new legislation.⁴

While it is important that California consider the long-term power market structure, the state must **first prevent a near-term shortage**. Only after ensuring that the state has sufficient capacity to meet its near-term needs will state agencies and investors be able to address the longer-term market structure and establish clear rules for competition and investment in the state's electric power infrastructure.

California must take five steps to resolve these energy challenges in an environmentally sensitive and economically feasible manner.

First, to ensure that the state has sufficient capacity over the next three years, it must implement a number of near-term fixes in a way that does not damage the long-term progress towards a competitive market:

1. The State must act today to facilitate the construction of new generation **before the summer of 2006**. It must accurately assess the potential level of future electricity demand. The California Public Utility Commission must take action now to allow utilities to sign long-term contracts (e.g., 5-10 years) with private sector generators to bring on line new capacity by 2006. These contracts should be awarded through a competitive RFP process, allowing competition between

1 A megawatt of capacity provides enough electricity to supply approximately 400-600 homes.

2 Based on plant announcements and capacity brought on line between the summer of 2001 and July 2004.

3 For more background on the origins and impact of the first power crisis, please see the previous BAEF reports.

4 AB2006 is currently up for review in the California State Senate. No long-term power procurement plans have been approved by the CPUC.

utilities and competitive generators, and should link energy pricing to market-based electricity indices.

2. California should install universal time-of-use metering for all power users and encourage more extensive use of other load management programs. Load management programs induce consumers to cut their demand during peak hours, and California lags far behind other states in this important area. Yet load management programs yield results fairly quickly, often faster than building new power generation capacity. In California, these environmentally sensitive programs could save consumers more than \$2.5 billion dollars over the next 10 years, alongside a potential reduction in peak energy demand of up to 20%. The California Power Authority has \$5 billion in funding authority to speed the investment of time-of-use metering programs and could permanently shift the landscape of the California market, making the state a leader in demand side management programs globally.
3. The State needs to speed the upgrade of its transmission capacity. Since the last energy crisis, the role of transmission capacity in balancing the power of the system has become clear and many new projects are in development. Unfortunately, a complex and overlapping set of regulatory jurisdictions, with no clear approval timelines, has significantly slowed the siting and development of needed transmission capacity. A single review process SHOULD coordinate the approval processes of the California Public Utility Commission, the California Independent System Operator, and the California Energy Commission.

Only after resolving the near-term shortage, will California policy makers be in a position to define clear rules for investors and energy service providers (ESPs) to ensure sustainable competition. The BAEF has addressed in previous reports the role of competition in promoting efficiency in the market and lowering costs to consumers and believes that competition for consumers is ultimately critical.

4. To promote long-term infrastructure additions, California should put a capacity market in place, combined with a required reserve margin target for all energy service providers by 2006. Capacity markets, along with adequate resource targets, send price signals to the market to build new capacity, help provide generation owners a return on their investment, and provide a liquid, market-based mechanism for trading capacity rights to help retail suppliers meet reserve margin requirements.
5. Finally, the State should re-introduce consumer retail choice through a core/non-core market structure that will contribute to lower long-term power costs. With a choice of their electricity supplier, large consumers can select the most economic and efficient supply source for their power needs. In other markets, choice has led to lower prices for consumers and greater efficiency. It will also help protect jobs and provide incentives for new investment in the state. Moreover, this can be done in a manner that protects small residential consumers and ensures repayment of the State's long-term DWR power contract commitments.

Market manipulation played an unfortunate but real role in the previous California power crisis, as evidenced by recent investigations at the FERC and in California. All of the steps above must be combined with strong oversight of market participants to protect against price manipulation. They

will also contribute to greater reserve capacity, more flexibility in peak demand, and will limit the market power of any one player, all key factors in reducing the potential for market manipulation.

Finally, although much of this report focuses on the market structure for supplying power to California consumers, the supply of fuel to power generators in the state, in the form of natural gas, remains an important issue. Bottlenecks in natural gas transmission contributed to spikes in natural gas prices during 2001, exacerbating the resource shortage and helping to drive the market to crisis. California should continue to ensure that sufficient clean-burning natural gas is available at reasonable prices through expanding major pipelines to and within the state and considering new supply sources such as LNG. Fuel makes up more than 60% of the cost of power generation and efforts to reduce fuel costs will be felt by all state consumers.

Competitively priced, reliable power is crucial to keeping California an attractive place for businesses to invest in and consumers to live in. **But the time to act is now.** Without quick action from state agencies, the state could see a second power crisis in the very near term. Actions to resolve this near-term risk should be combined with, and consistent with, a set of long-term, sustainable rules for a new market design that will protect consumers, provide incentives for investors in new generation capacity, and encourage competition throughout the power system (Exhibit 1).

Exhibit 1

THE STATE IS AT RISK OF ANOTHER POWER CRISIS, BUT 5 KEY STEPS WILL HELP TO ENSURE A SUSTAINABLE POWER MARKET

Action needs to be taken today to prevent another energy crisis

- CEC estimates indicate that operating reserves could drop below typical "emergency" levels if we have a hot summer
- The CEC's demand estimates appear low relative to trend and a "high demand case" (i.e., hot summer) may be as likely as a 1-in-5 occurrence
- Taking into account current levels of demand growth operating reserves could be extremely tight by 2006 – as low as 5.8% (in a 1-in-5 year demand case)

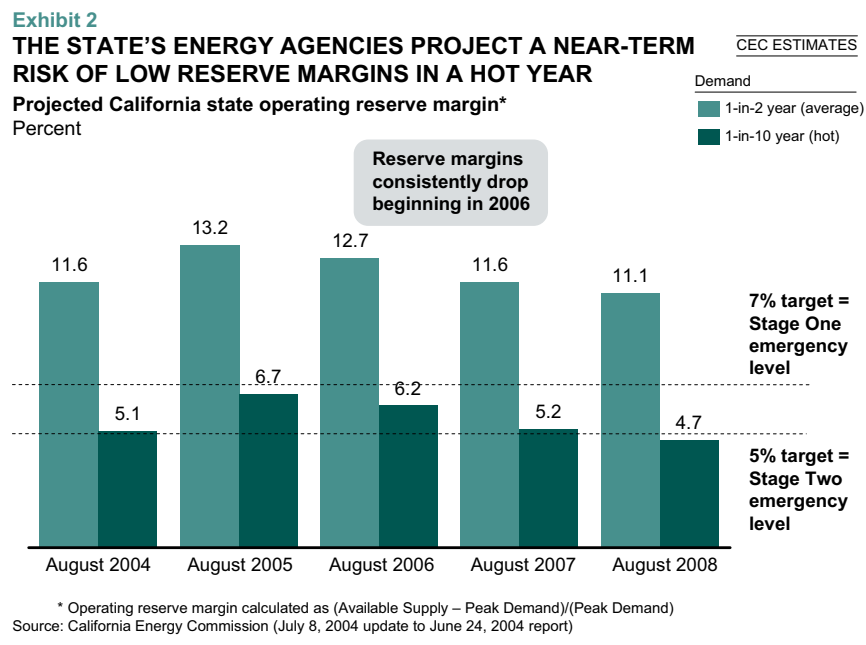
5 steps that will ensure a long-term sustainable market for power

1. New generation needs to be built today, given the long lead time, and a mechanism for market-based contracts with utilities needs to be introduced
2. California should introduce mandatory time-of-use metering for all classes of customers
3. New transmission needs to be built and facilitated through an expedited and coordinated approval process by the CPUC, ISO, CEC, and FERC
4. A formal capacity market combined with a mandatory planning reserve target (e.g., 15-20%) needs to be in place by 2006
5. The State should re-introduce elements of retail choice, providing an opportunity for large consumers to shop for power

PART I. INTRODUCTION: THE MAKINGS OF A SECOND POWER CRISIS

In May 2003, the Bay Area Economic Forum released a report highlighting the growing risk of a capacity shortage in California far earlier than the then-optimistic projections of 2008-2010.⁵ These risks have become a reality and the state now faces the very clear risk of a second power crisis.

The most recent California Energy Commission (CEC) report now estimates that California could suffer a significant shortage in any hot year, and after the summer of 2005, a consistent downward trend in reserves.⁶ For a state that has recently experienced a traumatic crisis, the possibility of a second crisis should galvanize policy makers and regulatory agencies to make real and lasting changes (Exhibit 2).



Yet California has made little progress towards averting a second crisis. Since 2001, more than 28,000 MW of new capacity has been announced for construction in California, but after retirements, only 3,800 MW of new capacity is actually available to state.⁷ Meanwhile, demand has continued to grow at an average of 2.7% per year as voluntary conservation efforts have fallen away and the economy has rebounded. Unless California either adds new capacity or controls demand, it may relive the situation in the 1990s, when peak demand grew by more than 10,000 MW but the state added only 1,200 MW of new capacity.⁸

Policy makers have been slow to implement a consistent set of policies to guide investors and to put in place a credible rate-making process to protect consumers. The Legislature passed AB57 in 2002, intended to provide a clear set of rules for procuring new power supplies, but the implementation of the law is still under debate and the subject of potential new legislation. As

5 "California is Still Coming Up Short on Electricity: The state's power sector remains troubled and is at risk of a future supply shortfall," May 2003.

6 CEC "California's Summer 2004 Outlook Electricity Supply and Demand," initially issued June 2004, revised July 2004.

7 Estimate from July 2001 to July 2004 in California.

8 Includes capacity growth in California between 1989 to 1999 net of retirements, and peak demand growth for California state over the same time.

these disputes about market structure rules continue, and as reserve margins tighten, we can hear echoes of the first round of deregulation during the 1990's.

The state faces a particular challenge in convincing investors to build in the state, for two reasons: 1) California lacks a clear wholesale market framework that unequivocally specifies who can sell power and under what rules, and 2) investors are reluctant to sign contracts with utilities because of the California Public Utility Commission's (CPUC) history of post-contract reasonableness reviews and contract abrogation. AB57 addressed this problem, establishing a framework for how utilities can procure power from investors, but delays in its implementation must be overcome before the state can consider itself back to normal.⁹

The pressure to create a long-term sustainable market through legislation and the implementation of existing law at the CPUC has distracted state agencies from the immediate problem. First, it is necessary to reduce the risk of a near-term capacity reserve shortage. As the near-term problem is addressed, state agencies must avoid encouraging investments that ultimately harm the state's prospects for future competitive private investment. The near-term fixes must remain market-linked and provide the state and consumers with as much flexibility as possible as the long-term market structure is being redesigned.

Only after addressing the near-term shortage will policy makers be able to implement a market structure that provides clear, sound rules for competitive long-term power procurement, while introducing elements of consumer retail choice.

California learned during the first crisis that a tight market and unclear market rules are a dangerous mix, creating opportunities for market manipulation and coercion. This formula allowed some market players to manipulate prices in California as shown by ongoing investigations at the Federal Energy Regulatory Commission (FERC) and in California. Experience in other power markets has shown that a market with sufficient power capacity, clear rules and effective oversight of generators is very difficult to game. The recommendations outlined below should all contribute to greater levels of reserve capacity, more flexibility to manage peak demand, and reduced market power for any one player, all key success factors to limiting the potential for market manipulation.

No silver bullet will resolve California's energy problems. The answer lies at the end of hard work, and a transparent and disciplined approach to market design. California's state agencies, utilities, and consumers will need to work together to ensure California avoids a second power crisis.

⁹ Utilities are submitting long-term procurement plans to the CPUC currently but the CPUC has yet to approve any long-term procurement plan or test the criteria for power contracts. Issues remaining to be settled include what is a diversified portfolio of short, medium and long-term contracts; when will reserve margin targets be implemented; what authority does the CPUC or DWR have to review contract administration after the fact; what are reasonable benchmarks for assessing the value of a procurement plan; and how will incentives help to reduce contract costs over the life of the procurement plan.

PART II. SUNSHINE AND THE ECONOMY: ACCURATELY GAUGING DEMAND

The first step is securing reliable information. California's state energy agencies need reasonable estimates of demand growth and available supply. The most recent California Energy Commission (CEC) estimates of demand growth indicate that the California market could fall short of capacity in any hot year.¹⁰ Last year's Bay Area Economic Forum report¹¹ examined the CEC's forecasting methodology and potential conservatism in its estimates. This report pointed out that greater growth in demand, more retirements than expected, and delays in new generating capacity could all leave the market short sooner than predicted. After that report, the CEC addressed many of these very issues and now uses improved estimates of generating capacity retirements and additions in its forecasts. However, the CEC may still be understating the potential for demand growth to cause a shortage sooner than expected.

Two areas of concern arise from the CEC's demand projections: 1) The rate of economic growth, and 2) the chance of hot weather causing demand spikes. Demand growth in electricity typically follows GSP growth in the long run and weather in the short run.

ECONOMIC GROWTH

The most recent CEC forecasts continue to assume slow economic growth on the order of 1.37% over the next 4 years (after 2004). However, there is evidence that growth is increasing. In the first 3 months of 2004, demand growth figures from the California Independent System Operator (CAISO) averaged approximately 3.5% (weather adjusted). The most recent CEC estimates reflect an expectation of increased 2004 summer demand based on the recent trend, but continue to assume growth at the lower level for the remaining years of the projection. It is unclear whether growth will stay at current levels, but if it does, this could cause an additional 2,100 MW of demand in the state as soon as 2006 and more than 3,000 MW by 2008 above current forecasts. Ironically, a shortage driven by a strong economic recovery, would actually create an obstacle to further, sorely needed, economic growth in the state (Exhibit 3).

WEATHER

Because peak summer demand in California is so sensitive to high temperatures, the CEC estimates weather-adjusted demand for a 1 in 2 year summer — average weather, and a 1 in 10 year summer — hot weather. As its name implies, the 1 in 10 year demand forecast assumes a set of temperature conditions that should occur once a decade. However, there is not a straight-line relationship between a 1 in 2 year demand forecast and a 1 in 10 year demand forecast. In fact, demand during a 1 in 5 year summer yields approximately 80% of the potential demand increase of a 1 in 10 year forecast (Exhibit 4).

In other words, the spike in demand from "hot" weather is actually far more likely than one would assume based on the 1 in 10 year forecast. Given historical weather patterns in California, the "hot" case is as likely as 1 in 5 and the state needs to encourage energy service providers to prepare for it.

Combined, the risks of greater economic growth and hot weather mean California may have significantly understated the likelihood and severity of a potential capacity shortage. Using a more

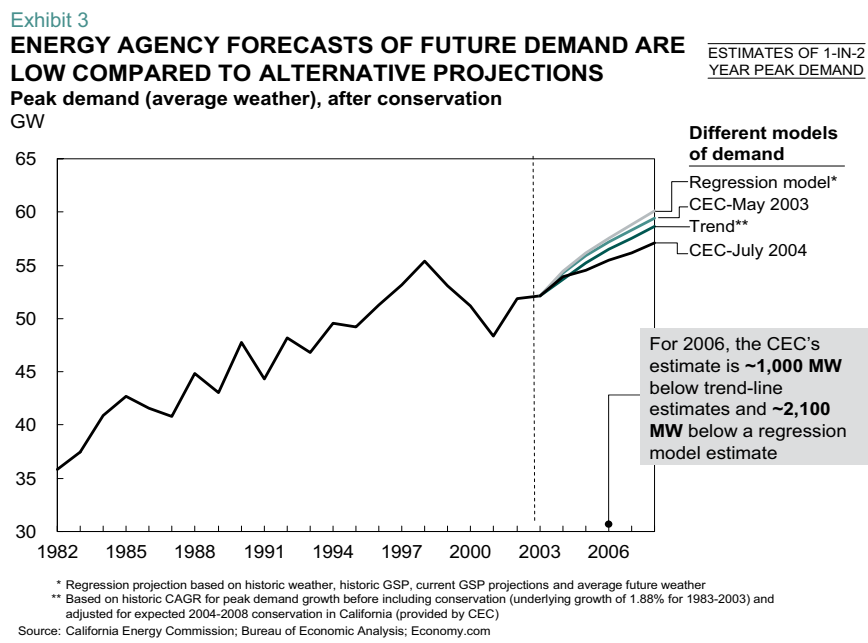
10 California Energy Commission and the CAISO assume that a 7% operating reserve margin is necessary for stable grid operation and begin to implement Stage One emergency responses at that level.

11 BAEF report "California Is Still Coming Up Short," May 2003.

prudent set of demand growth and weather forecasts, the chance of a shortage in California during the summer of 2006 exceeds current projections (Exhibit 5).

To reach the minimum operating reserve¹² needed to avoid a Stage One emergency level, California must add more than 750 MW of either new capacity or reduced peak demand above the current projections. Moreover, if the state is to move the targeted 15% planning reserve¹³ target set by the Governor's office and the CPUC forward to 2006, it could end up as much as 2,000 MW short of capacity in that year. The current implementation plan phasing in that target by 2008 could place the state at a real risk of a shortage — especially assuming continued demand growth. Finally, if California were to target a higher level of 20% in reserve planning to account for hydro availability, the state would need 4,900 MW of new capacity by 2006.

As a result, although it is important to develop a long-term competitive market in California, it is critical to ensure that the state has sufficient capacity available to meet demand growth over the next two years.



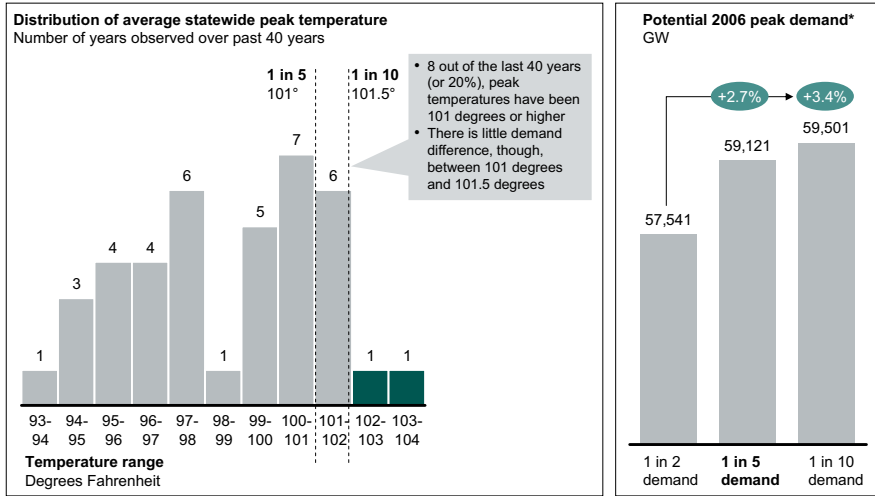
12 Operating reserve margins are defined as (available capacity (nameplate capacity net of planned and unplanned outages) – projected demand)/projected demand. Operating margins are valuable in estimating near-term potential outages and the grid's ability to meet actual demand load using all available resources.

13 Planning reserve margins are (total nameplate capacity – projected demand) / projected demand. Planning reserve margins are typically set at 15% and are usually used in long-term projections to ensure sufficient generating capacity is available to meet demand growth.

Exhibit 4

THE POTENTIAL FOR A “HIGH DEMAND CASE” IS AS HIGH AS A 1-IN-5 EVENT, RATHER THAN JUST A 1-IN-10 EVENT

BASED ON HISTORIC DATA



* Based on BAEF regression-model estimates of 2006 peak demand
Source: California Energy Commission

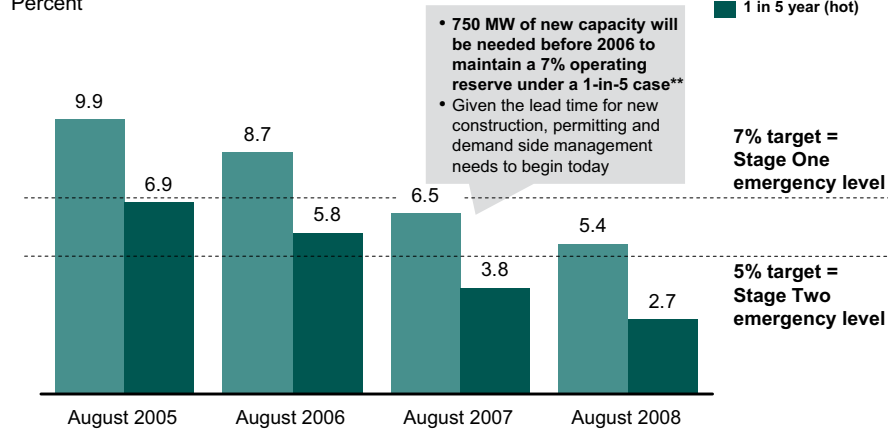
Exhibit 5

TAKING INTO ACCOUNT A DIFFERENT VIEW OF FUTURE DEMAND, THE RISK OF SHORTAGES IS EVEN STARKER

BAEF ESTIMATE

Projected California state operating reserve margin*
Percent

Demand
■ 1 in 2 year (average)
■ 1 in 5 year (hot)



* Operating reserve margin calculated as (Available Supply – Peak Demand)/(Peak Demand)
** As much as 2,000 MW would be required to maintain a planning reserve margin of 15% for the 1-in-5 case, which would equate to a 1-in-2 operating reserve of 12.1% and a 1-in-5 operating reserve of 9.1%
Source: California Energy Commission (July 8, 2004 update to June 24, 2004 report); McKinsey analysis

PART III. THE BALANCE OF POWER: IMPROVING NEAR-TERM DEMAND AND SUPPLY

The potential cost of a second power shortage in California cannot be overstated. The first California crisis resulted in more than \$48 billion in long-term contract costs¹⁴ signed by the California Department of Water Resources, and slowed the California economy by an estimated 0.7-1.5% in 2002.¹⁵ The potential impact on the state's investment reputation and business climate remains uncalculated but is significant. California can not afford to face this crisis again.

In some ways it is misleading to think of this potential crisis as a "shortage," it is really a supply/demand imbalance. Hence it is important to consider options that also manage demand and strengthen the transmission network linking California to other markets, instead of just options to increase power generation capacity.

California is not alone in this situation. There are positive examples from other markets that have implemented responses to developing shortages, without ruinous long-term costs. During the spring of 2001, the New York Independent System Operator (NYISO) released their first "PowerAlert"¹⁶ report identifying a looming shortage that could leave state reserve margins below adequate levels as soon as that summer — and getting worse every year afterwards. In response, the NYISO proposed a set of recommendations to expedite the approval of new capacity, accelerate consumer conservation and upgrade the region's transmission infrastructure. Over the next two years, through coordinated actions of the NYISO and state agencies, New York was able to bring more than 3,000 MW of new capacity on line, add 1,300 MW of dependable peak demand reduction and build 330 MW of new transmission capacity. At the same time, the state did not sign any long-term out-of-market contracts, and the new capacity replaced less efficient, higher emissions power plants. In 2004, the NYISO declared success and renamed its annual report — "PowerTrends" from "PowerAlerts" (Exhibit 6).

In California, a similar portfolio of actions, combined with a collaborative approach between state agencies, can address the near-term resource needs of the state while laying the foundation for a long-term market structure that will encourage competition.

RECOMMENDATION 1: DEVELOP ACCURATE ESTIMATES OF RESOURCE ADEQUACY AND SIGN LONG-TERM CONTRACTS TO ENSURE THAT NEW CAPACITY IS BUILT TODAY

There is more than enough capacity permitted, partially built, or mothballed in California today that could be brought on line by 2006 with expedited contracts backed by the CPUC and utilities to meet a potential shortage (Exhibit 7).

Clearly, the CPUC and utilities should not pursue contracts that will burden the state with high power costs for decades or relax environmental restrictions unnecessarily. An expedited RFP process that allows for competition from non-utilities and utility affiliates and is linked to market indices could bring new capacity on line at a reasonable cost by 2006. Utilities would need the authority from the CPUC to sign multi-year contracts with guarantees of adequate rate recovery.¹⁷ The RFP process should be structured to allow bidders to bid a capacity payment, based on a

14 Includes the current estimated costs of the long-term contract portfolio from 2004-2013 (\$28.3 billion) plus the actual DWR expenditures from 2001-2003 on energy (\$19.57 billion). Estimates are from the DWR Activities and Expenditures Report — year ended December 31, 2003. Energy costs do not include bond charges, reserves, administrative, or other costs.

15 Estimated from Public Policy Institute of California report "The California Electricity Crisis" January 2003.

16 For more detail on the New York market, see NYISO "PowerAlert: New York's Energy Crossroads," March 2001 and NYISO "Power Trends: New York's Success and Unfinished Business," May 2004.

Exhibit 6

NEW YORK WAS ABLE OVER THREE YEARS TO ALLEVIATE A DEVELOPING POWER SHORTAGE

	March 2001 Situation	NYISO recommendations	May 2004 Situation
Generation	<ul style="list-style-type: none"> Estimated 4-5 GW capacity shortfall by 2004 More than 29 GW of capacity in state siting pipeline 	<ul style="list-style-type: none"> Streamline siting process and agency coordination 	<ul style="list-style-type: none"> More than 3,000 MW built 2,038 MW under construction 3,120 MW permitted
Demand Response	<ul style="list-style-type: none"> <200 MW registered in demand response programs 	<ul style="list-style-type: none"> Accelerate consumer conservation options including price-sensitive load programs and "real time" metering 	<ul style="list-style-type: none"> Increased participation in load management programs by 1,300 MW
Transmission projects	<ul style="list-style-type: none"> Imports required to meet peak demand expected to quadruple by 2004, becoming 8% of load 	<ul style="list-style-type: none"> Upgrade state and region's transmission infrastructure 	<ul style="list-style-type: none"> 330 MW of transmission capacity added 600 MW permitted 2,000 MW in licensing

New capacity in New York "operate[s] under air-quality permits that are among the strictest in the nation" and "emissions would be higher" without them.
 - M.J. Bradley & Associates (2003) report on the NY Market

Source: NYISO PowerTrends (May 2004); NYISO Power Alert (March 2001)

Exhibit 7

THERE ARE A NUMBER OF SOURCES OF CAPACITY THAT COULD BE BROUGHT ON LINE BY 2006 IF THE STATE ACTS NOW

	California capacity Gigawatts	Estimated time to bring on line Months	Steps to bring capacity on line
Plants that have been mothballed, but could be brought back on line	0.5	3-6	<ul style="list-style-type: none"> Relaxed environmental restrictions Short term contracts E.g., Etiwanda
Plants partly constructed, but incomplete due to financing or lack of contracts*	3.7	8-12**	<ul style="list-style-type: none"> Mid- to long-term contracts (5-10 years) E.g., Metcalf, Pico
Plants with permits from the CEC but not under construction	6.5	12-18	<ul style="list-style-type: none"> Mid- to long-term contracts (5-10 years) Extended permit shelf life E.g., Tesla, San Joaquin

To ensure new capacity is brought on line by the summer of 2006, the CPUC must act now to ensure that long-term contracts are available to generators to complete existing projects

* Includes projects under construction delayed more than 24 months from initial planned online date
 ** Assumes most of these plants are 40% complete (as of July 2004)

Source: California Energy Commission; McKinsey analysis

17 The issue of debt equivalency raised by utilities (the additional equity return needed by utilities to offset the treatment of long-term contracts as debt by ratings agencies) would need to be addressed by an assurance to provide a sufficient rate of return in the utility's next rate review.

Exhibit 8

MARKET-BASED LONG-TERM CONTRACTS SHOULD BE ADOPTED TO FACILITATE GENERATION CONSTRUCTION

How contracts would work...

Who will build:

- Competitive RFP process allowing utility affiliates or merchant generators to bid

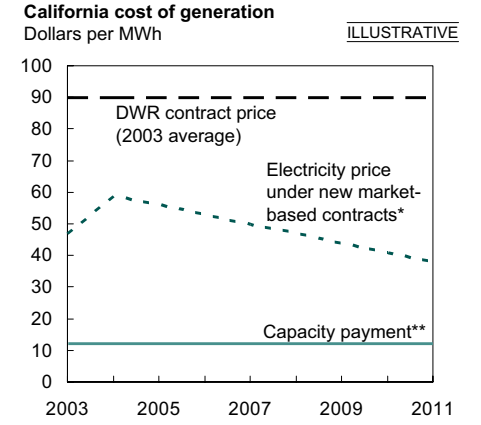
Who will buy:

- In the near term, utilities will be responsible for signing contracts with the winning bidders, with guaranteed rate recovery of contract costs

How will contracts be priced:

- Will be market based contracts, with a return on capital investment and pass through of variable generation costs
 - Capacity payment will provide return on capital investment
 - Energy payment will be based on a specified plant efficiency and indexed to natural gas prices

... and what market-based prices would look like under the contracts



* All-in wholesale electricity price including capacity payment, gas price, energy costs

** Assumes 15% ROE, 8% cost of debt, \$450/kW CCGT investment cost, 10-year return period

Source: California DWR; NYMEX; McKinsey analysis

adequate return on investment, and a pass through for fuel and operating costs (Exhibit 8).

Long-to medium-term contracts, competitively bid, can be signed in California without damaging the transition to competition or violating the premise of a competitive market. To accomplish this, the CPUC should move the 15% reserve planning target forward to 2006 and require utilities to file plans that would through demand management and multi-year contracts ensure adequate margins for reserves. The CPUC and utilities need to work together **now** to sign contracts and ensure that the state does not face a second power shortage.¹⁸

RECOMMENDATION 2: CREATE MANDATORY LOAD MANAGEMENT PROGRAMS

Given California's history of energy conservation and environmental sensitivity, California should not consider new capacity as the only means to offset a developing shortage. California should be a nationwide — if not global — leader in the use of demand side management (DSM) programs. Instead it lags behind the rest of the country.

Utilities and states commonly pursue two types of DSM programs: energy efficiency and load management. Energy efficiency programs are typically subsidized investments — in partnership with utilities — to install energy efficient equipment that cuts both peak demand and overall energy demand thus yielding year-round savings. These programs typically provide substantial returns for consumers in the form of reduced costs and to utilities through a reduced need for new generation capacity.

California is a leader in the use of energy efficiency programs, and they save the state more than 13,000,000 MWh a year, the equivalent of nearly 2,000 MW of baseload capacity (Exhibit 9).

¹⁸ This capacity, backed by utility contracts, could create a potential overhang of capacity not needed to supply the utility's core customers after the transition to a core/non-core market structure, creating some confusion for the ownership of the contract obligations. However, regardless of the confusion we believe that it is critical to bring the new capacity on line quickly and the utility backed contract is the fastest and most competitive approach. There are a number of alternatives being considered, including capacity tagging, that could be used to share the cost of the contracts with non-core customers over the next decade.

However, there is still room to improve, as other states have been able to reduce demand as a percentage of annual demand even more than California. (Exhibit 10).

However, California trails far behind other states in the second key area: load management. Unlike energy efficiency programs, which work year-round, load management programs control demand at peak hours in a year, thus providing flexibility to the grid and reducing the risk of power shortages. Controlling this demand is vital because, although peak hours are only 5% of the total, they account for more than 30% of the wholesale electricity costs for consumers.¹⁹

In 2002, California had approximately 800 MW of available demand signed up in load management programs. Those programs represented only 1.6% of peak demand, making California 20th in the nation — behind Georgia, Florida, Colorado, and many other states — in using load management to reduce peak energy needs (Exhibit 11).

Load management programs can be enormously effective in reducing peak energy demand. Georgia Power has successfully been using a real time pricing response program with large industrial customers in the state since the 1990s. By installing real time meters and providing a real time price on the internet, Georgia Power has reduced peak demand by more than 17% in its largest consumers (Exhibit 12).

Residential programs can take longer to implement but can also lead to substantial benefits in energy consumption. To be effective long-term, residential programs should combine price response tariffs that vary rates during the time of day with time-of-use metering.²⁰ Time-of-use programs allow utilities to charge customers more to use electricity during peak hours, and hence residential customers tend to shift demand to off-peak hours in the late evening or early morning, while reducing demand in peak hours.

Florida for example, with a similar customer profile to California, has developed one of the world's largest load management programs with more than 712,000 registered customers. The program focuses on residential consumption such as water heaters and pool pumps, and is now able to reliably reduce peak demand by more than 1,000 MW (Exhibit 13).

California can also learn from one of the first attempts to use residential time-of-use metering broadly in the US. During 2000-2001, Puget Sound Energy installed more than 300,000 time-of-use meters in consumers' homes in return for discounts on their monthly bill during the pilot program. Within two months of adoption, residential customers in the program shifted more than 5% of their load to off-peak periods. However, since the program was voluntary, it was too small generate substantial economic benefits, even though participants found it attractive (Exhibit 14).

A recent pilot program in California funded by the CEC and CPUC has also had very promising results at the residential level. By installing more than 2,400 time-of-use meters for residential customers, combined with a tariff that charges more for peak hours, participants have shifted more than 20% of peak demand to off-peak hours.

California has often underfunded load management programs because of difficulty in assessing their value. However, our analysis clearly shows that demand side management programs are self-funding and can lower energy costs to consumers substantially (Exhibit 15).

In California, a mandatory load management program, requiring universal real time metering for large industrial and commercial customers and time-of-use metering for urban residential and small commercial customers, could save consumers more than \$2.7-3.8 billion dollars (net of

¹⁹ Based on California wholesale power costs in California from 4/1998 through 1/2001. Similar results have been seen in PJM, New York ISO, New England ISO and the UK.

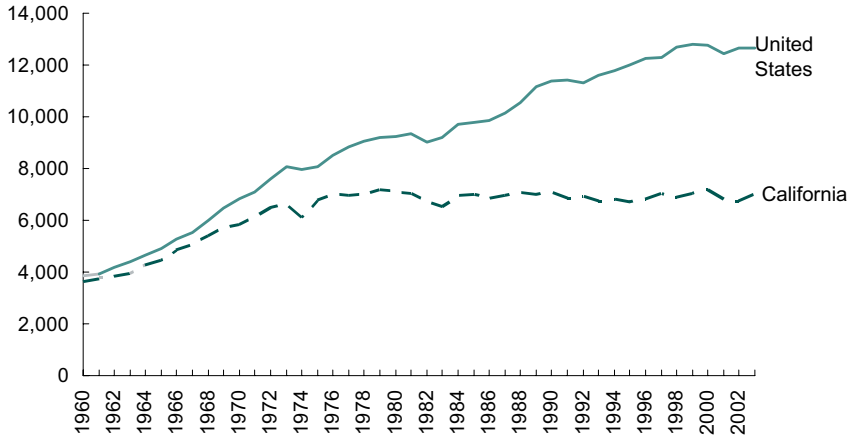
²⁰ Time-of-use meters are not real time meters that track usage in 1-15 minute intervals. Instead, time-of-use meters track consumption during intervals during the day and only need to be read monthly as normal meters are. Customers are then charged based on their consumption during different periods during the day.

²¹ Our analysis recognizes that some consumers, especially large industrials with inflexible demand profiles, could have higher rates as a result of real time metering. However, even in those cases, lower wholesale power prices usually result in lower costs in the end.

Exhibit 9

CALIFORNIA IS ONE OF THE MOST ENERGY EFFICIENT STATES IN THE NATION

Total Electricity Use per Capita 1960-2003
KWh / capita

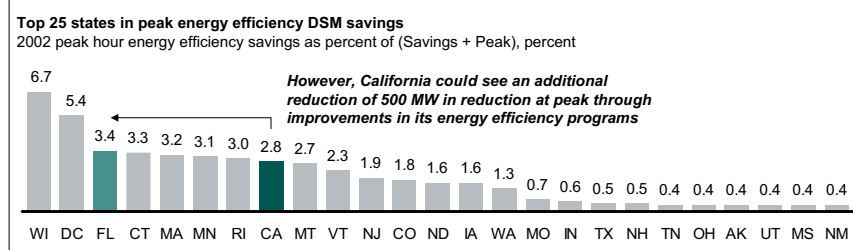
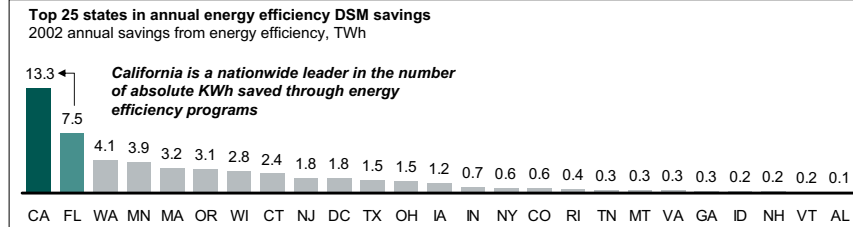


Source: US Census Bureau; US Energy Information Administration; California Energy Commission

Exhibit 10

CALIFORNIA LEADS IN TOTAL ENERGY EFFICIENCY BUT THERE ARE FURTHER EFFICIENCY SAVINGS OPPORTUNITIES AT PEAK

Florida
California

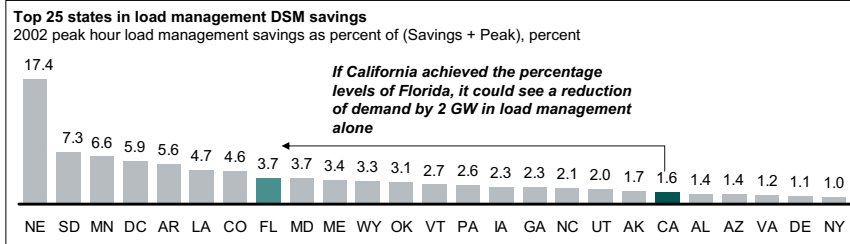
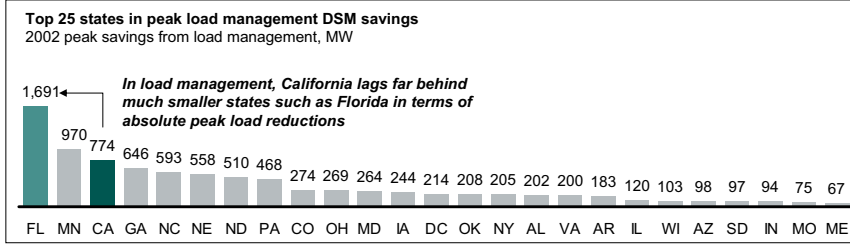


Note: Includes only utilities reporting DSM activities
Source: EIA; state disclosures

Exhibit 11

CALIFORNIA LAGS OTHER STATES IN ITS DEMAND SAVINGS FROM LOAD MANAGEMENT PROGRAMS

Florida
California



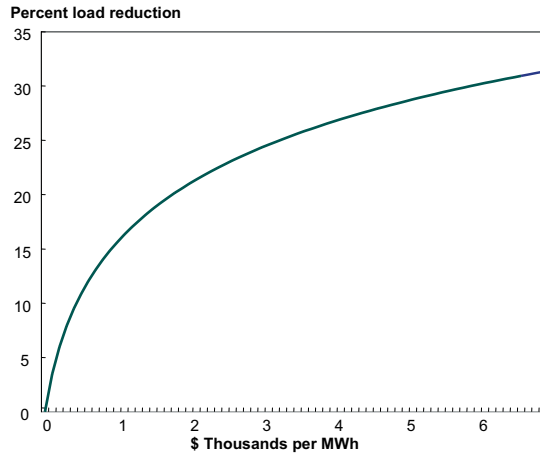
Note: Includes only utilities reporting DSM activities
Source: EIA; state disclosures

Exhibit 12

REAL TIME PRICING IS ONE VERY SUCCESSFUL WAY TO CONTROL PEAK DEMAND

Georgia Power load response curve

Percent of total real time price sensitive load



Implementation

- The meters reflect rates that vary hourly according to wholesale market prices and are posted on the Internet

Impact

- More than 1,700 businesses with a load of 5,000 MW enrolled in program with real time meters
- Customer peak demand has dropped by more than 17% on average since meters installed

Source: Christensen Associates; "Power by the Minute," (McKinsey Quarterly 2002 Number 1)

Exhibit 13

RESIDENTIAL LOAD MANAGEMENT PROGRAMS CAN HAVE A SUBSTANTIAL IMPACT

Utility:	Florida Power and Light
Program:	Load Management System (LMS)
Customers:	Approx 712,000 utility customers

Implementation

- 2-way power-line frequency system with LMS field equipment installed in the customer's home
- Customers give the utility permission to control their appliances
- FPL pays residential customers incentives of \$6 for controlling air conditioning and \$3.50 for water heaters per month
- Load control implemented on average 3-4 times a year; on a monthly basis, LMS performs a 15 minute control on water heaters and pool pumps year-round
- 5 years to develop and implement the use of the LMS as it is operates today

Impact

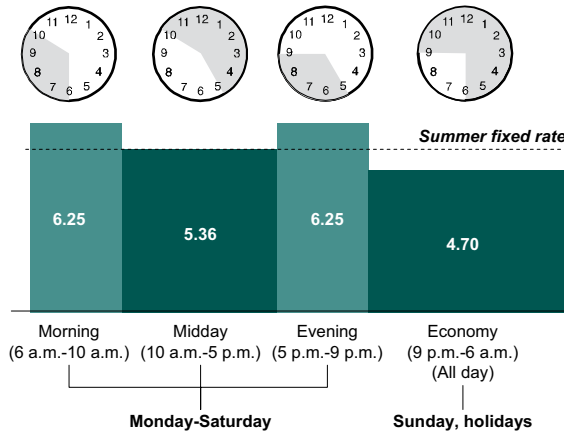
- 1,000 MW of peak demand savings (out of total 3,463 MW reduced from DSM programs)
- Total DSM savings have allowed Florida to avoid building approx 10 new 400-MW power plants
- Reduced blackouts and allowed FPL to sell energy to other utilities within Florida
- Incentives are major contributor to the ongoing cost of load control programs
- Returns on average 20-30% greater than investment in new power plants

Source: Michael Andreolas, Florida Power & Light Co. Feb 1, 2004; (Transmission and Distribution, 2004)

Exhibit 14

PUGET SOUND PERSONAL ENERGY MANAGEMENT PROGRAM

Puget Sound Energy's 2001 residential rates
Cents per kilowatt-hour*



* Rates based on average Apr-Sep usage of 869 kilowatts per hour per month
Source: Puget Sound Energy

■ Peak
■ Off-peak

Implementation

- Wireless devices to track hourly usage and transmit daily for more than 300,000 customers
- Customers tracked usage on website
- Pricing ~12% less during off-peak hours and 17% more during peak hours compared to base rates
- Customer bill reduced if load shifts away from high-priced periods

Impact

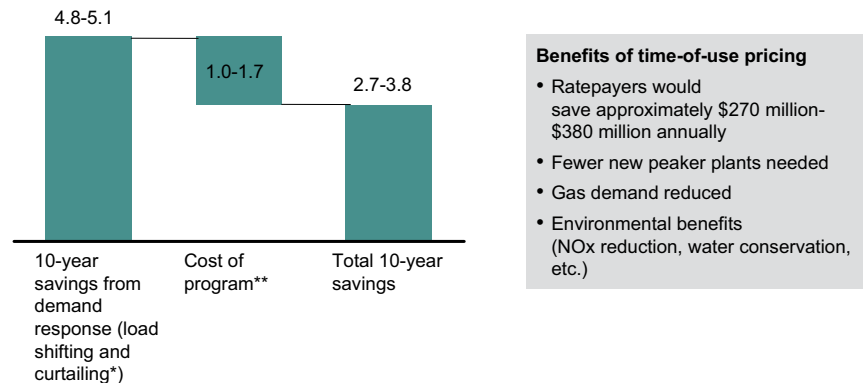
- Reduced PSE's exposure to soaring prices in the wholesale market and the need to ask regulators for rate increases
- Improved customer service
- Promoted conservation
- Customers response: within 2 months, shifted 5% of peak electricity consumption to off-peak periods

Exhibit 15

TIME OF USE PRICING IN CALIFORNIA IS A DEMAND SIDE MANAGEMENT PROGRAM THAT COULD PAY FOR ITSELF

Californians will benefit in many ways from time-of-use pricing

\$ Billions



Benefits of time-of-use pricing

- Ratepayers would save approximately \$270 million-\$380 million annually
- Fewer new peaker plants needed
- Gas demand reduced
- Environmental benefits (NOx reduction, water conservation, etc.)

* Assumes real-time prices will cause large C&I customers to shift 4%-6% and curtail 1%-2% of their load, and time-of-use prices will cause small C&I and residential customers to shift 5%-7% and curtail 9%-11% of their load

** Includes one-time real-time meter equipment capital cost and incremental maintenance costs for the remaining 70% of large C&I customers in California without meters and one-time interval meter equipment capital cost for 50% of small C&I and residential customers

Source: 1999 CalPX hourly data; interviews; McKinsey analysis

investment) over the next 10 years and offset much of the need to build new capacity towards the end of the decade.²¹ Full implementation of the program would cost approximately \$1-1.7 billion to implement over the next 5 years — less than the cost of 1,500-2,500 MW of new generation capacity — while at the same time it would substantially reduce the state's exposure to swings in demand and hydro availability. In addition, load management is environmentally sensitive, and reduces natural gas consumption, matching a key requirement for long-term sustainability in the state.

In other words, time-of-use metering is a significant opportunity for the state. The cost to implement for the entire state is not unreasonable and could ultimately save California consumers billions of dollars in reduced power costs.

The CPUC should mandate time-of-use metering for urban residential consumers and real time pricing for large industrials and commercial customers. The CPUC should also develop a tariff that encourages load shifting from peak hours for consumers to capture the full benefit of time-of-use metering.

The funding authority of the California Power Authority (CPA) could play a central role in speeding the forward progress of this program. The Power Authority was established in 2001 with \$5 billion in funding authority (backed by municipal bonds) to ensure a sufficient surplus of electricity in California so the state would never again face electricity shortages. To date, the CPA has authorized less than \$100 million in bonds and its funding authority ends in 2006, less than two years away. The California Power Authority, working with the CPUC and utilities, could

speed the investment in mandatory time-of-use metering throughout California and permanently change the structure of the California power market.

RECOMMENDATION 3: UPGRADE TRANSMISSION CAPACITY

Finally, transmission upgrades are important to leverage DSM savings and new generation capacity across the entire system. Electricity, unlike most commodities, is hard to store and there are few technically feasible ways of doing so (outside of hydroelectric dams). Broadening the transmission network can ensure that the whole system benefits from excess capacity in one area, and reduce duplication of resources.

Since the last power crisis, the need for new transmission capacity in California has become clearer and numerous new projects are in development:

- Improving the connection of Northern California and Southern California to take advantage of differences in peak demand and weather patterns
- Connecting Mexico and Southern California into the Los Angeles area to reduce the increasing congestion in the regions caused by an explosion of growth
- Connecting California to other states including Arizona and the Pacific Northwest to take advantage of seasonal differences and capacity growth in these states

Unfortunately, despite a number of project announcements, a complex and overlapping set of regulatory jurisdictions has significantly slowed the siting and development of needed transmission capacity. Currently, the CAISO conducts a review of transmission programs in California, including analysis of the economic impact of the investment and its impact on grid flow. After that, the CPUC conducts a nearly identical but separate examination of the same issues, sometimes with different results. This double review slows needed projects in the state and can yield irrational results. An initiative to merge these reviews is underway, but it is critical for the CPUC to accelerate its review of this effort and implement it quickly (Exhibit 16).²²

California faces the real possibility of a second power crisis. Reserve margins are tightening, power plant construction projects lie stalled, and state policy remains unclear. A second crisis would cast a pall on the California's attractiveness to investors, businesses and consumers, and also restart the cycle of accusations that has paralyzed state energy policy for three years. Implementing the recommendations above is a crucial first step to ensuring that California remains an attractive market for businesses and consumers. Only after addressing the issue of near-term resource adequacy, can the state reach resolution on the longer-term issues of competition and market structure to be addressed in the following section.

Exhibit 16

MULTIPLE AGENCIES HAVE JURISDICTION OVER TRANSMISSION PLANS, SLOWING SITING AND CONSTRUCTION

 Duplicate

	Required approval	Evaluation criteria	Typical time
Participating transmission owners	<ul style="list-style-type: none"> System impact study Facilities studies 	<ul style="list-style-type: none"> Scope and cost of transmission upgrades necessary for interconnection 	<ul style="list-style-type: none"> 30-60 days
CAISO	<ul style="list-style-type: none"> System impact study and facilities studies 	<ul style="list-style-type: none"> Verifies PTO analysis 	
CPUC	<ul style="list-style-type: none"> Certificate of Public Convenience and Necessity (above 200kV) 	<ul style="list-style-type: none"> Economic and reliability impact on overall grid Environmental, societal and aesthetic factors 	<ul style="list-style-type: none"> 60-90 days 12-30 months

Source: CEC reports

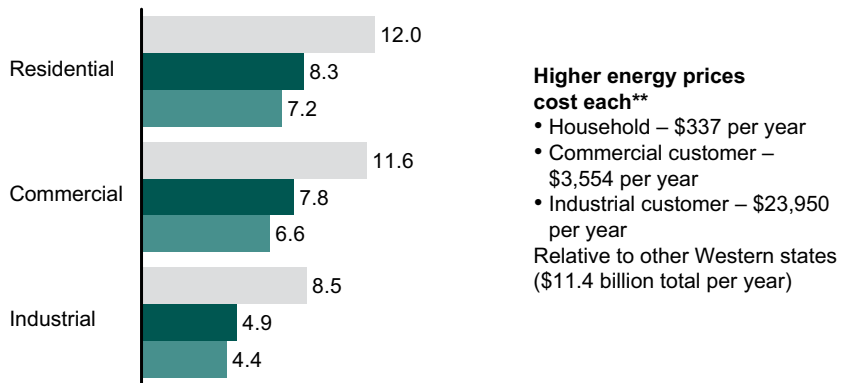
PART IV. BUILDING A SUSTAINABLE MARKET FOR THE FUTURE

In parallel with the near-term fixes identified above, California state agencies must also address the rules for a long-term sustainable market structure. California's pricing for business customers remain higher than anywhere else in the country and large consumers had to pay most of the cost of the recent power crisis (Exhibit 17).

Exhibit 17

CALIFORNIA RATE PAYERS CONTINUE TO PAY HIGHER PRICES THAN OTHER MARKETS

February 2004 average retail delivered power prices
Cents per kWh



* Includes Arizona, Colorado, Idaho, Montana, New Mexico, Nevada, Oregon, Utah, Washington, and Wyoming

** Per customer estimates based on 2002 customer totals

Source: *Platts; MegaWatt Daily; Bloomberg; McKinsey analysis*

In developing a long-term sustainable market, California must address the problems of both encouraging new generation capacity, and providing retail choice to customers who want the benefits of competition.

To encourage new investment in generation in a market-based fashion, other restructured power markets have turned to capacity markets. Combined with required reserve requirements, capacity markets provide a long-term price market-based signal to investors and encourage new investment.

RECOMMENDATION 4: CREATE A CAPACITY MARKET AND RESERVE MARGIN REQUIREMENTS

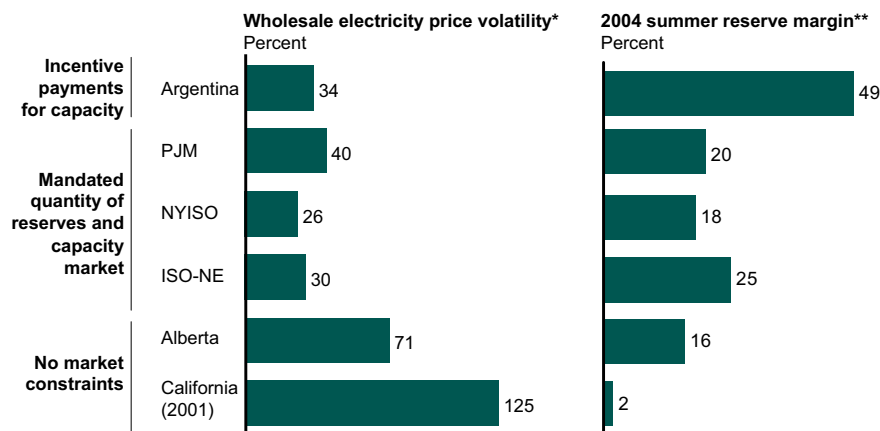
Energy service providers (ESPs) in California should have the obligation to own or acquire capacity resources greater than or equal to the peak load that they serve plus a reserve margin. These ESPs should be able to acquire capacity in a variety of ways, by either building generating units, entering into bilateral agreements or participating in a capacity credit market. Capacity credit markets provide a transparent, market-based mechanism for ESPs to acquire the capacity resources needed to meet their capacity obligations, and to sell capacity resources when no longer needed to serve load. Capacity markets typically operate on a daily basis, to meet daily shifts

in retail load, plus a longer-term market that ensures long-term resource needs will be met and encourages new power plant construction.²³

The signal works simply: If future needs are slight, bids for power in the capacity market will tail off, and investors will not make new investments. But as needs rise, the bids will grow more attractive to investors, and they will build new capacity. When combined with a mandated reserve target, capacity markets can provide appropriate price signals to investors in the forward market while protecting against price volatility in the spot market. Comparing across markets, capacity markets, combined with mandated reserve margins, appear to be the most effective market-backed mechanism to maintain adequate (but not excessive) reserve margins and protect against price volatility (Exhibit 18).

Exhibit 18

MANDATED RESERVES APPEAR TO BE EFFECTIVE IN MAINTAINING LOW VOLATILITY AND REASONABLE RESERVE MARGINS



* Measured by standard deviation divided by average of monthly wholesale prices. Later of April 1998 or market open through June 2004 (except California, through Jan 2001)

** Operating reserve margin calculated as (Available Supply – Peak Demand)/(Peak Demand)

Source: California PX; Alberta Power Pool; PJM ISO; CAMMESA; New England ISO; New York ISO; Platt's PowerDat

However, capacity markets are not perfect solutions. It is important for state agencies to aggressively review bids into the capacity market and ensure that investors do not “game” the market and bid up the cost of new generation. In 2000 and 2001, the PJM Market Monitoring Unit (MMU) investigated a substantial increase in capacity market prices that did not appear to be driven by any changes in the supply/demand balance. In response, the PJM MMU opened a formal investigation and changed the rules of the daily and seasonal capacity market to prevent a single player from setting the price.²⁴

RECOMMENDATION 5: REINTRODUCE ELEMENTS OF CONSUMER RETAIL CHOICE

Finally, California must reinstitute some form of retail competition. Experience in other markets shows that, although there are always challenges, customer choice consistently leads to lower price

23 Capacity markets will not guarantee investment in new generation. They must be backed by sufficient regulatory clarity to guarantee an adequate return to convince investors to back new projects.

24 For more detail on this investigation and response — see the “Report to the Pennsylvania Public Utility Commission on Capacity Market Questions” prepared by the PJM Market Monitoring Unit in November 2001.

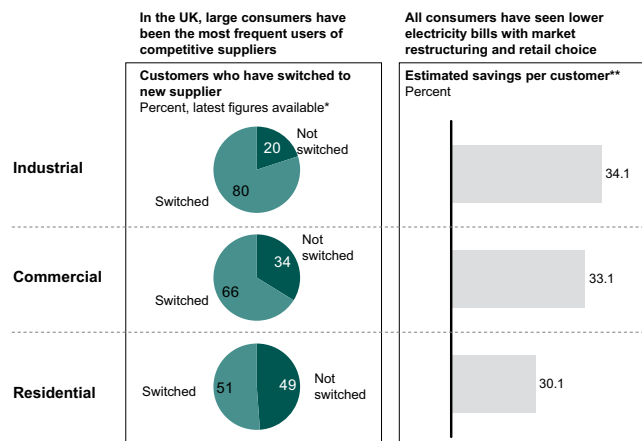
and increased efficiency. Customers who are flexible in their load patterns can capture substantial value through choice, and competition benefits all customers in the end (Exhibit 19).

The UK market introduced retail competition in the 1990's for all customers. As expected, large industrial and large commercial customers were the most active in switching to new suppliers while residential customers were less likely to seek new supplies. However, the benefits of competition were not limited to those who switched, and the market as a whole has seen a sharp reduction in retail power rates. The UK example helps to demonstrate that mandatory switching is not necessary for competition to benefit all players.

Exhibit 19

RETAIL CHOICE IS SOUGHT AFTER MOST BY LARGE CONSUMERS, BUT BENEFITS ALL CUSTOMER CLASSES

Case example: United Kingdom



* March 2000 for industrial/commercial, for England & Wales only, and end 2003 for households including Scotland

** Estimated savings in customer bills since privatization/deregulation adjusting for the effects of inflation

Source: EA Electricity Industry Review; OFGEM; McKinsey analysis

Currently, California policy makers are considering a core/non-core market structure. This two-tier framework has succeeded elsewhere, **including in California's natural gas market**. In a core/non-core market, the core consists of residential and small commercial customers not well-suited to competing for retail supply. Regulated utilities remain responsible for long-term planning and the provision of services to them. Non-core customers are the large buyers or aggregated smaller customers. They can opt out and assume the risk of contracting for their own generation needs. Current proposals suggest letting customers with more than 500 kilowatts of demand go non-core and seek their own electricity.

California will face some real challenges to adopting a core/non-core market structure, based on the state's recent history and market dynamics (Exhibit 20). Initially, there remains a significant overhang of Department of Water Resources (DWR) contract obligations that the ratepayers of California are responsible for. Much like the stranded cost discussion in the late 1990's, all customers must help pay down the DWR obligation for a core/non-core market structure to work and the cost must be shared evenly. If only core customers pay, large customers will have an unfair

incentive to opt out just to avoid the charges. If only non-core customers are burdened however with the cost, a viable competitive alternative will not exist.

A second challenge lies in establishing reasonable planning targets for core and non-core electricity service providers. In the first round of deregulation, customers were allowed to switch back and forth between utility tariff rates and non-utility retail generation suppliers without advance notice or paying a significant fee for returning to the utility load. Unfortunately, without a reliable estimate of future loads, the three large utilities found it impossible to plan for new generation capacity and have it approved by the regulator, but were still faced with the obligation to serve customers.²⁵

To ensure competition, suppliers should have the flexibility to switch between the core and non-core markets without prohibitive time windows or permanent elections. However, the new core/non-core market structure must provide a reasonable window of time for customers to return to or leave tariffed rates, allowing utilities to adequately plan for future reserve needs. Long time windows for switching and/or permanent election of customers create a strong disincentive for customers to consider competitive offers, thus weakening the non-core market. To ensure that the advance notice time is not prohibitive, the CEC and CPUC must accelerate the review, contract approval, siting and permitting process for new generation capacity in the state.

To ensure that the non-core suppliers do not have an unfair advantage over the core market, non-core ESP's must also meet the same state capacity requirements for reserves and renewable standards. This will ensure that non-core ESPs also share the cost of long-term sustainable planning.

Finally, the core/non-core market structure should provide access to choice for smaller consumers who wish to undertake the risk. Customer aggregation would allow small consumers to join together (without forming a municipal utility) to seek lower rates for generation capacity. These customer groups could pursue green power if they wanted, or adopt fixed rate price mechanisms

Exhibit 20

IMPLEMENTING A CORE/NON-CORE MARKET STRUCTURE IN CALIFORNIA WILL REQUIRE CAREFUL PLANNING

	Concerns	Key success factors
Market power	<ul style="list-style-type: none"> Controlling the market influence of a dominant player or players 	<ul style="list-style-type: none"> Strict market oversight committee and penalties Sufficient generation capacity to limit gaming
Resource adequacy	<ul style="list-style-type: none"> Ensuring sufficient new capacity built to serve core and non-core customers 	<ul style="list-style-type: none"> Capacity market mechanism to provide liquidity for trading capacity reserves Reserve margin targets (15-20%) required for utility and non-utility suppliers
Switching behavior	<ul style="list-style-type: none"> Lead time required for long-term planning by utilities 	<ul style="list-style-type: none"> Reasonable notice period required by non-core customers who plan to switch linked to the time to build new capacity
DWR cost overhang	<ul style="list-style-type: none"> Significant stranded costs from DWR long-term power contract obligations 	<ul style="list-style-type: none"> Equitable sharing of costs between core and non-core market customers, with no ability to avoid costs by shifting to a new supplier
Environmental issues	<ul style="list-style-type: none"> Mixed results for market mechanisms to manage emissions 	<ul style="list-style-type: none"> Renewable portfolio standard Credits for reduced emissions and cleaner burning technologies

25 For a detailed discussion of the previous power crisis, please see the Bay Area Economic Forum Reports including "The Bay Area – A Knowledge Economy Needs Power," published in April 2001; "California at a Crossroads – Options for the Long-Term Reform of the Power Sector," published in October 2001; and "California's Energy Future: A Framework for an Integrated Power Policy," published in November 2002.

from competitive suppliers. Providing the benefits of a deregulated market solely to large customers is unfair, since it keeps out the majority of California consumers.

The ongoing discussions evaluating the rules for a core/non-core market must proceed carefully to ensure the creation of a level playing field and adequate incentives for a non-core market to flourish. In market after market, all customers benefit from competition, even those that do not participate. A non-core market with no customers will not provide the competition that California customers deserve.

Part V. THE PATH FORWARD: IMPLEMENTING POLICY

Existing legislation provides the CPUC with the necessary authority to implement most of the recommendations above. Any additional legislation should be carefully tailored to provide authority to the CPUC that it does not already have and avoid rewriting existing legislation or adding unnecessary hurdles to an already complicated process.

State legislators, the California Energy Commission, the Governor's office and the CPUC need to work together to address the near-term shortage immediately and ensure that the state has sufficient resources to meet its demand over the next three years. At the same time, the continuing discussion of the long-term market structure should continue. To summarize, California needs to take five key steps to ensure near-term resource adequacy and lay the foundations for a long-term sustainable market structure

First, to ensure that the state has sufficient capacity over the next three years, it must implement a number of near-term fixes in a way that does not damage the long-term progress towards a competitive market:

1. The State must act today to facilitate the construction of new generation **before the summer of 2006**. It must accurately assess the potential level of future electricity demand. The California Public Utility Commission must take action now to allow utilities to sign long-term contracts (e.g., 5-10 years) with private sector generators to bring on line new capacity by 2006. These contracts should be awarded through a competitive RFP process, allowing competition between utilities and competitive generators, and should link energy pricing to market-based electricity indices.
2. California should install universal time-of-use metering for all power users and encourage more extensive use of other load management programs. Load management programs induce consumers to cut their demand during peak hours, and California lags far behind other states in this important area. Yet load management programs yield results fairly quickly, often faster than building new power generation capacity. In California, these environmentally sensitive programs could save consumers more than \$2.5 billion dollars over the next 10 years, alongside a potential reduction in peak energy demand of up to 20%. The California Power Authority has \$5 billion in funding authority to speed the investment of time-of-use metering programs and could permanently shift the landscape of the California market, making the state a leader in demand side management programs globally.
3. The State needs to speed the upgrade of its transmission capacity. Since the last energy crisis, the role of transmission capacity in balancing the power of the system has become clear and many new projects are in development. Unfortunately, a complex and overlapping set of regulatory jurisdictions, with no clear approval timelines, has significantly slowed the siting and development of needed transmission capacity. A single review process SHOULD coordinate the approval processes of the California Public Utility Commission, the California Independent System Operator, and the California Energy Commission.

Only after resolving the near-term shortage, will California policy makers be in a position to define clear rules for investors and energy service providers (ESPs) to ensure sustainable competition. The BAEF has addressed in previous reports the role of competition in promoting efficiency in the

market and lowering costs to consumers and believes that competition for consumers is ultimately critical.

4. To promote long-term infrastructure additions, California should put a capacity market in place, combined with a required reserve margin target for all energy service providers by 2006. Capacity markets, along with adequate resource targets, send price signals to the market to build new capacity, help provide generation owners a return on their investment, and provide a liquid, market-based mechanism for trading capacity rights to help retail suppliers meet reserve margin requirements.
5. Finally, the State should re-introduce consumer retail choice through a core/non-core market structure that will contribute to lower long-term power costs. With a choice of their electricity supplier, large consumers can select the most economic and efficient supply source for their power needs. In other markets, choice has led to lower prices for consumers and greater efficiency. It will also help protect jobs and provide incentives for new investment in the state. Moreover, this can be done in a manner that protects small residential consumers and ensures repayment of the State's long-term DWR power contract commitments.

Competitively priced, reliable power is crucial to keeping California an attractive place for businesses to invest in and consumers to live in. **But the time to act is now.** Without quick action from state agencies, California could see a second power crisis in the very near term. Actions to resolve this near-term risk should be combined with and consistent with a set of long-term, sustainable rules for a new market design that will protect consumers, provide incentives for investors, and encourage competition throughout the power system.

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