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Office of Economic, Electricity and Natural Gas Analysis
Office of Policy
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Acknowledgments

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Executive Summary

California residents are expected to face more frequent and pervasive rolling electricity outages this summer than those experienced over the past year, and wholesale electricity prices are likely to remain high. Recently, California has undertaken a number of steps to increase electricity supplies and reduce electricity demand. Those efforts will help to mitigate the frequency and magnitude of outages this summer. In addition, some State and Federal officials have called on the Federal Government to implement a cap on wholesale electricity prices. While a cap on wholesale electricity prices could reduce California's electricity expenditures, some of the price cap proposals are likely to increase the number of hours and the magnitude of the outages that California will experience. This report uses standard electric power industry reliability tools to estimate the number of hours and magnitude of electricity outages and evaluates the potential impacts of two price cap proposals on electricity outages in California this summer.

Using a method that takes into account variable weather patterns, historical data on planned outages, and industry standard probabilistic reliability tools, our reference case scenario estimates that California residents are likely to experience 113 hours of rolling outages this summer, with an average size of approximately 1,900 megawatts. Such an outage would affect approximately 1.4 million households—far more extensive than any experienced in California over the past year.[1] Demand relief and interruptible load programs play a significant role in reducing the number of hours of outages. If the State had not recently implemented these programs, the estimated hours of outages would increase from 113 to 191 hours, and the magnitude of the outages would increase by approximately 160 megawatts, affecting an additional 120,000 households.

Because there is significant uncertainty surrounding our estimates, we developed two additional scenarios: (1) an optimistic scenario, which assumes more new generation capacity, more hydropower availability, greater net imports, fewer qualified facilities shut down for financial reasons, and more effective real-time demand, efficiency, and conservation programs; and (2) a pessimistic scenario, which assumes less new capacity, less hydropower availability, fewer net imports, more qualified facilities shut down for financial reasons, and less effective real-time demand, efficiency, and conservation programs. Although all the assumptions used in either the optimistic or pessimistic scenario are unlikely to be realized simultaneously, the two scenarios provide useful upper and lower bounds on the range of potential outcomes (Figure ES1).

In the pessimistic scenario, the expected number of hours of outages could increase from 113 in the reference scenario to 479 hours, and the average size of each outage could rise from about 1,900 to 2,600 megawatts—affecting 1.95 million households, an increase of 550,000 over the reference scenario. Conversely, in the optimistic scenario, the expected number of hours of outages falls significantly to 14 hours for the entire summer, and the average size of each outage falls to 1,700 megawatts—affecting 1.14 million households, a decrease of 165,000 from the reference scenario.

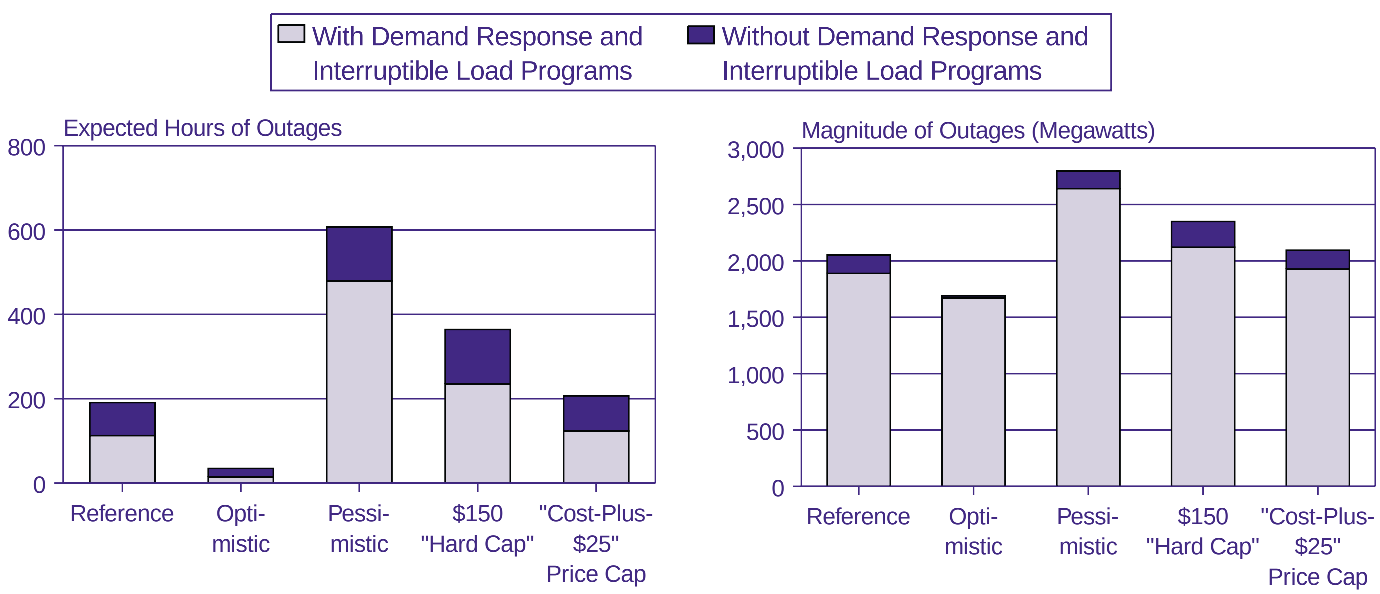
To reduce the probability of summer outages, California has taken a number of steps to both increase supply and reduce demand for electricity. Those efforts include raising rates, purchasing power on the behalf of utilities, implementing an emergency power plant siting program, providing financial incentives for plant completions, implementing a Summer Reliability Generation Program, implementing several real-time demand response programs, and funding efficiency and conservation programs. If these efforts are not successful, California might experience an additional 250 hours of outages.

[1] Throughout this analysis it is assumed that 1 megawatt is enough electricity to power 750 households.

In order to reduce high wholesale prices, various regulatory and legislative institutions are considering a number of price control mechanisms. We evaluate two price cap proposals in this analysis: (1) a $150 "hard cap" and (2) a "cost-plus-$25" price cap that would cover each generator's operating costs and provide an additional payment of $25 per megawatt-hour toward fixed costs. We conclude that either of the price caps would increase the expected hours of outages significantly. A $150 hard cap could force as much as 3,500 megawatts of natural gas-fired generating capacity in the State to shut down, depending on the price of natural gas. If 2,000 megawatts of generating capacity ceased operating, the expected hours of outages would more than double, from 113 to 235 hours, and the average magnitude of the outages would increase by 230 megawatts—equivalent to approximately 175,000 households. The "cost-plus-$25" price cap proposal would have a smaller impact immediately but a potentially greater impact over the long term, because it would affect new generating capacity additions. Under this proposal, the numbers of hours of outages this summer is projected to increase by about 28 hours, compared to a scenario where all proposed new peaking units are built.

We recognize there is a wide range of proposals currently being discussed to mitigate high wholesale electricity prices. This report is not intended to provide a complete analysis of all price mitigation proposals. Rather, it is intended to demonstrate the impacts on reliability that could result from a "hard cap" set at an arbitrary price level, and a "cost of service" type price cap that would not allow for complete recovery of fixed costs. Other price mitigation proposals might or might not affect generating supplies and would thus have different reliability impacts from those presented here. Any form of price controls, however, must take into consideration the impacts on available generating supplies and investment in new capacity, and their potential reliability impacts. We find that the proposals analyzed here could significantly increase blackouts this summer, threatening public health and safety.

Figure ES1. Expected Summer 2001 California Power Outages in Five Analysis Scenarios



Introduction

The summer of 2001 is likely to be a difficult one for California. The California Independent System Operator (ISO), the North American Electric Reliability Council (NERC), and other industry analysts are predicting widespread rolling blackouts for this summer. NERC's summer assessment forecasts 260 hours of rolling blackouts from June through September, and the California ISO estimates 34 days of outages or more. Their estimates are based on a number of assumptions about peak demand, new generating capacity completions, plant outages, and conservation efforts, all of which can be difficult to predict. In this report we discuss the Department of Energy's outlook for California and the potential impacts of various policy measures—including wholesale price caps—on electricity outages this summer. Other price mitigation proposals could have different reliability impacts from those presented here.

Background

Supply Shortage

The fundamental cause of the California power crisis is an imbalance between supply and demand for electricity. The lack of new generating capacity additions over the past decade, low levels of water available for hydroelectric generation, and rising demand for electricity due to economic and population growth have combined to create the predicament now facing California and other western States. Wholesale electricity prices have risen dramatically, followed by large increases in retail rates. While these price increases no doubt have serious impacts on consumers and businesses, the rolling blackouts seen over the past few months have had additional consequences, including inconvenience to consumers, severe financial losses for businesses, and threats to public health and safety.

Several factors have contributed to the recent supply shortages facing California. Most notable is the lack of new generating capacity additions over the past decade. In 1994, California began the process of restructuring its electricity market, and in 1996 the State legislature passed AB1890, which created both a centralized wholesale spot market for power and an ISO to manage the day-to-day operations of the bulk power grid. In addition, California was the first State to deregulate its retail market, allowing consumers to choose their retail electricity suppliers. These sweeping changes created considerable regulatory uncertainty, and power plant developers adopted a "wait and see" attitude while the legislation was being implemented and new market rules were being established. From 1990 to 1996, the California Energy Commission (CEC) received only a few applications to build new plants, totaling 1,000 megawatts.

Once electricity restructuring rules were in place, however, independent power producers responded quickly, filing applications beginning in 1997 to build more than 14,000 megawatts of new generating capacity. As a result of California's cumbersome siting process, however, only 1,400 megawatts of the new generating capacity proposed is scheduled to begin operation by this summer. While in most States new power plants are licensed in less than a year, in California the process has taken an average of 18 months for large plants, and for some plants it has taken as much as 3 years.[2] As discussed below, the State has recently taken steps to streamline the licensing process for smaller, peaking plants.

The lack of new capacity additions and the retirement of aging plants has resulted in an overall *decrease* in electricity capacity in California over the past decade. From 1990 to 1999, total generating capacity in California fell from roughly 60,000

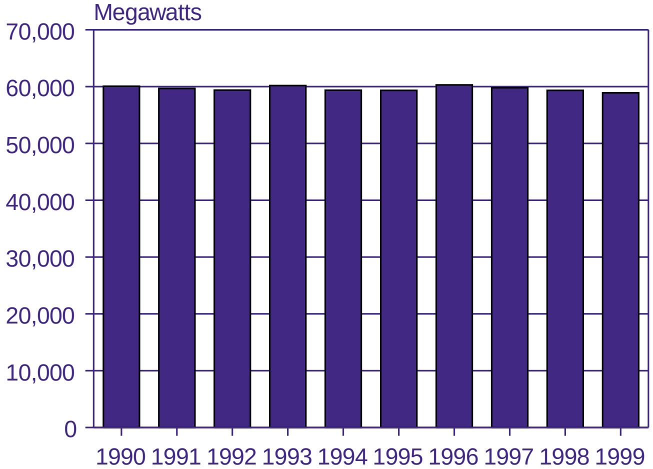
[2]Web site www.energy.ca.gov/sitingcases/approved.html.

megawatts to just under 59,000 megawatts (Figure 1).[3] Over the same period, however, total generation in California increased by nearly 10 percent (Figure 2), due in part to improved performance of the State's nuclear power plants. From 1990 to 1999, output from nuclear plants increased by 10 percent, despite the retirement of the 450-megawatt San Onofre Unit 1 reactor. Higher levels of hydroelectric generation during the latter part of the decade and increased generation from coal plants located in nearby States, but owned by California utilities, also helped to boost generation.

Both peak demand and total demand were essentially flat during the first part of the decade. As the California economy began to grow more quickly, however, demand increased. Peak demand grew at an average annual rate of 1.4 percent from 1990 to 2000, with nearly all of the growth occurring after 1995 (Figure 3). Total electricity consumption grew at roughly the same rate, averaging 1.5 percent per year from 1990 to 2000. In both cases, however, the growth rates were below the national average. U.S. peak demand grew by 2.4 percent per year from 1990 to 1999, and total electricity consumption grew by 2.3 percent per year.

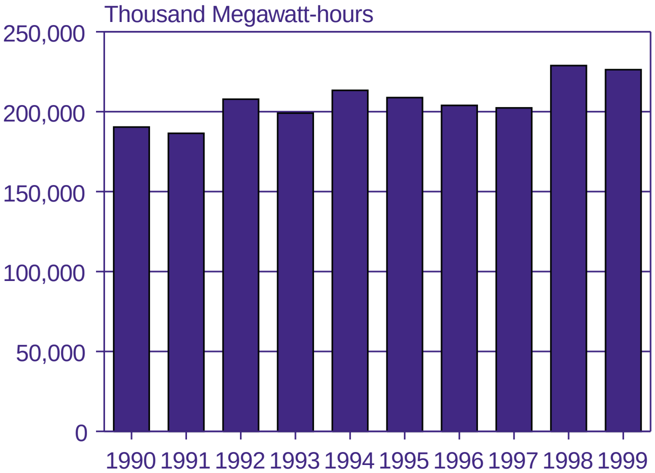
Thus, while total generating capacity in the State *decreased* by 1,500 megawatts over the past decade, peak demand *increased* by nearly 7,000 megawatts. As a result, California has grown increasingly reliant on imports from other States to meet its peak load over the past 10 years. The State has long been a net importer of electricity, buying from both the Pacific Northwest and the Southwest. In fact, for many years California has enjoyed a mutually beneficial exchange with the Pacific Northwest—a winter peaking system. The region sells its excess

Figure 1. California Electric Generating Capacity, 1990-1999



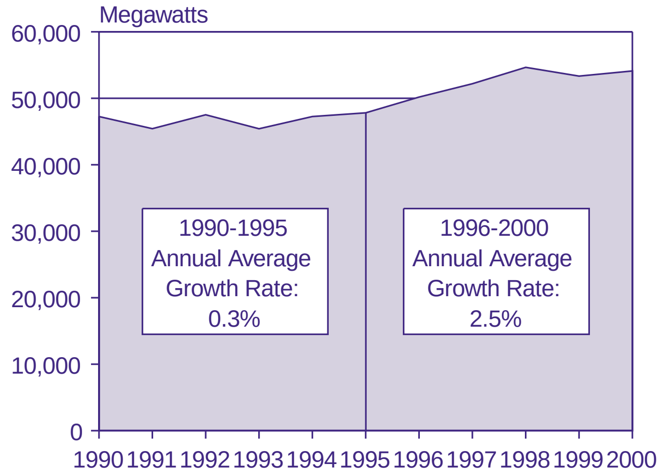
Sources (Nameplate Capacity): **Utilities:** Energy Information Administration (EIA). *Inventory of Power Plants in the United States*, DOE/EIA-0059 (1990-1999). **Nonutilities:** Forms EIA-867 and EIA-860B.

Figure 2. California Electricity Generation, 1990-1999



Note: Includes generation by providers located outside the State but contracted for the California market.
Source: California Energy Commission.

Figure 3. Summer Peak Demand in California, 1990-2000



Source: California Energy Commission. *California Energy Demand 2000-2010*. Pub. No. 200-00-002 (Staff Report, July 2000).

[3]Capacity is a measure of the amount of power a unit is capable of producing, whereas generation is the amount of power actually produced over some period of time.

power to California during the summer, and California, in turn, sells its excess power to the Pacific Northwest during the winter. In 1999, when summer peak demand in California was nearly equal to the State's available capacity, a staff report by the CEC warned of this growing dependence on imports:

> *In the absence of significant amounts of new generation capacity being added in the Southwest, less generation will be available from this region for export to California in the coming years. The State will, therefore, become increasingly more dependent upon imports from the Northwest to meet summer peak loads . . . . The availability of surplus hydro energy from the Northwest will become more critical to California being able to reliably meet peak demand in the summer until new merchant plants come on line in California.*[4]

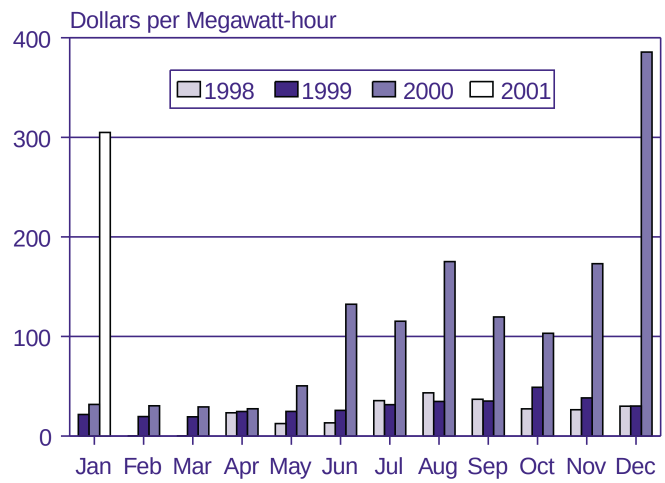
Significantly, the CEC report further warned that California could not continue to rely on electricity imports to meet its needs, stating that "historical levels of imports into California from both the Southwest and Northwest cannot be relied upon to be available in the future."[5] This prediction proved to be accurate. In the summer of 2000, net imports fell considerably from their levels in previous years. From May through August 2000, with reduced hydro availability and increased electricity demand throughout the West, average hourly imports into the California ISO were nearly 1,400 megawatts below 1999 levels. Although electricity exports from California in May 2000 were only slightly above 1999 levels, they increased dramatically over the course of the summer, driven in part by increased electricity demand throughout the West. In addition, the price cap on the California Power Exchange day-ahead market was lowered from $750 per kilowatthour to $250 per kilowatthour as the summer progressed. By August, average hourly exports were 3,000 megawatts greater than in May 2000. As a result, net imports in August 2000 were 3,500 megawatts below 1999 levels.[6]

High Wholesale Electricity Prices and Utility Financial Crisis

All the factors described above have contributed to high wholesale electricity prices in California over the past year. In addition, prices for natural gas and for nitrogen oxide (NO_x) emission credits in California increased dramatically last year, pushing electricity prices up even further. Generating capacity, natural gas pipeline capacity, and NO_x credits all became relatively scarce, and scarcity inevitably leads to higher prices in competitive markets. Figure 4 shows the average monthly wholesale prices in California's day-ahead market over the past 3 years. For June through November 2000, monthly average prices were 100 percent to 400 percent above 1999 levels, and by December 2000 they had risen to more than 10 times December 1999 levels.

Two key decisions by California regulators compounded the problems caused by high prices, leading to the financial crisis that now faces the utilities and the State. First, even as wholesale prices

Figure 4. Monthly Average Prices on the California Power Exchange Day-Ahead Market, 1998-2000



Note: Prices are monthly averages of California Power Exchange hourly unconstrained market prices, weighted by supply volume.

[4]California Energy Commission. *High Temperatures and Electricity Demand: An Assessment of Supply Adequacy in California* (Staff Report, July 1999).

[5]*Ibid*.

[6]Federal Energy Regulatory Commission. *Staff Report on U.S. Bulk Power Markets: Part 1* (November 2000).

climbed last year, the California Public Utilities Commission (CPUC) refused to allow utilities to pass wholesale power costs through to ratepayers. California utilities were required to sell power to their customers at rates far below the wholesale price. As a consequence, they have accumulated roughly $14 billion in debt. As the situation progressed, electricity producers feared that they would not be paid by the utilities, and they raised wholesale prices to compensate for the additional risk. In December 2000, major credit rating firms downgraded the utilities' credits ratings. In April, Pacific Gas & Electric declared bankruptcy. As a result, the California Department of Water Resources (CDWR) has been forced to step in and purchase power on behalf of the utilities, which are no longer considered creditworthy buyers.

Because the retail rate structure in California provided little incentive for consumers to conserve electricity during peak periods, peak prices were driven even higher. If wholesale power costs had been reflected in retail rates a year ago, consumers might have taken more steps to improve efficiency, resulting in lower electricity demand this summer. In addition, large commercial and industrial customers might have invested in distributed resources that would have reduced electricity demand from central-station generating facilities.[7]

The second decision was the requirement that utilities purchase power only through spot markets operated by the California Power Exchange and the California ISO. This decision left the utilities overexposed to volatile spot prices and prevented them from pursuing even basic risk management strategies. The CPUC did give the utilities permission to engage in limited forward contracting last year; however, any such contract would be subject to retroactive prudence review. Since the utilities feared regulators might eventually disallow costs if spot prices turned out to be lower than the forward contract prices, they for the most part did not take advantage of the opportunity to buy power under contract.[8]

The utility financial crisis has exacerbated the supply shortage in several ways. First, the utilities have been unable to pay for power purchased from "qualifying facilities" (QFs), which contract directly with the utilities to sell their power. QFs are independent power producers licensed under the Public Utility Regulatory Policies Act. By and large they are small renewable or gas-fired cogeneration plants. California has roughly 10,000 megawatts of QF capacity, although generally only 6,000 megawatts or so is supplied to the grid (the additional QF capacity is used for self-generation). Many of these generators have continued to operate for the past several months even though they have not been paid by the utilities. Further compounding the problem, the CPUC recently changed the methodology for calculating natural gas fuel costs for QFs. As a result of this change, some QFs cannot recover all of their fuel costs. Both of these factors have forced several QFs to curtail production.

Credit risks have also made other generators hesitant to sell to the utilities or the California ISO, which often purchases electricity in real time on behalf of the utilities. The lack of a creditworthy buyer could potentially cause reliability problems if the California ISO is unable to buy power needed to manage the system in real time. To minimize the risk of additional rolling blackouts, the State was recently forced to guarantee payment for all purchases made by the California ISO. Credit risk also contributed to high wholesale prices until the State stepped in as a buyer.

Recent State Actions

California has recently undertaken a number of steps to address both the supply shortage and the financial crisis. As noted above, the State has begun purchasing power as a creditworthy buyer to help lower prices and reduce reliability threats. In March, the CPUC ordered an increase in retail rates effective June 1, 2001, averaging 46 percent, so that utilities could pay for their QF power purchases and improve their financial integrity. The State

[7]The State has recently undertaken efforts to improve efficiency and encourage conservation, as discussed in the next section.

[8]For example, last spring, Duke Power offered to sell electricity to San Diego Gas & Electric (SDG&E) at a fixed price of $55 per megawatthour. Because SDG&E did not pursue the offer, details of the terms and conditions were never provided.

legislature and Governor Davis are also exploring alternatives to help the utilities pay their outstanding debt.

In February, Governor Davis announced plans to bring 5,000 megawatts of additional capacity on line by July 2001.[9,10] Before this announcement, 3,700 megawatts of capacity was already in development or under construction, including projects being built as part of the California ISO Summer Reliability Generation Program. As an incentive to finish the plants quickly, the Governor instituted bonuses of up to $5,000 per megawatt for plants that complete construction and begin operation by this summer.

The CEC established an emergency power plant siting program to build an additional 1,000 megawatts of peaking capacity by this summer as part of the Governor's efforts to increase supplies. As of May 25, the CEC had licensed 636 megawatts of new peaking capacity under the emergency siting process, and 585 megawatts were under review. These facilities are small peaking units under 50 megawatts that need only local siting approval and do not require licensing by the CEC. On average, the CEC has licensed these plants in less than 1 month. Each of the plants will be licensed for 3 years, at which time some of the plants may apply for relicensing. In addition, the California ISO estimates that 790 megawatts of new capacity will be built by this summer under its Summer Reliability Generation Program. In spite of these efforts, the State is unlikely to meet its goal of 5,000 megawatts. The California ISO currently expects only 1,700 megawatts of new capacity to begin operation by July, with an additional 1,000 megawatts by September.[11]

Regulatory uncertainty, however, could sharply reduce investment in new generating capacity. The Governor and other State officials have repeatedly threatened to seize power plants owned by out-of-state companies or impose stiff taxes on wholesale power sales. Such threats create significant risk for investors and will inevitably discourage construction of new generation. If the Governor does take the unprecedented step of seizing power plants this summer, investment could come to a complete halt. One 530-megawatt unit being built in Contra Costa County by the Mirant Corporation was recently delayed due to the uncertainty of the future market rules that would apply.[12]

In addition to encouraging the construction of new power plants, the State is also working to decrease demand through a number of conservation and efficiency programs. In April, the State legislature passed SB5X and AB29X, which together include more than $800 million in funding for efficiency and conservation programs. The legislation funds a wide array of programs, such as efficiency upgrades in State buildings, appliance rebates, peak load reduction and real-time demand response programs, and an extensive media campaign to encourage conservation. The State is also offering a 20-percent rebate to customers who reduce their summer electricity consumption by 20 percent compared with the previous year. Although the State originally hoped to reduce peak demand by 3,200 megawatts through efficiency and conservation,[13] the State's latest estimate indicates that the programs will reduce demand by just over 2,000 megawatts for this summer. There is limited time, however, for these efficiency measures to be put in place.

The retail rate increase recently ordered by the CPUC will also serve to reduce demand. Last year, when electricity rates rose in San Diego, customers responded by curtailing consumption. Although any estimate of the likely impact of the retail rate increase is uncertain (due to the manner in which the increase is designed), we estimate that electricity demand is likely to be reduced by 1,300 to 2,700

[9] "Governor Acts to Boost Power Generation." Press release, Office of the Governor (February 2, 2001).

[10] California Energy Commission and Electricity Oversight Board. "California Summer 2001 Forecasted Peak Demand and Resource Balance." Web site www.energy.ca.gov/electricity/SUMMER_2001_DSF.PDF.

[11] California ISO. *Summer 2001 Preparedness Update* (May 18, 2001).

[12] American Cities Business Journals, Inc. "Mirant Mulls CoCo Power Plant" (May 28, 2001).

[13] "Governor Davis Outlines $800 Million Energy Efficiency and Demand Reduction Program." Press Release, Office of the Governor (February 1, 2001).

megawatts as a result of the retail rate increase and efficiency and conservation programs.

California is also implementing several real-time demand response programs. The California ISO has established three distinct programs: the ancillary services participating load program, the demand relief program, and the discretionary load curtailment program.[14] The California ISO expects that up to 700 megawatts of real-time demand response will be available by July under its demand relief program. Additionally, the CPUC recently revamped utility interruptible load programs. Although it is currently unclear how much interruptible load is available from the utility programs, the California ISO estimates that interruptible customers, when they were called upon to curtail their electricity use, reduced load by 800 to 900 megawatts on 4 days, May 7-10, 2001.

Outlook for Summer 2001

The Policy Office undertook this analysis to improve the estimates surrounding the potential for rolling blackouts in California this summer. There have been a number of articles and claims that suggest outcomes ranging from little risk of outages to up to 1,000 hours of outages. This analysis is intended to narrow the range of plausible outcomes. In addition, because there has been such interest in wholesale electricity price caps, this analysis aims to clarify some of the problems associated with two of the price cap proposals that have been offered.

Methodology and Assumptions

As noted above, many analysts are predicting severe electricity outages in California this summer. Most of those predictions, however, are based on point estimates. In other words, they project supply and demand conditions during the peak hour of the summer to ascertain the potential supply shortfall, then attempt to forecast the number of hours such conditions might occur, in order to estimate potential electricity outages.[15] Although such analyses are useful, they provide little information on conditions at times other than the peak hours. In addition, they do not account for the variability of such factors as plant outages, and they use only point estimates to represent average conditions.

For this analysis, the Policy Office and OnLocation/ Energy Systems Consulting, Inc. adapted a reliability assessment model that forecasts both the number of hours of electricity outages and the magnitude of the outages.[16] The analysis overcomes some of the drawbacks of previous work by using probability distributions to forecast two critical assumptions—weather and plant outages. The model draws on 30 years of weather data to estimate hourly load conditions for peak period hours, 6 am to 10 pm, for June through September. By using probability distributions to forecast weather conditions, the model can produce forecasts in normal and severe weather scenarios. In addition, the model uses historical plant outage factors to determine the probability that a plant will unexpectedly shut down due to equipment failures, rather than derating the capacity and using a single estimate for the expected value of available supply capacity.

Because of the range of assumptions that must be made for the analysis, we modeled three scenarios—reference, optimistic, and pessimistic. The optimistic and pessimistic scenarios incorporate all of the most favorable and least favorable assumptions, respectively. In reality it is unlikely that either of these scenarios would occur; however, they provide a useful bound of potential outcomes.

[14]For a more complete description of these programs, see the California ISO Demand Response Program Information Page, web site www.California ISO.com/clientserv/load/index.html.

[15]The North American Electric Reliability Council Summer Special Assessment is one exception to this. NERC's analysis employed the same model used in this analysis to forecast hours of outages. Our estimates for rolling blackouts differ from NERC's as a result of different input assumptions.

[16]For a more complete description of the model, see Appendix A.

Table 1 lists the assumptions for each of the three scenarios. As noted above, the model projects hourly load conditions based on historical weather data; however, total electricity demand has been benchmarked to the California ISO summer energy forecast. As a result, peak load estimates are similar to the California ISO's. Estimates of monthly new capacity additions are based on information from the CEC and the California ISO. The reference scenario generally includes only capacity that has been licensed and is scheduled to begin operation this summer.[17] New peaking capacity still under licensing review by the CEC is not included. Because only nameplate capacity was provided for new plants, the capacity for each plant was reduced slightly to account for both summer ratings and potential forced plant outages. In addition, some capacity licensed only very recently is assumed to begin operation at a later date than scheduled, because it seems unlikely that the plants could be built in such a short period of time.

For hydroelectric generation, each scenario includes an estimate of the total water available for electricity production as a percentage of "normal" water conditions, as shown in Table 1. Hydroelectricity generation is limited by the amount of water available, and water is generally conserved for use in meeting peak demand (although environmental requirements may sometimes reduce operational flexibility). Although hydropower operations can be quite complex, we attempt to account for greater hydro usage during peak hours by creating a "super peak" demand period from 3 pm to 7 pm. For each scenario, we assume that 90 percent of total hydroelectric capacity will be available during the super peak. Any water still available after allocating needed water to the super peak period is then used to help meet demand in other hours. Thus, as more of the total water available is used to meet the super peak (as in the pessimistic scenario), less water is available to meet demand in other hours, and the probability of outages in other periods increases.

Demand reductions and efficiency programs were divided into two distinct categories. The first, real-time demand response and interruptible load programs, includes measurable, real-time reductions in demand made specifically in response to requests by the California ISO. Included in this category are utility-sponsored interruptible load programs, the California ISO demand reduction programs described above, and responses to emergency conservation appeals, such as 300 megawatts of California Department of Water Resources pumping load that can be curtailed briefly during peak periods. The impacts of these programs are calculated outside the model, as discussed below. The second category, efficiency and conservation programs, is modeled as broad reductions in

Table 1. Scenario Assumptions

Assumption	Scenario		
	Optimistic	Reference	Pessimistic
New Capacity (Megawatts)	105 to 3,565	60 to 2,703	60 to 2,295
Hydropower Availability (Percentage of "Normal" Water Conditions)	100%	85%	70%
Net Electricity Imports (Megawatts)	4,000	3,500	3,000
Qualifying Facility Capacity Shut Down for Financial Reasons (Megawatts)	0	700	1,500
Demand Reduction from Real-Time Demand Response and Interruptible Programs (Megawatts)	1,500	1,200	900
Demand reduction from Efficiency and Conservation (Percentage Reduction Across All Hours)	5.6%	4.2%	2.8%

Note: For new capacity, the low end of the range represents June and the high end of the range represents September.

[17]Estimates of new capacity licensed by the California Energy Commission were taken from web site www.energy.ca.gov/sitingcases/index.html (May 2, 2001 update). Estimates for new capacity under the California ISO Summer Reliability Generation Program were obtained from the April 6, 2001 California ISO Summer Preparedness Update, web site www2.CaliforniaISO.com/docs/09003a6080/0d/0c/09003a60800d0cdb.pdf.

demand that occur more or less evenly over all hours, rather than as real-time demand responses. This category includes the efficiency programs funded through SB5X and and AB29X, consumer responses to rate increases, and the State's conservation campaign. These reductions are included in the model as an overall decrease in load.

Results

Figure 5 compares the results of the three scenarios. The graph shows the magnitude of electricity outages and the expected number of hours at different outage levels. For the reference scenario, the model estimates 191 hours of rolling blackouts before accounting for the effects of real-time demand response programs. In the pessimistic scenario, the expected hours of blackouts are nearly three times higher than in the reference scenario. Most telling, however, is the optimistic scenario. Even using very optimistic assumptions across a range of factors, the model still predicts up to 35 hours of outages.

The analysis also predicts that rolling blackouts are likely to be much more extensive than any previously experienced in California over the past several months. To date, a maximum of 1,000 megawatts of load has been curtailed at any given time, equivalent to roughly 750,000 households. Rolling blackouts this summer could be more than three times that level, although the probability of such an extensive outage is low. The average magnitude of outages under the reference scenario is just over 2,000 megawatts, or 1.5 million households. Under the optimistic and pessimistic scenarios, the averages are 1,690 and 2,800 megawatts, respectively.

California has established a number of real-time demand response programs that allow the California ISO to reduce load when operating reserves fall. These programs can prevent any potential outages up to the level of load reductions available. As noted above, it is not entirely clear at this time how much interruptible load might be available through utility programs this summer, and the California ISO is still finalizing its own demand response programs. For this analysis, we assumed that 1,200 megawatts of curtailable load would be available in the reference scenario. Figure 6 illustrates the effects of these programs on forecasted outages in the reference scenario. The vertical line indicates the level of curtailable load and the hours of outages that could be avoided by demand response programs. The expected number of hours of outages for June through September after accounting for real-time demand response programs is 113 hours, and the average size of the outages is 1,889 megawatts.

The analysis shows considerable variability across the summer months (Figures 6 and 7). Figure 7 shows the expected hours of outages by month after accounting for the effects of real-time demand response and interruptible programs. While some factors are likely to improve over the summer, others will worsen. For example, only 60 megawatts of

Figure 5. Expected Summer 2001 Outages Under Optimistic, Pessimistic, and Reference Scenarios

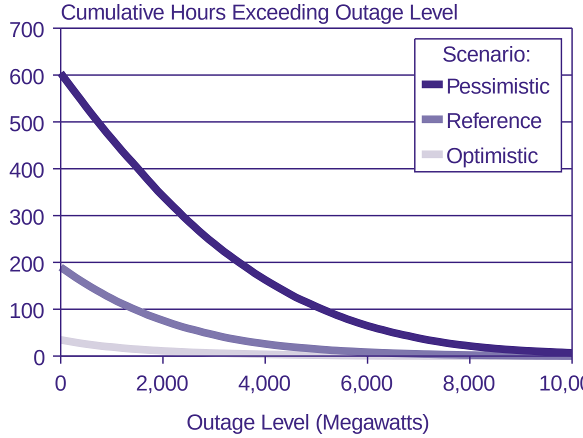
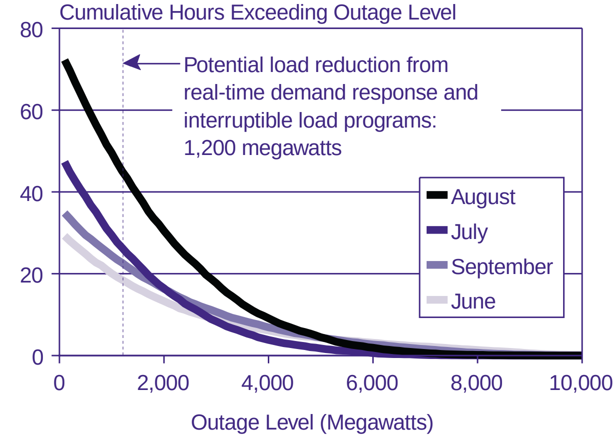


Figure 6. Effects of Real-Time Demand Response Programs in the Reference Scenario



new generation capacity is assumed to begin operation in June, while 2,700 megawatts of new capacity is assumed to be operational by September. On the other hand, temperatures and electricity demand will rise as summer progresses, and at the same time less hydroelectric generation will be available.[18] Based on this analysis, California is likely to see the bulk of this summer's outages in July and August.

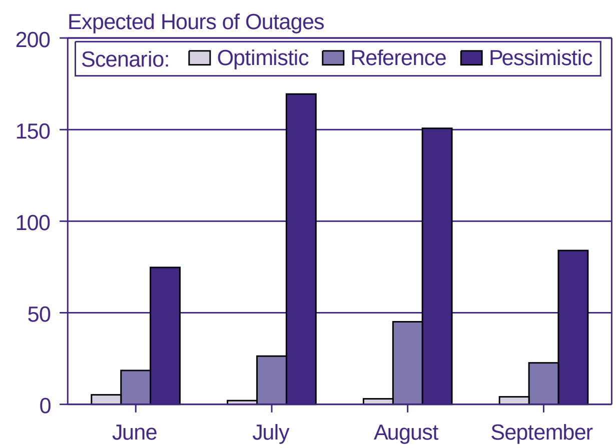
Policy Impacts

The model was also used to examine the potential effects of certain policies the State has undertaken in recent months. Using the reference scenario, we varied policy assumptions individually to determine the impact on the results. Two cases were examined: the effects of efficiency and conservation programs and the impacts of QF financial problems.

Efficiency and Conservation Programs. In addition to real-time demand response and interruptible load programs, a number of steps have been taken to improve energy efficiency and encourage conservation this summer. These programs will reduce electricity demand broadly over all hours. The reference scenario assumes that electricity demand will be reduced by 4.2 percent as a result of these efforts. When the effect of the programs is assumed to be 0, the expected hours of outages increase to 351, and the average size of the outage rises to 2,400 megawatts. In other words, the energy efficiency and conservation efforts could prevent up to 160 hours of outages this summer.

QF Capacity. The reference scenario assumes that 700 megawatts of QF capacity will be shut down for financial reasons. In order to estimate the impact of utilities' inability to pay QFs, we assumed that all QF capacity would be operational while maintaining all other assumptions in the reference scenario. The results indicate that QF financial difficulties could lead to an additional 38 hours of rolling blackouts this summer relative to the scenario in which all QFs are assumed to continue operating. In addition, the average size of the outages could increase by 83 megawatts, affecting an additional 62,000 households.

Figure 7. Hours of Outages by Month in Three Forecast Scenarios



Impacts of Price Controls on Electricity Outages

Over the past several months, a number of groups have called on the Federal Energy Regulatory Commission (FERC) to impose price controls in wholesale power markets as a means of reducing electricity prices while new capacity is built. The specific impacts of a price cap depend on how the cap is structured and how long it is in place. One widely discussed proposal is simply to replace FERC's "soft cap" with a $150 per megawatt-hour "hard cap."[19] Because natural gas prices are high in California, many natural gas-fired units would not be able to recover all their operating costs under this proposal and, accordingly, would choose to shut down rather than lose money for each kilowatthour sold. The California State legislature recently proposed a gross receipts tax on wholesale power sales. Any revenue from the sale of power on the wholesale market above a base price would be taxed at

[18]Historical data from Form EIA-759 indicate that generally less water is available for generation as the summer progresses.

[19]On December 1, 2000, Governor Davis requested that FERC institute a $100 per megawatt-hour "hard" price cap. Since December 15, 2000, when the FERC instituted a $150 per megawatt-hour "soft" price cap, many discussions have centered on a "hard" price cap of $150 per megawatt-hour.

rates ranging from 70 to 100 percent. Although the CEC would determine the base price, amounts as low as $60 to $80 per megawatt-hour have been proposed. Those base prices are well below many generators' current operating costs, and they would presumably shut down rather than operate at a loss. As such, the gross receipts tax proposed by the State Legislature would likely have impacts similar to or greater than the $150 hard cap.[20]

A second proposal widely advocated is a "cost-plus" price cap that would allow recovery of each plant's own variable operating costs (fuel, materials, etc.) and provide a payment of $25 per megawatt-hour to all its fixed costs (property taxes, debt payments, profit, etc.). This proposal can be thought of as a variation on traditional cost-of-service regulation. The rate allowed for the variable operating costs of a power plant would be the same as it is under cost of service regulation, and the payment of $25 per megawatt-hour would replace all allowances for fixed costs and return on investment provided under traditional ratemaking.

Because a cost-plus price cap would, by definition, allow generators to recover their full variable costs, supporters of this proposal have argued that it would not affect existing generation or reduce power supplies this summer. In addition, proponents have asserted that price controls could be imposed for only a few years and thus would have little effect on new investment, because many new plants would not begin operating until after the price controls expire, or would operate under price controls for only a short period of time.

While this proposal is somewhat similar to rate setting under historical cost-of-service regimes, it ignores the disparate relationship between a fixed payment of $25 per megawatt-hour and the amount necessary to recover fixed costs and allow investors the opportunity to earn a reasonable return on capital. As a result, it would likely hinder efforts by California to bring new capacity on line quickly under the emergency siting process and will likely derail that process. Peaking plants approved under California's 21-day and 4-month emergency siting process are being licensed for only 3 years, and only some of them will apply for relicensing at the end of the 3-year period, when they are also likely to face additional requirements. For example, one recently approved project must convert its single-cycle turbine to a combined-cycle turbine at the end of the 3-year period to be eligible for relicensing. Thus, many plant developers are likely to pursue projects under the emergency siting process only if they believe there is a reasonable chance of recovering their fixed costs within 3 years. It is unlikely that they will be able to do so under a cost-plus proposal, as shown below.

In order to demonstrate the likely effects of price controls, we analyzed the two specific proposals just described to determine their effects on existing supplies and expected new capacity, then estimated the impacts on electricity outages using the reliability assessment model.

The $150 "Hard Cap"

In December 2000 FERC approved its order directing remedies for California's wholesale electricity markets. Under the order, sellers bidding at or below a $150 per megawatt-hour breakpoint would receive the market clearing price, but not more than $150 per megawatt-hour. Sellers bidding above this price would be paid their as-bid price but would not be allowed to set the market clearing price. Furthermore, sellers would be subject to certain reporting and monitoring requirements and, potentially, could be ordered to refund payments that appear to be in excess of their generating costs. In fact, FERC has ordered potential refunds for roughly $125 million for January through March. FERC acknowledged in its December order that costs for natural gas-fired generators would likely be above $150 because of high natural gas prices and NO_x credit prices, and recently approved a new order that would set market

[20] Some of the gross receipts tax proposals would allow generators to apply for a refund if they could show that their costs were above the base price. If a gross receipts tax is passed, however, it will likely take regulators several weeks to establish the detailed rules regarding refund procedures. We find it unlikely that generators would continue to operate based on the prospect of eventually receiving a refund from the State that would allow them to recover their fuel costs.

clearing prices based on the cost of the last plant dispatched. Still, proponents of price controls advocate establishing a "hard cap" at the $150 level.

According to economic theory, a plant will continue to operate in the short run as long as it can recover its variable costs. Capital and other fixed costs, such as taxes, will not affect a firm's short-run decisions, because those costs must be paid regardless of whether or not the plant operates—i.e., they are "sunk costs." If a firm cannot recover its variable costs, however, it will stop operating immediately.

For existing generation, we compared published plant-level data on variable costs for plants in California with a range of price caps to determine the amount of capacity likely to stop operating as a result of a hard price cap.[21] Because fuel costs are the largest component of variable costs for many California plants, we also used a range of natural gas prices. Table 2 shows the results.

Depending on the price paid by electricity generators for natural gas, the imposition of a hard cap or gross receipts tax could have significant effects on the economic operability of existing generating plants located in California. High State-wide average gas prices together with price caps would make it impossible for some electricity generators to recover their fuel and maintenance expenditures. Roughly 1,300 to 3,600 megawatts of existing generating capacity in California would immediately stop operating under a $150 per megawatt-hour price cap if natural gas prices were between $8 and $11 per million Btu.[22] Generally, the affected plants would be peaking units—combustion turbines or oil/gas steam units that have high operating costs.

Three important caveats are worth noting. First, it is likely that some of California's gas-fired QF capacity would become uneconomical and cease operation at the $150 price cap. Given the questions surrounding QF contracts and how QFs will be paid, it is not clear whether these generators would be subject to price caps, and we decided not to include them in this portion of the analysis. Second, NO_x credit costs for plants included in the RECLAIM NO_x trading program are not included in this analysis. The South Coast Air Quality Management District, which administers the RECLAIM trading program, recently made several changes to the program, and NO_x credit prices will not be nearly as high as those seen last summer. Third, because no reliable estimates of plant startup costs can be inferred for peaking plants that run at historically low utilization factors, startup costs are not included as an additional component of variable costs.[23]

Table 2. Existing Electric Generating Capacity Unable to Operate Profitably Under Price Caps

Price Cap (Dollars per Megawatt-hour)	Average State-Wide Gas Price (Dollars per Million Btu)						
	$8.00	$8.50	$9.00	$9.50	$10.00	$10.50	$11.00
$100	5,238	6,224	14,577	17,439	20,566	23,071	24,195
$110	3,761	4,484	5,189	6,277	14,512	17,369	18,818
$120	2,885	3,722	3,830	4,784	5,609	7,311	14,512
$130	2,082	2,811	3,432	3,722	4,484	4,784	5,843
$140	1,602	1,877	1,936	2,878	3,553	3,715	4,477
$150	1,303	1,602	1,797	1,928	2,492	2,878	3,573
$160	1,108	1,284	1,436	1,656	1,909	1,917	2,547
$170	982	1,002	1,231	1,383	1,530	1,725	1,856
$180	850	982	1,002	1,231	1,278	1,383	1,725
$190	765	850	900	1,002	1,055	1,231	1,383
$200	600	600	600	735	755	890	1,066

[21] Cost data for California plants were taken from the RDI POWERDAT Database System.

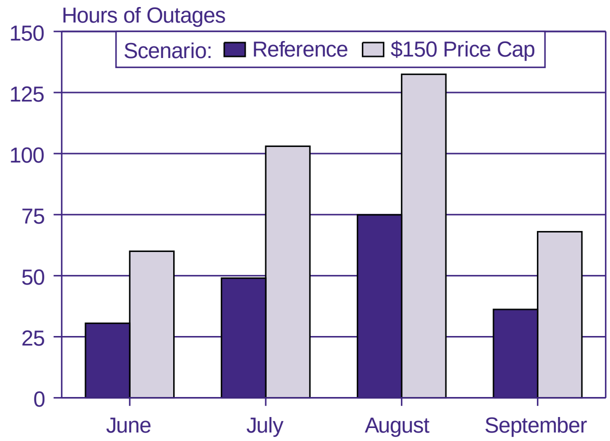
[22] Natural gas spot prices at the Southern California Border reportedly reached as high as $60 per million Btu in December, although prices have moderated since then. The range of prices chosen for this analysis is based on daily spot prices as reported by Economic Insight, Inc., *Energy Market Report* (February-May 2001).

[23] Some portion of startup costs is implicitly included in the analysis by using average heat rates.

Consequently, the estimates provided in Table 2 are conservative and may understate the generating capacity that would cease operation under a $150 price cap.

As expected, the decreases in electric generating capacity resulting from the price cap significantly increase both the number and magnitude of the expected electricity outages. To analyze the impact of the $150 price cap, we ran the California reference scenario again, this time assuming that 2,000 megawatts of existing capacity would no longer continue to operate as a result of the price cap.[24] The results are shown in Figure 8. A price cap at this level would more than double the expected hours of electricity outages, from a total of 113 hours to 235 hours for June through September, after accounting for the demand response programs. The average size of the outage would increase by roughly 230 megawatts, equivalent to about 175,000 additional households. Last year's experience reinforces these conclusions. On December 8, 2000, the California ISO filed an emergency petition with FERC to waive a $250 hard cap. According to the ISO, generators avoided the capped ISO market in favor of selling into uncapped markets where prices were higher.

Figure 8. Expected Hours of Electricity Outages Under a $150 Price Cap



The "Cost-Plus-$25" Price Cap

A cost-plus-$25 price cap, under which each generator would be paid its variable costs plus $25 per megawatt-hour,[25,26] would have significant effects on new investments, could disrupt the operation of existing units unable to maintain the strictures of their bond covenants, and could force the abandonment of existing units whose going forward costs (annual fixed operating and maintenance costs, property taxes, etc.) exceed the $25 per megawatt payment. Only the impact on new investments was considered in the reliability analysis.

Although existing units would continue to operate because they would be able to recover their variable operating costs—and because we assume that the $25 per megawatt-hour payment exceeds going forward costs—a firm would not build a new power plant unless it expected to recover both its variable and fixed costs. Plant developers must consider a number of factors in determining whether or not to build a new plant, including future fuel costs, financing costs, and how quickly the plant can recover its capital costs. In addition, because fixed costs are spread over all the megawatt-hours a plant produces, the number of hours a plant can expect to operate—i.e., the plant's expected capacity factor—is a critical assumption in estimating profitability.

[24]Many analysts have asserted that generators in California have been strategically withholding supplies in order to drive up prices. Both the reference scenario and the price cap scenario analyzed here assume that strategic withholding does not take place, and that all generators bid their available capacity. If we assume that generators would withhold capacity, then the expected hours of outages in the reference scenario would increase, and the difference in expected hours of outages between the two scenarios would be smaller. Regardless of whether generators have or have not withheld capacity in the past, we believe that the assumption of no strategic withholding in the reference scenario is valid for this summer. First, generators are under intense scrutiny by regulators, and plant outages are likely to be investigated by the California ISO. Second, FERC's April 26 order on market monitoring and price mitigation for California electricity markets requires all California generators to bid all their available capacity into the spot market.

[25]Commissioner William L. Massey, Federal Energy Regulatory Commission. Testimony before the Subcommittee on Energy and Air Quality, Committee on Energy and Commerce, U.S. House of Representatives (March 20 and 22, 2001). *Congressional Record*, Serial No. 107-6. Available through web site www.access.gpo.gov/congress/house/.

[26]"Governor Davis, Western Governors Ask FERC for Caps on Wholesale Power Costs." Press Release, Office of the Governor (March 12, 2001).

For this analysis, we examined the effects of a cost-plus price cap on single-cycle combustion turbines—the predominant generating technology being licensed under the State's emergency siting program. Combustion turbines have lower capital costs but higher operating costs than combined-cycle plants, and they are built to meet peak demand. As such, they generally operate fewer hours per year than do combined-cycle plants, which are built primarily to serve baseload and shoulder periods.

Figure 9 illustrates the cost recovery shortfall that a new, single-cycle combustion turbine is likely to encounter under a range of capacity factors, assuming that the price cap covers all its variable costs plus a $25 per megawatt-hour payment. Figure 9 includes the two critical assumptions noted above: the number of years over which a plant can recover its capital costs and its capacity factor. The point at which the line crosses the zero axis is the "break-even point," assuming a 16-percent return on equity. Thus, a new combustion turbine would have to operate for more than 55 percent of the hours in a year in order to recover its fixed costs over a 3-year period if it were paid only $25 per megawatt-hour above its operating costs.

Because combustion turbines have high operating costs and are built to meet peak demand, developers generally expect that they will have relatively low capacity factors, ranging from 10 percent to 30 percent—significantly less than would be required to recover capital costs in 3 years under the cost-plus proposal. Although capacity factors for new combustion turbines in California are likely to be above average over the next year, the projected break-even point of more than 55 percent represents a considerable risk for developers, which many will be unwilling to bear. Even if a developer expected to spread the plant's fixed costs over a 10-year period, the risk would still be high at a projected break-even capacity factor of nearly 30 percent every year for 10 years.

We examined two scenarios to analyze the effects of the cost-plus-$25 price cap proposal. The first scenario assumes that all new capacity additions proposed under California's emergency siting process will be licensed and operational by the scheduled in-service dates—a total of nearly 1,300 megawatts by September 1, 2001.[27] The second scenario assumes that, as a result of the price cap, none would be built. Monthly new capacity additions in the two scenarios are shown in Table 3. All other assumptions are the same as in the reference scenario.

While the forecast under the "cost-plus-$25" scenario is not as dramatic as under the "hard cap" scenario, the expected impacts are considerable. If none of the peaking plants proposed under the emergency power plant siting program is licensed,

Figure 9. Potential Cost Recovery Shortfall for New Plants Under the "Cost-Plus-$25" Price Cap

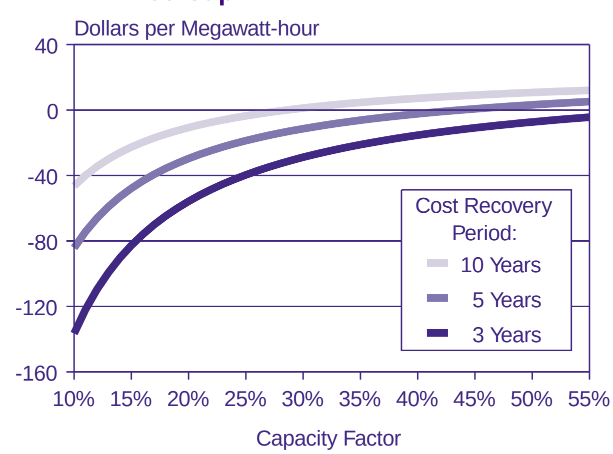


Table 3. Total Monthly New Capacity Additions for the "Cost-Plus-$25" Price Cap Scenarios

Scenario	Cumulative New Capacity Additions (Megawatts)			
	June	July	August	September
All Proposed Emergency Peaking Plants Are Built	60	1,329	2,346	3,700
None of the Proposed Emergency Peaking Plants Are Built. . . .	60	1,126	1,622	2,410
Difference	0	203	724	1,290

[27]Based on information from the CEC Power Plant Licensing website as of May 2, 2001. As with our other new capacity estimates, we assume that only 90 percent of the nameplate capacity will be available, in order to account for lower summer capability ratings and unforced outages.

electricity outages are likely to be 25 percent higher than if all the proposed peaking units are built. The average size of the outages expected rises from 1,979 megawatts to 2,094 megawatts, equivalent to about 85,000 additional households affected.

Conclusions

It is unlikely that California residents will escape rolling blackouts this summer. Based on this analysis, we conclude the following:

- California residents are likely to experience 113 hours of outages this summer. The likely magnitude of the outages is expected to be 1,900 megawatts, affecting 1.4 million households. Demand relief and interruptible load programs play a significant role in reducing the number of hours of outages. If the State had not recently implemented these programs, the estimated hours of outages would increase from 113 to 191 hours, and the magnitude of the outages would increase by approximately 160 megawatts, affecting an additional 120,000 households. Outages of these magnitudes would be far more extensive than any experienced in California over the past year.

- The outcomes of our reference scenario are based on what we believe to be the most likely set of input assumptions. Two additional scenarios were also developed. The optimistic scenario assumes more new capacity, more hydropower availability, greater net imports, fewer QFs shut down for financial reasons, and more effective real-time demand, efficiency, and conservation programs. The pessimistic scenario assumes the opposite: less new capacity, less hydropower availability, fewer net imports, more QFs shut down for financial reasons, and less effective real-time demand, efficiency, and conservation programs. Although the assumptions in the optimistic and pessimistic scenarios are relatively unlikely, the two scenarios provide useful upper and lower bounds for the range of potential outcomes.

- In the pessimistic scenario, the number of hours of outages expected rises from 113 hours in the reference scenario to 479 hours, and the expected average size of each outage rises from about 1,900 to 2,600 megawatts—affecting 1.95 million households, an increase of 550,000 over the reference scenario.

- In the optimistic scenario, the number of hours of outages expected falls to 14 for the entire summer, and the average size of each outage falls to 1,700 megawatts—affecting 1.14 million households, a decrease of 165,000 from the reference scenario.

- Actions undertaken thus far to reduce electricity demand and increase generating capacity have helped the situation. Without these programs, the State might have seen an additional 250 hours of outages.

- Price controls, which some have proposed, would increase the expected hours of outages significantly. The $150 "hard cap" could force up to 3,500 megawatts of natural gas-fired capacity in the State to shut down, depending on the price of natural gas this summer. If 2,000 megawatts of capacity ceases to operate, the expected hours of outages will double (from 113 to 235 hours), and the average magnitude of the outages will increase by 230 megawatts—affecting 1.57 million households, an increase of 175,000 over the reference scenario.

- The "cost-plus-$25" price cap proposal would have a smaller impact immediately but a potentially larger impact over the long term, because it would effect new capacity additions. Under this proposal, the expected number of hours of outages this summer increases by about 28 hours.

Any proposal aimed at mitigating high electricity prices in California and the West this summer should not reduce available generating supplies or impede investments in new capacity. Many of the proposals considered thus far, however, would do just that, thereby threatening public health and safety by significantly increasing the number of hours of outages and their magnitude.

Appendix A
Methodology and Assumptions

According to a load and resource summary prepared by the California ISO, during peak demand the control area is expected to experience resource deficiencies from a high of 3,647 megawatts in June to a low of 666 megawatts in September. The ISO load and resource summary is based on point estimates of the many components that define the region's potential capacity resources: existing generators, new generation, net imports, and mitigation measures such as load curtailment and conservation. The California ISO compared the total capacity resources with point estimates of forced outages, hydroelectric capacity limitations, and expected peak demand to arrive at the expected resource deficiency for each summer month.

Although the methodology used by the California ISO is straightforward and relies on the best-guess estimates of people knowledgeable about the California electricity industry, it does not provide a complete picture of the situation. There is a possibility that the expected amount of daily forced-outage capacity during the summer will never exceed the California ISO's estimate of 2,500 megawatts; however, it is likely that on some days forced outages will be higher. If this occurs on a day when peak demand is high, then the resource deficiency could be greater than 3,647 to 666 megawatts—reflecting the characteristics of a dynamic, rather than a static, system.

The approach used in this analysis by the U.S. Department of Energy recognizes the dynamic nature of the electricity generating system by assuming probabilistic distributions of hourly peak demand and power plant availability, and applies observations of these stochastic variables to a generalized Monte Carlo model. Assumptions regarding net imports, new capacity, load curtailment and the impact of conservation measures are used to define three broad scenarios: optimistic, reference, and pessimistic. Probabilities of load are matched with probabilities of supply, and when supply is less than load, it is counted as a shortage. This approach results in a probabilistic distribution of resource deficiencies for each scenario, from which the frequency and magnitude of resource deficiencies can be determined.

Peak Load and Operating Reserves

Load forecasts used in this assessment are based on a monthly distribution of hourly peak loads for each summer month. The distribution for each summer month is constructed by applying a 30-year distribution of California temperature data to a regression equation that captures seasonal, day of week, and hour of day load cycles. In addition to explicit demand, the model assumes operating reserves of 3.5 percent of demand.

Existing Generating Capacity and Capacity Limitations

Existing California generating capacity is based on data contained in the California Energy Commission's (CEC) plant-level database and the Energy Information Administration's *Inventory of Power Plants in the United States*. Data from the CEC database were further modified to yield a generator-level database, resulting in an estimated in-State resource base of 42,400 megawatts.[28]

Reservoir storage in the State is currently above normal capacity. Water content of snowpack, however, is approximately 60 percent of normal levels, as compared with 100 percent last year. Consequently, runoff is about 45 percent of average, as compared with 100 percent observed at the same time last year. For this assessment, hydroelectric generating conditions are assumed to be 85 percent of normal in the reference case and 100 percent and 70 percent of normal in the optimistic and pessimistic cases, respectively.

[28] Although the modified database includes the San Onofre 3 nuclear unit, the model assumes that this unit will be unavailable in June and July 2001.

Although the California capacity resource base contains nearly 10,000 megawatts of total QF capacity, a significant amount of the output from QF capacity is retained by some facilities to power industrial processes. For this assessment, total QF capacity is reduced by 2,500 megawatts in all three scenarios. QF capacity is further reduced by 700 and 1,500 megawatts in the reference and pessimistic cases, respectively, based on the assumption that additional QF capacity could be unavailable for economic reasons.

New Capacity

Assumptions regarding new resources that might be expected to begin operation during the summer are based on announcements of new capacity by independent power producers, the California ISO's Summer Reliability Agreement (SRA) project, and the CEC Emergency Peaker Project. Currently, suppliers have signed agreements for 7 projects with the California Department of Water Resources (CDWR) as part of the California ISO's SRA program. An additional 22 projects are either currently being negotiated with the CDWR or are likely to stay with the California ISO. Total new capacity brought on line under this program is expected to be 790 megawatts by October 2001.[29]

Although the original goal of the CEC's Emergency Peaker program was to bring 1,000 megawatts of capacity on line quickly, currently only 636 megawatts of capacity has been approved and should be available this summer. An additional 585 megawatts of capacity is currently under review.[30] A significant amount of new capacity will begin operation during the summer as a result of modernization of existing facilities or new greenfield construction of units greater than 300 megawatts. In particular, the Huntington Beach, Los Medanos, Sunrise, and Sutter plants will add a total of 2,300 megawatts during the summer.

Nevertheless, very little new capacity is expected to begin operation during June. While it is difficult to project the exact date on which each plant will begin operation, it is not unreasonable to expect that plants for which siting reviews have not yet completed probably will come on line later in the summer rather than sooner. The schedule of new capacity shown in Table A1 for each summer month is based on the current status of each project and the result of analysts' judgment regarding the probable online date implied by the filings submitted for each project.

Table A1. Expected New Generating Capacity in California by Month, June-September 2001
(Megawatts)

Scenario	June	July	August	September
Pessimistic . .	60	1,000	1,740	2,295
Reference . .	60	1,273	1,915	2,703
Optimistic . .	105	1,690	2,900	3,565

Unit Outage Rates

Unit outages are determined using Monte Carlo simulation. The availability of all units is adjusted by assumptions concerning expected forced outage rates. Forced outage rates used in this analysis are from the North American Electric Reliability Council (NERC) GADS database, with data specific to California. Assumptions from GADS about California maintenance outages are also applied.

Model Application

This model has been used by NERC in its analysis of shortages this summer in the California ISO.[31] The model also is being used to study the New York City and Long Island areas, which have the potential to have some shortages this summer because of their tight capacity margins and limited transmission capability.

[29]Debi Le Vine, California ISO Governing Board. Web site www.caiso.com/docs/2001/05/25/200105252009198832.pdf.

[30]"California Emergency Siting Peaker Power Plant Permitting, New Peaking Power Plants Less than 300 MW," web site www.energy.ca.gov/sitingcases/peakers/index.html.

[31]North American Electric Reliability Council, *2001 Summer Special Assessment: Reliability of the Bulk Electricity Supply in North America*, web site www.nerc.com/download/hotdocs.html.

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