

DRAFT

**The California Electricity
Crisis**

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Chapter 1: Introduction and Overview

Since mid-year 2000, California's electricity problems have been of a central concern in the State. Californians have faced blackouts, have seen the State budgetary surplus decimated, have watched as northern California's largest natural gas and electric utility, Pacific Gas and Electric, filed for bankruptcy, have wondered if and when Southern California Edison will follow the same route, have listened to politicians debate how much to pay to purchase transmission lines from financially strapped utilities, and have listened to state officials point fingers at a myriad of organizations and individuals for causing the crisis.

This book attempts to explain these events as an integrated saga that California has faced – and is still facing. The saga began with an opportunity for California to restructure its electricity system to make it more flexible and responsive to changing economic conditions. Following the flawed implementation of this restructuring, California's political leadership failed in 2000 to respond effectively to the challenge of tight electricity markets, mismanaged the electricity crisis in 2001, and thereby saddled the state with heavy long-term electricity-related financial obligations. As a result of the fundamental policy mistakes made by the State's governor and other political leaders, the saga continues, with California facing an electricity blight as it struggles to recover from its self-imposed wounds.

The restructuring, often mischaracterized as “deregulation”, included provisions that put the State and especially the investor-owned utilities in a very risky economic situation. With delays in new generating plant approvals, a failure throughout the western United States to match the growth in the consumption of electricity with new capacity, and problems with the newly created

California wholesale markets, the downside risks became reality and California faced a difficult challenge.

Difficult challenges require wise political leadership. Such challenges require strong, courageous political leaders willing to make difficult and potentially politically unpopular choices. But that type of leadership never emerged in California. Rather than solving the challenge by taking appropriate steps, California's Governor fundamentally failed to act and then, once he started to act, fundamentally over reacted. That failure of political leadership transformed the difficult challenge into California's energy crisis.

The "energy crisis" was a dual crisis: an electricity crisis associated with insufficient electricity supply to meet the electricity demands of the California economy and the rest of the west, coupled with soaring wholesale electricity prices, plus a financial crisis facing California's investor-owned electric utilities, the California State budget, and ultimately the taxpayers and electricity ratepayers of California.

During the height of the crisis and as the crisis subsided, the Governor and the California legislature responded to the short-term crisis by enacting a group of long-term measures, measures which now threaten to create a continuing blight on the State of California. These measures collectively seem designed to turn California into a public power state rather than one characterized by a free market system for electricity.

The changes in California moved through four somewhat distinct, although overlapping stages.

The following four chapters of this book correspond to those four stages:

- California's Restructuring: Turning Opportunity into Risk
- The Challenge
- Through Crisis
- Crisis to Blight

Each stage, and in fact the whole process, should be seen not as a random set of disconnected events, but rather as a continuing sequence in which choices were made at each juncture. At each juncture, there were problems to be solved, often because of earlier policy decisions. At each juncture, there were alternative actions that could have been taken. Given the political and economic forces at play at each juncture, there was logic underlying the decisions. However, the choices selected often created new difficulties later. At each juncture, different choices could have led to very different outcomes, and perhaps different problems.

Although one group of events led to another, in a causal chain, the results were far from pre-ordained, since very different choices were possible at almost all junctures. The different choices could have led to very different outcomes for California. The totality of the system changes and the totality of consequences for the State of California were the result of this sequence of public policy decisions. Unfortunately, the outcomes are now evolving in directions greatly different from the goals expressed by those instrumental in the initial restructuring.

The focus of this book is this series of policy decisions, the alternatives, and the consequences of the decisions, within the context of the process as a whole.

Figure 1 diagrams the chain of causation, linking one decision to the next. The various boxes represent issues, actions, or important system characteristics. The various colors of the boxes represent the four stages of development plus prior conditions. Arrows represent causal links, in the sense that conditions associated with each action created forces or motivations that encouraged the next decisions or constrained the next set of actions.

In green are issues underlying the restructuring decisions, decisions culminating in Assembly Bill 1890 (AB 1890), passed in by the legislature in August, signed by the Governor in September of 1996, and implemented in March of 1998. In yellow are some of the most important legal provisions of AB 1890 that created a high risk. In addition to these actions, are factors or changes that created a challenge to the State of California; the most important ones are shown in orange boxes.

The red boxes represent the key factors or actions that represented the dual crisis, the electricity crisis and the financial crisis. The red boxes include a group of these factors with a circular set of causation arrows. These factors mutually interacted, causing the system to spiral into a crisis. Indicated above the red boxes and shaping this whole process was the failure of political leadership.

Finally is a group of actions in gray boxes. These actions collectively are described here as the growing long-term blight on the State. Taken together, these actions are starting to change California into a public power state. The process can be stopped. Future political leadership can determine how far down this road California proceeds.

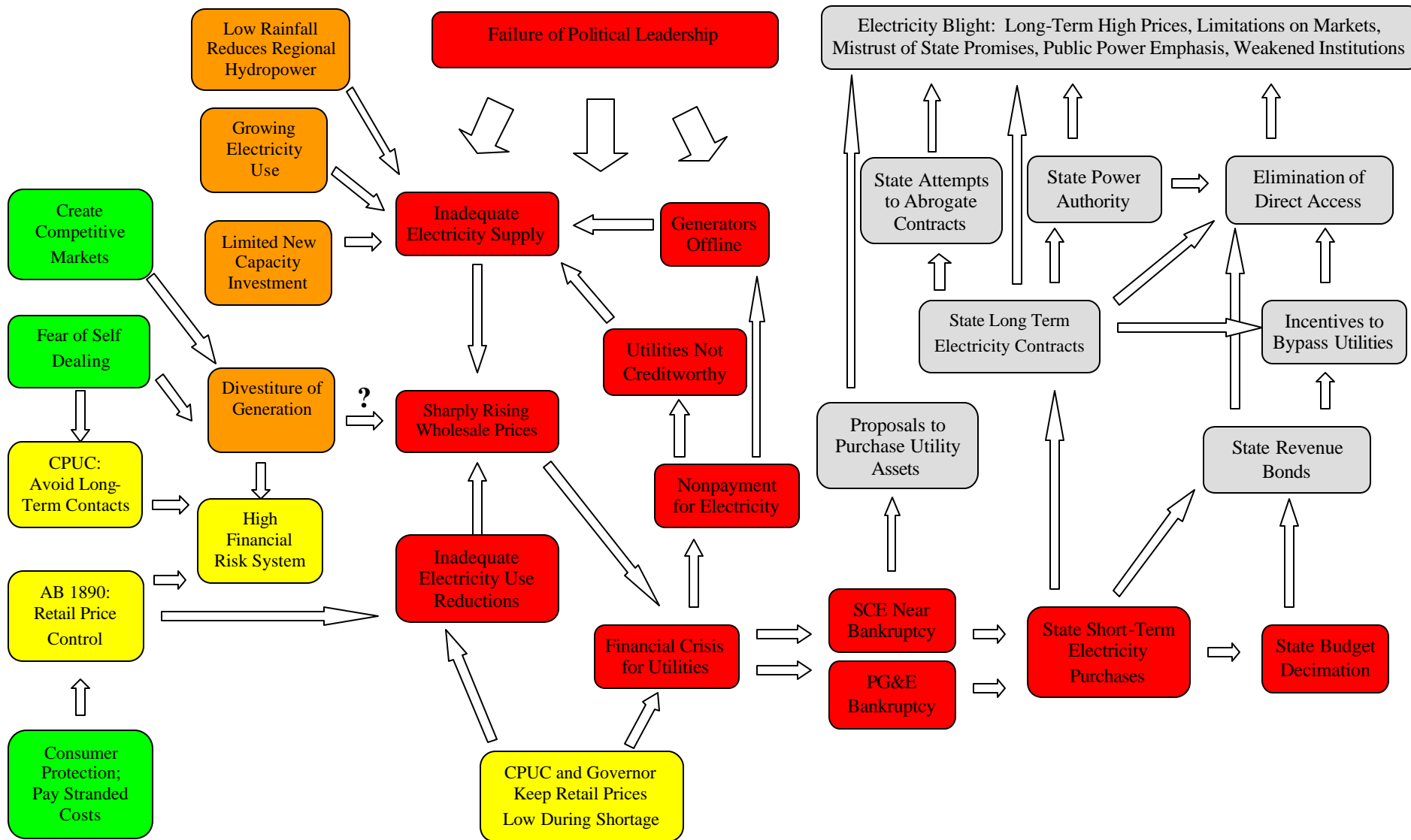


Figure 1 The Chain of Causation in California

This ultimate end-state of California's energy system remains unknown. Will California continue down the path towards public power? Will it return to the market-oriented goals of the original restructuring? Or will California move to some fundamentally different electricity system? Any of these paths remain open to the State. Which path is chosen depends on a combination of private sector actions, California legislation and regulatory decisions, and Federal governmental decisions. These then remain as collective choices for California.

What follows is an attempt to explain and makes sense of the changes implemented at each stage of the process. This discussion will take up the next four chapters of this monograph. Finally, two chapters are designed to look more to the future than to the past. Chapter 6 examines some of the policy issues that California should face and which could help move California out of the difficulty in which it finds itself. Chapter 7 offers reflections based on this sequence of events. Hopefully these reflections will be helpful for other states contemplating restructuring of the electricity system. And perhaps some will be more generally applicable to other major policy initiatives.

Chapter 2: California' Restructuring: Turning Opportunity into Risk

California Utilities before Restructuring

At the beginning of the saga, California's electricity system operated similarly to electricity systems throughout the United States. It included three large investor-owned utilities, collectively selling most of the electricity in California. Each investor-owned utility had a franchise in one of three separate parts of the State – Pacific Gas and Electric Company (PG&E) in Northern and Central California, Southern California Edison (SCE) in Coastal, Central, and Southern California, and San Diego Gas and Electric (SDG&E) in San Diego. In addition were several much smaller investor-owned utilities, several electric co-ops, and numerous municipal utility systems, the largest of which were the Los Angeles Department of Water and Power (LADWP), and the Sacramento Municipal Utility District (SMUD).

For reference, Table 1 shows a listing of the various retail sellers of electricity in California, separating the sellers into investor-owned utilities, municipal utilities, electric co-ops, and federal agencies. The numerical data are from the year 1999. Table 1 shows that the investor-owned utilities serve 78% of the California customers and the municipal utilities serve 22%. The electric co-ops and the federal agencies collectively serve less than 0.1% of the customers. In terms of total MWh of electricity, the investor-owned facilities sell 72 %, the municipal utilities, 24 %, and the federal agencies 3%.

Electric Utility	Number of Customers	Revenue (\$ Thousands)	Sales (MWh)	Avg.Revenue (\$/MWh)
Investor-owned utilities				
Pacific Gas & Electric Co.	4,535,909	\$6,785,994	70,186,749	\$97
PacifiCorp	41,473	\$53,324	778,531	\$69
San Diego Gas & Electric Co.	1,184,844	\$1,415,141	14,718,306	\$96
Sierra Pacific Power Co.	43,877	\$38,826	506,280	\$77
Southern California Edison Co.	4,213,562	\$6,692,164	67,206,530	\$100
Southern California Water Co.	20,988	\$13,275	127,135	\$104
Total	10,040,653	\$14,998,724	153,523,531	\$98
Municipal Utilities				
Alameda City of	32,569	\$38,979	371,326	\$105
Anaheim City of	105,755	\$220,932	2,416,302	\$91
Azusa City of	14,549	\$21,072	233,213	\$90
Banning City of	9,523	\$13,501	118,821	\$114
Biggs City of	656	\$787	7,340	\$107
Burbank City of	51,488	\$106,360	1,029,003	\$103
Colton City of	16,893	\$26,176	266,108	\$98
Glendale City of	83,100	\$112,701	1,071,277	\$105
Gridley City of	2,191	\$2,315	26,824	\$86
Healdsburg City of	4,903	\$7,397	69,904	\$106
Imperial Irrigation District	93,486	\$193,531	2,384,949	\$81
Lassen Municipal Utility Dist	10,162	\$12,227	136,909	\$89
Lodi City of	23,776	\$38,329	391,276	\$98
Lompoc City of	14,455	\$12,336	125,717	\$98
Los Angeles City of	1,385,396	\$2,080,736	20,056,691	\$104
Merced Irrigation District	148	\$5,362	113,305	\$47
Modesto Irrigation District	92,229	\$136,566	2,164,620	\$63
Needles City of	2,907	\$4,907	60,967	\$81
Palo Alto City of	27,723	\$66,503	1,124,025	\$59
Pasadena City of	58,378	\$129,657	1,129,383	\$115
Redding City of	38,295	\$68,937	683,493	\$101
Riverside City of	92,644	\$160,773	1,647,509	\$98
Roseville City of	36,243	\$60,003	819,570	\$73
Sacramento Municipal Utility Dist	503,615	\$722,046	9,284,751	\$78
San Francisco City & County of	9	\$40,588	728,342	\$56
Santa Clara City of	47,524	\$194,782	2,491,714	\$78
Shasta Lake City of	3,916	\$5,004	65,305	\$77
Trinity Public Utilities Dist	6,464	\$5,606	77,498	\$72
Truckee Donner Pub Utility Dist	10,324	\$8,615	122,029	\$71
Tuolumne County Pub Power Agny	30	\$1,194	23,162	\$52
Turlock Irrigation District	66,456	\$105,366	1,415,162	\$75
Ukiah City of	7,298	\$13,606	106,303	\$128
Vernon City of	2,026	\$55,056	1,161,173	\$47
Total	2,845,131	\$4,671,950	51,923,971	\$90
Electric Co-ops				
Anza Electric Coop Inc.	3,468	\$5,138	34,693	\$148
Plumas-Sierra Rural Elec Coop.	6,067	\$9,607	118,818	\$81
Surprise Valley Electric Corp	3,923	\$4,594	88,802	\$52
Valley Electric Assn Inc.	29	\$337	7,081	\$48
Total	13,487	\$19,676	249,394	\$79
Federal Agencies				
Bonneville Power Admin	10	\$6,365	264,515	\$24
Western Area Power Admin	98	\$94,914	6,019,473	\$16
Total	108	\$101,279	6,283,988	\$16
State Total	12,899,380	\$19,791,632	211,981,140	\$93

Table 1 Retail Sellers of Electricity in California: 1999 Source: Energy Information Administration

The average price of electricity was similar for investor-owned utilities and municipal utilities. As measured by the average revenue per megawatt hour sold, average retail price of electricity sold by the municipal utilities (including delivery services), was 8% less than it was for investor-owned utilities. Retail prices for municipal utilities varied over a wide range, from 30% above to 51% below the average investor-owned utility price. The largest municipal utility, Los Angeles Department of Water and Power, had an average price (more precisely, average revenue per megawatt hour) 6% above the investor-owned utilities' average.

Each investor-owned or municipal utility operated as a local monopoly, selling electricity in its own exclusive franchise area, with no direct retail competition from other electricity sellers. The large investor-owned utilities, as well as some of the municipal utilities, were vertically integrated to include three separate functions: generation, transmission, and local distribution. A typical investor-owned utility generated most of its electricity (generation), moved that electricity on transmission lines to local areas where it was needed (transmission), and sold that electricity to industrial, commercial, and residential users (local distribution). Some municipal utilities operated as only local distribution companies; some participated in one or both of the other two functions – generation and transmission.

For investor-owned utilities, almost all significant financial decisions involving any of the three functions were subject to the jurisdiction and control of the statewide regulatory body, the California Public Utilities Commission (CPUC). Customers paid retail prices for electricity based on operating costs plus a regulated rate of return on the prudently incurred “used and useful” invested capital. The CPUC would review whether costs were prudent and would

determine the “fair” rate of return on invested capital, a rate of return meant to approximate a normal rate of return for companies facing equivalent risk. Thus pricing was based primarily on cost of service and only secondarily on market conditions¹.

The significant decisions made by the publicly owned municipal utilities were subject to the jurisdiction and control of their appointed or elected governing bodies. Thus, their strategies could be based on local decision-making, rather than on statewide regulations. However, they typically were operated so that over a span of several years their revenues roughly equaled their total costs of operation. Thus, for municipal utilities as well as for investor-owned utilities, pricing was based primarily on cost of service and only secondarily on market conditions.

This particular industrial organization –utilities operating as regulated monopolies – had been justified for many decades by the increasing-returns-to-scale² nature of electricity generation, transmission, and distribution.

Retail distribution (the provision of delivery services: wires, transformers, and other physical equipment) provides the most obvious example of increasing returns to scale in the electric industry. A customer could double the amount of electricity used with no increase in the cost of providing wires to a home. Equivalently, if two competing companies were each to run electric

¹ Market conditions do have a secondary role because of the dynamic nature of the rate-setting process. Each rate case sets retail prices based on conditions in some base year or years. These rates stay in place until the next rate case. Thus if sales increase in the future beyond expectations, profits for the utility will rise and vice versa if sales decline. This provides an incentive to delay rate cases when sales and profits are higher than expected and to quickly initiate rate cases when sales and profits are low. In addition, the actual system creates incentives to block distributed generation investments that would reduce sales and to go slow on energy efficiency investments that would reduce sales of electricity.

² Increasing-returns-to-scale characterizes an industry if increasing the size of individual firms reduces the average cost of the product.

wires down the same streets to compete for customers, total cost and cost per customer would increase even with no change in the quantity of electricity delivered. Cost would be lowest if there were only one company providing the wires, transformers, and other physical equipment for local distribution of centrally generated electricity. Thus local distribution of centrally generated electricity is generally considered to be a natural monopoly and, as such, is typically allowed to operate as a monopoly franchise, subject to regulatory oversight, in California, as in other states³.

As distinct from electricity distribution services, retail electricity is not characterized by increasing returns to scale. In order to double the amount of electricity sold, a retailer would need to double the amount of electricity acquired at wholesale. For wholesale electricity prices held fixed, doubling the acquisition of electricity would double the total cost of acquiring the electricity. Thus the cost per MWh sold at retail neither increases nor decreases (at least not significantly) as the scale of retail operations changes. Retail sale of the commodity, electricity itself, is not characterized by increasing returns to scale and the retail electricity sales function cannot be viewed as a natural monopoly.

In principle, the regulatory system could logically separate delivery services from the retail sales of electricity itself. The retail sales function would be amenable to organization as a competitive industry even though the delivery function was not organized in a competitive market structure.

³ This argument cannot legitimately be generalized to include distributed generation of electricity, generation at the point of end use. Distributed generation includes both the generation and distribution function. In some cases addition of distributed generation to systems with existing distribution networks may reduce total system costs. Nevertheless, natural monopoly arguments have been used by some utilities to limit competition from distributed generation.

Although, in principle, delivery services and sales of the electricity could be separated, delivery services and the electricity were typically bundled: customers were charged a price for the combination of electricity and delivery services. In this way, the natural monopoly franchise for delivery services was extended into monopoly franchise for delivery services and for electricity. California operated this way, as did most states.

Increasing returns to scale also characterizes transmission of electricity, up to a point. Electricity moves on high-voltage transmission lines integrated into an electricity grid. A significant cost of this transmission system is payment for the right-of-way on which to build transmission lines. When the transmission lines are operating well below capacity, there would be little additional cost for moving additional electricity through these lines. Even at capacity, installing additional high-voltage wires on an existing transmission link involves substantially less cost than required to establish the link in the first place. Thus transmission also seems to be appropriately organized as a monopoly along a given transmission path, as it is in California.

Finally, electricity generation also seemed to have the increasing returns to scale characteristic of a natural monopoly. For many years the conventional wisdom was that the larger the electric generating plant, the lower would be the overall cost of electricity generation. Bigger was cheaper. This increasing-returns-to-scale characteristic of electricity generation led to the common belief that electricity generation should be organized as a monopoly.

Given that all three components of the electricity supply system were operated as monopolies, there was a tendency, although not a necessity, for these three elements to be vertically

integrated into a single company⁴. One fundamental reason was the need for coordination in planning for capital investments and operations. The amount of electricity sold by the distribution firm determined the amount of generation and transmission capacity needed. The location of transmission facilities and generation facilities required coordination in order to minimize overall cost. This need for coordination and for appropriate information flows helped justify the combination of these three entities into one vertically integrated company.

A second, and related, reason for vertical integration was based on reducing transactions costs. Three separate monopolies, all integrated into one supply chain, might choose to operate so as to each gain financial advantages over the other. Although this strategic problem could be controlled through the regulatory process, integrating the three entities into one company would reduce or eliminate those incentives and the resulting need for regulatory oversight.

Although the investor-owned utilities in California, and in the rest of the nation, operated as vertically integrated monopolies, they did purchase some electricity from external sources. These purchases involved a mix of long-term and medium-term contracts plus spot market purchases or sales, to match unexpected variations in their sales of electricity. In particular, California utilities had long-term contracts to purchase hydroelectric power from the Bonneville Power Administration (BPA), a federal power-marketing agency. BPA sells power generated primarily from federal hydroelectric projects in the Federal Columbia River Power System.⁵ Both municipal utilities and investor-owned utilities also had other contracts to purchase electricity from Federal projects. California traditionally sold electricity to entities in the Pacific

⁴ Many municipal utilities were not vertically integrated, even though all three large investor owned utilities were.

⁵ The largest of these federal dams is the Grand Coulee Dam.

Northwest in the winter, when Pacific Northwest demands peak and purchased electricity from the Pacific Northwest during the summer, when California demands peak. However, other than these low-priced sources of electricity, California's investor-owned electric utilities historically tended to acquire electricity from their own generating units.

The Changing Federal Regulatory Structure

PURPA

In 1973, energy markets, particularly oil markets, were severely shaken by the sudden jump in oil prices resulting from the OPEC-organized reduction in world oil production. President Nixon declared “Project Independence” and the United States began searching for means of reducing dependence on oil and natural gas. In 1973, oil accounted for about 20% of the fossil fuels used for electricity generation; natural gas accounted for another 20%. Although natural gas was not imported in large quantities, U.S. policies were shaped by a general belief that natural gas would be in short supply and that, as a “premium fuel”, natural gas should not be used for electricity generation. The efforts to reduce use of oil and natural gas left nuclear power, coal, and various renewable sources of energy as alternative primary sources of energy plus energy efficiency investments that provided energy services using smaller amounts of electricity.

In response to these public policy goals, Congress passed several laws designed to promote nuclear power, coal, energy efficiency, and small scale renewable energy sources (wood waste, solar, wind) and to discourage use of oil and gas⁶. However, many people feared that utilities

⁶ The Powerplant and Industrial Fuel Use Act of 1978 includes a provision: “Except to such extent as may be authorized under part B, no new electric powerplant may be constructed or operated as a base load powerplant without the capability to use coal or another alternate fuel as a primary energy source.” “Alternative fuel” within the

would favor their own generation and would avoid adopting the generation technologies Congress wished to promote. The Public Utility Regulatory Policies Act of 1978 (PURPA) was a legislative response enacted primarily to promote development of small-scale renewable sources of energy for electricity generation. Cogeneration⁷ was included as well, as a means of more efficiently converting primary energy into electricity and usable heat. PURPA mandated state regulatory commissions to establish procedures to require electric utilities to interconnect with and buy capacity and energy offered by any non-utility facility that qualified under PURPA. These so-called "qualifying facilities" or "QFs" were typically small generating facilities based on renewable energy, waste products, or natural-gas-fired cogeneration units.

PURPA required utilities to pay a price for electricity from QFs equal to the "avoided cost" of electricity generation. This avoided cost was meant to be the totality of costs that a utility would avoid by purchasing electricity from these small alternative sources. PURPA left it to the state regulatory commissions to interpret what dollar price corresponded to "avoided cost" and the precise conditions under which the electricity and capacity must be purchased.

PURPA had impacts well beyond the limited public policy goal that motivated its passage.

PURPA started to change the structure of the electric industry, providing the first challenge to the tightly integrated vertical monopoly structure.

definition of that Act excludes oil and natural gas. The Act explicitly did not apply to nuclear powered plants. And it provided a permanent exemption for cogeneration plants. (US Code Title 42, Chapter 92, Section 8301 - 8354)

⁷ Cogeneration units are those that both generate electricity and use the energy not converted to electricity for useful purposes such as space or water heating or industrial process heating. In so doing a large fraction of the input energy is harnessed for desirable functions. Many cogeneration plants are based on natural gas but PURPA promoted cogeneration based on any primary fuel.

Opening Transmission Networks

With the success of PURPA, by the mid 1980s analysts realized that it was not necessary to operate electric generation as a regulated monopoly. Analysts saw that there was an opportunity to create a competitive electric generation industry. By then, utility executives understood the high capital costs of nuclear power; no utilities were proposing new nuclear power plant construction. Natural gas had become broadly available throughout the United States and was no longer seen as a “premium fuel”; its use in new electric generating plants was no longer prohibited under federal law⁸. Thus, it became possible to construct gas-fired power plants. Combustion turbines had become more efficient, particularly in a combined cycle mode. These turbines could be built in modules – one turbine, then another, then a steam cycle. This modular construction allowed for much more flexibility and for the construction of smaller very efficient plants. However, although utilities typically had not been taking advantage of that opportunity, once PURPA opened the way for independent power producers, these firms began exploiting the profit opportunities of using the “waste” heat from turbines in combined cycle plants. Thus, the assumption that electricity generation exhibited increasing returns to scale was no longer seen as valid. Consequently, the idea of electricity generation as a natural monopoly was no longer consistent with technical reality.

However, utilities still controlled all electricity transmission lines, lines still seen as natural monopolies. A utility that wished to stifle competition in electricity generation could do so by refusing to allow its competitors to transmit electricity along its transmission lines. Thus

⁸ In 1987, the Powerplant and Industrial Fuel Use Act was amended to permit electric utilities to burn oil or natural gas in new baseload generating facilities, if the plants could permit future voluntary conversion to coal. However, even prior to that time exemptions to the restriction had been routinely granted.

creating a truly competitive market for electricity generation required federal officials to deal with issues of utility control of transmission lines.

The first step was the Energy Policy Act of 1992 (EPACT). Among its many provisions, EPACT opened access by non-utilities to the transmission networks. And in 1996, the Federal Energy Regulatory Commission (FERC) issued Order 888 which much more generally opened transmission access to non-utilities. These regulatory changes together started to transform the electricity transmission system into a common carrier system. With EPACT and Order 888, it became much more difficult to control electricity generation markets by controlling electricity transmission. Utilities still made the investment decisions for transmission facilities and thus could still exercise some control over generation markets, but this form of control was less effective than direct control over access to transmission line. These two changes were fundamental for establishing the opportunity for wholesale competition in electricity.

Impacts on California Electricity before Restructuring

In California, the CPUC took a very aggressive stance implementing PURPA. It set high prices for electricity purchased by the investor-owned utilities⁹ under PURPA, requiring the investor-owned utilities to sign contracts based on standard offers with guaranteed prices that rose sharply over time¹⁰. The financial incentives and guaranteed market for QF electricity, coupled with tax incentives established by the Federal government, created a significant industry of renewable

⁹ Since the CPUC did not regulate the municipal utilities, these high prices were not relevant to these entities.

¹⁰ Under Interim Standard Offer No. 4 (ISO4), a QF based on renewable energy could sign a contract based on a fixed forecast of future electricity price. Such a QF entering a contract would be guaranteed \$57/MWh in 1985, \$81/MWh in 1990, and \$109/MWh in 1994. After 10 years the contract price reverted to the short run avoided cost, which typically would be far lower than the fixed price guarantee. Gas-fired cogeneration units were not treated nearly as generously but were generally paid an annual average of about \$25/MWh for capacity and about \$25 to \$30/MWh for energy.

electricity generation in California, including wind farms and electricity generation from wood wastes. These policy changes also led to large increases in cogeneration capacity¹¹, which was largely natural gas-fired. By the end of 1994, 20% of the electricity generation capacity in California was from QFs, 11.5% of which was cogeneration, 8.3% was renewable generation capacity, the largest inventory of renewable generation capacity in the nation.

However, with long term contractual obligations to purchase electricity from QFs at a high cost, by the early 1990s the utilities were facing a high average cost of electricity generation. In addition, California utilities had invested in nuclear power plants, units whose construction costs turned out to be far more greatly than initially predicted, further increasing the average cost of electricity generation.

These factors together helped make California's retail prices among the highest in the nation. Figure 2 shows retail prices¹², or, more precisely, a state-by-state comparison of the 1998 average revenue per kilowatt-hour (measured in cents per kilowatt-hour) sold to residential customers. Only in the states of California, Alaska, Hawaii, and the Northeastern states did average retail prices exceed 8 cents/KWh (\$80/MWh). California's average revenue was 9 cents/KWh per kilowatt-hour (\$90/MWh).

¹¹ Cogeneration now is the single biggest source of PURPA electric generation capacity in California. Of the roughly 10,200 MW of total QF nameplate capacity in California in 2001, about 5,700 MW is cogeneration, 4,500 is generation from renewables such as wind or organic wastes. (Data from California Energy Commission database of electric generating plants on line in California.)

¹² Source: U.S. Department of Energy, Energy Information Administration

**Average Revenue from Electricity Sales to All Retail Consumers
by State, 1998 (cents per kilowatthour)**

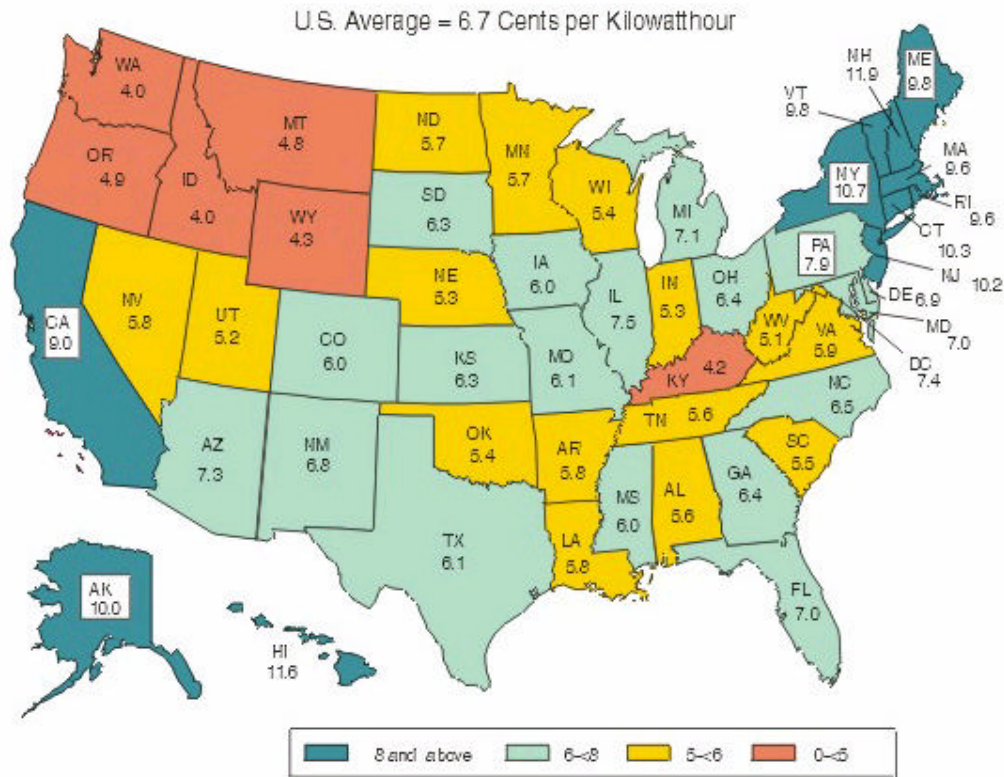


Figure 2 Average Revenue from Electricity Sales to All Retail Consumers. Source: Energy Information Administration, US Department of Energy

Motivations for California Electricity Deregulation

Generation/Wholesale Markets

The high retail price of electricity in California, relative to that in the rest of the nation, was one basis for arguments that California’s electric system should be deregulated to create a more competitive and presumably lower cost, electricity system. The concern about high retail costs logically translated to an argument about electricity generation because major contributors to the high retail price in California were a high average cost of generating electricity and the high

prices embedded in contracts for purchasing electricity under PURPA contracts, issues of generation or wholesale costs. Many advocates of electricity generation deregulation expected deregulation to reduce retail prices of electricity quickly.

But this expectation was based on a fundamental fallacy. It implicitly assumed that deregulation in the present could somehow correct the historical problems that had led to the high generation costs and high costs of purchasing bulk power under contracts. However, the costly investments in nuclear power plants and the long-term contracts for QFs could not be reversed. At the time of the restructuring debate, the state was no longer investing in new nuclear power plants. New cogeneration plants and renewable energy investments were being made on a market basis when such investments were expected to be economically attractive. The high price standard offers under PURPA were no longer required for new contracts. If the problem to be solved was higher prices caused by the historical nuclear power plant investments and QFs contracts, restructuring could do nothing to solve that problem.

Moreover, if, by some miracle of time travel, California could have gone back in time to restructure the wholesale electricity markets prior to the investments in the nuclear power plants and the QF contracts, it is doubtful whether California could have avoided those high electricity costs. After oil prices jumped in the mid-1970s and early 1980s, oil was no longer an economically attractive source of energy for electricity generation. Initially, natural gas was not available in large quantities and, beginning in 1978, federal law precluded its use in new baseload electric generating units. The sites for developing high-head hydroelectric power plants in California had already been well developed. Coal was not a good option: California had no

indigenous coal; cooling water needed for coal-fired units was limited, except on California's coasts; new railroad lines to haul coal to California's coasts would have been a very costly; environmental impacts of coal-fired facilities on California's coastline would have been unacceptable; problems of transporting vast quantities of coal to those plants by railroad would have been overwhelming. The United States had been investing in nuclear power plants based on a belief that nuclear power would be the least costly method of generating electricity, a belief which turned out to be false. Moreover, the geologically active faults near the California coastline made design and construction of nuclear power plants more difficult. Thus, the most attractive options for new generation capacity were renewables and cogeneration. Those supply sources, combined with energy efficiency programs – programs that reduced the need for new generation – were probably the best choices given California's realistic options.

The cost of contracts to purchase electricity from QFs could have been significantly lower, but only if the CPUC had chosen a much more realistic calculation of the "avoided cost" of electricity. And, even under the time travel miracle, restructuring of electricity markets was unlikely to have forced CPUC away from their politically inspired very high calculations of "avoided cost".

In short, even if California could have gone back in time and restructured electricity markets in the mid-1970s, it is dubious whether the particular factors that led to high electricity prices in California would have been significantly different as of the 1990s.

There was a more subtle argument, however, that deregulation would reduce costs, although the cost reductions would be gradual, not the instant cost decreases some expected. It was questionable whether the regulatory system provided strong enough incentives for utility-owned electricity generators to minimize costs and whether the regulated system led to the lowest cost mix of energy generation technologies. There were questions whether the utilities were favoring their own generation over generation by independent power producers and thus not cost minimizing. There remained incentives and opportunities for utilities to block distributed generation and to rely instead on central-station power, even if distributed generation had lower overall costs. Whether the regulated system was leading to too much investment in capital-intensive generation and to too much investment in generation relative to expenditures on demand management was a more subtle debate. However, economists and other industry analysts were arguing that creating competition could change economic incentives facing the utilities. The change in incentives would gradually reduce costs of electricity generation. This would gradually reduce retail prices. This argument, although not proven, was probably valid, even though the hope of fast cost savings was probably never realistic.

In addition, many asserted that expansion of wholesale markets would encourage more California investment in new generating capacity by independent power producers. In the early 1990s there was a surplus of California electricity generating capacity (including expected electricity imports), albeit a small surplus. However, most analysts anticipated that the healthy California economy would continue to need more electricity over the years. Many doubted whether the old regulated system would be responsive enough to those economic needs¹³. And

¹³ Traditionally rate-of-return regulated utilities invest in more generation than might be expected under a purely competitive regime. However, their incentive to reduce purchases from independent power producers could reduce

many argued that the old regulated system would let utilities discourage new investment by independent power producers. The expansion of a competitive wholesale market was intended as a long-term solution to a long-term problem.

The nationwide trends toward smaller, modular electric generation units were quite evident in California. The combination of broadly available natural gas and technological change had led independent power producers in California during the 1980s to invest in smaller gas-fired plants. These plants could be distributed throughout the State and electricity could be generated close to where it was needed, saving costs of expanding electricity transmission lines¹⁴. It had become clear in California that bigger was no longer cheaper and thus that electricity generation was not a natural monopoly. Since most new investment in electricity generation was by independent power producers, not utilities, deregulation of electricity generation and expansion of wholesale markets was supportive of this pronounced trend.

Thus, there was the opportunity in California to deregulate electricity generation to expand the scope of the existing competitive portion of the electricity generation industry. Expanding competition in electricity generation was expected to create incentives for cost cutting, to encourage investments in new generating capacity by independent power producers, and to provide a flexible system for a dynamic California economy.

total investment in new generation. For example, in 1993, the CPUC directed the utilities to issue a solicitation for a little over a 1,000 MWs of electricity. QF bids undercut the costs of the utility projects, with price of about \$44/MWh. But SCE (and to a lesser extent SDG&E) successfully resisted entering the new contracts, asserting that no new capacity was needed since conservation could meet any new needs.

¹⁴ Such more localized, small scale generation could also reduce the need for new transmission lines with the very large costs and the environmental impacts of such new development.

Stranded Costs

The prospect of low wholesale electricity prices coupled with high costs for some past investments created challenges for deregulation. If future costs would be low for new generation, then future wholesale prices could be expected to be low, as well. However, with low wholesale costs, the existing high cost generating units might no longer be economically viable in a competitive environment. The investment costs incurred by the utilities in constructing these plants would be “stranded”. Utilities would incur losses because of these stranded costs, absent policy intervention.

The issue of stranded costs was not fundamentally a problem of “going forward” costs – future total costs of electricity generation ignoring sunk costs -- even if those costs might be very high for some of the units. If future wholesale electricity prices turned out to be lower than marginal operating costs of these plants, the plants would shut down in a competitive environment and their entire remaining book value would be a loss to its owner. However, such plants should be shut down for economic efficiency reasons: the value of electricity they produced would be less than the additional cost to produce that electricity. On the other hand, if the future wholesale electricity prices turned out to be higher than the marginal operating costs of these plants, these plants could sell electricity at the wholesale price and would find generation to be more profitable than shutting down. These plants could compete in a market environment, as would be desirable for economic efficiency. However, there would still be a fixed loss: the owner would not be able to recover all of the remaining book value. Although the loss would be strictly less than the book value, it might still be large.

These fixed losses were sunk costs, and therefore not expected to influence the market-clearing price. But someone would have to bear the losses. Who should bear these losses – the utilities or their customers – was a politically important issue. Thus, the issue of stranded costs was simply the issue of who should bear the burden of these fixed costs.

Given the issue of stranded costs, there were several possible alternatives consistent with deregulation of generation. One alternative would be to allow the utility to include those costs in retail prices. That option would keep the retail prices high, just as they would be absent restructuring. That solution would provide motivation for customers to bypass those utilities with large stranded costs. Consumers might purchase directly from generators or might generate electricity themselves, say by investing in cogeneration units. The customers most able to do so would be the large industrial users of electricity that could go directly to new electricity generators and could enter contracts based on the lower costs of new generation or could invest in cogeneration units near the point of use. If enough large customers bypassed the utilities, these utilities would primarily sell electricity to residential and small commercial consumers; small users would thus pay most of the stranded costs. Many consumer groups, not surprisingly, opposed this option.

Another option would be to require the utility to write off the assets as their losses, requiring stockholders would face all consequences of stranded costs. The utilities argued persuasively that it would have been fundamentally inequitable for their investors to bear all the stranded costs of long-term contracts and generating investments that, in many instances, were forced upon them under the old "regulatory compact". They argued that they should be entitled to

recover all of these "prudently incurred" investments. The basic justification was that there had been an implicit contract between the regulators and the utilities, an implicit contract under which utilities would make investments to serve needs of ratepayers and ratepayers would pay back the costs of those investments plus a fair rate of return on the investments, over the life of the equipment. On the other hand, advocates of requiring the utilities to bear those losses argued that the utilities were not blameless in the past investments, that they had proposed most of the investments themselves, that they had mismanaged the long-term contracting for QFs, and that many of the investments were simply mistakes by the utilities. Their recommendation was that the investors in those utilities, not the ratepayers, should be required to bear the stranded costs.

This debate – who should pay the burden of historical investments, now uneconomical – became central to the subsequent regulatory hearings and legislation. In addition, calculations of the magnitude of stranded costs, by necessity, include many subjective elements. No one could predict with any confidence the future sales prices over time of wholesale electricity nor the future natural gas prices. Thus issues of methods for calculating stranded costs and of market methods for reducing the need to calculate stranded costs also remained important. Once the crisis occurred, the theme returned. And as we now look to the future subsequent to the electricity crisis, this class of issues remains central to the policy options, since the State of California incurred large financial obligations during the crisis, obligations that are likely to be losses for someone. We will thus return to these questions in subsequent sections and chapters.

Retail Sales

In addition to expanding competition in electricity generation was the possibility of creating competitive markets for retail electricity. During the 1980s, there was a growing recognition that electricity as a commodity could be unbundled from electricity distribution services. One could envision a local distribution company that provided electricity distribution services as a monopoly, with those services being subject to regulatory oversight, and simultaneously a market in which many firms competed with one another to sell electricity, with that electricity delivered by the monopoly distribution company. In fact, Chile had put such a system in place in the early 1980s, followed by the U.K. and by Argentina in the late 1980s. Australia and New Zealand, also had unbundled electricity in this fashion¹⁵. Thus, it had become clear there was an opportunity for retail competition for electricity sales.

Retail competition offered the possibility that competing retailers would provide differentiated energy services that would be attractive to consumers. Some retailers could provide “green power” to the more environmentally conscious consumers. Others could bundle energy efficiency measures with electricity to help consumers reduce the overall cost of obtaining energy services (e.g., warmth, lighting, cooking, clothes drying, refrigeration). Some retailers could provide higher reliability of electricity for the industrial or commercial customers for whom reliability was essential or interruptible service for those customers willing to accept service interruptions in exchange for a lower overall bill. Some could sell electricity at real-time prices for those customers that wished lowest average cost but did not mind price variability and others could sell electricity at guaranteed prices, essentially selling risk management services

¹⁵ For a discussion of restructuring efforts in other countries, see “Not Invented Here: What California Can Learn from Elsewhere about Restructuring Electricity Supply”, Robert Thomas Crow. Stanford Institute for Economic Policy Research Working Paper, December 2001; Available at <http://siepr.stanford.edu/papers/pdf/01-10.html>

bundled with electricity. A competitive retail market could enhance consumer options and create a more flexible system.

Thus, in the 1990s, there was the opportunity to restructure both the generation function and the local distribution function of the California electricity industry. In addition, there was a motivation to do so. These factors set the stage for the debate on how to deregulate or restructure the California electricity system.

California Public Utilities Commission Leadership

It was California's regulatory agency, the California Public Utilities Commission, that deliberately took governmental leadership to reduce economic regulation in electricity markets, spearheading the move toward electricity deregulation in California. Contrary to the common view of regulatory agencies as bodies working to preserve their own power, the CPUC, or at least CPUC commissioners and staff in the early and mid-1990s, took aggressive leadership on a course of action that promised to reduce their own authority over electricity markets. The deregulation that they envisioned, and at that time it was still deregulation, not simply restructuring, would rely more on competitive market forces in both wholesale and retail electricity markets and less on governmental control over electricity production and use.

Yellow Book and Blue Book

In April 1992, the CPUC initiated a review of trends in the electric industry, which initially resulted in a staff report¹⁶ published in February 1993. This report, commonly referred to as the “Yellow Book,” outlined a set of broad strategies for restructuring the electricity industry to rely more fully on market forces.

Following the Yellow Book was a CPUC Order proposing a process of restructuring California's electricity industry. This Order¹⁷, often referred to as the “Blue Book”, issued in April, 1994, envisioned competitive retail markets, in which “customers would have choice among competing generation providers”¹⁸, with electricity generated through a competitive wholesale market. However, the Yellow Book and subsequent restructuring Orders all maintained the utilities as monopoly providers of delivery services.

The Blue Book laid the foundation for California's subsequent electricity restructuring, proposing several fundamental changes, including replacing cost-of-service regulation with performance-based regulation, wherever regulation was needed. It would thereby strengthen regulated utility incentives for cost reduction. At the retail level, the Blue Book proposed to grant all purchasers of electricity voluntary and direct access to electricity suppliers, in a time-phased manner. In addition, retail customers would be able to purchase electricity from the local utility. The Blue Book envisioned that both the regulated utility (operating wherever possible

¹⁶ “California’s Electric Services Industry: Perspectives on the Past, Strategies for the Future,” February 3, 1993, California Public Utilities Commission.

¹⁷ “Order Instituting Rulemaking on the Commission’s Proposed Policies Governing Restructuring California’s Electric Services Industry and Reforming Regulation” and “Order Instituting Investigation on the Commission’s Proposed Policies Governing Restructuring California’s Electric Services Industry and Reforming Regulation”. R.94-04-031/I.04-04-032

¹⁸ Quotation from Decision 95-12-063 (December 20, 1995). A more complete discussion of this procedural history appears in that document.

under performance-based regulation) and unregulated retail purchases would coexist. Electricity generation would be fundamentally deregulated. Wholesale prices would be kept “just and reasonable” by the discipline of competitive wholesale markets.

The Blue Book addressed the issue of stranded costs by proposing a financial transfer from the utility customers to the generation side of the utilities. This solution to the stranded cost issue essentially remained through the subsequent legislation. The financial transfer would be in the form of a limited-time-duration "competition transition charge". Each retail customer in the utility's service area would be required to pay the competition transition cost for all electricity purchased. The competition transition charge would be non-bypassable: even if a customer were no longer served by the utility, whatever entity sold that customer electricity would be required to collect the competition transition charge. Thus, although the total amount of money collected by the competition transition charge would depend on the total amount of electricity sold at retail, it would not depend upon whether the incumbent utility or some other firm sold the electricity.

The utility would receive all money collected through the competition transition charge, allowing it to recover stranded costs. The magnitude of the competition charge would be chosen to pay for the entire stranded costs for the given utility over a target number of years. Thus, under the Blue Book proposal, The CPUC would estimate the total of stranded costs for a given utility and would estimate the total amount of electricity that would be purchased by customers in the utility's service area over the target number of years. The estimate of total stranded costs would

be divided by the estimate of future electricity sales to determine a competition transition charge (CTC) measured as a dollar per megawatt-hour of electricity sold¹⁹.

The total of stranded costs itself depended on the market-determined wholesale price of electricity. If the wholesale price were very low, then the total stranded costs could be as large as the total of book values of the old plants owned by the utilities plus costs associated with the QF contracts. Conversely, if the wholesale price were very high, then the total stranded costs might be negligible. Thus, the size of the CTC would depend on the expected wholesale price and would need to be periodically adjusted with changing wholesale prices.

In many ways, the CTC looked very much like a temporary tax on electricity use, a tax that was different in each investor-owned utility's service area, depending on the magnitude of the stranded costs of that utility, and differed with the prevailing wholesale price. Unlike most taxes, the revenues would go directly to those utilities with stranded costs, not to a government entity.

If all of a utility's customers remained with the utility and none switched to other suppliers, then the CTC would simply take money from the retail side of that utility and pass the exact same amount of money to the generation side. The CTC would have no financial consequences for the utility as a whole, unless it caused the retail price to change (which it would not under most regulatory regimes.)

¹⁹ The calculation would account for financial discounting of future cash flows by allowing the stranded costs to earn a financial return that would itself be included as part of the calculation of the CTC.

The CTC would be financially beneficial to the utility, however, if some retail customers did switch electricity retailers, no longer purchasing from the incumbent utility. These customers would continue to pay the CTC and the money, so collected, would be paid to the generation side of the utility. The payments to the generation side of the utility for stranded costs would be invariant to the fraction of customers who remained with the utility and the fraction that purchased from other retailers or entered direct contracts with generators.

Decision 95-05-045

Although the “Blue Book” laid the foundation for the restructuring, many steps were required to complete the process. And each step seemed to add more complexity to the restructured system. In May 1995, the CPUC issued a Decision that laid out two broad policy alternatives for organization of restructured wholesale markets and transmission management: a preferred (majority) and alternative proposed policy²⁰.

The preferred structure was a wholesale power pool, managed by an Independent System Operator (ISO). The ISO would dispatch generation based on a day-ahead bidding mechanism and would arrange transmission access for generators that bid to sell electricity at prices no greater than the market clearing price. Under this proposal, management of the grid, dispatch of generators, and wholesale trading would be integrated functions.

Wholesale prices for electricity could vary sharply with supply and demand conditions, with risk for both generators and consumers. Risk management would be available through financial instruments to hedge prices. These instruments, in principle, would be immediately available to

²⁰ CPUC Decision D.95-05-045.

any parties that mutually agreed on them, but the CPUC was to take no responsibility for establishing markets for such hedge instruments. Energy traders and marketers such as Enron seemed prepared to organize such markets. The new system would allow physical, bilateral contracts after two years. Such contracts could be used for risk management after the two years.

The alternative policy recommended consumer choice through direct access contracts. This plan would allow physical, bilateral contracts, separate from any pool bidding, to be available immediately. This alternative would allow the opportunity for competing operators of the transmission grid, with a role for the ISO only when there were transmission constraints. Under this alternative, financial instruments to hedge prices could still be available and risk management through long-term bilateral contracts would have been available to those customers who were able to negotiate such contracts.

The Memo of Understanding

In September 1995, four major participants, including a utility, a group of generators, and two electricity user groups,²¹ presented a Memorandum of Understanding (MOU) with their joint recommendations. Although it addressed virtually all elements of the proposed restructuring, the MOU focused on market structure and stranded cost issues²². The proposed market structure combined features of the preferred and of the alternative proposals from May. The new proposed system would be more complex and less coordinated than would either the preferred or the alternative proposals.

²¹ The Memorandum of Understanding or MOU was submitted by of Southern California Edison (SCE), the California Manufacturers Association (CMA), the California Large Energy Consumers Association (CLECA), and the Independent Energy Producers (IEP).

²² For more discussion of these changes, see “Electricity Market Restructuring: Reforms of Reforms”, by William W. Hogan, May 25, 2001, Harvard University.

The MOU proposed creation of a Power Exchange (PX), creation of an ISO, and early phase-in of direct bilateral contracts between generators and individual customers or distribution companies. Importantly, under this proposal, the ISO and the PX would be separate entities, operating independently of one another. The PX would develop a visible electricity spot market with transparent electricity prices. It would be open to all suppliers, both within and outside of California. The ISO would manage the grid.

This organization structure, with management of the grid, dispatch of generators, and wholesale trading functions kept separate, was very different from the systems that had been adopted in other countries that had restructured their markets. Normally these functions, which are integral parts of a smoothly functioning system, would be tightly integrated into one organization. This structure created the great risk that the functions would not be well coordinated with one another.

The resulting inefficiencies in these markets would provide opportunities for energy traders, such as Enron, to operate profitably; market inefficiencies could create profit opportunities through arbitrage and through selling financial instruments for managing the increased risks. Such profit opportunities to traders would stem directly from the costs the inefficiencies would otherwise impose on generators or consumers. It was a most remarkable public policy concept: California was creating market inefficiencies to make the system profitable for arbitrageurs. More benign explanations for this separation are difficult to conceive.

CPUC Restructuring Order of 1995: The Preferred Policy Decision

A continued set of hearings and public submissions led to a final CPUC restructuring Order²³, issued in December 1995, often referred to as “The Preferred Policy Decision”. The CPUC restructuring Order followed the MOU recommendation to separate the ISO (to manage the grid) and PX (to create wholesale markets.) The organizational separation of the two closely connected functions, unique to California, promised to create an extremely complex and untested system. Like the Blue Book, the restructuring Order proposed to deal with stranded costs through a CTC. The CTC would be designed to allow utilities to recoup all stranded costs²⁴ by the year 2005, a long transition period.

At the retail level, like the Blue Book, the CPUC envisioned a system in which consumers would face many options for electricity purchases. Consumers could continue complete reliance on a local distribution company to purchase and deliver electricity or could opt for direct access through bilateral contracts to deliver electricity. Those relying on a local distribution company could agree to either pay the average cost of electricity throughout the year or pay a real time price, a price that varied on an hour-by-hour basis with changing wholesale market conditions. Those paying a real time price could choose hedging contracts with third parties to reduce the risk.

²³ *Order Instituting Rulemaking on the Commission’s Proposed Policies Governing Restructuring California’s Electric Services Industry and Reforming Regulation*. Decision 95-12-063 (December 20, 1995) as modified by D.96-01-009 (January 10, 1996).

²⁴ In addition, long term contractual obligations entered into before January 1, 1996 would be recovered over a longer time period.

The CPUC restructuring Order included one provision that some have interpreted as imposing a price cap on retail electricity prices. The language of the order was as follows²⁵:

“One of the goals of this proceeding is to lower the price consumers pay for electricity. Recovery of transition costs frustrates this goal because it is possible that the surcharge will exceed price decreases in a given year, resulting in higher electricity-related costs for consumers. To avoid this result, we will cap transition cost recovery so that the price for electricity does not rise, on a kWh basis, above current rate levels in effect as of January 1, 1996 without adjustment for inflation.”

This provision would have limited the size of the CTC, assuring that if the CTC otherwise would have increased electricity prices above the January 1966 levels, then the magnitude of the CTC would be reduced. The precise language suggests that this provision was not intended to prevent increasing wholesale costs from being passed through to retail prices but only to limit the size of the CTC. Thus, it was not strictly a cap on retail prices but a cap on the CTC.

Electricity distribution functions would remain with the utilities and would be regulated by the CPUC. The regulated distribution costs would include a separate non-bypassable component of retail rates that would have provided funds for other social goals: a Public Interest Energy Research Program and demand side management programs to promote energy efficiency.

This restructuring Order had set the framework in place, but not the implementation details. That phase was left to a sequence of other CPUC decisions, including the 1996 Decision, commonly referred to as the Roadmap Decision²⁶. This Decision set in place a process for forming working groups of interested stakeholders to identify and discuss options for addressing many of the implementation issues. Thus, even after the restructuring Order and after the

²⁵ Decision 95-12-063 (December 20, 1995) as modified by D.96-01-009, page 139.

²⁶ CPUC Decision D.96-03-022

passage of AB 1890 (discussed in the next section), the CPUC continued to take the lead in translating the framework of the restructuring Decision and of the legislation into operational rules. Later sections of this book discuss impacts of the CPUC implementation.

Assembly Bill 1890

Although the CPUC had issued the restructuring Order, such a fundamental reform would be politically more viable if it were the product of legislation, not simply regulatory rulemaking. Soon after the CPUC restructuring Order, the State legislature embraced this role. State Senator Steve Peace (D-El Cajon), a highly respected legislator, deeply knowledgeable about energy issues, provided the leadership throughout the process.

The legislative process culminated in Assembly Bill 1890 (AB 1890), formally authored by State Assembly member James Brulte (R-Rancho Cucamonga). This measure was passed by the California Legislature and signed into law in September 1996, by then Governor Pete Wilson. It ultimately became effective in March 1998.

The bipartisan nature of the restructuring legislation was striking. Primary leadership for the entire legislative package came from a Democratic member of the State Senate, Steve Peace; in the State Assembly, a Republican, Jim Brulte (now a State Senator), authored the bill. The bill passed with no dissenting votes from legislators of either party. A Republican Governor, Pete Wilson, signed the bill. Moreover, the bipartisan legislation built upon a very open, very public process led by the CPUC. Although, in retrospect, many commentators critical of California's

restructuring have pointed to Governor Wilson or Senator Peace, in reality the strengths and weaknesses of the restructuring were the result of a remarkably open and bipartisan process involving literally hundreds of participants from both political parties and many with no particular party affiliation.

The legislative process started from the CPUC restructuring Order of 1995, but modified several central provisions and added its own features. AB 1890 recognized that most of electricity was generated, transmitted, and distributed by private corporations. Given this recognition, like the various CPUC Orders leading up to AB1890, this legislation was designed not to change the dominantly private ownership of the electricity system. Rather it was designed to allow competition in places that competition seemed appropriate.

AB 1890, like the CPUC restructuring Order, promised to reduce sharply the degree of vertical integration in the industry. Under AB 1890, a utility could still include the three separate functions: generation, transmission, and local distribution. However, ownership of the three functions would not translate to decision making coordinated among these functions. Decision-making and control of its transmission function would be in the hands of the CAISO, not the utility owning the transmission lines. The market structure provided incentives for local distribution decisions to be made entirely separately from fossil-fuel-fired electricity generation decisions²⁷, so that a utility that both generated electricity from fossil-fuel-fired plants and sold electricity at retail would operate as if two separate companies owned these two functions.

²⁷ Hydroelectric generation could still be coordinated with retail sales and would thus provide the utility some opportunity of changing production with changes in load.

This separation of generation and local distribution was accomplished by requiring the utility to sell through the PX or the CAISO all electricity it generated using fossil-fuel-fired plants. AB 1890 included the following language²⁸:

“All ‘going forward costs’ of fossil plant operation, including operation and maintenance, administrative and general, fuel and fuel transportation costs, shall be recovered solely from independent Power Exchange Revenues or from contracts with the Independent System Operator....”

If the investor-owned utility needed all electricity it generated for sales to its retail customers, the utility was still forced to sell that electricity through the PX or CAISO and purchase that same amount of electricity back. The market clearing conditions operated independently of the identity of buyers or sellers. Thus, in selling electricity, the utility would be unable to show itself any preference as a buyer; in buying the electricity, the utility would be unable to show itself any preference as a seller.

As proposed by the CPUC restructuring Order, AB 1890 separated distribution services from retail sales of electricity. The Act confirmed that distribution services would continue to be subject to CPUC regulatory authority. Distribution service would include a charge, per KWh, to pay for public benefit programs. These included 1) \$228 million per year to pay for energy efficiency and conservation activities that had been supported by utilities, financed through their retail rates; 2) \$62 million per year to create a Public Interest Energy Research program, to be managed by the California Energy Commission; and 3) \$109 million per year to support emerging renewable electricity generation technologies. The total charge would be somewhat

²⁸ Although this language does not strictly require that all electricity the utility generates be sold through the PX or the CAISO, it assures that the utility can recover none of its costs if it fails to do so. That economic incentive is as strong as a strict requirement.

less than 3% of the total revenues of the investor-owned utilities and the majority had already been included in retail electricity prices prior to restructuring.

The Act promised to create competition for retail electricity sales by authorizing direct transactions between electricity suppliers and end use customers and by allowing electricity aggregators. The investor-owned utility would be the default seller of electricity. Direct access was to start simultaneous with the initiation of the PX and CAISO and was to be phased in for all customer classes by January 2002. The CPUC was directed to authorize aggregation of customer electrical load for all customer classes. Aggregation would be allowed by private sector marketers or by cities or other public agencies, as long as individual customers could freely choose remaining with the local utility or purchasing electricity from the aggregator.

The transition period, during which the stranded costs would be recovered, was made much shorter than proposed under the CPUC restructuring Order. This period would end no later than March 31, 2002, or whenever the stranded costs had been fully recovered²⁹, whichever came sooner.

AB 1890 transformed the cap on the CTC into a retail price cap for electricity, a subtle, but very important change. AB 1890 required that the investor-owned-utilities' electricity prices for residential and small commercial customers would be reduced immediately by at least 10% below their June 10, 1996 levels. Since the retail electricity price and the price for distribution services were about the same magnitude, this requirement that the bundled rates be reduced by

²⁹ The utility would be at risk for costs not recovered by March 31, 2002.

10% translated to a requirement that the retail electricity price be reduced by about 20%. For other customers the retail prices could not increase above their June 10, 1996 levels.

In order to recover its stranded costs, each utility would propose to the CPUC a cost recovery plan that included the capped retail prices described above. Significantly, in order for the cost recovery plan to be approved, it had to meet the following criterion:

“These rate levels for each customer class, rate schedule, contract, or tariff option shall remain in effect until the earlier of March 31, 2002, or the date on which the commission-authorized costs for utility generation-related assets and obligations have been fully recovered.”

Thus, under AB 1890, recovery of stranded costs required utilities to formulate and the CPUC to approve a plan in which retail rates would remain constant until the stranded costs were fully recovered.

The system was designed under the anticipation that the CTC would lead to financial accumulations each year and that the stranded costs would be paid over a limited transition period. However, of course, wholesale prices could not be predicted well. In the legislation, there was no statement of what might happen if the wholesale price exceeded the capped retail price, perhaps by a large amount, so that a utility could not pay for the authorized stranded costs nor even preserve any financial assets, as happened during the electricity crisis.

However, AB 1890 imposed no restrictions to stop the CPUC from modifying or abandoning the stranded cost recovery plan once it had been approved, if so requested by the utility. In particular, since the CPUC could agree to reduce the amount of stranded costs to be recovered, it

had the ability, if requested by a utility, to reduce authorized stranded costs to just the amount that had already been recovered. This reduction would terminate the requirement that retail rates for that utility remain at their price-capped level and would allow the CPUC to raise retail prices if needed.

High wholesale prices turned out to be a very large risk. But the risk may have been severely underestimated or completely unrecognized by many participants in the process. The utilities (or their parent corporations) could have protected themselves against high wholesale price by entering contracts for financial hedges, designed to cover risks of buying power from a volatile spot market while selling it at a frozen retail rate. However, although such hedge contracts were offered to utilities, they rejected these offers, apparently believing that the hedges included overestimates of the risks and thus that the prices of the hedges were too high.

In addition, an important safeguard could avoid the anomalous situation of skyrocketing wholesale prices, draining utilities of all financial assets and bringing them to the verge of bankruptcy, while retail price caps were enforced on grounds that the utility was still entitled to recover additional stranded costs. The CPUC could simply reduce allowable stranded cost recovery, terminate the transition period, and raise retail rates. However, the participants in the process probably did not recognize the risk that the CPUC would fail to act in this way when such actions were needed.

AB 1890, like the CPUC restructuring Order, kept organizationally separate the management of the grid, dispatch of generators, and wholesale trading. AB 1890 directed the CPUC work with

the utilities to develop a PX. The PX was to be governed by a board that included representatives of the various stakeholder organizations in California that might be affected by operation of the PX. Otherwise, AB 1890 gave very little guidance about its functions. The only explicit language in AB 1890 was the following³⁰:

“The Power Exchange shall provide an efficient competitive auction, open on a nondiscriminatory basis to all suppliers, that meets the loads of all exchange customers at efficient prices.”

In particular, there was no further guidance about the competitive auction, the bidding structure, or length of the advance period during electricity could be purchased. Such implementation issues were left to the CPUC, the PX Board, and to FERC, the Federal organization that ultimately had the authority to approve or reject any plans developed in California.

Under AB 1890, the transmission system would continue to be owned by investor-owned utilities, but would be subject to FERC review. AB 1890 directed the CPUC to work with the utilities to develop an independent not-for-profit ISO to control the use of the transmission system. This ISO would also be governed by a stakeholder board including representatives of the affected various parties. This organization ultimately became the California Independent System Operator (CAISO).

AB 1890 described in some detail the technical functions of CAISO required for system reliability. However, it gave no guidance to the market functions of CAISO. The only language in AB 1890 hinting at the need for market functions was the following³¹:

“The Independent System Operator shall ensure that additional filings at the Federal Energy Regulatory Commission request confirmation of the relevant provisions of this

³⁰ Section 10 of AB 1890.

³¹ Section 10 of AB 1890.

chapter and seek the authority needed to give the Independent System Operator the ability to secure generating and transmission resources necessary to guarantee achievement of planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council and the North American Electric Reliability Council.”

As with the PX, AB 1890 left implementation issues to the CPUC, the CAISO Board, and to FERC.

The restructuring plan implied that the ultimate control over the design and operation of both the PX and CAISO would be at the Federal level, with FERC, the Federal Agency with regulatory power for wholesale markets for electricity³², rather than with the State of California.

Nevertheless, the design and operating principles would be crafted in California.

AB 1890 directed CPUC to work with the utilities to obtain authorization of FERC for the creation of CAISO and the PX. In April 1996, the three investor-owned utilities -- PG&E, Southern California Edison, and San Diego Gas and Electric -- submitted requests to FERC³³ requesting approval of those restructuring elements subject to FERC jurisdiction. These included creation of the PX, authority to sell electricity through the PX at market rates, the creation of CAISO, the vesting of operational control of transmission with CAISO, approval of PX and CAISO tariffs, and the jurisdictional split, with FERC regulating the wholesale markets and CPUC regulating the retail markets. FERC largely approved these proposals and in 1997, FERC authorized the first limited operation of CAISO and the PX.

³² FERC has jurisdiction over sales of electricity for resale -- wholesale electricity -- and the state remains jurisdiction over retail sales of electricity and intra-state electricity transmission.

³³ FERC Dockets No. ER96-1663-000 and EC96-19-000. The applications were filed after the CPUC restructuring Order but before passage of AB 1890. These applications were approved only after AB 1890 was signed into law. FERC took due note of the passage of AB 1890 during its proceedings.

The set of regulatory changes, culminating in AB 1890, promised to fundamentally change the electricity system from one strictly regulated from “cradle to grave”, into one in which market forces would play the primary role once each utility passed its transition period. Wholesale markets were intended to allow competition to determine supply, demand, and prices of electricity in wholesale transactions. Although analysts envisioned that most retail customers would continue obtaining their electricity bundled with distribution services, sold by regulated utilities, the seeds for a competitive retail market were planted.

The set of changes thus was designed to transform the system while grappling with transition problems of moving from a system of vertically integrated regulated monopolies to a competitive system. This was to be a fundamental and radical transformation of the system, a transformation that required leaders to face a series of challenges. In facing these challenges, new problems were created, as will be discussed in subsequent sections of this monograph.

AB 1890 thus set the framework for the fundamental transformation. However, it was simply a framework, not a set of detailed designs for system implementation. The structure of the PX and the CAISO, as well as of the markets they were to operate, was left to stakeholder committees and the CUPC in California to design and left to FERC to approve or disapprove the designs. Careful delineation of the jurisdictional split between the Federal regulators and the State regulators was left to the various parties to work out.

AB 1890 left the parties with many complex and potentially divisive issues to work out and very little time in which to accomplish that end. AB 1890 came into effect only eighteen months after

it was signed. With such a tight implementation schedule, the original applications to FERC were filed while the California legislature was still considering AB 1890. Once FERC approved the applications, the large size and diversity of the part-time stakeholder boards made it difficult, if not impossible, to seriously rethink or revise the original structure. Working out jurisdictional conflicts within the short time frame was close to hopeless.

The following examines these various system components, in depth.

Wholesale Markets under the Restructured System

The restructured system required several markets and market institutions for buying and selling electricity at the wholesale level. Much work was needed to implement this complex system. Because the system had been newly designed, it was reasonable to expect that some elements of the system design would prove to be flawed and would require modification once the flaws were identified. In addition, because the particular market institutions and the relationship between these institutions could not initially be completely understood, there were significant risks associated with these wholesale markets.

The California Power Exchange (PX)

The investor-owned utilities and the CPUC developed, and FERC approved, plans for the PX and for the wholesale markets that the PX would manage. The PX organized a set of competitive

auctions, open on a nondiscriminatory basis to all suppliers³⁴. The PX initially established one-day-ahead and day-of wholesale markets for electricity. Only much later did it establish markets that allowed contractual agreements extending longer than one day in advance.

For both the one-day-ahead and day-of wholesale markets, the PX accepted bids to sell electricity hour-by-hour and bids to purchase electricity hour-by-hour. Prices for each hour were determined on a market-clearing basis with all buyers for a given hour paying the same market-clearing price and all sellers receiving the same market-clearing price.

In this market, each generator would bid to sell its available supplies at some offer prices³⁵ and each utility (or other load serving entity) would bid to purchase electricity at some offer prices³⁶. Once the market clearing price was determined, all bids to sell with offer prices lower than or equal to the market clearing price and all bids to purchase with offer prices greater than or equal to the market clearing price would be accepted; all sales bids with higher offer prices or purchase bids with lower offer prices would be rejected. The market-clearing price would be determined as the lowest price that would provide enough electricity from accepted sales bids to satisfy all the accepted purchase bids.

This market clearing price setting can be envisioned in an equivalent way. The sales bids would be ranked from lowest offer price to highest offer price – that is, in their merit order. The

³⁴ The three large investor-owned utilities were required to sell through the PX. For all entities other than the three large investor owned utilities, use of the PX was optional.

³⁵ Most of these offer prices would be determined by the owner of the generator itself, although some generators, designated as “must run” would be required to set offer prices equal to zero.

³⁶ In practice, utilities could simply state a quantity of electricity they wished to purchase. That would be equivalent to purchase bid at some very high price, a price assured to be higher than the market clearing price.

purchase bids would be ranked from their highest offer price to the lowest offer price, in their merit order. Equivalently, for purchasers that simply offered to buy a fixed quantity, the quantities would just be added up. At some price, the total of sales bids up to that point in the merit order would be equal to the total of purchase bids down to that point in the merit order. That price would be the market-clearing price.

All sellers would receive the market-clearing price for their electricity, even if they bid less than that price; all buyers would pay the market-clearing price, even if they bid more than that price. This one-price market system was fashioned after typical commodity markets, in the recognition that bulk power was a non-differentiated commodity.

The theory with such a bidding system is that all bids to sell electricity would be priced at the marginal cost of that electricity³⁷. This theory was based on the observation that under such a bidding system, a supplier, bidding its total quantity at a single price in a competitive market, could make the most profit by bidding at a price equal to its marginal cost for producing that electricity. Increasing the sales bid above marginal cost would not increase the payment the supplier would receive from that sale, since all payments would be equal to the market-clearing price, but could cause the firm to lose a profitable sale. Bidding at a lower price than marginal cost would not change the revenues either, if the bid were lower than the market-clearing price. However, such a bid could result in the firm selling electricity at a price lower than its marginal cost, and thus losing money. Therefore, for a firm operating competitively, bidding a price equal to its marginal cost would lead to the greatest profit. For such firms bidding in a competitive

³⁷ The theory was also based on the symmetric assumption that all bids to purchase electricity would be priced at just the marginal value to the user. However, the regulatory system for retail sales of electricity assured that assumption was never valid.

market to sell electricity, there was a strong incentive to offer to sell at the marginal generation cost³⁸.

This system was designed to simulate a perfectly competitive commodity market. In such a market, price would be known and each firm would be able to sell its commodity at that price. It would choose to do so if its marginal cost (including any opportunity cost) were lower than its price. In theory, such a competitive market would be desirable for the wholesale electricity markets and would result in the lowest total cost to generate a given amount of electricity.

There were several alternatives to such an auction system. One alternative, in principle, would have been to set up a normal commodities futures market. People would enter bids to buy and to sell, prices would adjust, and ultimately equilibrium would be reached. However, such an adjustment process would take time. And electricity markets had to adjust on a much faster time scale than normal commodity markets. Markets would need to clear on an hourly basis; there were 24 separate markets to clear for each day. Moreover, all adjustments would have to be completed, starting at most one day before the day of electricity delivery. Thus, prices would need to adjust very quickly. The only viable method was a computer-based system that calculated market clearing prices and matched buyers and sellers of electricity for each hour. That system would simulate the workings of a competitive commodities market without actually being such a market. The single price auction was designed to serve that function.

³⁸ The theory would be precisely correct only if there were a continuum of bid prices so that if the highest successful bidder were to increase its bid price at all, it would then become higher than the next more expensive bid. If, however, there was any gap between the highest successful bid and the next more expensive bid, the firm could make more profit by bidding a tiny amount below the next bidder, not by bidding at marginal cost. But if a firm did not know exactly the prices others were planning on bidding, such a strategy would not be possible. In that case there would still be an incentive to bid just a bid more than the marginal cost.

A second alternative would be to design the system to pay bidders just what they bid, rather than to pay them the market-clearing price. Under such an alternative, just as under the market-clearing system, bids would be arrayed in merit order until sufficient quantities were available to satisfy the bids to purchase electricity. This point in the merit order would determine a cut-off price. Any higher bids higher than the cut-off price would be disregarded, just as under the market-clearing system, while any bids lower would be accepted. Bidders would be paid the price they bid rather than the market-clearing price. The total cost of all purchases would be averaged, and the buyers would each pay the average bid price.

Many have argued that a system of paying on an as-bid basis rather than on a market-clearing basis would result in smaller total payments by the buyers of electricity. After all, those bidding to sell at prices below the cut-off price would not receive the cut-off price but would receive only their bid prices. The fallacy of that reasoning is that it implicitly assumes that the sellers of electricity would offer the same bids under an as-bid system as they would under a market clearing system. However, in fact, the bidding strategies would be very different under the two systems.

Under an as-bid system, each firm makes the most profit by guessing the cut-off price and bidding at or just below that price, as long as the cut-off price is at least as high as its marginal cost. Thus, even in a competitive market, suppliers would not bid at their marginal costs.

If all firms could guess the cut-off price perfectly, then each firm whose marginal cost was no larger than the cut-off would bid the cut-off price and each would be paid the cut-off price³⁹.

The cut-off price would be the same as the market-clearing price. Thus if each firm could guess the cut off price perfectly, an as-bid system would result in the same payments as would a market clearing system. The advantage often postulated for such a system would disappear under the best of conditions, one of perfect guessing.

Although each firm would learn much from observing the results of the hourly bids, 24 per day, there would undoubtedly be mistakes. Expecting to make errors, firms would bid somewhat below their estimate of the cut off price. Some lower cost firms would guess incorrectly and would bid above the cut-off price, thereby leading to increases in the cut off price. Thus, some higher cost firms would generate electricity while some lower cost firms would remain idle. The total cost of generating the given quantity of electricity would therefore be increased above what would be the case in a market clearing system.

The net result would be some variability in the prices paid for electricity at any hour, with some prices higher than what would have been the market-clearing price and possibly some lower.

Whether such a system would increase or decrease the total payments for obtaining a given quantity of electricity would depend upon the precise bidding strategies of the various market participants. However, an as-bid system could be expected to increase the total cost of

³⁹ No firm would bid lower than its marginal cost, the cut off price; the cut-off price would be as high as the price that would be the market clearing price.

generating electricity and would therefore be less efficient than would be a one-price market clearing system⁴⁰.

There was another difficulty with the auction system, arising because the system was based on hour-by-hour bidding and hour-by-hour market clearing. Some generating plants, typically operating as base-load plants, have very long and very costly periods for ramping up from no production to full capacity. These plants might be profitable to operate if they received at a least a particular price, say \$30/MWh, for a large fraction of the day or for all of the peak period during a day. However, if they were operating only a few hours, even at a higher price, say \$40/MWh, they might not be profitable to operate, since the fixed costs of ramping up could be greater than the profit earned during those more limited hours. For such plants, their offer price at any hour must depend on whether they would be generating electricity at the other hours during the day.

For such plants, bidding based on unit commitments, commitments of the unit to operate for long blocks of time, would be more appropriate and might result in lower bid prices. This issue was most likely to be relevant for when market clearing prices were near the costs of baseload plants and least likely to be relevant when market clearing prices were near costs of peaking units. Thus, this issue threatened to increase market-clearing prices during periods of relatively low prices but to have little or no impact during periods of relatively high prices.

⁴⁰ The optimal bidding system in such markets remains a controversial issue and there is much economic literature on the question. England pays on an as-bid system.

Given the alternative auction systems that could be designed, the bidding system designed for the PX was reasonable, although not perfect. Nevertheless, since the system was necessarily untested, it could be flawed in other ways not predicted. In fact, given the potential for strategic bidding or other means of exercising market power, any system designed for the PX could have been flawed. Any system that gave generators an incentive and ability to increase the market clearing price or the cut-off bid price significantly had the potential of driving prices well above competitive levels. Any system that excluded bidding for long term commitments could be awkward for some baseload generators. The possibility of such flaws was an important risk associated with restructuring the California electricity markets, a risk that implied the importance of monitoring the system and then changing the system when problems were identified.

The California Independent System Operator (CAISO)

The system was even more complicated than has been suggested in the previous paragraphs, primarily because of the special characteristics of electricity:

- The amount of electricity used varies sharply over the course of the day as well as over the course of the year.
- The amount of electricity used at any instant cannot be perfectly predicted.
- The amount of electricity used cannot be controlled by CAISO or the utility. When an appliance, machine, computer, or light goes on, it draws electricity from the system. This is true even if insufficient electricity is available.
- Electricity cannot be stored. It is used at the instant it is generated. Therefore, electricity generation must be balanced against electricity use at every instant of time.

- When loads and electricity generation are spatially separated, electricity must be transmitted from the point of generation to the point of use. But transmission capacity is limited. Attempts to transmit too much electricity over transmission path will result in the line shutting down to protect from permanent damage.
- If too little or too much electricity is generated in any locations, relative to the use of electricity, the entire grid could become unstable and could crash.

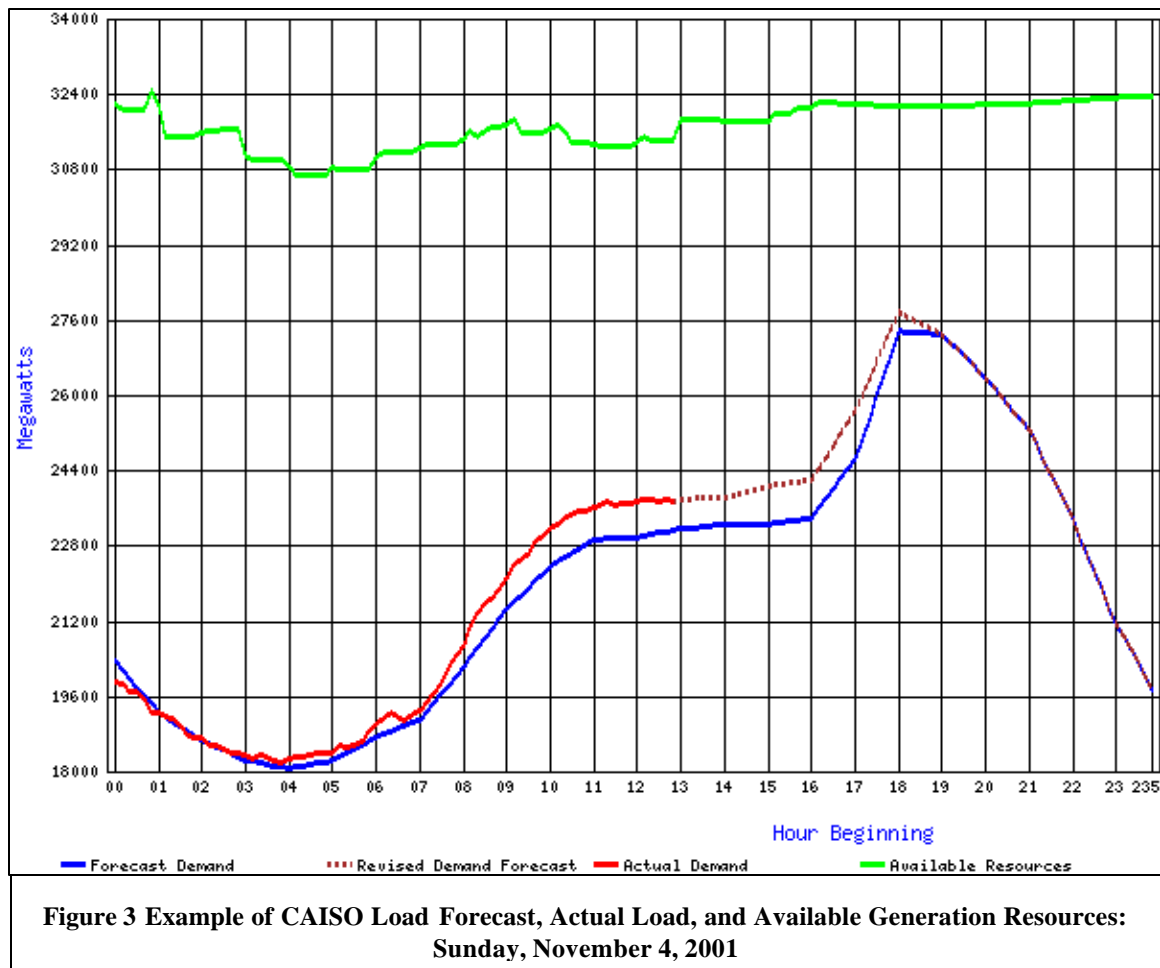
These characteristics necessitated the creation of an organization which would be responsible for managing the transmission grid and for assuring that resources were available to assure safe operations of the grid, including assuring that there would be sufficient quantities of electricity available at all times to support the use of electricity. This organization was to be the California Independent System Operator.

Once markets cleared in the PX for a given hour, utilities and generators would have commitments to receive and to supply electricity. All utilities, in principle, would have balanced loads and resources, that is, the total load they expected, in principle, would be equal to the electricity generation resources committed.

However, those commitments could not assure that the system would operate correctly. First, although each utility might have commitments to supply the total amount of electricity it needed, the individual commitments could well exceed the limitations of the transmission system to move electricity from points of generation to points of load. Some organization was needed to manage this transmission system.

Second, although all loads and resources were to be balanced, in practice the participants in the market, even early in the day of actual delivery, could not perfectly project the electricity needs. Loads could not be perfectly predicted, if for no other reason, because the weather could not be perfectly predicted.

Figure 3, copied from the CAISO web site (<http://www.caiso.com/SystemStatus.html>), illustrates the issues of forecasting electricity usage. This graph shows one day of actual and projected loads, on a 10 minute at a time basis. The particular day is a normal Sunday in November 2001. The top line of the graph shows, in green, the available resources for each ten-minute interval during the day. For this day, the available generating resources are approximately in the range of 30,000 to 32,000 MW.



The lower set of three curves show two projections of electricity consumption and actual consumption. The blue line shows the forecast electricity use completed once the previous day's electricity markets had closed. This forecast provided the basis for scheduling the resources for the day. Note that, unlike the quantity of available resources, the forecast of actual load includes substantial variation over the course of the day. The solid red line shows the actual system demand (plus a 3% reserve margin) on from midnight until noon, when the graph was generated. The broken red line shows the "revised demand forecast", the forecast of the system demand expected for the remainder of the day. CAISO revises this forecast on an hourly basis to reflect changing conditions.

In comparing the actual load with the forecast, one can see that although actual demand closely follows the forecast, at some moments demand is as much as 800 MW greater than the forecast. Even small variations of this type require response by the system operator. Because the actual use of electricity exceeds the forecast, and because the forecast formed the basis for procurement of electricity, the system operator would be required dispatch additional electricity, with very short notice. The requirements to modify generation with short notice are even greater than suggested by Figure 3, since the graph illustrates only the variability across the entire control area. However, additional variability between northern California and Southern California could require generation to be decreased at one location and increased at another.

Third, safe operation of the electricity system requires that operating reserves of generation capacity be made available in order to compensate for unexpected changes: a generator suddenly failing, a transmission line or transformer damaged, a sudden increase in electricity usage. Some organization was needed to obtain contractual assurance that electric generators could be brought on line very quickly if needed. This function will be described more fully in the section “Ancillary Services.”

CAISO Real Time Markets

To perform these functions, the CAISO collected the schedules of electricity to be generated and of the electric loads to be served by the investor-owned utilities, by the municipal utilities, and by a host of other entities, on an hour-by-hour basis. Forty-some “scheduling coordinators” reported their schedules to CAISO; CAISO integrated these schedules and assured that these

schedules collectively did not overload any parts of the transmission grid or were in any other ways not feasible.

Each scheduling coordinator was required to submit a balanced schedule in which the total loads and resources were equal to one another⁴¹. That is, the total projected use of electricity at each hour and the total generating resources to provide that electricity were required to be equal to one another for each submission by every scheduling coordinator. Thus, in theory, the sum total of loads and resources would be balanced for the system, unless the individually submitted schedules would have created too much congestion on the transmission system, in which case CAISO was charged with rescheduling in order to keep the overall system operating appropriately.

However, as noted above, the participants in the market could not perfectly project the electricity needs and the loads and resources could become unbalanced. To correct such imbalances, the CAISO was to run a real time energy imbalance market, buying and selling electricity after the PX day-of market had closed. CAISO, therefore, had to monitor closely the actual use of electricity, comparing that to the quantities submitted by the scheduling coordinators, and had to use that evolving information to guide its purchases and sales of electricity in the real time imbalance market. Purchases and sales could occur up to a few minutes before the electricity would be needed.

⁴¹ More precisely, the sum of all loads and the sum of all generation submitted by a scheduling coordinator must be within 2 MW of each other.

Deviations between predicted and actual supplies and demand would be corrected on this imbalance market. System designers expected these differences to be small: it was anticipated that the imbalance market would require only small purchases or sales. But the CAISO did not institute penalties for imbalances, even for extreme imbalances, although such penalties would be needed to assure that scheduling coordinators did not deliberately mis-schedule whenever it was economically advantageous to do so. Thus, it should not have been a surprise that imbalances turned out to be large fractions of scheduled power.

CAISO was the entity with the detailed minute-by-minute information. Moreover, it was responsible for purchasing and selling electricity on behalf of the scheduling coordinators. Because it was engaging in these balancing transactions, its decision rules were central to the real-time market for electricity. These decision rules were encoded into CAISO software and were made publicly available as part of the published CAISO tariff. Thus, the market participants were fully aware of the rules and the operations of the market. As such, they could make their bidding decisions with full knowledge of how the markets would operate.

One rule was that the CAISO would acquire sufficient electricity to meet the loads it predicted. These predicted loads would not depend on the prices CAISO paid for the electricity and, in particular, CAISO would not reduce its electricity acquisitions, even if the acquisition prices became very high. This rule allowed prices for electricity purchases on the imbalance market to become very high without the discipline of short-run demand reductions limiting such price increases. A second rule was that CAISO would reject bids above some wholesale price cap level. This wholesale price cap (to be discussed at a later point) was during different times

\$250/MWh, \$500/MWh, or \$750/MWh. This rule put limits on wholesale prices in the imbalance market, but they were high limits.

CAISO Ancillary Services Markets

In order to manage the system, given the special characteristics of electricity, CAISO needed to obtain agreements with generators to provide generation reserves, reserves that could be called upon at short notice to increase or to decrease the total generation of electricity. These reserves plus additional resources or loads that can be controlled to keep the system stable are referred to as “ancillary services”.

Ancillary services (see box) include units whose output can be adjusted continuously and remotely by CAISO, units that can be brought up to full load within ten minutes, loads that can be reduced within ten minutes, and generation and loads available within one hour. Because CAISO balances scheduled load and in the actual loads every ten minutes, and adjusts its forecasts on an hourly basis, it acquires a portfolio of reserves that it can dispatch with different amounts of advance notice.

CAISO pays sellers of ancillary services to make their generating units available, should they be needed. If it turns out that these units are needed, the sellers are paid for the electricity generated⁴².

Every load-serving entity (typically an electric utility) is responsible for its proportional share of ancillary services. Each scheduling coordinator can choose whether to provide its share of ancillary services or to have these services purchased on its behalf by CAISO.

For those ancillary services not self-supplied by the scheduling coordinator, CAISO manages a single-price bidding system that operates in day-ahead and hour-ahead periods. The CAISO can obtain additional ancillary services through supplemental bids offered during the hour the reserves are needed.

Types Of Ancillary Services:

- *Spinning Reserve* - Spare synchronized capacity that can be loaded to a specified amount within ten minutes and be sustained for at least 2 hours.
- *Non-Spinning Reserve (Generation)* - Offline capacity that is capable of starting up and ramping to the desired level within 10 minutes and can be for at least 2 hours.
- *Non-Spinning Reserve (Dispatchable Load)* - Dispatchable loads that can be reduced within 10 minutes and can sustain interruption for at least 2 hours.
- *Replacement Reserve (Generation)* - Generation Capacity secured in the day-ahead or hour-ahead market to cover forecast inaccuracies or system contingencies. Units are capable of starting and ramping up to the desired output within an hour.
- *Replacement Reserve (Dispatchable Load)* – Dispatchable loads that can be reduced to a specified amount within an hour.
- *Regulation* - Units controllable by ISO whose output is adjusted continuously by ISO, to balance demand. Must be available to control with ISO AGC Package.
- *Black Start* – Units which can start without an external source of power. Not currently running in auction via SI scheduling system.
- *Voltage Control* – Units which contribute reactive support into the system to maintain system stability. Not currently running in auction via SI scheduling system.

Source: “Scheduling and Bidding Guidelines. Market Operations” California ISO

⁴² Initially this system was set up so that these units would be paid for the electricity plus paid for the ancillary services. However FERC later required CAISO to change the rules so that generators would be paid for either generating electricity or providing ancillary services but not all.

Every generator selling ancillary services, by necessity, could generate electricity (although the converse is not true.) Thus, the generation resources being bid into the ancillary services markets could have been used as resources to generate electricity and many of the resources that were being bid into the real time electricity market could be used as ancillary services. A single resource owner could submit bids to the CAISO to generate electricity and submit bids for each one of the ancillary services. However, the single resource could not be used simultaneously for the various purposes.

Thus, an additional complication for the CAISO was for its software to choose which bid to accept from a single generating resource, if any of its bids were to be accepted.

Relationship of PX Market Clearing and CAISO Market Clearing

The electricity to be bought and sold on the CAISO real time market was exactly the same electricity that could have been bought and sold under the PX in the day-ahead or day-of market. Thus, the PX markets and the CAISO imbalance market were simply alternative venues under which the same electricity purchases and sales could be arranged. Buyers could choose in which markets to make their purchase commitments just as sellers could choose in which markets to sell their electricity. The commitments to purchase and to sell through the PX were simply made up to a day earlier than the commitments to purchase and to sell through the PX real time imbalance market. The PX and CAISO markets therefore were tightly linked to one another.

Moreover, the market participants understood that linkage. Therefore, prices on the two markets could be expected to be statistically very similar as long as firms were allowed to substitute

freely between these two markets. If generators expected the price on the real time market to be higher than the price on the PX, they would avoid bidding into the PX and would choose to sell on the higher priced real time market. This would drive up the prices on the PX and down on the real time market until the expected price difference disappeared. Similarly, if generators expected the imbalance market price to be lower, they would try to sell all of their electricity through the PX, thus lowering the PX price and raising the real time price until the expected price difference disappeared. Incentives were equivalent for wholesale purchasers of electricity. They could schedule their purchases on the day-ahead or day-of PX markets or could acquire their electricity through the CAISO real time imbalance market. This process of adjusting on which market to bid would normally increase or decrease prices on the two markets until market participants expected the prices would equate on the two markets.

However, the rules established for the scheduling coordinators to some extent limited this free substitution between the markets and had the potential of increasing market inefficiencies. In principle, the requirement that all submitted schedules be balanced might imply that firms would not be allowed to substitute completely between these two markets and that there would be relatively little electricity transacted on the imbalance market, except during those times when demand was unexpectedly large or small.

In practice, if utilities expected prices to be significantly lower on the real time market, they would have a strong incentive to submit an unbalanced schedule, with scheduled resources well short of projected loads. However, the rules did not permit anyone to submit unbalanced schedules. This conflict between the incentives for unbalanced schedules and the requirements

that the submitted schedules be balanced could be easily resolved through systematically biasing the projections of loads. A utility that systematically and purposely underestimated load could submit a schedule that would in fact be unbalanced but that appeared on paper to be balanced, thus meeting the letter, but not the spirit, of the requirement for balanced loads. Thus, the requirement that schedules be balanced did not substantially limit the ability of the electricity buyers and sellers to substitute between the two markets and did not lead to systematic price differentials between the PX markets and the CAISO real time market.

In particular, the ability of the utilities to systematically under-estimate their loads implied that wholesale price caps in the CAISO real time markets would translate to market prices in the PX limited by the same price caps, even though there were no formal price caps in the PX markets. If the wholesale market-clearing price would naturally exceed the CAISO price cap, utilities would under-schedule on the PX until the PX price was driven down to the CAISO price cap. The remaining transactions would occur on the CAISO real time market that was controlled by the price cap. Thus, the CAISO price cap would limit all PX prices.

When the price caps were controlling prices, there could be a shortage of electricity: the utilities might not be able to satisfy all remaining electricity demands through purchases on the CAISO. Normally one would expect that the prospect of a shortage in the real time market would cause utilities to bid above the price cap in the PX so that they would not be the ones to experience the consequences of the shortage. That is, if there were a \$250/MWh real time price control that was leading to shortages, one would expect a utility to be willing to bid \$260/MWh or more in the PX in order to acquire all the electricity it needed. Normally, that would assure that utility's

customers would not face required load shedding or blackouts (see discussion about energy emergencies in Chapter 4). However, California had established rules so that during a shortage all utilities would equally share the consequences of the shortage, whether they had purchased enough electricity on the PX to cover their needs or they had greatly under-scheduled. Under these rules, bidding \$260/MWh would cost the utility more but would provide no additional protection. Therefore, there was no incentive for any utilities to bid above the price cap on the PX and the CAISO real time price caps effectively controlled the maximum prices on the PX⁴³.

When a utility consistently under-projected its loads, utility personnel would expect the schedule to be unbalanced and CAISO personnel would expect so as well. However, the submitted schedule would meet the formal requirement to be balanced. One unfortunate result was that the imbalance market would involve a much larger transaction volume than ever intended. In addition, operating rules that kept the CAISO separate from the PX restricted CAISO personnel from working to clear the imbalance market earlier than the hour during which the electricity was needed. This set of rules together made the imbalance market unnecessarily chaotic and further created the inefficiencies that justified the role of energy traders⁴⁴.

⁴³ It should be noted that had the situation been reversed – price caps existed on the PX but not on the CAISO real time market – the PX price caps would not have limited the wholesale price level. In the presence of such PX price caps, if market clearing prices would normally exceed the price cap, utilities would try to schedule all of their loads on the PX but the sellers would offer to sell only on the CAISO real time market. There would be a shortage in the PX market: demand would exceed supply at the controlled price. But that shortage would have no particular relevance to the electricity system since no electricity was dispatched through the PX. The utilities, unable to purchase enough electricity on the PX would need to purchase it on the CAISO real time market; their electricity demands would simply become demands for purchases on the real time market. With no price caps on the real time market, prices would rise to market clearing levels. The fundamental difference from the actual rules is not that the CAISO real time market clears later than the PX markets, as some commentators have suggested. The difference is that electricity is dispatched through the CAISO and shortages there would have a real significance; electricity was not dispatched through the PX and shortages there would create difficulties for the market managers and the participants but would have little or no real significance for the electricity system.

⁴⁴ It is not clear whether energy traders understood that the requirement for balanced loads would create further market opportunities for them or whether that was simply a lucky outcome from their perspective and an unlucky outcome from California's perspective.

There is a second implication of the ability for sellers and buyers to substitute between the various markets for their transactions. Not only would the market-clearing price be statistically the same under the PX markets and the real time. In addition, the price would depend on the total electricity supply and total electricity demand for each particular hour, and not on the fractions of the electricity sold on the various markets. Therefore, for discussions of the overall wholesale price level, it will not be important to distinguish between sales on the PX markets and sales on the CAISO real time market.⁴⁵

Bidding Strategies for Electricity Generators

As discussed above, design of the various markets operated by the PX and by the CAISO was based on the theory that all bids to sell electricity or ancillary services would be priced at just the marginal cost. However, there are reasons that theory might be invalid. First, there was the possibility of exercising market power, and second, optimal bidding in competitive markets may require bidding above the marginal cost. Either reason would lead to bids that exceeded the marginal cost of generating electricity or providing ancillary services.

The theory that a firm would always bid to provide electricity or ancillary services at marginal cost depends on an assumption that a generator or marketer would bid competitively, that is, would bid taking into account the expected prices in the market and would not attempt to change the prices. However, there would be an incentive for a firm to attempt to increase prices if it could do so and still sell its electricity. A generator could bid a high price, expecting it to be rejected. Rejection of the bid would move the market-clearing price up the merit order, and

⁴⁵ However, many issue of short term risk bearing and issues of market inefficiencies will still depend on understanding the differences between these two markets.

might lead to a price increase. However, since the bid would be rejected, the generator's electricity would not be sold and that generating unit would earn less profit not more.

If the generator had a portfolio of units, however, the high price, sure-to-be-rejected offer on one unit could sacrifice profits for that unit but might increase prices on all other units. If the gain on the other units were great enough, then bidding a high price only on one unit could be a profitable strategy. If that were the case, the firm would have an incentive to bid above the marginal cost to increase the market-clearing or cut-off price.

If some bidding strategies were allowed, a generator would not even need a portfolio of generating units. If it were allowed to offer different bids for various portions of the capacity of a single unit, it would not need multiple units. A hypothetical example of the incentive to increase bids above marginal cost can be illustrated. Assume that a firm has 1000 MW to offer for sale in a given hour, has a marginal cost of \$35/MWh, and that the market-clearing price would be \$40/MWh if the firm bid all 1000 MW at its marginal cost. The firm would earn \$5,000 during that hour⁴⁶. The firm may choose as a bidding strategy to offer to sell only 900 MW during that hour at a price of \$35/MWh and the last 100 MW at a price of \$70/MWh. That bidding strategy would change the merit order; assume that the market-clearing price would rise to \$41/MWh, a 2.5% increase. That firm would forgo the opportunity to sell the last 100 MW but would sell the first 900 MW at an increased price, obtaining a profit of \$6/MWh on 900 MW sold for an hour. This profit would now be \$5,400, an increase of \$400. That firm would have a financial incentive to follow such a bidding strategy, increasing the bid price for some fraction of

⁴⁶ The firm would be selling 1000 MW for one hour; the market clearing price would exceed the marginal cost by \$5/MWh.

its capacity above its marginal cost, even though it would not be able to sell the last 10% of its potential output⁴⁷.

The bidding strategy described above might be profitable for many firms, but whether it would be profitable was not known at the time of the restructuring, and is not yet known with certainty even several years later. In the California context, the example, the generator had a capacity equal to only 2.5% of the total generation capacity⁴⁸, a very small market share. Its bidding strategy reduced the amount of electricity offered for sale at market clearing prices by 0.25% of the total and, as a result, increased the market-clearing price by 2.5%. Thus, the example assumes that the percentage increase in price is equal to 10 times the percentage reduction in quantity offered for sale. This assumption might be realistic when the California electricity system was operating near full capacity, the California retail price caps were limiting retail responses, and there were few opportunities for importing additional electricity into California. In this example, under those assumptions, a firm having only a very small market share had the incentive to bid so as to raise the market-clearing price by 2.5%.

Under these assumptions, all firms with market shares of 2.5% or greater and marginal costs of \$35/MWh or greater would have the same incentive as shown above, if such bidding strategies were allowable. If, for example, firms collectively having 50% of the market share would independently all follow the same strategy, then the market clearing price could increase by around 50%, or to \$60, in response to the 5% reduction in total quantity sold. At this higher

⁴⁷ This example depends on the firm bidding high enough so that the high price bid is rejected. If the firm simply offers an increased bid but is able to sell its electricity on this market, it cannot increase its profit this way. In addition, this example assumes that the firm does not expect it might have to repay any overcharges it creates by utilizing this strategy.

⁴⁸ For this example, it will be assumed that at the original market clearing 40,000 MW would be utilized.

wholesale price, a 2.5% market share firm would no longer have an incentive to follow this strategy, but a firm having 5% or more market share would still have an incentive to do so⁴⁹.

If any of the basic assumptions are relaxed (full capacity, retail price caps, little opportunity to import additional electricity, multiple bid levels allowed from one unit) then there would not be an incentive or the incentive would be greatly reduced. The relaxation of any assumption (other than the fourth one) would reduce the impact of supply reductions on price. In that case, the incentive to bid above marginal cost would be sharply reduced and would be relevant only for firms with significantly greater market share.

For example, assume that under the same assumptions as described above, the percentage increase in price would be twice as great as the percentage decrease in supply. If the firm offered to sell only 900 MW at marginal cost and the last 100 MW at a price above market clearing, then the market clearing price would rise to \$40.20/MWh, a 0.5% increase. That firm would obtain a profit of \$5.20/MWh on 900 MW, sold for an hour: a profit of \$4,680, a decrease of \$320. That firm would not have a financial incentive to follow such a bidding strategy. Similarly, a 5% market share firm would not find such a strategy profitable⁵⁰.

⁴⁹ With a market clearing price of \$60/MWh, the firm having only 1000 MW of capacity would no longer have an incentive to bid high prices for 10% of its capacity. However a firm with 2000 MW, a 5% market share, would have such an incentive. That firm, if it bid all 2000 MW at cost would obtain a profit of \$50,000 for the hour. The firm reducing its sales to 1800 MW could increase market clearing price 5% to \$63/MWh. This would increase the difference between price and marginal cost to \$28/MWh and would increase profit to \$50,400. Thus the incentive to offer a very high bid on a small fraction of the output would remain for firms with a 5% market share even though it would disappear for firms with only a 2.5% market share.

⁵⁰ If the firm offered to sell 1800 MW at marginal cost and the last 200 MW at a price above market clearing, then the market clearing price would rise to \$40.40/MWh, a 1% increase. That firm would obtain a profit of \$5.40/MWh on 1800 MW sold for an hour, earning \$9,720, rather than the \$10,000 it could earn by bidding at marginal cost.

If the firm were restricted in its bidding so that a segmented bid would require 50% of its output to be offered at the higher price, the incentive would also disappear. Assume again that the percentage increase in price would be 10 times as great as the percentage decrease in supply. If the firm offered to sell only 500 MW at marginal cost and the last 500 MW at a price above market clearing, then the market clearing price would rise to \$45/MWh, a 12.5% increase. That firm would sell the first 500 MW obtaining a profit of \$10/MWh on 500 MW sold for an hour. This profit would now be \$5,000, neither increasing nor decreasing. That firm would not have a financial incentive to follow such a bidding strategy.

Thus, exercise of market power would be less likely when the system were well below capacity or when additional electricity could easily be imported into California. In addition, if demand for electricity were more responsive to price changes, then supply reductions would have only smaller impacts on prices and the incentives to bid above marginal cost would be much smaller than suggested in this example.

With California's restructuring there was a significant risk that firms could and would exercise market power in the manner described above or by following other bidding strategies. This created risks that the wholesale market prices would be too high. Moreover, the risk that firms might exercise market power did not depend on the particular auction system. The potential would have been as great for an as-bid auction system as it was for a market-clearing system. Thus, this was a risk of moving to almost any deregulated wholesale market.

In addition to the risk that generators could exercise market power was the possibility that competitive reasons would cause generators to offer bids to sell electricity or ancillary services at prices greater than marginal generation costs. These competitive reasons would likewise lead to market-clearing prices higher than would be the case in their absence.

As indicated above, generators selling ancillary services could generate electricity and, for many firms, generators selling electricity could have used the capacity to sell ancillary services.

Although a single resource owner could submit bids to CAISO to generate electricity and bids for each one of the ancillary services, the single resource could not be used simultaneously for the various purposes. The generator had to decide what prices to place on each of its bids, given its understanding about how the CAISO software would select among the various bids from a single generator. The generator bidding on the PX had to decide what prices to bid, given its belief about the CAISO prices for real time imbalance electricity and for ancillary services, markets into which it could bid, but only if it did not commit its electricity on the PX.

Given multiple opportunities, a firm bidding competitively – that is, not expecting to change any market clearing prices -- would not obtain the greatest profit by bidding at just its marginal cost. Such a profit-maximizing firm, when bidding to sell electricity on either the PX or CAISO markets, had a financial incentive to take into account its opportunity cost⁵¹ of not being able to sell the capacity as ancillary services. Taking into account the opportunity cost would lead to increases in the offer price at which it would bid to sell electricity. Similar considerations would hold for bidding into the ancillary services markets. A profit-maximizing firm, when bidding to

⁵¹ The opportunity cost is the cost of having to forgo one opportunity in order to pursue another opportunity. Although opportunity cost is not easily measurable, it is a real economic cost often important for decisionmaking.

sell its capacity as non-spinning reserve, must take into account its opportunity cost of not being able to sell the capacity as another ancillary service, say regulation. Thus, the bid to sell as non-spinning reserve normally would be increased above marginal cost.

In general, optimal bidding will require the generator to estimate an opportunity cost based on the most profitable of the alternative uses for the generation capacity. This opportunity cost must be added to the marginal cost in order to determine optimal bids if the firm were operating competitively. Thus, firms bidding competitively can be expected to bid generation capacity at prices that are greater than marginal costs.

The magnitude of the opportunity cost will depend on the expected market-clearing price for electricity or for ancillary services in the most profitable of the alternative uses. However, the generator does not typically know these market-clearing prices at the time it submits its bid, but must guess them. Thus, for a firm bidding competitively, the bid prices for each possible use of the generation capacity must take into account the bidder's best estimates of the market clearing prices for each ancillary service and for electricity in addition to the bidder's estimates of its own marginal costs. Given the number of interacting markets, the problem of choosing the profit maximizing bids would be very complex⁵². But, no matter how complex the bidding problem, the optimal bids will normally be at prices greater than marginal cost.

⁵² Consider, for example, a firm bidding to sell electricity into the PX. It knows it could bid to sell the generating capacity as a reserve in an ancillary services market. It knows that if it makes the capacity available as a reserve, there would be some probability the capacity will be called upon to deliver electricity. Thus the opportunity cost would take into account the profits it would expect to earn being available as a reserve and the profits it would earn if it agreed to remain as a reserve but were called upon to generate electricity, with each term scaled by the probability of that event. Thus the firm would need to evaluate the expected prices for ancillary service and the prices it would be paid for electricity, as well as the probabilities of the various outcomes.

The role of opportunity costs in raising prices can be difficult to evaluate quantitatively by an independent market observer because opportunity costs cannot be directly observed. Similarly, the role of market power in raising prices can be difficult for independent market observers to evaluate quantitatively since the exercise of market power may involve complex bidding strategies. These difficulties translate to monitoring problems since the two issues are, at least on the surface, observationally equivalent. The simple observation that bid prices exceed marginal cost does not establish how much of the deviation is the product of market power and how much is the product of a purely competitive recognition of opportunity costs.

Divestiture of IOU Generating Assets under the Restructured System

AB 1890 and subsequent CPUC rulings sharply reduced the degree of vertical integration in the industry. Although an investor-owned utility could still include the three separate functions – generation, transmission, and local distribution – the legislation assured that ownership of the three functions would not translate to coordinated decision making among these functions.

However, there was still a concern that common ownership of generation and retail functions would make it difficult to operate a competitive wholesale market and that utility ownership of large market share of generating capacity would give the utilities market power, resulting in wholesale prices of electricity that would be too high. To address that concern, several options could have been implemented at the time of the restructuring.

First, the restructuring legislation could have allowed the utilities to continue acquiring electricity directly from their own generators, as well as buying it from non-utility generators,

either through organized markets or through bilateral contracts. This option would have allowed the utilities to maintain some vertical integration. However, this could have posed incentive problems. First, it was recognized that acquisitions by the distribution component of the utility from the generating component would not be at arm's length. This would be true even if these functions were organized into two companies operating under the same corporate ownership, selling to one another. Prices would be set as inter-corporate transfer prices and thus would not be truly arms length. Therefore, inter-corporate transfer pricing for financial regulation would not be dependable; there could well be incentives for increasing or decreasing the transfer price.

In addition, many people believed that a competitive wholesale market would not be possible without divestiture of generating assets. In particular, the local distribution component of the utility would choose to purchase from its own generating component even at a higher cost than electricity offered by new market entrants generating electricity. Once beyond the transition period, those high costs would simply be passed on to the consumers⁵³. Since potential entrants in the wholesale market would understand these incentives, there would be only reduced incentives for new companies to invest in new generating assets. Existing electric utilities would then not face the market competition in their roles as electricity generators that was the goal of the restructuring. The desirable benefits of a competitive system might not emerge.

Finally, this plan would not reduce the market power of the utilities in the wholesale markets.

Although they would be net sellers of electricity as a corporation, if they faced average cost

⁵³ Any utility that paid its own generating assets a higher than competitive price at the wholesale level of the market would increase its own average cost. A regulated utility would pass on these higher costs as higher prices to retail customers. If there were full retail competition, the increase in price of the regulated utility would give its competitors an advantage and the regulated utility would begin to lose market share. However without such full retail competition one could not assure that retail competition would fully discipline such wholesale transactions.

regulation for their retail sales, there still would be an incentive to exercise market power in wholesale markets since they were net sellers in those markets.

A CPUC ultimately implemented a two-fold solution. First, the CPUC required and/or strongly encouraged the utilities to divest themselves of their generating assets, wherever possible. They were required to divest 50% of their generating assets and they faced strong financial incentives to divest the remainder. Second, all remaining fossil-fired electricity generation owned by the utility could be sold only through the PX or the CAISO⁵⁴. Together, those rules would assure that the PX and the CAISO markets would include large volumes of transactions and that utilities would be precluded from any meaningful self-dealing between their wholesale and retail operations, and would eliminate or sufficiently reduce their market power in the wholesale markets.

Divestiture would have one other regulatory advantage. Once the CTC was selected as a mechanism for recovering stranded costs, there still was the problem of the appropriate measurement of stranded costs. If the utilities continued to own the generating plants, there would not be a clean test of how large were the stranded costs. There would be the need for further hearings and possibly litigation to determine the values of the plants the utilities still owned. However if they sold the plants, the economic loss could be measured easily as the difference between the remaining book value of the generating plant and its sales price. Thus, although this was at most a secondary reason, it did provide some motivation for encouraging the utilities to divest much of their fossil generation capacity.

⁵⁴ More precisely, no costs could be recovered for this generation unless the electricity were sold through the PX or the CAISO.

The incentives for divestiture were successful. As of 2000, only 29% of the electricity sold in the State was generated by the utilities and 44% of the electricity was generated through plants that had been divested by the electric utilities and was then owned by non-utility generators. Details of the sales appear in Table 2 below, including which plants were sold, to which firms, of what nameplate capacity, the book value and the sales price.

When generation plants were sold at prices above their book value, the transaction would reduce the amount of stranded costs yet to be recovered through the CTC. Although some plants sold at prices below their book value – and thus were truly stranded costs – most plants sold at higher prices. On net, the divestiture of plants resulted in sales prices that exceeded the remaining book values by more than 70%, significantly reducing the amount of stranded costs yet to be recovered through the CTC.

Power Plant	Purchaser	Nameplate Capacity MW	Book Value \$million	Sale Price \$million
Morro Bay, Moss Landing, Oakland Contra Costa, Pittsburg, Potrero Geysers (Sonoma & Lake Counties)	Duke Energy Corp.	2,881	390.2	501.0
	Southern Energy	3,166	318.3	801.0
	Calpine Corp.	1,353	273.1	212.8
	PG&E Subtotal	7,401	981.6	1,514.8
Alamitos, Huntington Beach, Redondo Beach Cool Water, Etiwanda, Ellwood, Mandalay, Ormond Beach El Segundo, Long Beach San Bernadino, Highgrove	AES Corp.	4,706	224.1	781.0
	Houston Industries	4,019	288.3	277.0
	NRG Energy and Destec	1,583	168.8	116.6
	Thermo Ecotek	300	(4.3)	9.5
	SCE Subtotal	10,607	676.9	1,184.1
Encina, Kearny, and other Peakers South Bay	NRG Energy and Dynegy	1,347	94.8	365.0
	San Diego Unified Port District	833	64.4	110.0
	SDG&E Subtotal	2,180	159.2	475.0
Total		20,187	1,818	3,174

Table 2 Divestiture of IOU Generating Assets in California. Source: California Energy Commission

Long Term and Medium Term Wholesale Contracts for Electricity

The divestiture, required by the regulations, created potential new problems, problems associated with the accounting to recover stranded costs. As the investor-owned utilities divested their generation assets, there could be incentives for the utilities to enter into long term electricity purchase contracts with the company buying the generators. If there were linked agreement both to sell the generator and to purchase electricity under a long-term contract from that generator, there was a fear that the financial incentives could distort the selling price and the long-term sales price. Guarding against this potential would require more regulatory oversight.

In addition, there was a fear that long-term contracts could simply substitute for a utility ownership of the generators and a competitive market might not be created. Potential new entrants into the wholesale electricity market might be discouraged in the same way as would be the case absent divestiture of the assets. In order to assure that the wholesale markets would not be too thin and there would be too little competition, there was a desire to limit the long-term contracts at the wholesale level.

However, this fear failed to recognize that with growth in electricity use would be growth in the needs for new electricity generation. There would be competition among the suppliers to provide for these new needs. That competition could be through spot markets or through market competition for long-term contracts.

The competition to offer electricity on long-term contracts can as intense as, or more intense than, spot market competition. Such competition for long-term contracts could allow a buyer of

electricity and the seller of electricity to negotiate for a set of mutually satisfactory contractual terms, including appropriate distribution of risks and obligations. Because of the long-term significance of such a contract, the competing sellers tend to put much attention into their offers and the purchasers tend to evaluate the alternative offers very carefully.

Since long-term contracts can include mutually beneficial agreements on risk sharing, the average prices in these contracts could be lower than the expected prices when all competition is based on spot markets. A merchant generator facing the vagaries of water conditions, temperature, gas prices, and day-to-day fluctuations on spot markets may need a higher average market clearing price to finance new generation than would a merchant generator with a long-term contract, having secure commitments to buy electricity at fixed prices or prices indexed to a reasonable set of external market conditions (such as the natural gas price).

Thus, the linked beliefs that 1) exclusive reliance on spot markets was necessary to assure competition and that 2) negotiated long-term contracts would limit competition were both fallacious. However, these beliefs, even if they were fallacious, seemed to motivate the CPUC, in implementing AB 1890, to impose regulatory restrictions against the utilities entering long-term contracts.

In order to guard against the perceived problems of long-term contracts, once AB 1890 had been passed, the CPUC restricted the ability of the investor-owned utilities to enter into any long-term or medium term contracts. The CPUC required the utilities to acquire all their electricity, not already under long-term contract, through the PX or through CAISO. This restriction went well

beyond the long-term contracts. Since the PX and the CAISO originally did not have long-term or medium-term contracts, this requirement effectively prohibited the utilities from entering any long-term or medium-term contracts.

The utilities tried as early as 1999 to gain the right to procure electricity on a longer term basis. In March 1999, SCE filed an application for a pilot program under which it could enter traditional power purchase agreements for electricity and for capacity. But the CPUC denied the application. In mid-1999 the PX applied to organize a block forward market, FERC approved the application, and the CPUC approved the request by SCE and PG&E to participate in that market. But the block forward market allowed contracts for no more than one year. More significantly, such markets, by necessity, offered a standardized contract and did not allow the wide range of contractual agreements that would be desirable for a utility to cover its purchases. But it was a step, albeit a small step, toward allowing the utilities to move away from exclusive reliance on spot markets to acquire electricity. However, until August 2000 the utilities had no right to enter bilateral contracts. The year 2000 events will be discussed in the following chapter.

Although there may have been a reason for discouraging long-term contracts during divestiture, once the divestiture was completed, there was no continuing need to regulate against such contracts. There was already much economic bias discouraging investor-owned utilities from committing to purchase very large quantities of electricity under long-term contracts⁵⁵.

⁵⁵ This issue is discussed more fully in a later section “Risk Bearing in the Restructured Retail Market.”

There remains debate about whether the CPUC decisions following AB 1890 were completely responsible for the investor-owned utilities' lack of long term contracts or whether the utility executives should have entered these contracts, with the stock holders bearing the asymmetric risk. Whatever the resolution of this debate, if it ever is resolved, factually, the utilities had been relying dominantly on short-term spot markets for electricity when it became apparent that wholesale prices were rising rapidly. The financial risk was very great.

If investor-owned utilities had, after the restructuring, developed portfolios of contracts, some long term, some medium term, and some more flexible, they could have managed some of the risks inherent in the new system.

It is important to note that long-term contracts would not have been a panacea. Nor would long-term contracts have assured that the investor-owned utilities would be able to buy wholesale electricity at lower prices than they could with short-term contracts. Contracts, whether short-term, medium-term, or long-term must have two parties. If the parties knew with significant certainty that the short-term prices would always be higher than the proposed long-term contract price, the rational electricity supplier would never be willing to offer such a long-term contract. Conversely, if the parties knew with significant certainty that the short-term prices would always be lower than the proposed long-term contract price, the rational electricity buyer would never be willing to accept such a long-term contract. For both parties to agree on a long-term contract price, they must assign a significant probability that short term prices will be higher than the long-term contractual price and a significant probability they will be lower. Thus, it was never

the case that entering into long-term contracts could have dependably reduced electricity acquisition prices from what the spot prices.

However, entering such contracts could have substantially reduced the risk of large changes – up or down – in the acquisition cost of electricity. Utilities with such contracts thereby could have guarded against or at least limited the high risk of large fluctuations in the wholesale price of electricity. But that was not to be the case and thus the system was characterized by unnecessarily large risks.

Risk Bearing

Restructuring of wholesale markets created deep economic risks for investor-owned utilities.

The wholesale market for electricity promised to be very volatile. Capacity limitations of electricity generators implied that if the system were to approach capacity, marginal cost would increase sharply. All spot sales of electricity would sell at a price equal to this marginal cost. Thus, small differences in requirements for electricity generation could lead to very large differences in the spot wholesale price. Moreover, the utilities were buying most of their electricity on these spot markets, because they had divested most of their generating assets and had not entered long-term electricity supply contracts. Thus, total expenditures for acquiring electricity could increase sharply. Although this would not be a particular issue if the system would never approach full capacity, continuing excess generation capacity could not be guaranteed.

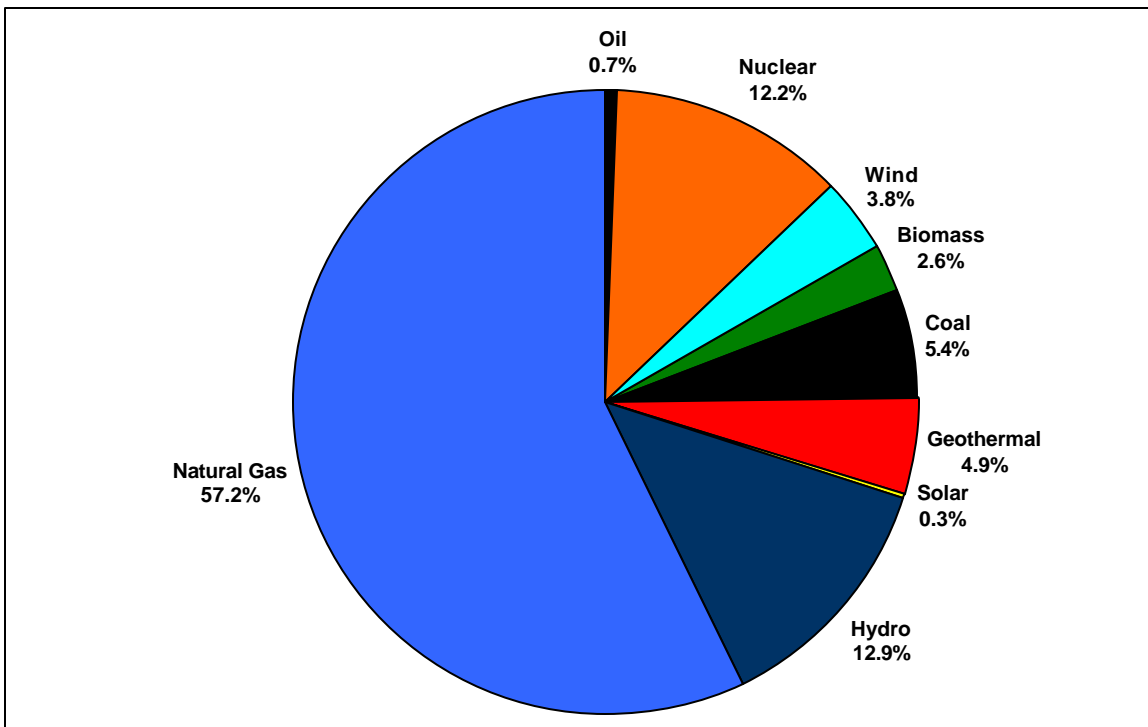


Figure 4 Operational Capacity of California's Three Investor-owned utilities. Some Nuclear, all Coal Are Out of State. Source: California Energy Commission.

The mix of generating facilities increased the risk that the system could approach capacity limitations or otherwise face volatile prices. Figure 4, to the left, shows the operational capacity of California's three investor-owned utilities in terms of the primary sources of energy used to generate electricity.

Over half of the primary energy was natural gas. However, the infrastructure of pipelines to move natural gas in California was extremely limited, as was the capacity of pipelines to bring natural gas into California. Therefore, the risk stemming from the high volatility of natural gas prices and natural gas availability in the State was great. Utilities could, and did, sign long-term contracts to buy natural gas. However, such contracts, while reducing this risk, did not eliminate the risk entirely and would not assure that additional gas could be obtained when needed.

Another twenty percent of the electricity was generated through hydropower. However, the amount of available hydropower depended upon the rainfall during the previous year. More significantly, much of the imports of electricity into California were derived from hydroelectric power in the Pacific Northwest. However, the availability of this electricity also was subject to much uncertainty. In addition, low rainfall in California could be expected during those years of low rainfall in the Pacific Northwest. These risks were highly correlated so that overall risk was increased.

Nuclear power had its own financial risks. In addition to cost and reliability variability, nuclear power faced political risks that nuclear electric generating plants would be shut down for safety or other environmental reasons.

Divestiture had greatly increased the risk facing investor-owned utilities, although it did not change the inherent system risk. If the utilities had continued to own their generating capacity, they would have faced cost variations that changed with the average generation cost; but because they had divested the assets, they would face cost variations that changed with the marginal cost of electricity. Since the marginal cost is much more volatile than the average cost, divestiture led to far more cost volatility for the investor-owned utilities.

This risk could have been mitigated by long-term contracts, even long-term contracts whose prices were indexed to some measure of average cost of electricity generation, say contracts indexed to natural gas prices. However, the CPUC discouraged long-term contracts.

Generation Capacity Risk

Under both the old integrated system and the restructured competitive system there were inherent risks associated with decisions on how much new generation capacity to build, with costs of operating existing capacity, and with contractual commitments to buy or sell electricity. The fundamental risks associated with costs of fuel to generate electricity were the same under either system, as were the uncertainties about demand growth. If reserve capacity were the same under the two systems, then the risks of short supply of energy would be the same under the two systems.

However, the incentives for capacity investment and utilization are very different under the restructured system than under the old system of vertically integrated utilities.

Under the old integrated system, if all utilities maintained enough reserve capacity so that marginal generation costs remained very low, all could still earn sufficient financial returns on the capacity to justify the investment. Thus, utilities could continually invest in new generating capacity and the system could maintain equilibrium with adequate reserve capacity. The retail utility customers would continue paying the cost of the infrequently used capacity and electricity prices would remain systematically high. The systematically high prices would remain quite stable over time. Risks would be low because there would adequate reserve capacity.

With competitive wholesale markets, if all merchant generators maintained enough reserve capacity to assure that marginal generation costs remained low, wholesale prices would remain

low. However, most generators could not earn sufficient financial return on the capacity to justify the investment. Investment would be halted, leading to reductions in reserve capacity over time. As reserve capacity dropped, the frequency of price spikes would increase and the average price of electricity would increase. The incentive to build new generation capacity would increase. If all went well, the system would approach a new equilibrium in which the average price of electricity would be equal its average cost and the average over time of its marginal cost. In this equilibrium, the system would have less reserve capacity than it would under the old integrated system. As a result, the average cost and the average over time of price would be lower than under the old integrated system. However, prices would not be stable. Risks would be larger than under the integrated system because there would be only smaller amounts of reserve capacity.

However, in this new restructured system, reserve capacity might not smoothly approach a new equilibrium, especially if there are long lags from the decisions to invest in new generating capacity until the time that generating capacity were online. It would be quite possible to have periodic times of inadequate reserve capacity and periodic times of excess reserve capacity, classic “boom and bust” cycles. During times of inadequate reserve capacity, wholesale prices would become very high, encouraging much new investment, particularly if investors did not have good information about future conditions; during times of excess reserve capacity, wholesale prices would be very low, discouraging investment. Unless investors could reasonably project future conditions, including the new electricity generation capacity to be constructed, each boom period would set the stage for the next bust; each bust would set the stage for the next boom. Risks would be further increased.

Such wholesale market fluctuations would be very disruptive even if they, on average, did not increase the wholesale electricity price. Such fluctuations could create political pressures for price stabilization regimes at either the wholesale or the retail level. In addition, if, as was the case in California, retail price controls were already in place, such fluctuations, even short-term fluctuations, would carry with them the possibility of financial crises.

In a competitive market system, encouraging the right amount of reserve capacity is very difficult and, to reduce the risks, careful policy development is needed. Several options can mitigate the risks of “boom and bust” cycles in competitive wholesale markets. First, good market information on projected demand growth, energy efficiency investments, and new capacity investments helps to reduce the cycles associated with myopic decision making. Markets for capacity in addition to markets for the electricity itself could help, but have their own difficulties. Long-term contracts between generators and utilities can help match capabilities with needs and can reduce the problem.

However, in the period after AB 1890 was signed, none of these options was adopted. The California Energy Commission reduced its role in creating forecasts of future electricity supply and demand conditions. No capacity markets were established. Long-term contracts were discouraged. Thus, the new system created risks of severe long-term price fluctuations but did nothing to mitigate those risks.

Wholesale Markets: In Summary

AB1890 and CPUC rules created a complicated set of wholesale markets imperfectly coordinated with one another. These markets were given monopoly or near monopoly status and thus utilities could not escape any problems associated directly with these markets. There remained opportunities for exercise of market power by even those generators with small market share. Risk management options were taken from the investor-owned utilities through divestiture and through over-reliance on spot wholesale markets. And volatility in the wholesale markets was nearly assured. The risk of boom and bust cycles was created. The interplay of these various markets, the resulting bidding strategies of utility-buyers, generators of electricity, electricity marketers, and municipal utilities, and the responses of the CAISO and the PX personnel were all untested at the time of the restructuring.

The associated risks through the wholesale markets were natural implications of this particular system restructuring, and in fact, would have been risks of any radical restructuring of the electricity system. The existence of risks does not imply that the undesirable outcomes will occur, but that they may occur. Risks suggest the need to monitor the wholesale markets and to be prepared to modify the system if the undesirable outcomes in fact came about, something that political leaders need to be willing to do.

Retail Markets under the Restructured System

Creating competitive retail markets was seen to be even more of a challenge, even though there had been extensive experience in other nations such as Australia, New Zealand, and Great

Britain. An ultimate goal was for there to be a competitive retail market for electricity.

However, at least two factors stood in the way: retail market power and risk management.

Although issues of retail market power and risk management could, in principle, be the same for investor-owned utilities, municipal utilities, and co-ops, the restructuring legislation treated investor-owned utilities differently than the others, if for no other reason, because the CPUC had jurisdiction over only investor-owned utilities. Thus, the initial CPUC restructuring Order and AB 1890 applied only to investor-owned utilities, not to the municipal utilities or the co-ops. Since the rules for investor-owned utilities fundamentally changed and the rules for municipal utilities and co-ops did not, most of the following sections will discuss the investor-owned utilities and little attention will be paid to municipal utilities and co-ops.

Local distribution companies had a natural monopoly for the delivery services, the wires, transformers and control systems. In addition, in the short term they could be expected to have a significant degree of market power for the electricity itself, since electricity had always been sold as a commodity, bundled with the delivery services. Unless retail sales of electricity were unbundled from sales of delivery services, the issue of retail market power would remain.

The system established by the CPUC and AB 1890 therefore allowed delivery services to be decoupled from the retail sales of electricity. The delivery services would still be provided by the investor-owned utilities, operating as monopoly franchises, earning a regulated fee. The commodity itself could be sold by aggregators or by generators. Or utilities could sell electricity bundled with distribution services.

Investor-owned utilities would operate as regulated retail sellers of electricity, subject to review and control by the CPUC. The CPUC communicated its intention to move to performance-based regulation, a system whereby performance goals would be negotiated, including cost performance improvements. Nevertheless, whether such a system was implemented, the investor-owned utilities would remain as regulated firms.

As discussed above, during the transition period, AB 1890 imposed price caps for retail electricity sales by the incumbent utilities during a transition period. This price cap created a dilemma. On one hand, the utilities were being required by AB 1890 to reduce electricity prices for residential and small commercial customers. On the other hand, the CTC magnitude was to be chosen so that all stranded costs would be recovered over a small number of years. Thus with the CTC, the retail price of electricity would be approximately equal to the recent historical electricity component of the bundled retail price, not 20% below that level.

The dilemma was resolved through a financial instrument. The utilities were authorized during the transition period to issue “rate reduction bonds” to finance the difference between their cost for electricity (wholesale price plus CTC) and the price capped retail price as well as to refinance some of their existing capital equipment. These bonds would be repaid once all stranded costs had been recovered and the CTC was no longer in operation. This plan implied that the retail electricity price reduction that the ratepayers thought they were enjoying would be repaid in later years.

Retail Competition

The CPUC restructuring Order and Assembly Bill 1890 created the opportunity for competition for retail electricity sales, in principle allowing any customers to enter bilateral contracts with electricity suppliers and therefore to bypass the electric utilities, even though the CTC could not be bypassed.

The investor-owned utilities would be default sellers of electricity, available for everyone who wished to purchase their retail electricity from these utilities. Their price-capped rates would be available for all customers, even those that switched to other retail suppliers but subsequently chose to return. This implied an asymmetrical relationship between the utility and the new competitors: the new competitors could choose whether to take new customers, but the utility had no choice whether to take new or returning customers.

Direct access and retail electricity competition for residential and small commercial customers was made more difficult by the retail price cap. For other electricity suppliers to be competitive on the basis of price, these other sellers would have to sell electricity at the investor-owned utility's capped price as well, after paying the CTC: they would have to sell electricity at prices lower than the sum of the wholesale price plus the CTC, losing more money the more electricity they sold.

New entrants could create a distinction in the minds of consumers about electricity delivered from different companies. For example, they could sell "green" electricity, advertised to be generated entirely or primarily by renewable sources. But this component of the market would

necessarily be small, if for no other reason most of the renewable forms of electricity were being sold under contract to the large electric utilities.

Entrants could bundle energy efficiency measures with electricity to help consumers reduce the overall cost of obtaining energy services (e.g., warmth, lighting, cooking, clothes drying, refrigeration). The utilities themselves were offering some of these services using some of the public benefit charges included in delivery fees.

New entrants could compete on the basis of price if they marketed electricity primarily to those customers whose loads were less time variant than typical loads. These could be industrial customers who used electricity at a roughly equal rate throughout the day or whose use of electricity did not vary across the year. For these customers, a new entrant could save money on the wholesale purchases of electricity and might be able to sell electricity at a lower retail price than did the incumbent utilities. However, the new entrant would have to pick its customers carefully.

In principle, some retailers could provide higher reliability of electricity for the industrial or commercial customers for whom reliability was essential or interruptible service for those customers willing to accept service interruptions in exchange for a lower overall bill. However, because electricity was being delivered by the same utility, no matter which firm was selling the electricity itself, it was not clear that an individual electricity retailer could economically offer such services without much cooperation from the utility providing the delivery services.

These market opportunities provided some opportunities for new entrants, but at least during the transition period, were niche markets. Thus, it could be expected that during the transition period retail competition would be relatively limited.

Risk Management in the Restructured Retail Market

Utilities had historically played a fundamental role of managing retail price risk for their customers. Utilities invested in a portfolio of electricity supply assets, some with costs that would vary with market conditions (e.g. natural gas fired units), some with costs that were predictable over time (e.g. QF contracts or geothermal units), some with costs that remained low but had less predictable capacities (e.g. hydroelectric), and some that provided energy services by using less electricity (e.g. energy efficiency investments). For gas-fired units, whose cost could vary with market conditions, utilities would secure long-term contracts for natural gas to reduce the risk.

However, in competitive retail markets, risk management could be a challenge. As it turned out, California never came to grips with that challenge until it was too late.

Under the restructured system, management of retail price risk would be left entirely to the competitive market place. Given that the investor-owned utilities were required to divest most generation, to buy their electricity on spot markets, and to avoid long-term contracts, they had few instruments left for managing price risk. During the transition period, retail prices were expected to remain fixed, although the wholesale price of electricity and the CTC would both vary. However, once the transition period was over, the retail customers could be expected to bear most of the risk of price fluctuations on the volatile wholesale market.

Retail customers remaining with the utilities, and wishing for financial stability after the transition period, would be expected to purchase financial hedges against fluctuations in wholesale prices. The expectation that many residential and small commercial customers would be willing to engage in sophisticated financial transactions in order to stay with the default utility seems improbable⁵⁶. The more likely outcome, once the transition period were over and consumers began understanding the issues, would be for customers to accept the risk of price variations or to buy electricity from retailers that were willing to offer some assurances of price stability.

New electricity retailers could assure price stability by providing risk management electricity sales contracts to attract customers. These retailers could purchase electricity under a mix of different contracts to manage the risk for their customers. Retail prices would vary with wholesale market conditions, but the variations would be greatly moderated.

If a variety of retail sellers emerged after the transition period, customers would be able to purchase retail electricity from retailers who hedged price risk in ways appropriate to their customers. This would require customers to be willing to leave the default utility.

The CPUC could have chosen an alternative. Utilities could have operated as regulated monopolies, selling primarily to small residential and commercial customers and providing risk management for their customers. The utilities would negotiate a mix of short-term, medium-

⁵⁶ See “Revisiting ‘the Genius of the Marketplace’: Cures for the Western Electricity and Natural Gas Crises”, By Ralph Cavanagh, *Electricity Journal*, June 2001.

term, and long-term contracts to purchase electricity for resale. Risk of price variations could be minimized, although not completely eliminated.

However, the CPUC rules created strong incentives for default utilities to avoid great reliance on long-term contracts, even when such contracts would be in the interests of their customers.

Under the CPUC rules, retail customers could choose to buy from competitors of the investor-owned utilities whenever those competitors offered electricity for sale at a price more attractive than that offered by the investor-owned utilities. However, those competitors were never obligated to sell electricity nor were regulated in the price at they offered to sell. The investor-owned utilities, on the other hand, were obligated to serve all customers, including those that switched back from an unregulated competitor. Moreover, the retail price that they would charge would be based on the average cost of their acquisition of electricity, at least whenever there was no retail price cap.

These differences in obligation to serve and in the retail price-setting rules between the investor-owned utilities and the unregulated competitors created the incentive against the utilities relying heavily on long-term contracts. For one can consider what might happen if the regulated utilities did rely very heavily on long-term, fixed price contracts to purchase electricity.

If the spot prices turned out to be much lower than the prices in the long-term contracts, the unregulated firms could offer to sell electricity at a much lower price than could the regulated utilities and large numbers of customers would shift their purchases to these firms and away from the regulated utilities. With fewer customers, the regulated utilities would purchase smaller

quantities of electricity on spot markets. However, because the spot price of electricity would be lower than the contract price, reduced purchases on the spot market would increase the average cost and therefore the price charged to those customers remaining with the regulated utility. The price increase would cause even more customers to leave the regulated utility, thereby further increasing the price for those remaining. The greater the fraction of electricity the utility had contracted to purchase under long-term contracts, the more severe would be this "spiraling downward" process. If the purchases were dominantly long-term contracts, then the utility could end up obligated to purchase more electricity than they could sell.

If, on the other hand, spot prices turned out to be much higher than the average acquisition cost (including the cost of the long-term contracts), customers would abandon the unregulated competitors and would purchase electricity from the utilities. This, in fact, happened when the spot prices of electricity started rising in the summer of 2000. The increased retail sales would require increased spot market purchases, thereby increasing the average cost and the regulated price.

But the unregulated retailers are not restricted in this manner. In particular, they need not allow their customers to ebb and flow this way. Retailers offering risk management contracts could choose to sell to only those customers who were willing to sign yearlong or longer time period contracts. Thus, if spot prices were to drop sharply below the average acquisition price, these customers would be precluded from leaving. Moreover, they could base new contracts on their expectations of market conditions. If spot prices were to rise sharply above the average

acquisition price, they need not take new customers or they could charge the new customers based on the prices for new wholesale contracts⁵⁷.

This difficulty could be overcome. However, to do so, the incumbent utility would have to be allowed to impose contractual constraints on its existing customers⁵⁸, stopping them from leaving when spot prices dropped and allowed to limit the new customers it would serve, particularly when spot prices increased above average wholesale acquisition costs. But the CPUC did not provide these options to the investor-owned utilities.

Risk problems for the utilities would be especially threatening during the transition period because the price caps disabled a central adjustment mechanism. Typically, production costs are translated through wholesalers and retailers into consumer price increases. Price increases motivate reductions in demand for electricity, which in turn place downward pressure on wholesale prices. However, during the transition period the retail price caps would disable this process. Thus, the natural economic process limiting the magnitude of wholesale price increases would be missing and the risks associated with large wholesale price increases would be amplified.

⁵⁷ In addition, the unregulated competitors could earn profits when the spot price was above the contractual price and would take losses when the spot price was below the contract price. But since long-term contracts typically have prices roughly equal to the expected average spot prices, then over time these unregulated firms would not be disadvantaged by long term contracts in the same way as would be the regulated utilities.

⁵⁸ For example, all customers could be given a limited time (say six months) to sign a one year contract to purchase their electricity from the utility. If they do not do so, then the utility would no longer be obligated to sell electricity to them. Similarly, if they switch to another provider, then they might be allowed to switch back to the utility only if they sign a one year contract with a price designed such that their purchases from the utility will not increase prices facing the rest of the customers.

In addition, during the transition period, since retail prices were capped, increases in wholesale prices would directly reduce retail margins possibly resulting in a negative retail margin. Some retail risk would be hedged to the extent the utility generated electricity. But since each investor-owned utility was required to divest most of its generation capacity, as a company, each would be a large net seller of electricity. Thus, risk of wholesale price increases would be borne disproportionately by the utilities even if wholesale prices soared well above retail prices so that the utility were losing money on every megawatt hour of electricity it sold.

Generally, however, a company losing money on everything it sold could sharply reduce or halt its sales. However, the utilities were required to sell electricity to everyone who turned on their lights, appliances, machinery, or air conditioning. Thus, they were precluded from that normal adjustment process.

In summary, the restructured system put the utilities in an untenable risk bearing posture, increasing risk during the transition period in three ways:

- 1) Wholesale price fluctuations would not be moderated by market forces;
- 2) Wholesale price increases would result directly in financial losses, since none could be passed on as retail price increases;
- 3) The utility could not reduce transactions when retail margins became negative. Worse yet, its obligation to take back customers implied that its transactions would increase when the loss per transaction became large.

Thus during the transition period, investor-owned utilities, facing a profoundly high degree of risk, were precluded from most strategies for hedging or reducing risk. Traditionally “safe”, blue chip investments, the investor-owned utilities were placed into a posture more risky than that facing most companies.

Although these were all important risks, at the time AB 1890 was passed, all participants anticipated that the cost of wholesale electricity would remain well below the retail price⁵⁹, and the economic isolation between producers and consumers would not create a problem. However, no one could be sure this would be the case. The risks were large, although many of the participants in the process may have underestimated these risks.⁶⁰

These risks could be viewed as merely theoretical, since anyone could have reasonably expected there to be one protection in the unlikely event of soaring wholesale prices. The newly restructured system was a politically designed process. The high risks were not inherent to the economic system but were the results of definable design flaws in the regulatory system. At the time of the restructuring, it would have been reasonable to believe that if the “perfect storm” descended on the State, then the political system would adjust to the new reality. Unfortunately, as has become painfully apparent, this reasonable belief has proved to be disastrously wrong.

Municipal Utilities

⁵⁹ More precisely, the cost of wholesale electricity would remain well below the retail price of the electricity itself, the retail price charged to customers minus the fixed costs of wires and other distribution services.

⁶⁰ The published analyses, including those done by the California Energy Commission and those published through the academic community all forecast relatively low wholesale prices.

California's many municipal utilities, serving 22% of California's customers, were allowed to continue operating as they had prior to the restructuring. Each municipal utility had a governing board, either appointed or elected within the municipality, responsible for managing the utility to benefit residents. Typically, municipal utilities were expected to cover their costs through sales of electricity. The governing boards retained the ability to increase retail prices at which the municipal utility sold electricity, if the need arose. These utilities typically purchased electricity using a mix of short, medium, and long-term contracts so they were hedged from rapidly changing wholesale prices.

Municipal utilities, therefore, differed sharply from the investor-owned utilities in that they retained all capabilities to manage their risks. As it would turn out, this ability to manage risk was fundamental in differentiating the impacts of the California electricity crisis on the municipal utilities from the impacts on the investor-owned utilities.

In Summary

California began the decade of the '90s with a completely vertically integrated electricity system that had been working reasonably well as a regulated system. However, there were opportunities for improvement.

Some reasons for restructuring the system were good. The old system encouraged the investor-owned utilities to build too much capacity at too high cost. It discouraged appropriate risk

bearing on the part of the utilities and discouraged innovation. It included incentives for the utilities to favor their own generators and to avoid purchases from new competing alternatives.

Some other reasons were not good. The advocates of restructuring expected significant immediate cost reductions, pointing to the high average prices of California retail electricity. However, these high prices were based primarily on the contracts to purchase electricity from qualifying facilities and on the high capital cost nuclear power plants. But the QF contracts, particularly the high prices in those contracts, had been forced by the CPUC. Moreover, at the time the nuclear power plants were initiated, it had been expected that they would provide low-cost power. A market restructuring would not eliminate the historical costs, no matter who was responsible for past decisions. Market traders expected that the particular California restructuring would create profit opportunities for their firms, a good reason from their perspective, but a not good reason from California's perspective.

Although some reasons advocates advanced for restructuring were weak, there were sufficient good reasons to proceed.

The process of analysis and debate from the early 1990s through the signing of the bill was remarkably open and allowed many opportunities for knowledgeable parties to participate into discussions. Many analysts, observers, and especially, stakeholders joined the debate. In short, the process, through the signing of AB 1890, was remarkable for debate that was encouraged and that influenced the final legislation. However, the broad participation may have resulted in a

system designed by committee, with features beneficial to some participants but harmful for the overall design.

AB 1890, like all legislation, represented a series of compromises and included some mistaken judgments. However, it should not be judged as the final product. Rather it should be seen as a framework for further restructuring, since so many elements out of the system would require continued implementation and continued change.

Nevertheless, absent these additional changes, the restructured system left the investor-owned utilities and the State in a more risky situation than appropriate. From the perspective of those times, it was reasonable to believe that the state would pass through the transition period unscathed and would be able to move forward, once the stranded costs had been recovered, into a new era. However, even though not recognized, the risk was there from the very beginning that things could go wrong. And go wrong they did.

Chapter 3: The Challenge

The year after AB 1890 was passed, a group of consumer advocates, led by Harvey Rosenfeld, started the process of legally challenging the restructuring legislation. This group began collecting signatures to qualify what became Proposition 9, voted on in the 1998 statewide California ballot. Proposition 9 would have turned back the restructuring and would have reinforced a system of tightly regulated electricity transactions. It was not until the defeat of Proposition 9 in November 1998 that assured AB 1890 would be allowed to operate.

Until its defeat, Proposition 9 created much uncertainty and reduced the incentives for private companies to invest in new electric generating facilities. By creating significant delays in the capital investment associated with investing in new generating plants, Proposition 9 increased the risks that were inherent in this newly restructured system.

Until early 2000, in terms of the publicly visible goals, the new system seemed to be operating as intended. Wholesale prices remained below historical average costs and the utilities gained profits that they could apply to cover the stranded costs. By 1999 SDG&E had earned sufficient profits that they covered all of their stranded costs and would no longer be subject to the retail price caps.

The divestiture of generating assets owned by the utilities was proceeding well, surprisingly well, in fact. Many old generating plants had been sold, and at prices that far exceeded the prices that had been expected. These sales moved the electric utilities closer to the time at which they would be able to leave the price control regime.

However, the high sales prices should have raised questions in the CPUC. It can be presumed that those plant buyers were not being irrational and that they believed future electricity wholesale prices would rise. These high selling prices thus should have suggested to CPUC members that there was a significant risk that future wholesale prices would increase significantly and could have implied the need for long-term contracts or other methods for the utilities to protect themselves and the ratepayers from such risks.

Although the overall supply/demand balance had not yet improved in California or the western region, improvements were under way. In California, applications to construct many new electricity generating units had been filed and approved; construction had begun for many thousands of megawatts of new capacity. Demand for electricity continued to grow, but was growing at a relatively slow pace. Looking ahead, it was reasonable to project that the new electric generation plants would be online before growing demand surpassed the available supply of electricity.

One disappointment with the operation of the new system seemed to be the lack of a competitive retail market for electricity. Several companies entered the market to sell consumers “green” electricity, advertised to be generated entirely by renewable sources. However, this component of the market was small. Other companies that tried to enter the market complained that the tightly regulated system gave them no opportunity to compete successfully.

Less publicly visible, however, were the operations of the PX and the CAISO. The market structure continued to prove unwieldy and CAISO submitted to FERC a sequence of proposed

amendments to its tariff. After 24 amendments were filed, the FERC finally summarized its perceptions: “The problem facing the [California] ISO is that the existing congestion management approach is fundamentally flawed and needs to be overhauled or replaced.”⁶¹ This started a process of rethinking the market design, a process that was never completed, since the events beginning in the spring of 2000 overtook the process.⁶² There were clearly continued problems with the market design and its detailed implementation. However, personnel within the PX, CAISO, and FERC, as well as analysts studying electricity markets, were working to improve the market system.

By spring of 2000, warning signs about the supply and demand imbalance throughout the western region had become obvious. Wholesale prices spiked upward in May 2000 and then again in June. There was insufficient electricity available in San Francisco on one day, causing a blackout in that city. Lawsuits were filed to identify and hold accountable any companies responsible for the rapid price increases. The challenge had become apparent, not just to technical specialists, but also to the public and to the political leaders of the state.

In what follows, we analyze the changing circumstances that turned the risky situation into a challenge for the State of California. The challenge to California initially arose from changes in the supply and demand patterns throughout the western portion of the United States coupled with characteristics of electricity markets, characteristics that inherently made electricity wholesale prices highly volatile. Particular characteristics of California's restructuring combined with these

⁶¹ Federal Energy Regulatory Commission, "Order Accepting for Filing in Part and Rejecting in Part Proposed Tariff Amendment and Directing Reevaluation of Approach to Addressing Intrazonal Congestion," Docket ER00-555-000, 90 FERC 61, 000, Washington DC, January 7, 2000, p. 9.

⁶² For more discussion of the problems with the market system appearing before Spring of 2000, see “Electricity Market Restructuring: Reforms of Reforms”, by William W. Hogan, May 25, 2001, Harvard University.

additional changes to create the "perfect storm". This was the challenge that California needed to face in the year 2000.

The Nature of the Challenge

The challenge grew in terms of two types of problems: 1) an electricity challenge associated with very tight wholesale markets for electricity in the West and California's management of its electricity markets and 2) a financial crisis of California's investor-owned utilities associated with the State's regulatory control of these utilities.

The electricity challenge was primarily part of the challenge facing the Western states as of mid 2000. Demands for electricity throughout the West had grown over the years but supply had not. New generation capacity in California was under construction but construction had not been completed. There were no direct incentives for consumers in California to reduce their demands for electricity because the State rigidly maintained retail price controls. Short-term supply reductions led to very tight markets and wholesale spot prices increased sharply in California and throughout the West.

The financial challenge was one facing the investor owner electric utilities. As wholesale markets grew tighter, the investor-owned utilities, forced to rely to an inappropriately large extent on spot prices, faced the prospect of sharply escalating costs of acquiring electricity on wholesale markets. Yet the retail price controls, were they to be continued, would preclude the utilities from passing any of those costs on to their customers: the investor-owned utilities would

be required to subsidize deeply electricity use by their customers⁶³. The difference between acquisition cost and retail selling price was threatening to become great enough to deplete all their financial assets, absent relaxation of retail price controls. During this challenge period, two things were needed to avert a crisis: the retail price controls needed to be relaxed and the utilities needed to move away from spot wholesale markets and toward medium term and long-term electricity supply contracts.

In what follows these two challenges are discussed separately, with the electricity market challenge presented first.

Electricity Supply and Demand Patterns

Regional Market Linkage

Contrary to many popular discussions, supply and demand conditions in California's electricity system are tightly linked to conditions throughout the Western region of the United States; California's system is not isolated from electricity markets in the rest of the West. High-voltage transmission lines, across which electricity can be transmitted, connect adjacent states and adjacent regions within a state. Through this transmission system, the eleven western states, plus the Canadian provinces of British Columbia and Alberta, are electrically linked to one another. In principle, electricity generation in any part of the western region – more precisely, the Western Systems Coordinating Council⁶⁴ (WSCC) – could be used to satisfy electricity loads in any other part of the western region, subject to transmission constraints.

⁶³ The California municipal utilities were not so required and were free to increase their prices, based on decisions by their governing boards.

⁶⁴ Eleven states are interconnected as part of the Western Systems Coordinating Council (WSCC) area: Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming. WSCC

Figure 5, created by the Western Governors' Association⁶⁵ gives an indication of the transmission capacity between the various states and portions of states. The widths of the blue lines connecting the circles are proportional to the relative transmission capacities.

Figure 5 shows that there is much transmission capacity between California and the Pacific Northwest and between California, Nevada, and Arizona. Thus, these parts of the western region are linked particularly closely and the greatest flows of electricity occur among these areas. California represents 42% of the generation and 51% of the consumption in this tightly linked portion of WSCC.

Given the possibility of transmitting electricity among states and given that Federal regulations allowed open access to the transmission network⁶⁶, utilities in the West had either traded with one another, directly or through marketers, well before California restructured its electricity markets. Significant quantities of electricity generated in one state have been routinely bought, sold, and transmitted between states. This was not the product of California's restructuring. California's restructuring did allow the possibility of increased trade and increased electricity flow between states.

also includes the provinces of Alberta, British Columbia, the northern portion of Baja California, Mexico, and portions of several other states.

⁶⁵ "Conceptual Plans for Electricity Transmission in the West" - Western Governors' Association - August 2001

⁶⁶ Particularly important were EPACT and FERC Order 888. See Chapter 2.

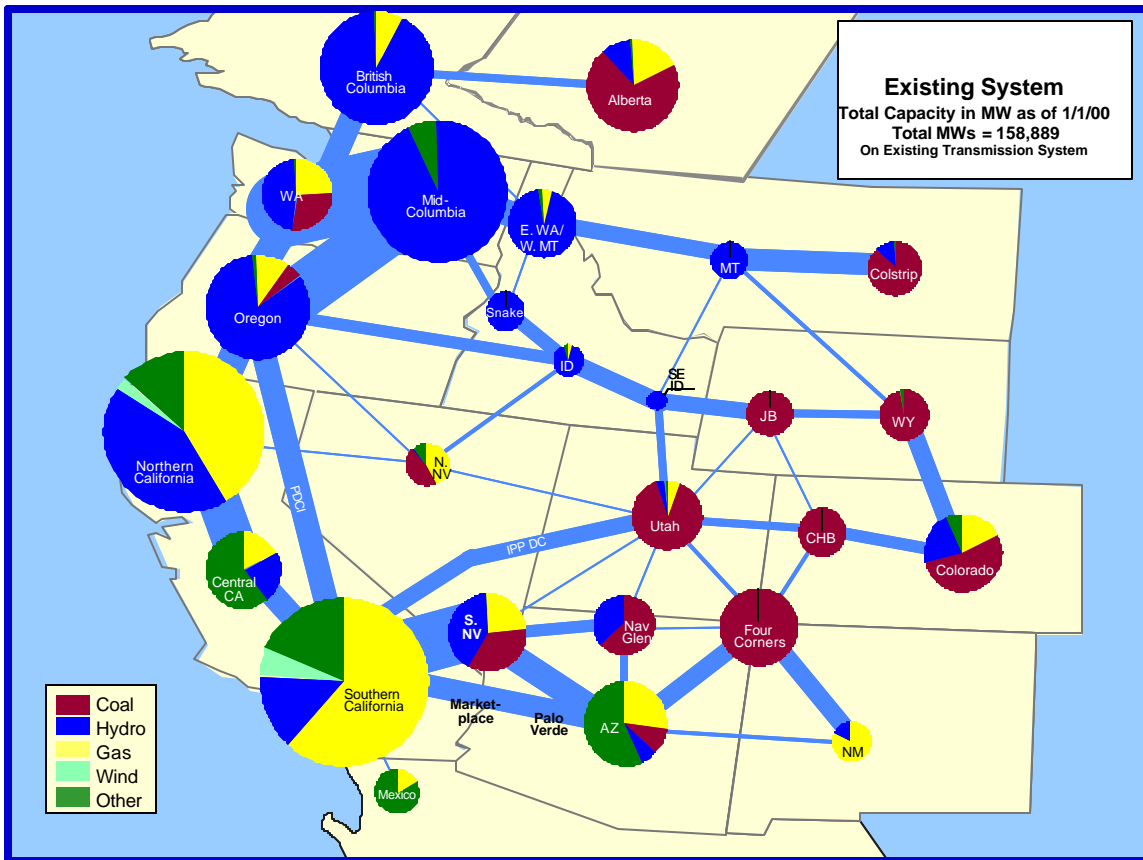


Figure 5 Installed Capacity by Generation Type in the Western Grid, as of January 2000.
Source: Western Governors' Association

Thus, for the most part, in practice, electricity generation in any part of the West could be used to serve the electrical loads in any other part of the West, including in California, subject to transmission constraints which at some times could limit the amount of trade. Conversely, electricity loads in any part of the West could reduce the amount of electricity available to serve loads in any other part of the West, including California.

Since utilities and marketers can freely trade across state boundaries (subject to transmission constraints), spot prices tend to equate between any two adjacent regions whenever the

transmission interconnections between the regions have excess capacity⁶⁷. Any price difference would be an opportunity for traders to arbitrage the differences, buying at the low price area and selling in the high price area, thus eliminating price differences.

Because of the relative ease of electricity trade among the Western states and the tendency towards price equality among the states, changing supply and demand conditions anywhere in the interconnected Western region have similar impacts on spot market prices throughout the entire region. A tight market in the Pacific Northwest can easily translate to a tight market in California, and vice versa. The tight market any place will typically lead to high spot wholesale prices everywhere in the West.

Although spot wholesale prices across the region tend to equalize quickly, long-term contractual arrangements reduce the amount available for sale on the spot markets at any moment of time. In most of the states, other than California, the vast majority of electricity is generated by the utilities themselves or is contractually committed to the various publicly owned or privately owned utilities. Under such contracts, generators have committed to provide fixed quantities of electricity to particular utilities or have dedicated all electricity from particular generating plants to those utilities. Electricity so committed under firm contracts is not available for sale on the spot markets.

Spot market prices respond to the demand and supply for electricity transacted on the spot markets, not necessarily to the overall demand and supply in the region. In the short run,

⁶⁷ Whenever the interconnections reach capacity, price differences can persist, just as there are price differences between the Western region and the Midwest.

electricity loads and electricity supplies committed under long-term contracts are removed from transactions the spot market, leaving a smaller spot market supply and an equivalently smaller spot market demand.

Residual quantities are not removed, however. Utilities operating under long-term wholesale contracts but with projected loads exceeding their committed generation are free to compete to purchase electricity on the spot market. Similarly, generators with supplies greater than their long-term contractual sales are free to offer the sell the surplus on the spot markets. Thus, supply and demand variations within the region translate directly to equivalent volume supply and demand variations in the spot markets.

Because long-term contracts reduce the total volumes available for transactions on the spot markets, a given magnitude supply or demand variation on the spot market represents a much larger percentage variation on the spot market than would be the case absent the long-term contracts. This in turn implies that spot market prices are far more volatile than they would otherwise be. A given magnitude supply reduction or demand increase leads to a much greater price increase on the spot markets than would be the case if there were no long-term contracts. Similarly, the large number of long-term contracts implies that supply increases or demand decreases have disproportionate impacts on spot market price reductions.

Thus, in the mixed system characterizing the West – most electricity sold on long-term contracts and a smaller amount sold on spot markets – spot market prices tend to vary sharply while

existing long-term and medium-term contracts continue to operate at the contractually agreed prices⁶⁸.

In the longer term (say over a course of weeks or months), spot market conditions do influence the supplies and loads committed under long-term contracts. Buyers of electricity under long-term contracts may be able to reduce their use and sell the saved quantities into the spot markets when spot prices are significantly higher than long-term contractual prices. Alternatively, sellers and buyers may renegotiate long-term and medium term contracts to allow both to benefit from the opportunity to respond to high spot prices. The adjustment process, however, under such long-term or medium term contracts is much slower than the adjustment in the spot markets.

Thus, in the mixed market system with most electricity sold on long-term contracts and a smaller amount sold on spot markets, those participants with long term contracts are buffered from the changing market conditions. Because they are buffered, they need not respond as quickly or as greatly as those facing the more volatile spot markets. The diminished responses from those with long-term and medium-term contracts have direct implications for the dynamics of the spot market. The diminished responses imply that a greater response is called for from those participating primarily in spot markets and imply that spot market prices will be more volatile than would otherwise be the case.

⁶⁸ New long-term and medium-term contracts however may reflect the volatility in the spot markets, since those contractual terms reflect the expectations of the buyers and sellers about the future expected spot market prices. In addition, if contract prices diverge greatly from current market prices for long periods, contracts can be renegotiated so as to benefit both contracting parties.

Given the regionally linked electricity system and given the mixed market system of term contracts and spot markets, supply and demand changes occurring either inside of or outside of California could translate to very tight supply and demand conditions throughout the West, slow supply and demand adjustment throughout the region, and rapid and profound changes in wholesale spot market prices.

California's investor-owned utilities, after divesting most of their own generating capacity, and facing prohibitions against buffering themselves with long-term contracts, were forced to acquire much of their electricity on the very volatile spot markets. Thus, as a result of California's restructuring, California investor-owned utilities were in the unenviable position as buyers participating primarily in spot-markets, while most utilities throughout the West and most municipal utilities in California were well buffered by a mix of long-term and medium-term contracts. The fury of the "perfect storm" would be concentrated on the California investor-owned utilities, amplified by the buffering the other utilities were enjoying.

Western Regional Supply and Demand Balances

Figure 6, using data from the US Department of Energy, Energy Information Administration, shows the year 2000 yearly average rate of net generation⁶⁹ and the yearly average rate of utility sales in the eleven Western States that are interconnected as part of WSCC. California's retail sales of electricity account for 40% of the total retail sales in these eleven states; California generation accounts for 30% of the total. Thus, although California is the largest single state, neither its generation nor its consumption represents a majority of the West.

⁶⁹ Net generation is generation net of the electricity used in the generating plant itself. Net generation is measured at the generating plant. Line losses and other distribution losses must be subtracted from net generation in order to determine the amount of electricity available for utility sales.

The total electricity use in a state must be the sum of net generation plus net imports from other states, minus transmission and other losses. Therefore, whenever electricity sales in a state exceed net generation less losses, the difference is made up through electricity imports from other states or other countries (Canada and Mexico).

In a typical year, California generates 75% of its electricity in state, importing 25% from the Pacific Northwest and the US Southwest. These are not simply one-way flows of electricity into California. In the summer, California imports much electricity from the Pacific Northwest. In the winter, California exports electricity to the Pacific Northwest. Figure 6 shows that California and Idaho are the only states that must import large fractions of their electricity. Most of the other Western states are nearly balanced or are net exporters of electricity.

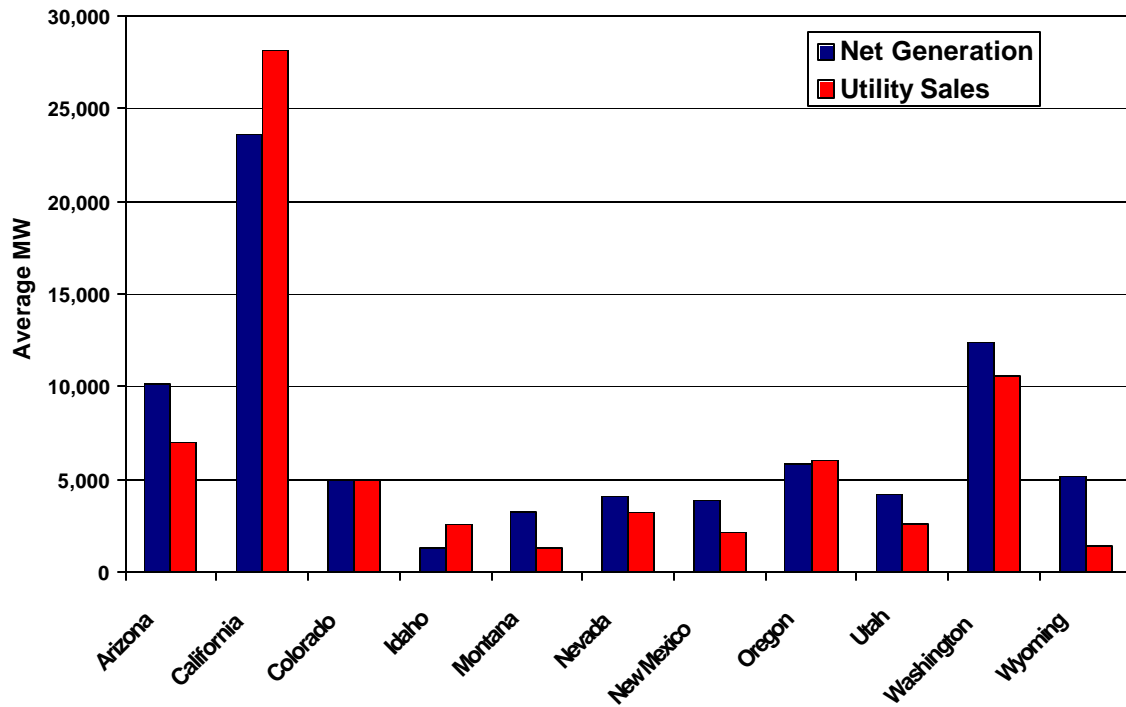


Figure 6 Net Generation and Utility Sales, WSCC States, 2000

In addition to information about transmission capacities, Figure 5 provided data on the primary sources of electricity generation in each state. The circles on the chart show the summer-installed generating capacity, by generation type, for each state or portion of a state. The sizes of the circles are proportional to the summer installed capacities, as of January 2000. Figure 5 shows that the primary energy source for electricity generation varies significantly across the western region. The Pacific Northwest dominantly relies upon hydropower, with some natural gas and coal. The mountain states, except Colorado, dominantly rely upon coal as the prime energy source for electricity generation. Colorado uses coal, hydropower, and natural gas. California relies on a mix of energy sources, including natural gas and hydropower.

Although Figure 5 shows generation capacity in 2000, an analogous diagram for 1990 would look virtually the same. There had been very little growth in generating capacity in the decade prior to 2000 throughout the western region⁷⁰. However, there had been continuing growth in electricity use throughout the region. Thus, the amount of reserve capacity throughout the western region had been declining steadily for at least a decade before 2000. Tight supply and demand conditions had started to characterize most of the western region.

Throughout the region, most of the municipal utilities and investor-owned utilities had adjusted to this market tightening by assuring their own supplies of electricity, either through their own generating units or through a combination of medium-term and long-term contracts to purchase electricity. California investor-owned utilities had not been allowed to do so.

The generation capacity shown in Figure 5 could vary significantly with changes in the local conditions. In particular, the hydroelectric capacity represents the capacity of generators. But if the amount of available water were insufficient, some of that generated capacity must remain unused. Thus, low rainfall conditions in northern California and in the Pacific Northwest can, and did, reduce the amount of hydropower that could be generated in those locations.

In addition, the electricity demand was also notoriously time dependent. A hot summer could greatly increase the demand for electricity in California or Arizona, because of the large air

⁷⁰ A complete discussion of the long term trends in California and the West appear in “Trends in Electricity Consumption, Peak Demand, and Generating Capacity in California and the Western Grid, 1977-2000”. Jolanka V. Fisher and Timothy P. Duane, September, 2001, working paper from the University of California Energy Institute Program on Workable Energy Regulation (POWER).

conditioning loads; a cold winter could greatly increase the demand for electricity in the Pacific Northwest, because of the large electric resistance space heating loads.

In the spring of 2000, then, California was part of a region that was tightly electrically interconnected. With California's particular regulatory environment, the dynamics of wholesale electricity market adjustment were skewed against California's investor-owned utilities. Most electricity either outside California or sold to California's municipal utilities was committed to long-term contracts. Most electricity purchased by California's investor-owned utilities was transacted on spot markets. Supplies on those markets could shrink rapidly in response to changing conditions either inside of or outside of California. The markets for electricity had gradually become tighter and tighter throughout the region. Moreover, in the spring of 2000, rapidly changing conditions external and internal to California created for California the "perfect storm".

The following sections focus more sharply on California and its changing supply and demand conditions. Understanding these conditions can help explain why California was not prepared to weather the storm.

California Electricity Use

California has been a relatively low user of electricity, when measured on a per capita basis. The industrial structure, although intensely dependant on electricity, particularly for the high-tech industries, is not a heavy electricity consumer, relative to industry in other states. The State is blessed with a temperate climate and thus air conditioning loads are relatively low. High prices

of electricity, coupled with aggressive energy demand management programs have kept consumption relatively low. California has had a long tradition of efficiency incentives and services that have helped to reduce California’s electricity intensity in recent decades.

	California	All US	California Relative to US
Monthly Average Residential Consumption (MWh)	0.548 MWh	0.866 MWh	37% below National Average
Average Residential Consumption Rate (MW)	0.75 MW	1.19 MW	
Retail Average Revenues (\$/MWh)	\$107/MW	\$82/MW	9 th Highest

Table 3 California vs. All US Residential Electricity Use per Residential Customer

Table 3, using 1999 data from the US Department of Energy⁷¹, illustrates that the residential electricity consumption per customer was 37% below the US average during that year. Thus, the challenge California was facing did not stem from California as being a particularly large user of electricity on a per capita basis. Conversely, that California had a lower per capita use of electricity than most states did not allow California to avoid the challenge.

During the period from 1997 through 2000, the consumption of electricity in California continued to grow slowly as it had for the last ten years. The California economy was remaining healthy and population was continuing to grow steadily. Per capita electricity use grew modestly during that time. Figure 7, below, shows the net result. From 1990 to 2000, use of electricity increased from 26,000 MW average consumption rate to just above 30,000 MW, a growth of 16% over ten years, or 1.4% per year. Growth in energy consumption, however, was somewhat

⁷¹ Data from table at <http://www.eia.doe.gov/cneaf/electricity/esr/esrt14p4.html>. Data are based on number of customers in the residential sector. This figure corresponds closely to the number of households.

faster from the 1997 through 2000 period, increasing by almost 2,000 MW during the three years, or an average growth rate of 2.3% per year average. From 1999 to 2000, average consumption increased slightly more than 1,000 MW, almost 4%. Peak loads were growing at roughly the same rates.

Thus, although peak loads and total electricity consumption grew, growth was relatively slow. Taken alone, neither the absolute magnitude of electricity use nor the growth rate would have been likely to create a particularly significant challenge.

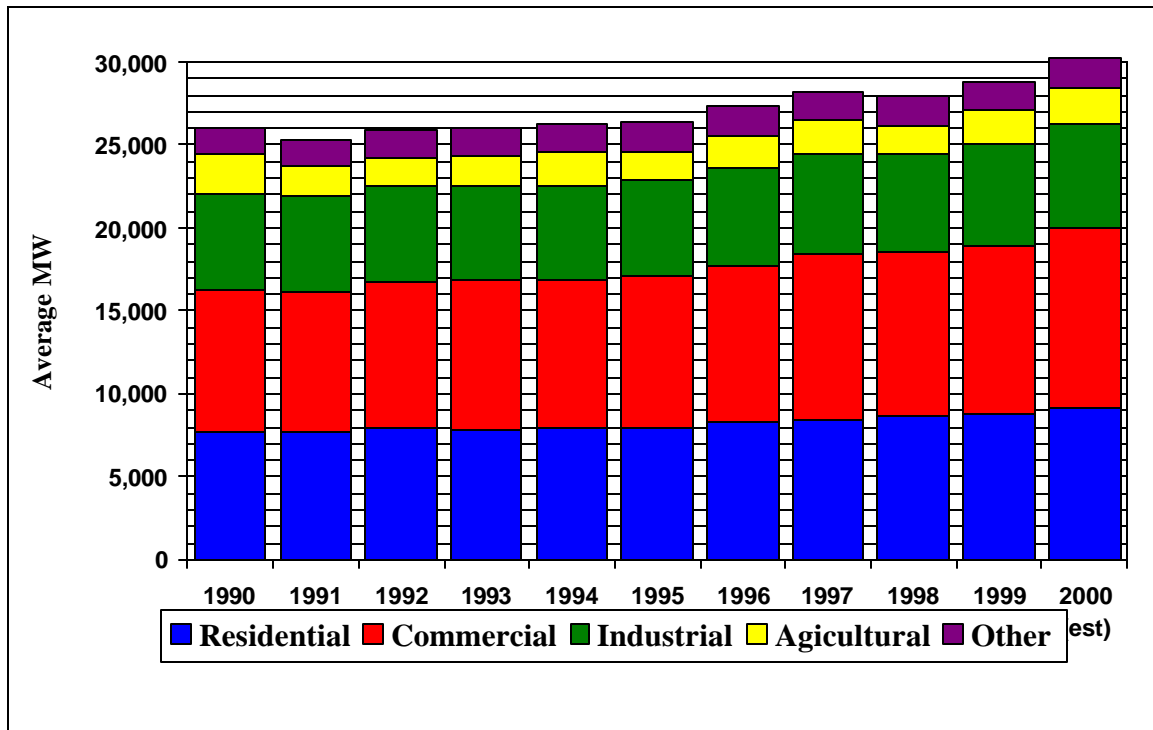


Figure 7 California Energy Consumption Growth

Some have argued that electricity demand in California has grown much more rapidly than expected, even if not particularly rapidly on an absolute scale. Although it is difficult to

document the wide range of growth expectations, it is possible to compare actual growth to California's official forecasts of growth in electricity consumption and growth in peak loads.

Table 3.2 shows these forecasts of growth and actual growth over the five-year interval, from 1995 to 2000, based on two California Energy Commission reports, the 1996 *Electricity Report* and the 1998 *Baseline Energy Outlook*. Since measured peak demand can be influenced strongly by curtailments, peak demand growth is shown first ignoring the curtailments and then adjusted for curtailments. Adjusting for curtailments, peak demand grew 13.4% from 1995 to 2000, in contrast to the 10.4% growth forecast in the California Energy Commission's 1996 *Electricity Report*.⁷² Total consumption grew 14.5% from 1995 to 2000, in contrast to the 11.6% and 11.7% total growth in consumption forecast in the 1996 *Electricity Report* and the 1998 *Baseline Energy Outlook*, respectively.

⁷² The growth forecasts are based on non-coincident peaks, since no forecast was available for coincident peaks. The actual peak growth is based on coincident peaks. The year 2000 coincident peak demand in the CAISO control area was 43,784 MW, but there were 1,710 MW of voluntary curtailments that day. No adjustment for curtailments was made for total electricity consumption since voluntary curtailments had a much greater percentage impact on peak demand than on total consumption during the year.

		Actual or Forecast Five-Year Growth	Underestimate of Five-Year Growth
Five-Year Growth in Peak Electricity Demand	Actual Growth Ignoring Voluntary Curtailments	9.2%	
	Actual Growth Adjusted for Voluntary Curtailments	13.4%	
	<i>1996 Electricity Report</i>	10.4%	3.0%
Five-Year Growth in Electricity Consumption	Actual Growth	14.5%	
	<i>1996 Electricity Report</i>	11.7%	2.8%
	<i>1998 Baseline Energy Outlook</i>	11.6%	2.9%

Table 3.2 “Official California Forecasts of Electricity Demand and Consumption Growth vs. Actual Growth.”

Table 3.2 thus shows that electricity consumption and peak demand did grow somewhat faster than forecast by the California Energy Commission. However growth, measured by peak demand or by total electricity consumption, was no more than three percentage points greater than those forecasts. Therefore, the “electricity demand grew surprisingly fast” explanation can account for only a part of the tight market conditions.

California Electricity Generation and Imports

Total generation⁷³ required to support electricity consumption is shown in Figure 8, below, in which the vertical axis has a suppressed zero and which shows data only for the 1990 through

⁷³ Data in this graph and the following graphs of California energy generation have been obtained from the California Energy Commission web site: http://www.energy.ca.gov/electricity/electricity_generation.html

2000 period⁷⁴. Note that total generation is slightly larger than use since there are losses in the transmission and distribution system.

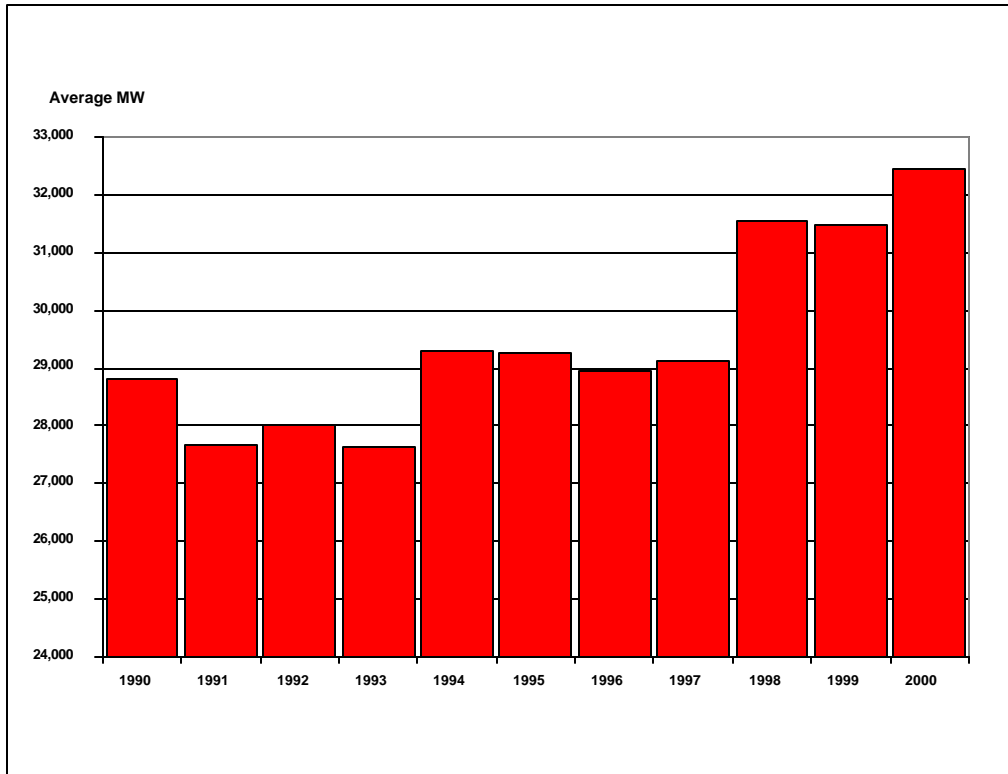


Figure 8 Electricity Generation Supporting California's Electricity Use

From 1997 to 1998, total generation required to support California loads increased by 2,500 MW average and increased again by 1,000 MW in 2000. From 1990 to 2000, total generation required increased 12.6% over ten years, or 1.2% per year. Growth, however, was somewhat faster from the 1997 through 2000 period, increasing by 3.7% per year average. Measured in terms of electricity generation required to support California's electric loads, the growth rate was

⁷⁴ Note that the consumption data for 1997 and the generation data seem inconsistent, with consumption shown as only 500 MW larger than generation in this year, in contrast to each other year. This is most likely an error in California Energy Commission data.

slightly faster than that measured by California data on electricity consumption, but under either measurement, growth was not particularly fast, and that growth alone would not have created a particularly significant challenge.

California had two generic sources of electricity to support the slowly growing electrical loads: electricity generated in California plus the net⁷⁵ imports of electricity into California. The two, added together, must be equal to the total use of electricity (consumption plus losses). Thus, if one of these two sources were to decline, the other had to increase more rapidly to satisfy the slow growth in use.

With tightening of electricity markets in the West, the amount of electricity available for sale on spot markets was shrinking, with that shrinkage occurring primarily outside of California. This resulted directly in an increase in the exports of electricity from California and a decrease in the imports of electricity to California: thus net imports into California declined.

Since 1990, imports had been averaging just above 5,000 MW, with, on average, equal quantities from the Pacific Northwest and the Pacific Southwest. However, in 2000 imports from the Pacific Northwest dropped sharply with the extraordinarily low rainfall, following years of particularly high hydroelectric supply. Imports from the Pacific Southwest dropped somewhat. The overall impact was a reduction in net imports to California of 2,200 MW (see Figure 9).

This measured reduction in net imports to California from surrounding regions underestimates the significance to the California energy crisis of the changes in the supply and demand balance

⁷⁵ The net imports are the difference between imports into California and exports from California.

in the remainder of the WSCC.⁷⁶ In response to the tight market conditions, spot market prices of electricity in these regions increased sharply during 2000. Increases in electricity prices reduced demand in these regions and increased supply, making more electricity available for export to California. The data in Figure 9 reflected the equilibrium quantities of net imports from these regions once the market prices in these regions adjusted to the supply/demand conditions. The measured level of net imports into California during 2000 therefore overestimates the net imports that would have been available absent the sharp increases in spot market prices. The drop in measured imports underestimates the impact of changing import availability in reducing the supply function in 2000 for electricity in California.

The combination of the increase in California consumption and the reduction in available net imports implied that more electricity was needed from domestic sources. Figure 10, below shows the total production of electricity from California sources⁷⁷ grew sharply since the electricity restructuring, with increases from 1997 to 1998 of 3,000 MW and from 1999 to 2000 of 3,100 MW, an increase of 12% in that year.

⁷⁶ This was pointed out by Jolanka V. Fisher and Timothy P. Duane (op. cit.), who reach similar conclusions: “Neither increases in California’s annual consumption (or peak demand) nor decreases in California’s historical share of WSCC-wide generating capacity is therefore at the heart of the state’s supply and demand relationship from 1977 to 1998. Instead, the tightening of supplies throughout the WSCC during this period primarily reflects increases in consumption and peak demand in other states and a region-wide decline in new capacity additions relative to those increases in consumption. Above-average hydropower production (especially in the Pacific Northwest) from 1996 to 1999 masked this shift, then hydropower availability decreased significantly in 2000 (combined with significant increases in consumption in California and throughout the WSCC) to reveal apparent shortages.”

⁷⁷ In this figure and in the following figures coal fired units are included as California generation even though they are located outside of California. This coal-fired generation capacity is owned by or controlled by California utilities.

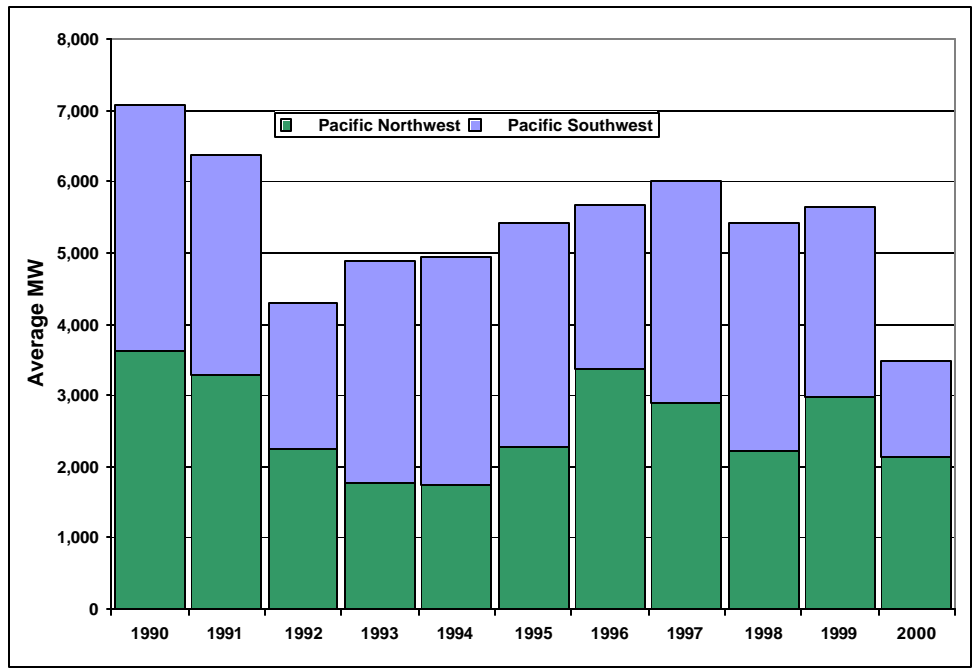


Figure 9 Electricity Imports into California

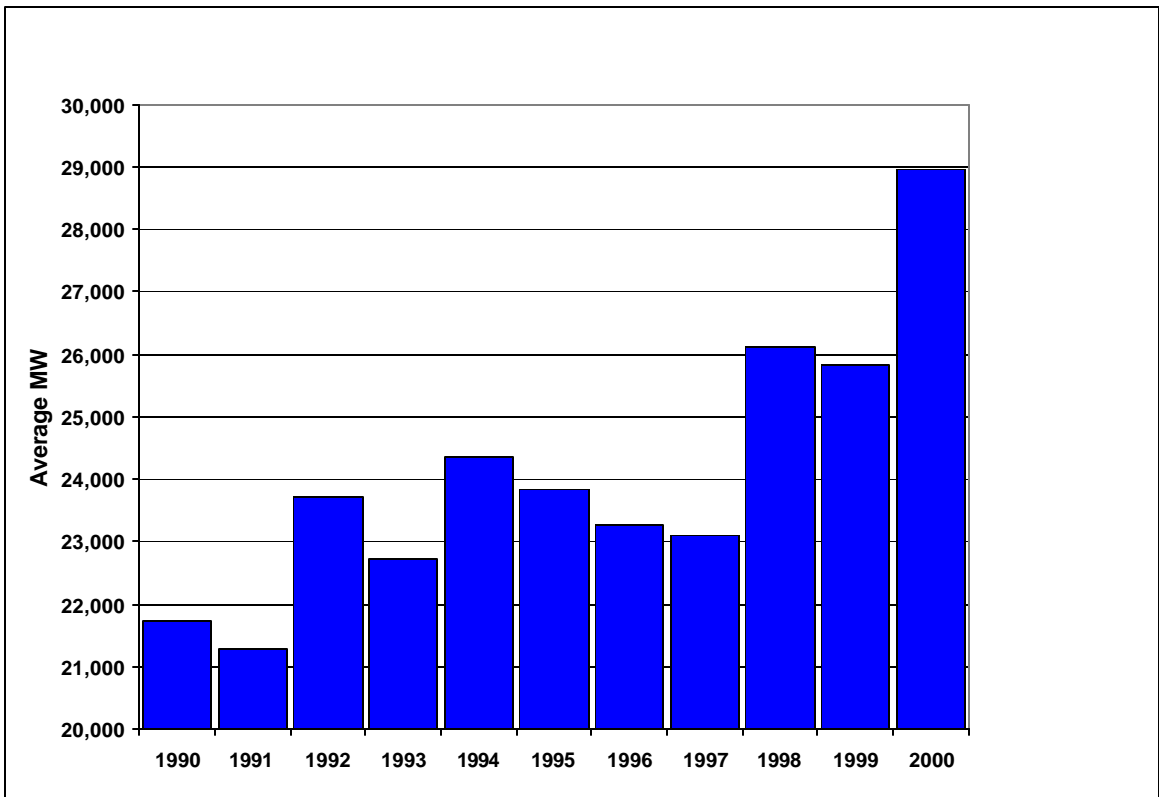


Figure 10 In State Electricity Generation

The pressure on California's electricity supply was even greater than that suggested by those figures, since, other than the natural gas fired and oil fired units, virtually all of the generating sources run at full available capacity⁷⁸. Almost all of the oil-fired facilities have long ago been converted to natural gas, and thus, virtually all of the generating facilities were capacity limited, with the exception of natural gas fired units. Figure 11 shows the production over time from these various sources, except for natural gas.

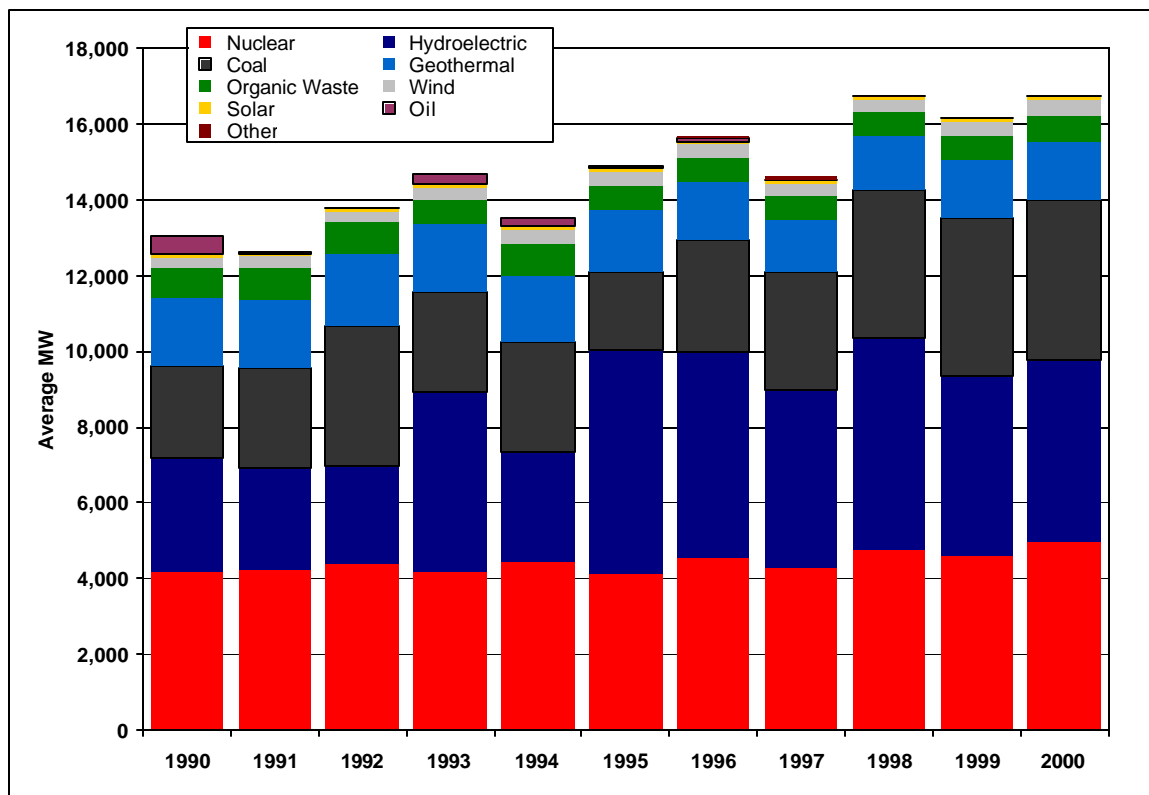


Figure 11 Sources of California Electricity Generation, Other than Natural Gas

⁷⁸ Available capacity for wind machines and solar generators is considerably less than name-plate capacity.

Hydroelectric power does vary in quantity from year to year, but variation is controlled by rainfall and thus the maximum hydropower output cannot adjust significantly to economic conditions.

The remaining supply of electricity came from natural gas fired units. Figure 12 (below) shows this total generation from gas-fired units over the last decade. Figure 12 shows that from 1999 to 2000, generation from these units increased 26%, reaching an all-time maximum production rate. However, during the decade from 1990 through 2000, 1500 MW of gas-fired generation was retired. Thus, more gas-fired electricity generation was needed even though there were fewer gas-fired generating units left to generate that electricity.

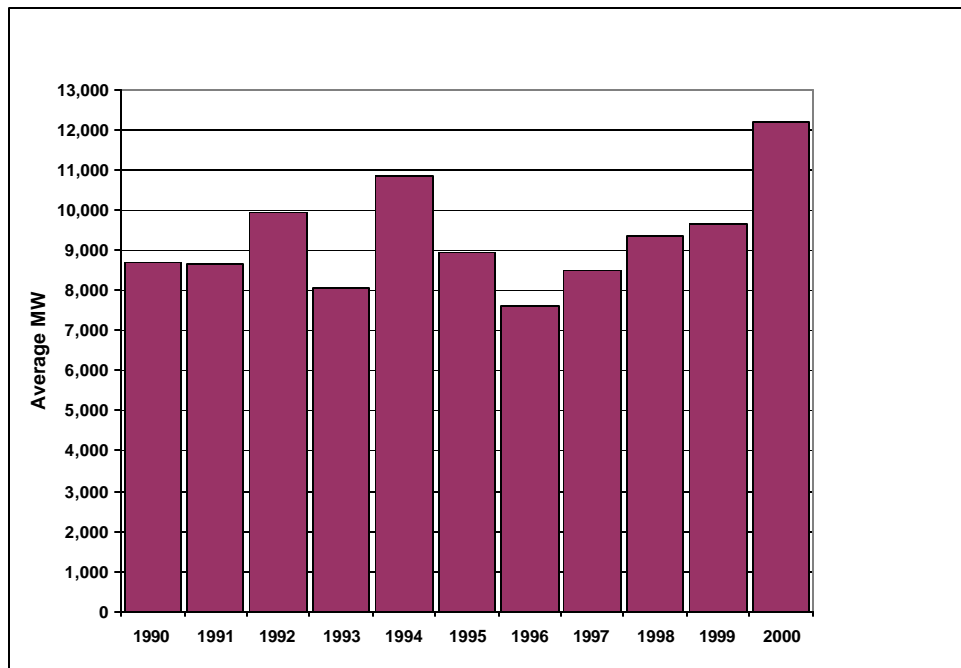


Figure 12 Gas Fired Electricity Generation in California

This sudden increase in the generation from gas fired units coupled with the retirement of units could normally be expected to greatly increase the marginal cost of generating from these units

and thus, under the wholesale market system, absent new construction, to increase the price of all wholesale electricity. Absent new construction, such a change would require the oldest and least efficient plants to be brought into service. Moreover, this change could be expected to increase the demand for natural gas in the State, increasing its price, further increasing the marginal cost of generating electricity and thus further increasing the wholesale price. Each of these impacts that would normally be expected, in fact occurred, as will be discussed at a later point.

Investment in New Generating Units in California

One of the reasons for the restructuring of the electricity system was that market forces were expected to call forth new supplies of electricity in California if needed. However, new supplies could be brought forth only if there were sufficient capacity to generate the electricity. For the private market to create additional generating capacity takes time. Moreover, the California process is particularly lengthy.

The sponsor of the new plant larger than 50 MW of nameplate capacity must bring an application to the California Energy Commission, proposing new plant construction. The California Energy Commission conducts an extensive review process, involving both in house review and public hearing, often taking two or more years⁷⁹. Once the plans for the plant are approved, construction can start. Other than for simple cycle peaker plants, construction can take one to two years.

Once the construction is complete, the plant is tested, first offline and then in a low level of power output before it is finally certified for operation. Until the last step is completed, the plant

⁷⁹ In February 2001, Governor Gray Davis signed six Executive Orders to expedite the review and permitting process of power generating facilities in California.

cannot supply electricity. The entire process from application to on-line status typically takes three to four years for large plants but can be reduced to less than one year for peaker plants⁸⁰.

Thus, the issue of whether the restructuring was leading to greater supplies of electricity generated in California⁸¹ was whether there was a significant change in the applications for new plants, in their approvals, and in the numbers subsequently under construction. It was unrealistic to expect that new capacity resulting from the restructuring, would be on line by the summer of 2000.

The following graph (Figure 13) provides the estimates of new applications, approvals, cancellations, construction, and subsequent operation of new generating plants in California, including the period before the restructuring, through 1996, and the period after restructuring, 1997 through 2001. Data are based on the year the application for certification was filed. The total height of each bar in the graph shows the number of applications made during a year. Data include utility owned generation and QFs, including cogeneration plants and renewable energy⁸². Currently operational plants of capacity smaller than 50 MW are shown separately from plants with capacity 50 MW or greater.

⁸⁰ Peakers are simple, relatively low efficiency plants that generally are used only at times of peak need. Often these are simple cycle plants.

⁸¹ Electricity destined for the California market did not have to be generated in California. Merchant plants could be built just north of the California-Oregon border or just east of the California-Nevada or California-Arizona border without facing the slow approval processes in California. The following discussion, however, limits itself to generation plants in California.

⁸² Application dates of plants of 50 MW capacity or greater are available from the California Energy Commission. For smaller plants data are available for the years the plants went online. In constructing this graph it was assumed that the smaller plants had a planning start date, equivalent to an application date, two years before they went on line, except for the 2001 applications that were completed that year.

Figure 13 shows that that in the 1980s annual applications to build new California electricity generating capacity additions in most years were about 4% of total capacity, growing faster than electricity use. The majority of these were plants with capacity below 50 MW, plants not subject to California Energy Commission approval. But, between 1990 and 1996, annual applications for certification averaged less than 300 MW per year⁸³, while about 3,100 MW of generating capacity was retired⁸⁴, leaving a decrease in generating capacity within California during those seven years. Electricity use during that time continued to grow in California, as in the rest of the West. As opposed to the 1980s, when capacity was increasing by more than electricity use, California was increasing its need for electricity generation without increasing the capabilities to provide that electricity.

⁸³ New capacity growth was similarly very slow throughout WSCC

⁸⁴ Source: California Energy Commission. www.energy.ca.gov/electricity/inactive_plants.html

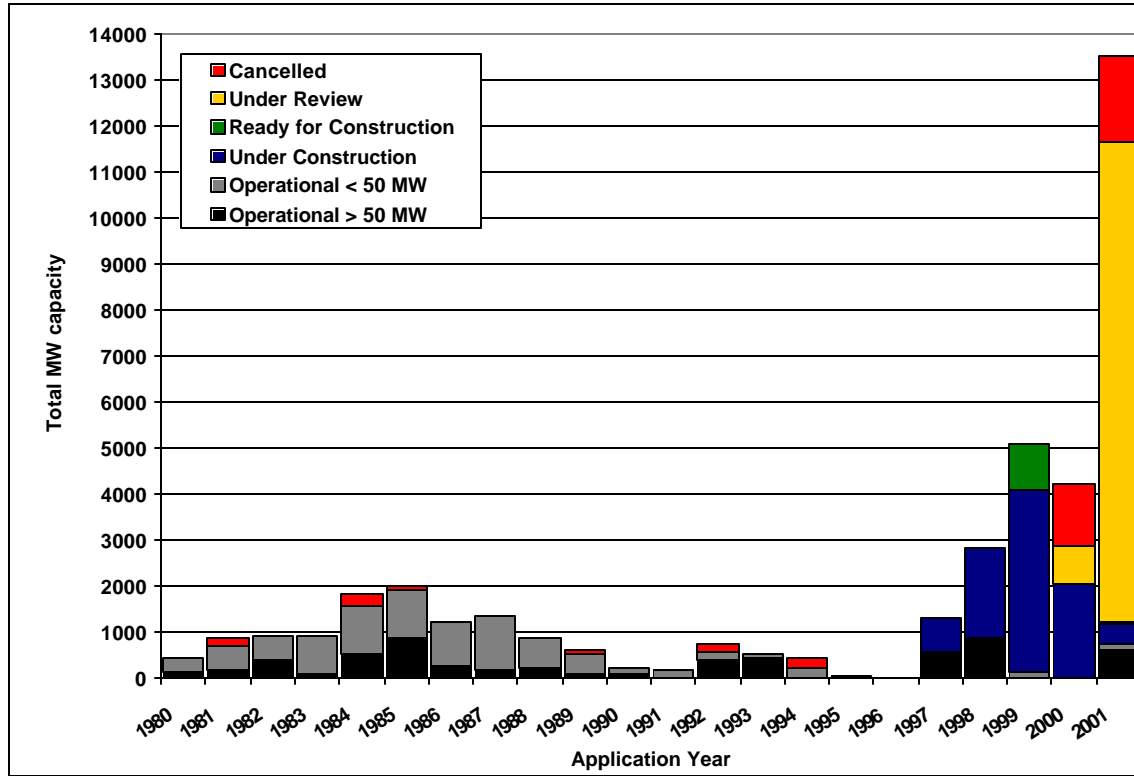


Figure 13 Present Status of New Generating Plants, Applications Since 1980

Figure 14 shows in more detail the composition of the new generation capacity in California coming on line since 1978 (as opposed to Figure 13, which shows applications.) The blue component of the bars shows the plants that required California Energy Commission approval, those plants with nameplate capacity 50 MW or greater. The red component of the bars shows plants that did not require California Energy Commission approval: plants with nameplate capacity smaller than 50 MW.

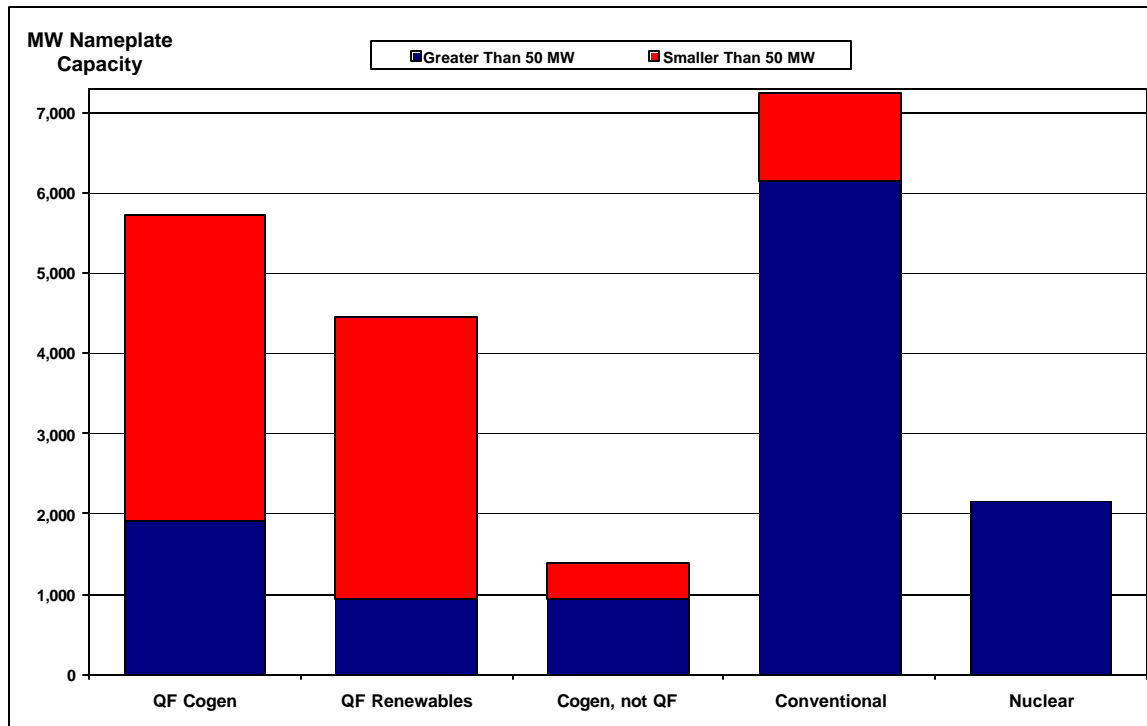


Figure 14 New Plant Construction Since 1978

Figure 14 shows that the largest single source of new nameplate capacity was conventional generation, including both baseload facilities and peakers. QFs based on cogeneration or QFs based on renewables, each have a comparable nameplate capacity⁸⁵. The majority of the QF capacity was from small units (nameplate capacity smaller than 50 MW) and thus much of this capacity is often not highlighted in many public information sources⁸⁶.

The restructuring marked a sharp turnaround in applications. In the years 1997 through 2001, applications averaged about 4,500 megawatts per year. All applications in the years 1997 and

⁸⁵ Delivered electricity from many renewables, particularly wind and solar, are significantly smaller than suggested by the nameplate capacity.

⁸⁶ For example, the California Energy Commission shows a graph that looks somewhat like Figure 13 on its web site, but with far less new capacity constructed in the 1980s. The difference is that the California Energy Commission graph excludes all nuclear power plants and small QFs.

1998 resulted in plants that are now either operational or under construction. Of the three plants now operational, one, a peaking plant with nameplate capacity of 320 MW first went on line in late June 2001, and two combined cycle plants with total nameplate capacity of 1100 MW went on line in early July, 2001. Of the 1999 applications, all that had been approved are now either under construction or about to begin construction. One 1999 project, the Metcalf energy center in San Jose, only recently has been approved and construction started⁸⁷. The applications remained high in the year 2000 and jumped sharply in 2001, largely in response to the very high electricity prices. Therefore, in terms of the goal of calling forth increased supply, restructuring has been a complete success.

As of the end of the year 2000, none of this new supply was yet operational and, as of mid 2001, only 1400 MW of this new capacity was on line. In addition, 500 MW of peaker capacity, whose applications were filed in March 2001 or later, went on line during the summer or fall of 2001. Table 4 provides basic data on these post-restructuring plants currently on line and Table 5 provides similar data for those plants (300 MW or greater) which have been approved but that are not yet on line.

⁸⁷ The approval was blocked for around two years by objections raised by Cisco Systems. Environmental groups, including the Sierra Club and the American Lung Association endorsed this plant.

Project	Applicant / Host	Size (megawatts)	Project Type	Location	AFC Filing Date [1]	Date Deemed Data Adequate [2]	Date Approved	Construction Start Date	Date On Line
Sunrise Power	Texaco Global Gas & Power	320 MW	Simple Cycle (Peaker)	Fellows, Kern County	Dec. 21, 1998	February 1999	12/6/00	December 2000	June 27, 2001
Sutter Power	Calpine	540 MW	Combined Cycle	Yuba City area, Sutter County	Dec. 15, 1997	January 1998	4/14/99	July 1999	July 2, 2001
Los Medanos Energy Center	Calpine	555 MW	Combined Cycle	Pittsburg, Contra Costa County	June 15, 1998	July 1998	8/17/99	September 17, 1999	July 9, 2001
Calpeak Border	Calpine	49.5 MW	Simple Cycle	Otay Mesa, San Diego Co.	June 16, 2001	June 18, 2001	7/11/01		Oct 27, 2001
Calpeak Escondido	Calpine	49.5 MW	Simple Cycle	Escondido, San Diego Co.	May 8, 2001	May 16, 2001	6/6/01		Sept 30, 2001
Alliance Century	Alliance Colton LLC	40 MW	Simple Cycle	Colton, San Bernardino County	March 23, 2001	April 5, 01	4/25/01		September 11, 2001
Alliance Drews	Alliance Colton LLC	40 MW	Simple Cycle	Colton, San Bernardino County	March 23, 2001	April 5, 2001	4/25/01		August 16, 2001
Hanford Energy Park Peaker	GWF Power Systems	95 MW	Simple Cycle	Hanford, Kings County	April 5, 2001	April 11, 2001	5/10/01		September 3, 2001
Indigo Units 1, 2 and 3	Wildflower Energy LLP	135 MW	Simple Cycle	Palm Springs, Riverside County	March 7, 2001	March 16, 2001	4/4/01		July 26, 2001 unit 3, 9/1/01
Larkspur	Wildflower Energy LLP	90 MW	Simple Cycle	San Diego San Diego County	March 7, 2001	March 16, 2001	4/4/01		July 13, 2001

Table 4 Electric Generating Plants Going On Line after Restructuring

Both Tables Source: California Energy Commission. Web site: www.energy.ca.gov/sitingcases/approved.html

[1] Applicant's filing date of Application For Certification (AFC).

[2] Formal process begins following Executive Director recommendation and Commission acceptance of Data Adequacy of the AFC.

Project	Applicant / Host	Size	Project Type	Location	AFC Filing Date [1]	Date Deemed Data Adequate" [2]	Date Approved	Construction Start Date, % Completed	Estimated On Line
Blythe Energy	Wisvest	520 MW	Combined Cycle	Blythe, Riverside Co.	Dec. 9, 1999	March 2000	3/21/01	April 27, 2001 10% complete	July 2004
Contra Costa Repower	Southern Energy	530 MW	Combined Cycle	Antioch, Contra Costa Co.	Jan. 31, 2000	May 2000	5/30/01	August 1, 2001 1% Complete	June 2003
Delta Energy Center	Calpine and Bechtel	880 MW	Combined Cycle	Pittsburg, Contra Costa Co.	Dec. 18, 1998	February 1999	2/9/00	April 2000 58% complete	April 2002
Elk Hills	Sempra/OXY	500 MW	Combined Cycle	Elk Hills, Kern Co.	Feb. 24, 1999	June 1999	12/6/00	May 7, 2001 8% complete	March 2003 (simple cycle 3/2002)
High Desert	Inland Group and Constellation Energy	720 MW	Combined Cycle	Victorville, San Bernardino Co.	June 30, 1997	December 1997	5/3/00	May 1, 2001 11% complete	July 2003
Huntington Beach Modernization	AES	450 MW	Combined Cycle	Huntington Beach Orange Co.	Dec. 1, 2000	February 7, 2001	5/10/01	May 1, 2001 95% complete	November 2001
La Paloma	PG&E National Energy Group	1,048 MW	Combined Cycle	McKittrick area Kern Co.	Aug. 12, 1998	August 1998	10/6/99	January 2000 70% complete	4/02 turbine #1, 5/02 #2, #3, 6/02 #4
Metcalf Energy Center	Calpine and Bechtel	600 MW	Combined Cycle	San Jose, Santa Clara County	April 30, 1999	June 1999	9/24/01		
(Western) Midway -Sunset	ARCO Western Energy Company	500 MW	Combined Cycle	McKittrick, Kern Co.	Dec. 22, 1999	March 2000	3/21/01	March 2002	July 2004
Moss Landing	Duke Energy	1,060 MW	Combined Cycle	Moss Landing, Monterey Co.	May 7, 1999	August 1999	10/25/00	November 2000 40% complete	June 2002
Mountainview	Thermo Ecotek	1,056 MW	Combined Cycle	San Bernardino Co.	Feb. 1, 2000	May 2000	3/21/01	August 21, 2001 1% Complete	June 2003
Otay Mesa	Otay Mesa Generating Company, LLC (Calpine Corporation)	510 MW	Combined Cycle	Otay Mesa area, San Diego Co.	August 2, 1999	October 1999	4/18/01	August 24, 2001 0% Complete	July 2003
Pastoria	Enron	750 MW	Combined Cycle	Tejon Ranch, Kern Co.	Nov. 30, 1999	January 2000	12/20/00	June 1, 2001 1% complete	January 2003
Three Mountain Power	Ogden Pacific Power	500 MW	Combined Cycle	Burney, Shasta Co.	March 3, 1999	June 1999	5/16/01	Sept. 2001 0% Complete	January 2004

Table 5 Electric Generating Plants, Greater than 300 MW, Approved After Restructuring, Not Yet On Line

Supply - Demand Summary

As of May 2000, much new electricity generation capacity was under construction. However, approval of new plants remained slow and had been delayed by the abortive Proposition 9 campaign. Electricity use – both average use and peak load – continued to grow. The entire Western region was facing very tight electricity supplies. Electricity imports into California were reduced because of the needs in neighboring states. The amount of reserve generation capacity was shrinking rapidly. California’s electricity system was facing a very severe challenge, a challenge stemming from regional changes, not simply California changes.

Wholesale Price Increases

The growing challenge showed up temporarily in increased regional spot prices in May, but become readily apparent in June of 2000, when wholesale electricity prices in all of the regional markets, including the California PX, reached⁸⁸ peaks above \$400/MWh. In July, peak prices soared even higher on all of the western markets, with all markets showing highest prices exceeding \$500/MWh during one week.

Figure 15, below, shows the range of prices, estimated in *Clearing Up*, on a week-by-week basis, from April 1, 2000, through September 30, 2000. Data are present for three market centers – at

⁸⁸ The Energy NewsData publication, *Clearing Up* reported on June 16, 2000: “Markets throughout the region were drawn into price spikes. Power prices at Palo Verde/Four Corners and Mid-Columbia/COB moved upward in huge increments all week, with almost no overlap from day to day. At the peak of trading on Wednesday Palo Verde peak power was fetching 450 to 500 mills/KWh. COB and Mid-C had been over 400 mills/KWh.”

the California-Oregon Border⁸⁹ (COB), receipt points along the Columbia River (Mid-C), and at switchyard of the Palo Verde nuclear power plant, Arizona – and for the exchanges on the PX. For each market and each week, Figure 15 shows the lowest prices and the highest prices estimated in *Clearing Up* for the given week.

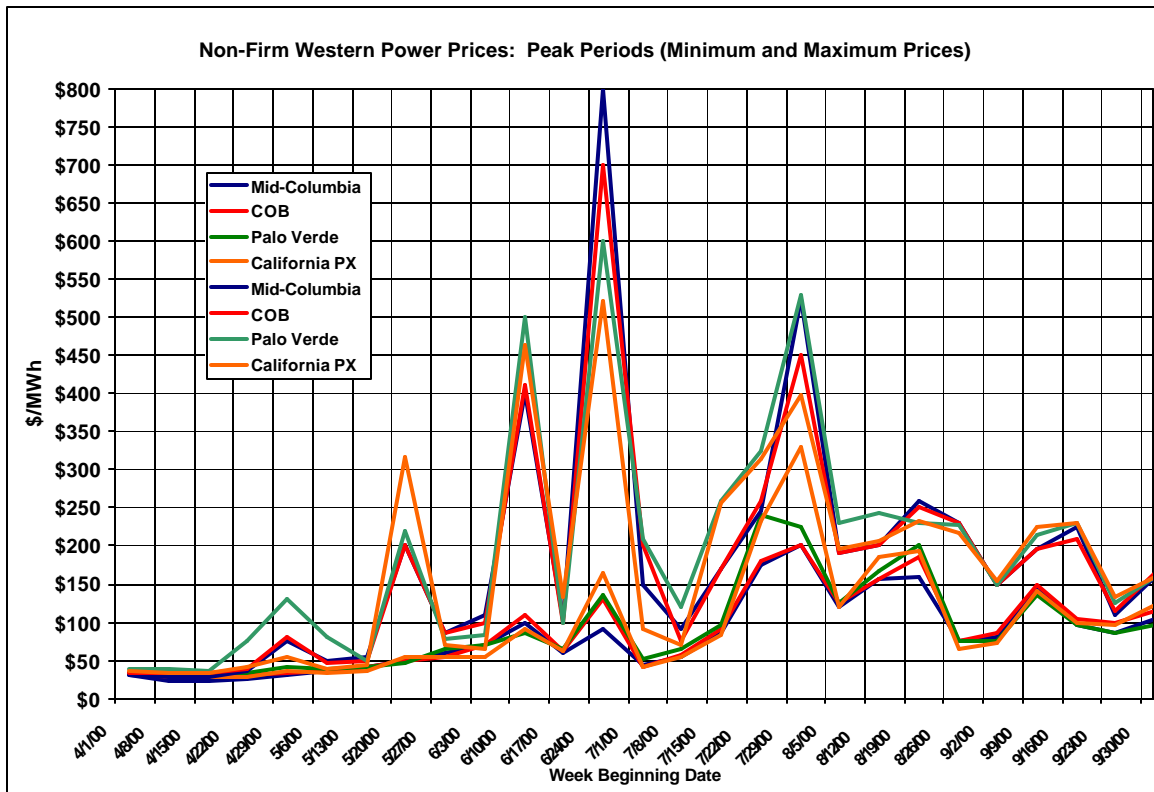
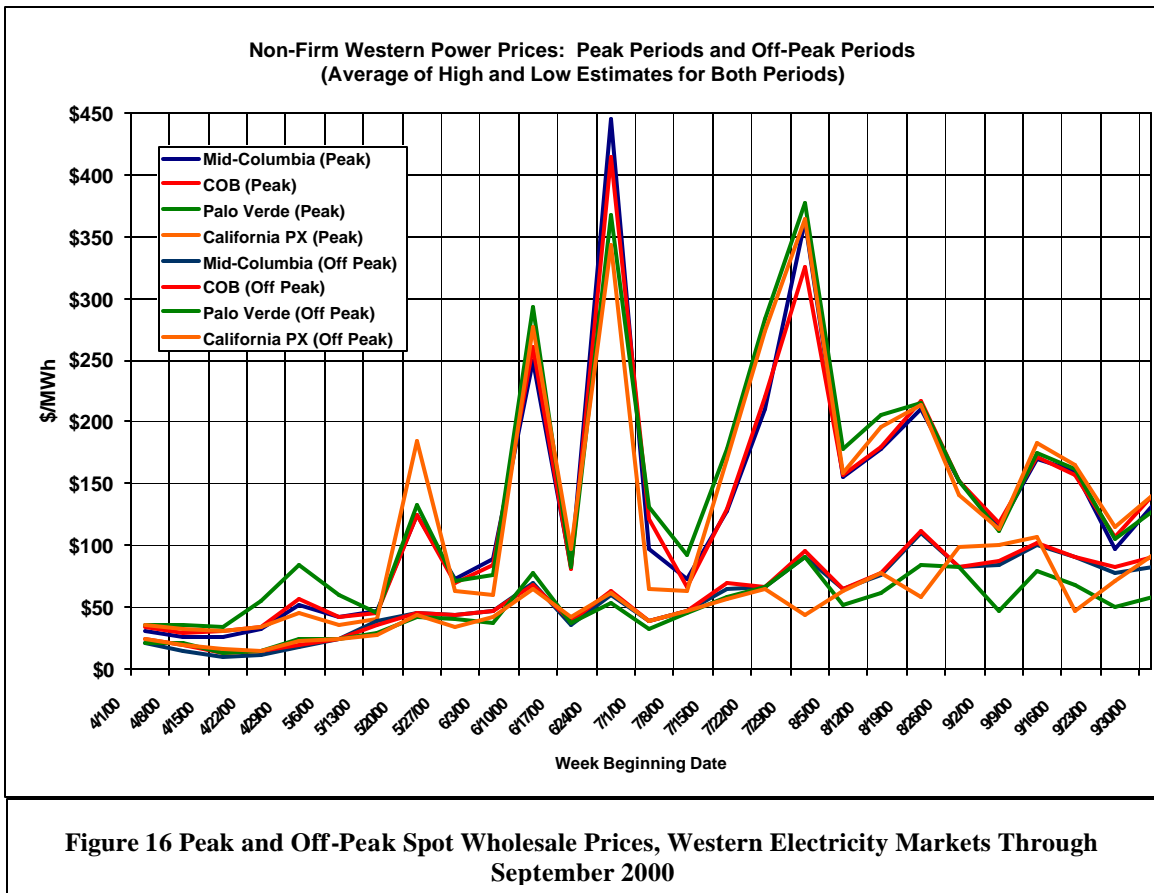


Figure 15 Spot Wholesale Prices, Western Electricity Markets through September 2000

Figure 16 shows the off peak and peak electricity spot prices, at the same four locations as shown in Figure 15. Here the data are the average of the highest and of the lowest peak prices estimated during the various weeks, as well as the average of the highest and of the lowest off-peak prices. The tight markets in the West led to large percentage increases in even the off-peak wholesale electricity prices, not only to the peak period wholesale prices.

⁸⁹ The interconnection point at the California/Oregon border of the Pacific Northwest/Pacific Southwest AC Intertie



Although those not carefully watching the electricity system might not have noticed the changes in supply and demand conditions described above, the dramatic changes in the wholesale price made the challenge obvious. Moreover, by that time, SDG&E had gone past the price control period and its retail prices increased correspondingly. Newspapers throughout the state covered the story. The first lawsuit was filed. The public had become aware that something dramatic was happening to the electricity system. There was a severe challenge to be overcome. Nevertheless, reasonable solutions were available and, at that point, the crisis could have been averted.

Why did Wholesale Prices Increase So Much?

The question of why wholesale prices increased so much in California and throughout the West is a subject of debate and will possibly be the subject of future litigation. Some of the issues are inherent in the changes in supply and demand; others resulted from the restructured system; still others stemmed from the actions taken by various participants in the system.

Most fundamentally, the growth in demand with no growth in generation capacity led to a very tight market for electricity throughout the West. Peak loads and the system resources to meet these loads were almost equal to one another so that there was very little unused generation capacity. In addition, the nature of the supply functions and the demand functions in this market implied that small variations in supply or demand for electricity could lead to disproportionately large variations in price. This characteristic – small quantity changes can lead to very large price changes – is typically to be expected in wholesale electricity markets, absent sharp changes in the structure of those markets. California's retail price control made the matter worse. In addition, there was probably an increase in the degree to which merchant generators were able to exercise market power to raise wholesale prices. These issues will be discussed in the following sections.

Short Run Supply Functions for Electricity

On the supply side of the market, the essential feature is the capacity limitation of generating facilities. Each generator is constrained by a physical capacity to produce electricity. The operator can choose to produce below capacity and can choose maintenance and repair policies that influence the fraction of time that the plant operates, but cannot generate electricity from a

given plant at rates beyond its capacity. For plants operating below capacity, the marginal cost of operation is not much larger than the marginal cost of the fuel used to power the facility. In California, many plants are quite similar to one another so that many would have similar marginal costs if they were operating significantly below capacity. For these reasons, the short run supply curve for the system took on a “hockey stick” shape. For a wide range of system-wide outputs, the supply price increased gradually with increases in generation. However, as the system neared full capacity, larger fractions of the generating units operated at full capacity and more of the inefficient high cost units were brought into service. At some point, even these very inefficient plants would be operating at full capacity. This physical capacity constraint leads to the “hockey stick” shape of the supply curve⁹⁰.

Figure 17 illustrates this short run supply function, using data from the PX during July 1999. Each dot represents an observation of an hourly price and total quantity supplied during the month of July. The horizontal axis represents the MW of electricity committed through the PX for given hours during the month. As such, it includes both electricity generated in California and that imported to California. It excludes the electricity purchased by municipal utilities under medium-term and long-term contracts, since that electricity was not exchanged on the PX. The vertical axis represents the market-clearing price for electricity for those hours. Under the assumption that the power exchange was operating as intended, the vertical axis is approximately equal to the highest marginal cost of generating facilities, given the total quantity sold.

⁹⁰ Whether this curve is both a supply curve and a marginal cost curve depends on whether the generators at the margin were bidding their units at their marginal cost. If so, then this is both a marginal cost curve and a supply curve. If not, it is still a supply curve.

The particular points were determined by market equilibria on different days of the month and during different times of the day. During the middle of the day, particularly on weekdays, the demand for electricity was high; during the night demand was low. A process under which the demand function has moved while the supply function has remained approximately stationary has generated these points. Thus, the set of dots trace out a short run supply curve for electricity. If the sellers were bidding their particular quantities at their marginal costs, then this set of dots also traces out a marginal cost curve.

The “hockey stick” character of the short-run supply function is obvious. For quantities between 20,000 and 30,000 MW the price varied generally between \$10 and \$30 per MWh. However, for quantities around 34,000 MW the locus of points became nearly vertical.

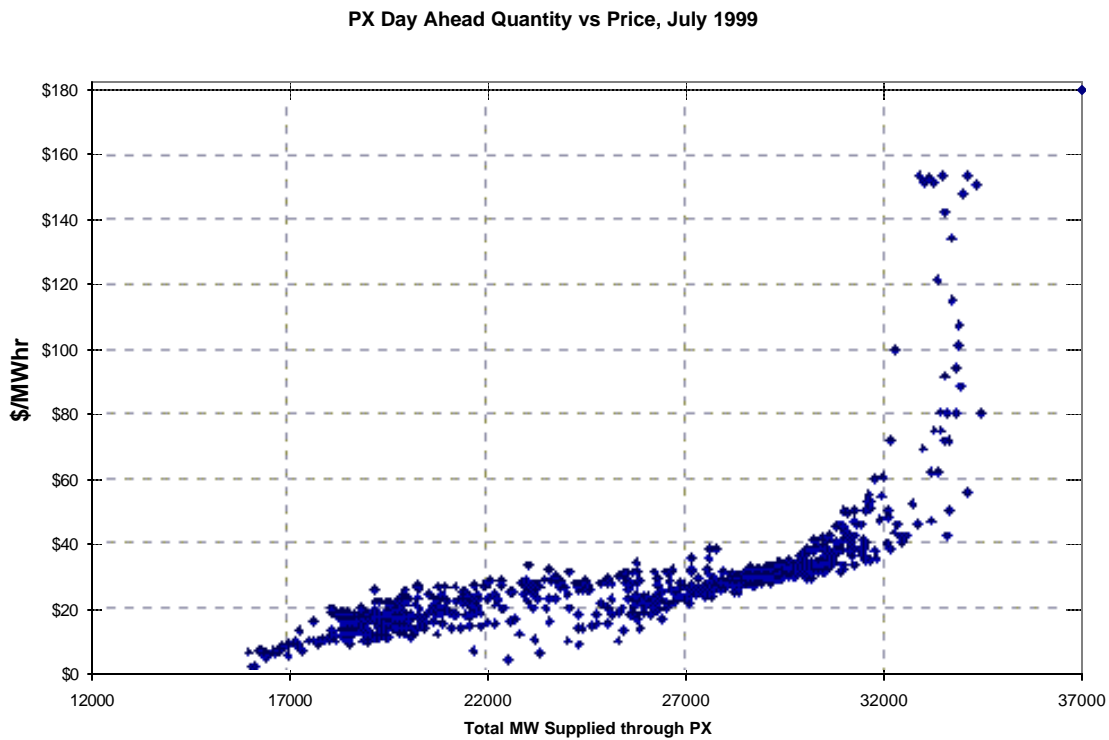


Figure 17 Price vs. Quantity for California PX, July 1999

This “hockey stick” shape of the short run supply function is the result of the physical capacity limitations in the generating system, as discussed above. These physical limitations would be inherent in this system whether there had been the restructuring.

Contractual commitments throughout the rest of the West played a significant role in the shape of the short-run supply functions in California. Given the contractual commitments, available imports into California responded very little in the short-run to changing prices in California. Had they been more responsive, then the total quantity of electricity made available in California would have not had such a vertical section to the supply curve, since imports into California would increase in response to price increases.

In the longer run – say over the course of several months – imports to California would be more responsive to the average price expected during a day⁹¹. Over this period, demand could adjust and contracts could be renegotiated. For example, in Washington, aluminum plants and other intense users of electricity shut down and eliminated their use of electricity altogether in response to the electricity price increases. A significant share of that electricity would then be available for exportation to California. Therefore, the medium term supply curve can be expected to be somewhat less steeply sloped than the one in Figure 17.

The isolated nature of the west coast electricity market also played a role. Because there are only very limited interconnections between the Western region of the United States and the rest of the

⁹¹ This implies that analyses of the California electricity markets that use data on the intra-day adjustment of imports into California in order to estimate the slope of the import supply curve will systematically underestimate the impact of prices on supply to California.

nation, price differentials between the Pacific Coast and, say the Midwest could persist indefinitely without electricity being transmitted from the Midwest of the West Coast. Thus, even in the long run, given that regional isolation, changing imports from the rest of the country would play little or no role in influencing the shape of the supply curve for electricity into California.

In what follows, I will abstractly represent the short run supply curve by a line that generally has a shape as shown in Figure 17, but has quantities more responsive to price than does the curve in Figure 17. However, the electricity generated in California and the imports to California will be separated in order to clarify the analysis.

Short Run Demand Functions for Electricity

The use of electricity declines in response to increases in the retail electricity price, even over a period of months, although over a many month period the demand declines by a far smaller percentage than the retail price increases. Using conventional estimates of the elasticity of demand⁹² for electricity -- the percentage reduction in demand motivated by a 1% increase in price -- each average retail price increase of 10% could be expected to motivate a roughly 1% - 3% reduction in demand over the short run, perhaps over several months.

Therefore, to motivate a 4% reduction in demand, an amount, which would roughly compensate for the demand increase from 1999 to 2000, would require a 13% to 40% increase in retail price.

⁹² Here, and for other numerical examples, a short run elasticity of demand for electricity will be approximated as 0.1 - 0.2. Long run elasticities have typically been estimated to be as large as 1.0.

The average retail price of electricity⁹³ was about 12 cents/KWh (equivalent to \$120/MWh) and the retail price would need to rise by between 1.6 cents/KWh and 4.8 cents/KWh to motivate that demand reduction. This would correspond to an increase of \$16/MWh to \$48/MWh to motivate the demand reduction⁹⁴.

However, because of the retail price control in California, the increase in wholesale price did not lead to any increase in the retail price for most California customers. Therefore, when the wholesale market price increased, the ultimate consumer of electricity in California did not face a direct economic motivation to reduce demand. In addition, the investor-owned utilities did not have the legal option to reduce their wholesale purchases⁹⁵ but were required to acquire as much electricity as their customers used. With this economic isolation between the wholesale price and the retail price, demand for electricity at the wholesale level in California was made very unresponsive to the wholesale price.

There were demand responses for customers of the municipal utilities in California, or for industrial customers purchasing directly from generators or marketers.

Most other utilities had sufficient medium-term and long-term contracts so that retail rate increases were not required, at least not immediately. Therefore, these demand responses were muted or eliminated as well. In fact, almost all utilities sell electricity at prices corresponding to

⁹³ This is actually the bundled price of electricity and electricity delivery services. The conventional estimates of demand elasticity were based on this bundled combination.

⁹⁴ This amount is roughly the price increase that was allowed by the CPUC in January plus March 2001, an average price increase of 4 cents/KWh.

⁹⁵ Utilities could choose to reduce their purchases through the PX by under-scheduling the amount of electricity that they would need to satisfy their customers. If they under-scheduled on the PX, they would be required to purchase additional electricity on the CAISO imbalance market. One way or the other, the utility had to acquire all electricity its customers used.

the average cost of acquiring that electricity and acquire their electricity dominantly under long-term contracts. Therefore, the average cost – and thus the retail price -- changes by far less than does the spot wholesale price. Thus, even without retail price caps, spot wholesale price changes translate to only far smaller changes in retail prices for most utilities.

Some large industrial customers and state agencies, such as the California Department of Water Resources, had contracts to buy electricity at prices responsive to wholesale prices. And some had contracts to purchase a fixed quantity of electricity at a negotiated price. If this quantity could be resold, that user had an incentive to reduce electricity use when prices increased. In addition, some consumers chose to reduce electricity use because they understood that there was an “energy crisis” and they chose to help the State by reducing demand.

The net result is that short-run demand functions for electricity, when measured at the wholesale level of the market, tend to be almost, but not quite, vertical. That is, very large increases in wholesale spot prices lead to only small reductions in demand. Thus, I show demand functions as steeply sloping, but only somewhat responsive to prices.

There were demand responses in other states for those utilities whose retail rates increased. Some companies, for example, those making aluminum in the Pacific Northwest, shut down all production, therefore completely eliminating their need for electricity. However, those responses would be reflected in the availability of net import supply of electricity to California. These demand (and supply) responses in other states would have the effect of making the supply curve for electricity more responsive to price than illustrated in Figure 17.

Impacts of Supply and Demand Changes on Wholesale Prices

Figure 18 illustrates what would be the combined impact of increasing California electricity demand and reduced supply of electricity imports on the spot wholesale price of electricity, if the wholesale price increase had been allowed to translate to retail prices in California. The horizontal axis on this graph represents sales of electricity on the wholesale market for California use; the vertical axis represents the spot wholesale price of that electricity.

The upward sloping “hockey stick” shaped lines together represent the supply function. The green line (the left-most of the three) represents the supply function for electricity generated in California. The two blue lines (the right-most line) add the supply of electricity imports into California to the supply of electricity generated in California. The dashed blue line represents the 1999 situation with normal import availability; the solid blue line represents the 2000 situation with sharply reduced import availability.

There are four downward sloping lines representing different California electricity demand functions, under the assumption that the increases in the average wholesale prices facing California investor-owned utilities were passed on to retail customers⁹⁶. The right-most two represent the demand conditions in the years 1999 and 2000, with the dashed line representing 1999 and the solid line representing 2000. The left-most two represent low demand conditions and will be discussed at a later point.

⁹⁶ If the entire spot market price increase were passed on to the retail customers, the demand functions would be less steep than shown here: there would be greater demand reductions in response to the price increases than shown here.

Black dots are drawn at the 1999 and 2000 points of intersection between the California demand functions and the electricity supply functions (California-generated plus imports to California). Broken lines show the spot prices that would occur in the two years, under the counter-factual assumption that wholesale prices of electricity were passed on to retail customers. In response to increased retail prices, California consumers would find ways of reducing electricity use, by turning off lights, unplugging spare refrigerators, turning off their air conditioners or adjusting the thermostat. Even with the demand response plus the supply response to higher prices, the spot wholesale electricity price would have increased significantly, as shown in this graph.

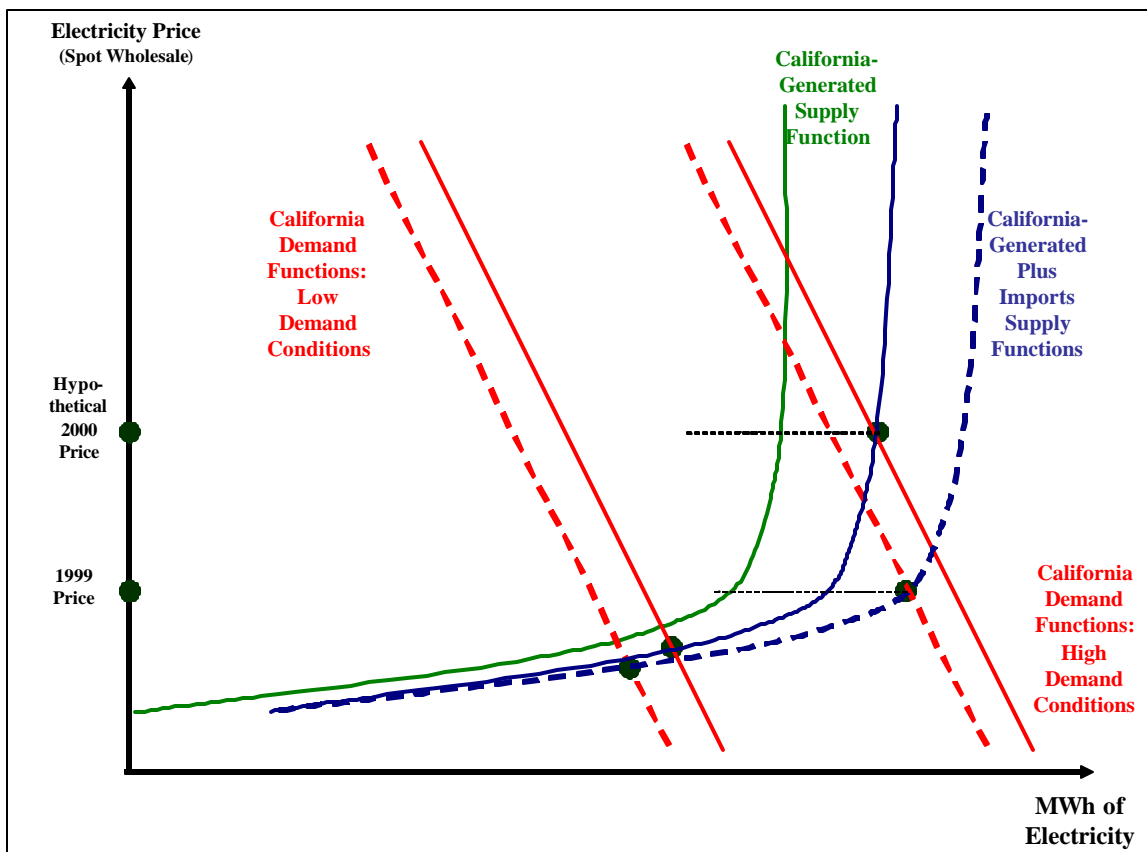


Figure 18 Market Equilibria Without Retail Price Control

Similarly, Figure 19 illustrates the impact of changing demand on the wholesale price of electricity, given the reality of the retail price caps in California. The only difference between this graph and the graph of Figure 18 is that the demand functions are much steeper than those in Figure 18; price increases lead to much smaller reductions in demand. The demand functions are much steeper because California's retail price cap did not allow wholesale prices of electricity to be passed on to retail customers. Therefore there was not a direct economic incentive for California consumers to find ways of reducing electricity use, by turning off lights, unplugging spare refrigerators, choosing to not use their air conditioners or adjusting the thermostat.

Figure 19 shows that absent the demand response, the spot wholesale electricity price increased dramatically. Spot wholesale price increases were limited somewhat by the increased supply of California-generated electricity as prices increased and by the increase in imports to California in response to the price jumps (increases relative to the downward shift in supply resulting from the reduced rainfall in the Pacific Northwest and the increased use in the Pacific Southwest.) But absent demand reduction by consumers, spot wholesale prices jumped much more than they would have increased, had retail prices been allowed to increase along with the wholesale electricity prices.

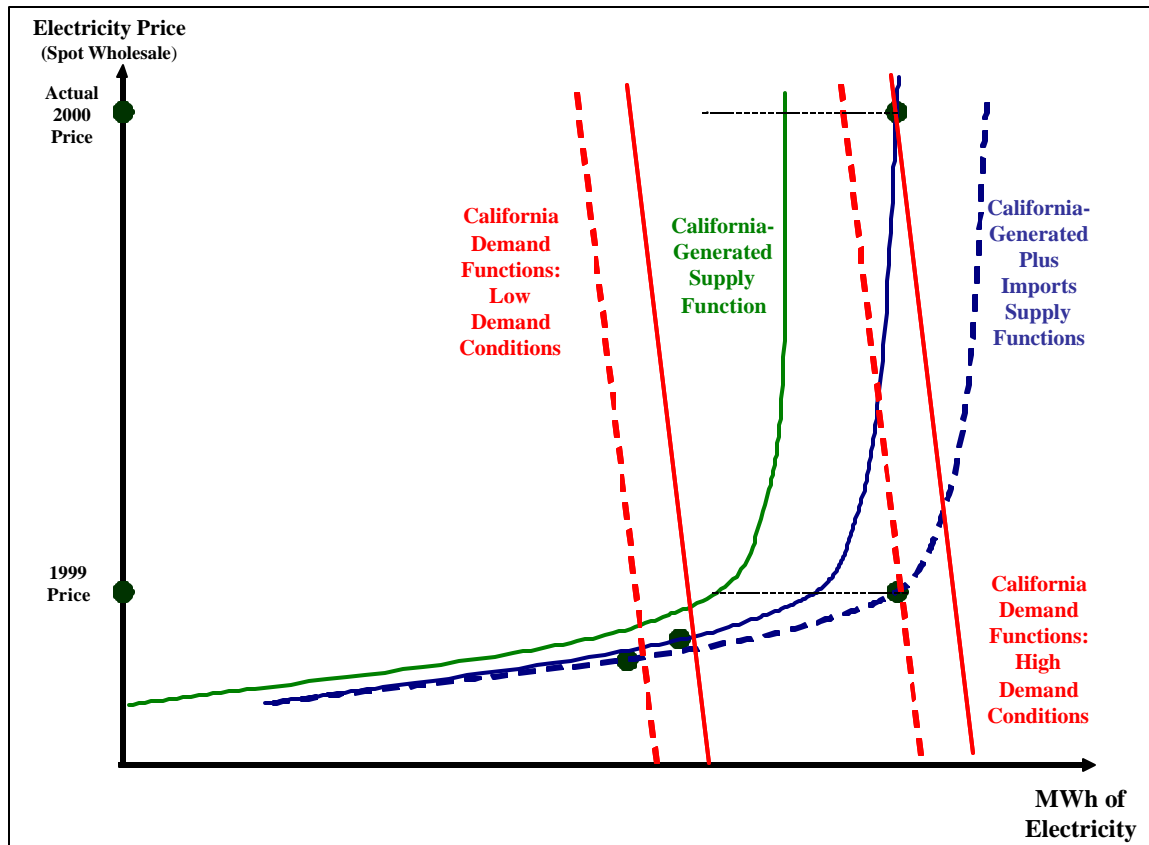


Figure 19 Market Equilibria with Retail Price Control

In both of these graphs, in addition to the 1999 and 2000 demand functions, are two other, lower quantity demand functions. These left-two demand functions represent the operation of the system during those times when there was sufficient excess capacity in the system. Modest increases in the demand function coupled with the decrease in import supply would lead to only small changes in price (the vertical position of the two dots are very similar to one another.) The response of electricity supply to prices, when there is adequate capacity, would serve to limit greatly the increases in wholesale prices resulting from demand increases, even if demand is very unresponsive to prices.

A comparison of Figure 18 to Figure 19 suggests that had retail prices been allowed to move with wholesale prices in California, there still would have been a challenge and there still would have been wholesale price increases. However, because consumers would observe these price increases and would be motivated to reduce demand, the wholesale price increases would have been much smaller than in fact occurred. Thus California alone, with no changes in regulation from the neighboring states, could have sharply reduced the wholesale price increases that each of the states faced. But California political leaders chose not to take this action.

Figure 19 gives a primary explanation of why wholesale prices jumped greatly once the system neared capacity after remaining relatively stable for several years when there was adequate capacity⁹⁷.

These figures also suggest that wholesale price volatility should not be viewed as an anomaly of the California situation but rather as inherent in electricity markets, as long as both the supply functions and the demand functions are very steep at the point of their intersection. The California price caps simply made a difficult situation much worse.

Increases in Electricity Generation Costs: Natural Gas Prices

Increasing demand for natural gas, coupled with the limitations on pipeline capacity into California and within California, led to an increase in the natural gas price, a change that increased electricity generation costs. Figure 20, based on data from Enerfax.com, below shows

⁹⁷ See EMF Report 17, “Prices and Emissions in a Restructured Electricity Industry”, Energy Modeling Forum, Stanford University, May 2001 for a model-based analysis of the sensitivity of electricity prices to economic growth rates. This phenomenon is illustrated quantitatively by that study.

increases in the California natural gas spot prices from April 1998 through October 2000. Note that in this period price more than doubled from \$2.50 per million Btu to \$6.00 per million Btu.

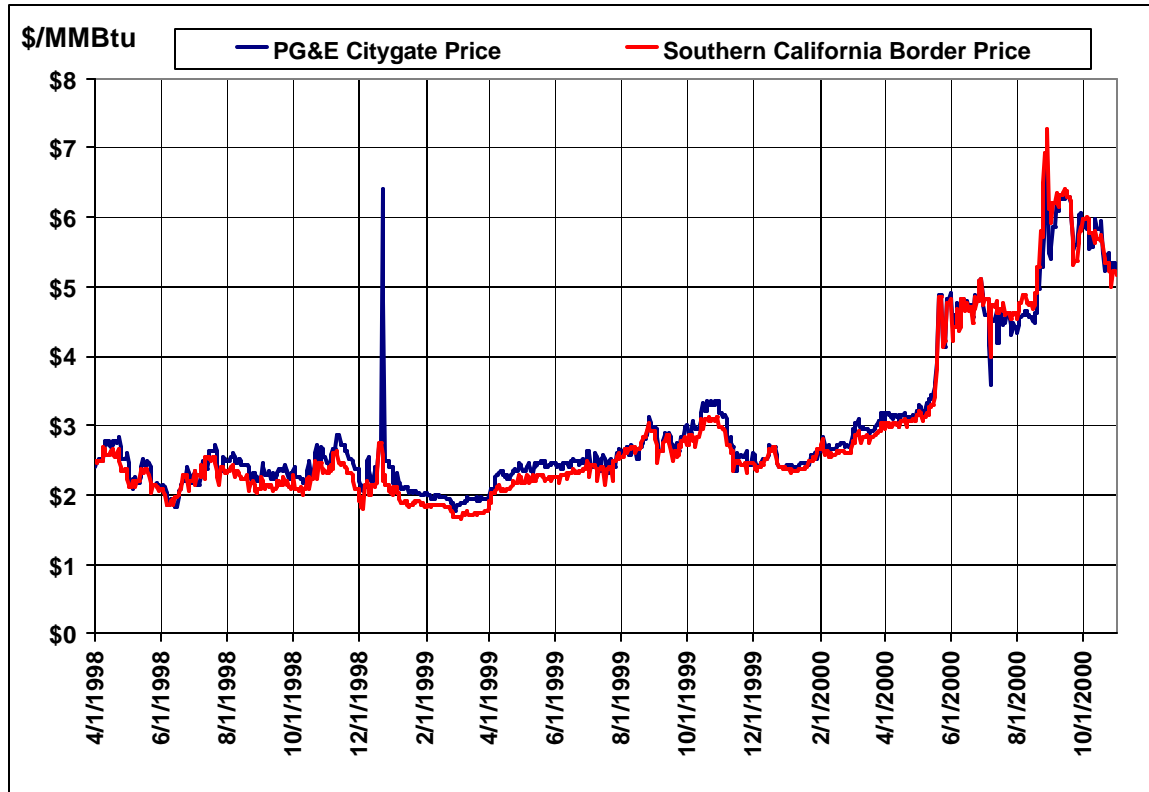


Figure 20 Natural Gas Spot Prices in California

It is possible to estimate the impact of this increase in the natural gas price on the increase in the cost of operating a typical new combined cycle plant and on the increase in the cost of an inefficient unit. This analysis implies impacts on the wholesale electricity prices.

Heat rates of a new combined cycle power plant may be as low as 6.8 million Btu per MWh. For such a new combined cycle power plant, when natural gas was selling for \$2.50 per million Btu,

the cost for natural gas alone would be roughly \$17/MWh. When the natural gas price increased to \$6 per million Btu, this cost of natural gas alone would increase to \$41, a jump of \$24/MWh, and the marginal cost of electricity generation would increase by \$24/MWh. If these plants were at the high cost end of the merit order and thus determining the wholesale price, absent demand adjustment, wholesale price of electricity would increase by \$24/MWh. In terms of Figure 19, the supply curve for California-generated electricity would shift upward by \$24/MWh; the import supply component of the total supply function would not adjust; thus, the total supply function would shift upward by somewhat less than \$24/MWh. With price controls in place, there would be only a small further adjustment of demand and the wholesale price of electricity could increase by almost \$24/MWh.

The cost increase would be greater, however, for older, less efficient plants. Older plant may have twice the heat rate as the newer combined cycle plants. For example, the SCE Highgrove 1 & 2 plants have heat rates estimated⁹⁸ to be about 13.4 million Btu per MWh. For these older plants, the marginal cost of the natural gas alone would be roughly \$34/MWh when gas was selling for \$2.50 per million Btu. However, when natural gas price increased to \$6, this marginal cost would increase to roughly \$80/MWh, a jump of \$46/MWh. In terms of Figure 19, the high-price portions of the nearly vertical section of the supply curve for California-generated electricity would shift upward by \$46/MWh; the total supply function would shift upward by somewhat less than \$46/MWh.

⁹⁸ Data estimated from "The Use Of Heat Rates In Production Cost Modeling And Market Modeling," Joel B. Klein April 17, 1998, California Energy Commission

In times of excess capacity, the older inefficient plant would be rarely, if ever, used, but as total generation increased, the old inefficient plants became the source of the additional generation. Thus, the old inefficient plants, rather than the new combined cycle power plants, became the highest cost units used and the operating costs of these old plants determined the marginal cost of electricity generation. Therefore, two factors worked together to increase wholesale prices: the marginal electricity-generation units used to set the wholesale price shifted from new efficient plants to old inefficient plants and the natural gas price used by these plants increased. These two factors together implied that the natural gas costs of the marginal electricity-generating unit increased from \$17/MWh to \$80/MWh, an increase of \$63/MWh. This increase directly increased the wholesale price of electricity.

In addition, as the system reaches full capacity, and the use of natural gas increases, the quantity of natural gas needed exceeds the quantity purchased under long-term contracts. Therefore, the additional natural gas is purchased on the spot market. Thus although long-term contract prices for natural gas may have influenced pricing behavior when the system was well below full capacity, at full capacity the spot market price of natural gas determines the marginal cost of electricity generation.

The simultaneous shift to use of the inefficient plants, the shift from contract natural gas to spot natural gas markets, and the overall increase in the natural gas price could account for a large share of the increase in the wholesale price of electricity occurring in this period. It should be recognized that these shifts did not cause the wholesale electricity price increase but rather were

a response to the changing supply and demand conditions that were the primary cause of the wholesale price increases.

It should be noted that because most of the electricity generated from gas-fired units is based on combined cycle units, the average cost of electricity generation increased by far less than did the marginal cost. This increase in the natural gas price, therefore, led to increases in the profits of most electricity generators running gas-fired plants. If there had been long-term contracts in place, even contracts indexed for the price of natural gas, the cost that the utilities would have paid to acquire their electricity would have increased by far less than it actually increased.

Increases in Electricity Generation Costs: RECLAIM Credits and Annual Emissions Constraints

A change in the price of one additional input was significant. In 1993 the South Coast Air Quality Management District instituted the REgional Clean Air Incentives Market (RECLAIM) and to meet the target the NO_x and SO_x emissions. The RECLAIM program, a market based approach to regulation, required emitters of NO_x and SO_x to acquire enough RECLAIM Trading Credit permits to match their actual emissions each year. Through 1998, there was an excess supply of permits in the market, primarily because the number of allocated permits exceeded the normal emission levels. However, the number of allowed permits was decreasing sharply and during 1999, the number of allocated permits had diminished to be equal to the total emissions. Through compliance year 1999, the price of NO_x trading credits ranged from \$1,500 to \$3,000 per ton. For compliance year 2000, although permits had been selling for

approximately \$4,300 per ton in 1999, the prices for the first ten months of the year 2000 increased to an average of about \$45,000 per ton⁹⁹.

The significance for electricity of this price increase is related to the emission characteristics of electric generating plants. A typical baseload gas fired generating unit releases about 0.1 pounds of NO_x per MWh of electricity generated. At a price of \$2,000 per ton, or \$1.00 per pound, the price of RECLAIM credits would add an insignificant amount (10¢ per MWh) to the marginal a cost of such units. When the price soared to \$45,000 per ton, or \$22.50 per pound, this added about \$2.25/ MWh for a typical base load gas fired generating unit, an increase that still was small in comparison to the wholesale price increase. In terms of Figure 19, some of the flat, lower portions of the supply curve for California-generated electricity would shift upward by between \$2.25/ MWh, but this, itself, would have no impact on the high price equilibrium.

Old gas-fired turbines, however, may emit up to 4 pounds of NO_x per MWh. For such units, the price of \$2,000 per ton would add to the marginal cost of electricity generation about \$4/ MWh, still small but significant. However, when the price soared to \$45,000 per ton, for the old turbine releasing 4 pounds of NO_x per megawatt hour of electricity generated, this increased the marginal cost by \$90/MWh.

During times of energy emergencies, when all available generating units were operating, old gas fired turbines, many of which were very inefficient, would set the marginal cost of generating electricity in California. For these plants, the incremental cost of natural gas could have been \$80/MWh and the incremental cost of RECLAIM credits could have been \$90/MWh. Adding

⁹⁹ “White Paper on Stabilization of NO_x RTC Prices”, South Coast Air Quality Management District, web site: <http://www.aqmd.gov/hb/010123a.html>

these two costs together, in terms of Figure 19, the very highest-price portions of the nearly vertical section of the supply curve for California-generated electricity would shift upward by \$170/MWh, resulting in much greater increases in wholesale prices for the very limited times in which the system was operating at that point.

Here too, it should be recognized that these shifts did not cause the wholesale electricity price increase but rather were a response to the changing supply and demand conditions that were the primary cause of the wholesale price increases. The significant of the increase in RECLAIM costs is that the uppermost part of the vertical section of the California electricity supply function was made more nearly vertical by the tight limitations on the RECLAIM market.

In addition, many plants, both inside and outside the South Coast Air Quality Management District, had annual emissions limits, in particular, annual NO_x emissions limits. Absent retrofits to install new pollution control equipment, annual emissions limits translate directly to limits on the total megawatt hours of electricity that can be generated from an individual unit in a given year.

Violation of those emissions limits was punishable by large fines and therefore to avoid fines, generators had an incentive to reduce their electricity generation from those units. In one well-publicized case, the South Coast Air Quality Management District brought legal action against AES Corporation for exceeding its annual allowable emissions by about 600 tons. In December 2000, the District and AES reached a settlement in which AES agreed to pay a \$17 million penalty, equivalent to about \$28,000 per ton of NO_x *in addition to* purchasing emissions credits

to make up for the excess emissions, installing state-of-the-art air pollution controls on three of its power plants, and deducting the year 2000 excess emissions from its future year allocations. (Ironically, although AES was fined because it produced more electricity in 2000 than allowable within its annual emissions limits, California officials have accused AES of withholding generation in 2000 – that is, of producing too little electricity.)

A power plant facing an annual emissions limit, and therefore able to generate only a limited number of annual megawatt-hours, incurs an opportunity cost in addition to the marginal cost of electricity generation. The opportunity cost exists because generating an additional megawatt-hour of electricity at one time eliminates the opportunity for the plant generating an additional megawatt-hour of electricity at some other time. The cost to the plant owner of that eliminated opportunity – the “opportunity cost” of generation – is measured by the additional profit that could be earned at that other time from generating an additional megawatt. More precisely, the “other time” must be when the firm expects not to operate at capacity and therefore when it could generate and sell another megawatt-hour. The opportunity cost is equal to the maximum additional profit that could be earned at such a time.

A profit maximizing generator would not be willing to sell electricity unless the price it expected to receive were at least as great as its marginal cost *plus* opportunity cost. A firm bidding competitively thus would not offer a bid equal to its marginal cost but rather would offer one equal to its marginal cost *plus* opportunity cost. Therefore, annual emissions limits lead competitively bidding generators to increase bid prices above marginal cost and further reduce electricity generation. Bidding to sell electricity at a price equal to marginal cost plus

opportunity cost is thus *not* an indicator the firm is gaming the market or exercising market power but rather that the firm is bidding competitively, recognizing its annual emissions limits.

Possible Exercise of Market Power by Generators

A second possible explanation for the rapid increase in wholesale price is the exercise of market power by electricity generators selling into California markets. This explanation continues to have great political appeal, partly because, if true, it can be asserted that the challenge was not caused by flaws of the restructured system but rather by actions of corporations supplying electricity to California.

As discussed in Chapter 2, the theory underlying the operation of the California PX was that each generator of electricity would bid in its available supplies at its marginal cost. The quantities would be ranked in merit order from lowest cost to highest cost until sufficient quantities were available. The market-clearing price would be set equal to the marginal cost of the highest cost unit needed to satisfy the demand for electricity on the wholesale market. Each supply that was bid into the market at a marginal cost below the market-clearing price would be able to sell its electricity at what ever it was the market-clearing price. Any quantity bid at a higher marginal cost would not be sold. In this way, in theory, for each hour a price would be set so that all the electricity generating units with marginal costs lower than that price would be called upon to supply electricity and all the units with marginal costs higher than that price would not be called upon.

That theory was based firmly on a belief that the price bids of the generators would always be equal to their marginal cost of generating that electricity. That belief was itself dependant on an

assumption that each generating unit was being bid independently of every other unit. However, for generators owning multiple units, it could be expected that the bidding would be coordinated among the various generating units¹⁰⁰; the units would not be bidding independently of one another.

A company that owned several generators could choose to bid at prices higher than its marginal cost for some of its generating units (or to refrain from bidding at all). For those units whose bid were below the market clearing price, such a bidding strategy would be irrelevant, since the payment would be based on the final market clearing price. However, if a unit increased its bid sufficiently so that the bid became higher than the market-clearing price, then the result would be the same as if that firm withheld from bidding entirely. The relevant portion of the supply curve – that below the new market-clearing price – would be moved to the left and the market-clearing price would be driven upward. As long as that firm had additional units that bid below the market-clearing price, then the firm could make additional profits from those units.

In terms of Figure 19, the impact of such bidding would be to shift the California-generated and the total supply function towards the left, increasing the equilibrium wholesale price. When the system was near full capacity, this reduction in supply would increase the market-clearing price substantially. The firm could make additional profits from the rest of its generating units that would enjoy the higher price but would have to trade those additional profits against the lost profits from the unit that increased its bid.

¹⁰⁰ Under the US antitrust laws companies are not prohibited from coordinating their price bids internally, that is, within one company. However, any coordination of price bids between two or more companies would generally be illegal under the Sherman antitrust act.

The success of these strategies was made more likely by the California retail price control and the resulting very steep demand curve, as could be seen by comparison of the price responses to a given supply shift illustrated in Figure 18 and Figure 19. Since in market clearing, as suggested through Figure 19, there would be little reduction in the observed generation of electricity and since there would be an incentive on many of the generators to follow similar strategies, there may be little changes in the mix of electricity ultimately generated by the various companies. Thus, aggregate quantity data might not readily show the impacts of the strategy.

The incentive on firms to increase their bids in this way was intensified by the operations of the CAISO. The mission of the CAISO was to assure that there would always be sufficient electricity available to avoid blackouts. In order to do so, the CAISO stood ready to purchase electricity on the imbalance market at any price up to some price cap, which varied over time (see the section “Wholesale Price Control Regimes”). Since this quantity to be purchased did not vary significantly with the prices of the electricity offered for sale at that time, the very short run demand curve was very steep.

Generators understood this willingness and thus this willingness would have provided a significant incentive on generators to alter their bidding into the PX. In particular, firms increasing their bids on electricity they offered for sale could be expected to trade the possibility of increased profits against the risk that they would bid too high and would not be able to sell their electricity at all. However, the CAISO on most days needed to acquire additional quantities of electricity on the real time imbalance market, the next day. Thus, firms that bid too large might not sell any electricity on the PX but could sell it the next day on the real time market.

Moreover, because there was an incentive for utilities to acquire significant quantities of electricity from CAISO real time purchases¹⁰¹, the suppliers could have reasonable confidence there would be a demand for their electricity. Therefore, the dual market reduced the risk facing firms that were tempted to increase their bid prices greatly on the PX.

In addition, any incentive to withhold supplies to increase price would be made stronger by the lack of long-term contracts by the utilities to buy electricity¹⁰². If a generator had a long-term fixed price contract to sell its electricity, then even under the incentives described above, that generator would have no incentive to withhold its generation. Withholding would increase market-clearing price but that firms would reap no benefits from the increased price, given the fixed price contractual sales of electricity. However, the deliberate public policy decision to discourage such long-term contracts assured that there would be strong incentives to withhold supply to drive prices upward.

Whether exercise of market power was important to the price jumps early in 2000 or whether the fundamental issue was the growth basic problems of supply and demand, is still subject to disagreement¹⁰³. Nevertheless, several issues do seem clear.

¹⁰¹ As will be discussed at a later point, the CAISO price caps provided an incentive for utilities to under-schedule their electricity needs on the PX. Therefore they had to acquire significant quantities on the imbalance market.

¹⁰² Some of the generators did have long term contracts, although with marketers, not utilities. Such contracts would have reduced incentives to reduce their electricity supply, but would not reduce the incentives on the marketers to exercise market power in ways described above.

¹⁰³ For a more complete theoretical and empirical examination of the exercise of market power through September 1999, see "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market," by Severin Borenstein, James Bushnell, and Frank Wolak, August 2000, University of California Energy Institute. For analyses of market power during the summer of 2000, see: P. Joskow and E. Kahn, "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000," NBER Working Paper 8157, March 2001; Scott Harvey and William Hogan, "On the Exercise of Market Power Through Strategic Withholding in California," April 2001; Paul Joskow and Edward Kahn, "Identifying the Exercise of Market Power: Refining the Estimates", July 5, 2001.

First, the restructured system included short-run incentives for firms, operating fully within the regulations promulgated by the CPUC, to submit bids above their marginal cost when the entire system was near capacity. When the system is near capacity, the “hockey stick” character of the supply function, in particular, the nearly vertical section of the supply function is relevant. In that situation, small changes in electricity supply could lead to large changes in price, or equivalently, large changes in price could be associated with only small changes in quantity supplied. Under those circumstances there is an incentive for firms to submit bids significantly in excess of their marginal cost if they believe those price bids can influence the revenues they receive for the electricity they sell¹⁰⁴. However, how much above marginal cost these firms could be expected to bid depends on several factors which have not been adequately quantified: the short-run and medium-run responsiveness to wholesale prices of electricity imports into California, the beliefs of generators about impacts of current price increases on future electricity demand reductions and consequently future profit reductions, the perceived risk of FERC-imposed penalties for firms found to be bidding significantly above costs, the supply and demand responses of the municipal utilities.

Second, pricing goods for sale anywhere in the economy exactly at marginal cost is probably the exception, not the rule. The issue is the degree of divergence between price and marginal cost. Non-marginal-cost pricing should not be a surprise.

Third, the requirement imposed on the utilities that they buy and sell all of their electricity on the PX or the CAISO precluded them from purchasing electricity through bilateral contracts or on

¹⁰⁴ Note that when the system is well below full capacity, there is some incentive for firms with multiple units to bid above the marginal cost, although the incentive is small and the optimal bid exceeds the marginal costs by only a small amount. This is because in that circumstance large reductions in supply result in only small price increases.

other markets. To the extent that the State chartered markets – the PX and the CAISO – had flawed rules that encouraged the exercise of market power, the ability to exit these markets would have been valuable to the utilities. However, the California rules prohibited that exit, giving the PX and CAISO monopoly positions.

There was a clear challenge to the State to the extent that firms were withholding supplies entirely or were bidding well above their marginal costs. Market rules did provide opportunities for firms to increase their bids above their costs of operations, and to do so perfectly legally. However, California public officials were expressing outrage that the firms might have responded to incentives created by public policy. The challenge then, to the extent market power was a fundamental problem, was to change the behavior of the firms without changing the market rules or to change the market rules. As will be discussed below, the State actions focused on trying to change the behavior of firms or to strengthen the price controls that had been imposed on the markets. The Federal actions focused more on modifying the market structures.

California-Controlled Wholesale Price Controls

As the challenge became more severe, California officials began calling on FERC to limit the increases in wholesale electricity prices in California through the imposition of wholesale price controls. However, price caps had been features of the California wholesale market from soon after the approval of the restructuring plans and the management of those price caps was in the hands of California organizations.

In March 1998, CAISO observed large increases in prices for some ancillary services and proposed price caps in the ancillary services markets as well as in the imbalance market as the solution. In July 1998, FERC responded, authorizing CAISO to reject any bids to provide ancillary services whenever CAISO believed those bids were higher than appropriate. FERC explained that because CAISO had a responsibility as procurer of ancillary services, CAISO had the discretion to reject bids that were too high¹⁰⁵. By this decision, FERC gave the State of California discretionary power over the price caps applicable to CAISO.

Subsequently FERC authorized CAISO to treat the real time imbalance market similarly. FERC authorized CAISO to adopt price caps for its purchases in the imbalance (real time) energy market. FERC allowed CAISO to set the purchase price at whatever level it deemed necessary and appropriate, thereby ceding a significant price control authority to a State institution. FERC granted this authority until November 1999. However, FERC offered CAISO the opportunity to ask to extend the duration of its authority if CAISO determined that there remained serious problems in the design of the markets.

CAISO set an initial price cap of \$250/MWh for its purchases in both the imbalance market and the ancillary services markets. In September 1999, CAISO proposed to extend the price cap authority for one year, until November 2000. That same month CAISO raised the price cap from \$250 to \$750/MWh, but indicated that it might lower the caps to \$500 in June 2000 or to some unspecified amount if it determined that the markets were not workably competitive. FERC accepted these proposals. In July 2000, CAISO did lower the price cap to \$500/MWh and in

¹⁰⁵ Subsequently FERC ruled that CAISO's maximum purchase price authority was acceptable because CAISO did not have the authority to require sellers to bid into its markets and thus could not dictate the prices of those sellers.

August 2000 CAISO further reduced the purchase price cap to \$250/MWh. CAISO applied the same price cap for ancillary services and for real time electricity purchases.

Although FERC authorized these price caps for CAISO, FERC never authorized formal price caps for sales on the PX. Nevertheless, as discussed in Chapter 2, because buyers could choose to purchase from either the PX or the CAISO, the CAISO price caps translated to price caps for the wholesale price in each of the markets.

Thus the price caps for the CAISO markets created incentives for sales and purchase transactions to be moved to the imbalance market (or ancillary services markets), greatly increasing the transactions in the real time market. However, the imbalance market had never been designed for large volume transactions. Since these transactions were conducted in real time, there could never be an assurance that sufficient electricity would be available for the expected consumption. Therefore, the price-cap-induced movement of transactions from the day-ahead and day-of markets to the real time imbalance market significantly increased the likelihood that there would be insufficient electricity to satisfy customer needs and therefore significantly increased the probability out of blackouts, blackouts which fortunately did not occur during the period of growing challenge.

This incentive to move transactions to the CAISO imbalance market was so strong that by November the PX data no longer gave any indication of a conventional supply curve for electricity. Figure 21 shows the prices versus the quantities of electricity sold on the PX for November 2000. This figure show the same data measured in the same way as does Figure 17.

Figure 21 is based upon observations of prices and quantities of electricity transacted on the PX in November 2000, while Figure 17 provides information for July 1999.

The wide spread of prices for any given quantity primarily resulted from transactions moving away from the PX and toward the CAISO imbalance market. By November 2000, as much as 30% of the electricity (10,000 MW) was sometimes bought and sold on the imbalance market, not going through the PX at all. In Figure 17, the supply curve became almost vertical for total transactions through the PX of about 34,000 MW. Because so much electricity was being transacted directly on the imbalance market, the maximum quantities being bought and sold on the PX during November never exceeded 26,000 MW, even though the peak load most weekdays was between 32,000 MW and 34,000 MW.

Figure 21 also shows the direct result on the PX prices of the CAISO price caps, with all PX prices remaining at or below \$250/MWh.

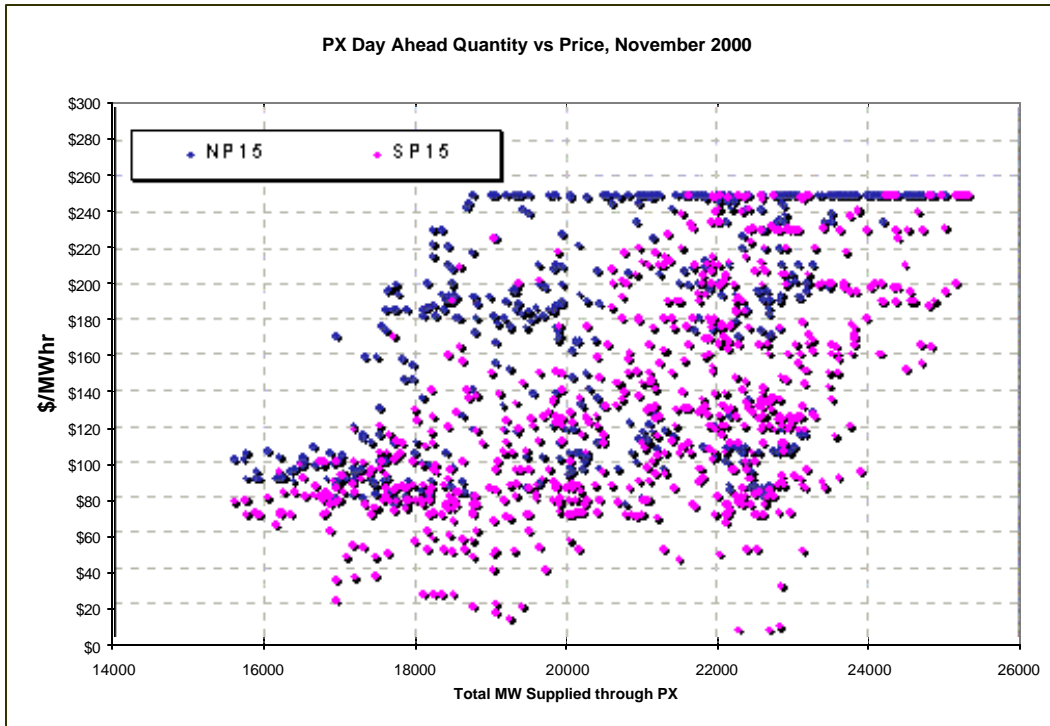


Figure 21 Price vs. Quantity for California PX, November 2000. Source: California Energy Commission

In addition, price controls themselves created incentives for California suppliers to sell their electricity out-of-state whenever the out-of-state prices exceed the California price caps. For example in the final week of June, 2000 the Bonneville Power Administration and utilities and the Pacific Northwest outbid California for electricity, reportedly paying as much as \$1400/MWh to buy electricity.

Single-state price caps in a regionally interconnected market proved, not surprisingly, to be a recipe for creating shortages. However, fortunately, the shortages were relatively mild during the period of growing challenge and did not escalate to blackouts.

Governor Gray Davis seemed to understand these facts, but placed blame on the generators, not on the state market structure. Looking back on the period of growing crisis, Governor Davis, in his January 2001 State of the State speech asserted:

“On many days, 10 to 12% of the electricity generated in California leaves our state in search of even more exorbitant prices elsewhere. On some occasions, the merchant generators have brought the State to the very brink of blackouts by refusing to sell us back our own power because they could find higher prices elsewhere.”

Although the Governor was aware that price caps in California were creating problems, he continued to advocate for even greater price control authority.

Given that price caps on the CAISO imbalance market, absent explicit price caps on the PX, were creating more difficulties than would CAISO price caps alone, there were at least two possible policy directions: eliminate the price caps on the imbalance market or increase the scope of price controls, imposing price controls on the PX as well.

California political leadership chose the latter strategy. In August 2000, after being encouraged by Governor Davis, the PX proposed to FERC that it be allowed to change from implicit price caps to explicit price caps. It proposed to impose maximum prices on demand and supply bids for the day-ahead and the day-of markets to be equal to \$350/MWh. The \$350 figure was calculated as the sum of the \$250 price cap on CAISO purchases of imbalance energy plus a \$100/MWh estimate of the cost CAISO at that time was paying for replacement reserves¹⁰⁶.

¹⁰⁶ Price caps on the ancillary services markets, combined with the price caps on the imbalance market, could impose an effective limit on PX prices. Under CAISO procedures, offering electricity as replacement reserves could be a particularly profitable strategy whenever the generators believed the total supplies for electricity would not be adequate to meet the demands without drawing on the replacement reserves. A supplier could offer its capacity into the replacement reserves market and would receive \$100/MWh of capacity each hour. If that electricity were sold, the supplier would receive an additional payment of \$250/MWh, for a total payment of \$350/MWh. If the

Soon thereafter, in September 2000, also after urging by Governor Davis, CAISO proposed to FERC that it be allowed to further extend beyond November 2000 the termination date of CAISO purchase price cap authority. In October, the three investor-owned-utilities plus The Utility Reform Network (TURN) filed a request to FERC that would impose a price cap of \$100/MWh for all electricity sales. The CPUC filed a motion requesting the \$100/MWh price cap but with a set of defined exceptions.

California's electricity organizations were lining up behind price controls rather than correcting the fundamental flaws in its markets, a pattern that would continue beyond the challenge period and into the crisis period. As will be discussed in the following section, this strategy of continued pressure on FERC for wholesale price controls was consistent with Gray Davis' challenge-period policy framework.

In November 2000, FERC took decisive steps to remove price cap authority from California organizations. It denied the PX request for its price control authority. It announced that it was removing the CAISO price cap authority in sixty days. In the interim, it removed the authority from CAISO to modify the price caps, freezing the CAISO price cap at the then current level of \$250 for 60 days, until the price cap authority would disappear. The era of California-managed wholesale price controls was about to end.

probability of selling electricity were high, then that strategy would be as profitable as selling the same electricity on the PX for almost \$350/MWh. In this case, the market clearing price on the PX would be almost \$350. The PX proposal was designed to set an explicit price cap equal to this implicit cap.

In place of California-managed wholesale price controls, FERC ordered that at the end of the sixty days CAISO and PX auctions be changed to a “soft price cap” system that would limit market clearing prices to \$150/MWh, but would allow market participants to submit bids over \$150/MWh with appropriate cost verification. Such bids above \$150/MWh could be paid “as bid”, but they would not set the market-clearing price.

But before the end of the sixty days, the CAISO markets were on the edge of collapse. CAISO was forced to declare Stage 2 emergencies for four days in a row and saw no end to the shortage. Blackouts were imminent. The electricity challenge was turning into a full blown crisis. On December 8 2000, Terry Winter, chief executive officer of CAISO, asked FERC to allow CAISO to replace its \$250/MWh price cap with a soft price cap system, similar to the one scheduled for the end of the sixty days, but with the interim break point set at \$250/MWh. FERC agreed immediately and California could then purchase electricity to avoid blackouts. Predictably, Governor Davis and the California legislature vilified Mr. Winters for that action, but it probably saved California from wide-scale blackouts during December. These FERC-controlled changes in price caps are discussed more fully in the following chapter.

The Financial Challenge

The high wholesale prices, the lack of long-term contracts, the divestiture of utility generation assets, and the retail price control together created a tremendous financial challenge for the utilities, one that urgently needed to be addressed during the challenge period. In early 2000 the utilities had seen that there would be pressures on supply and demand for electricity and knew

they faced a fundamental challenge, a challenge they could not surmount absent action by the Governor, legislature, or CPUC.

By the time the challenge became apparent, they had divested about 60% of their generating assets. Divestiture itself would have not been particularly harmful if the utilities had replaced these generating assets with long-term contracts to acquire the electricity, perhaps at prices indexed to natural gas prices¹⁰⁷. But they had not been allowed to do so.

As of mid 2000, the utilities could have reduced, but not eliminated, the risk of wholesale price increases if they were able to enter long term contracts to purchase electricity at fixed prices. In early spring, these contracts were being offered to the utilities. For example, in June and July several of the larger generators were offering to sell significant amounts of capacity with opening offer prices of about \$50/MWh.¹⁰⁸ Prices were likely to have been lower than \$50/MWh earlier in 2000. Both PG&E and SCE made requests of the CPUC and appealed to Governor Davis to allow them to enter such contracts. The initial response was quite negative.

On June 22, 2000 the CPUC decided, in a narrowly split vote, to allow the utilities to buy power outside the CAISO and the PX markets. However, the California Legislature subsequently overrode the decision, requesting that the CPUC demonstrate to the Legislature that allowing utilities to purchase energy from outside of the CAISO and the PX was in the public interest, a demonstration that was never forthcoming from the CPUC. Thus the utilities were forced to continue purchasing and selling all electricity on these two markets.

¹⁰⁷ In fact many municipal utilities had no generating assets at all. But they maintained portfolios of medium-term and long-term contracts under which they acquired electricity.

¹⁰⁸ Private communication from Robert Weisenmiller, based on his polling of many of the larger generators.

However, in August, once prices had jumped sharply, the CPUC did file an order allowing the utilities to enter limited amounts of bilateral contracts. Even then, any purchases other than from the PX would either need pre-approval or face an after-the-fact reasonableness review, while all purchases from the PX were considered *per se* reasonable. And without clear guidelines about the CPUC vision of reasonableness, utilities faced the prospect of being severely penalized if, retrospectively, their long-term contracting decisions turned out to be economically unattractive, but they could not expect to be rewarded if, retrospectively, their decisions turned out to be economically attractive. But throughout the challenge period – in fact, throughout the electricity crisis – the CPUC never adopted any guidelines and did not pre-approve any contracts. These strong asymmetric economic incentives gave the investor-owned utilities a significant incentive to rely on the PX and to not enter into longer term forward contracts to buy electricity. Thus, even this limited concession did not reasonably encourage long-term contracts.

This failure to encourage long-term contracts and the resultant over-reliance on spot markets help establish the financial challenge. The over-reliance on spot markets assured that when wholesale prices began to soar, the utilities would pay these high prices for almost half of the electricity they would need to serve their loads. This lack of reasonable risk management options was central to the financial challenge.

By fall 2000, the challenge was hitting the electric utilities with a tremendous force¹⁰⁹. The restructured system left them selling electricity to their customers at an average price of about

¹⁰⁹ An excellent timeline of these events, compiled by Southern California Edison appears on the WWW. The URL is http://www.sce.com/005_regul_info/005c6b_chronology.shtml.

\$65/MWh for the electricity (plus another \$60/MWh for transmission, distribution, and other delivery services) yet the wholesale price of electricity ranged from \$150/MWh to \$1000/MWh for half of the electricity they were selling (See Figure 15). Almost one-half of the remainder, from the QFs, was already being purchased at high prices. Generation from their own hydroelectric assets and nuclear power plants accounted for only 30% of their electricity, thanks to the divestiture.

The accumulations into the transition accounts to pay for stranded costs quickly reversed, with large negative competition transition charges. Thus, the more electricity they sold, the more money they lost. But, unlike most other businesses, they were not allowed to tell their customers that, because the cost of the product was too high, they would not supply it. Not only were the utilities subsidizing all industrial, commercial, and residential customers, they were forced to continue doing so.

The utilities could readily project forward to the time at which all of their financial assets would be spent and their credit would be gone. The option of medium term and long-term contracts was no longer helpful because the pricing being offered for medium-term and long-term contracts had risen along with the spot wholesale prices.

During the challenge period the political institutions – the Governor, the legislature, the CPUC – needed to allow the wholesale price increases to be translated to retail prices. Without reductions in the wholesale prices or corresponding increases of the retail prices, the utilities could project their own insolvency.

Once the financial imbalance became obvious, each of the utilities requested increases in retail rates to cover the average cost of the electricity they were selling. Even though there were price controls on the electricity sales, these price controls had been established to allow the utilities to accumulate sufficient revenues over time to pay for the stranded costs. Thus, it was perfectly logical that if the pricing structure were no longer serving the goal for which it was established -- enabling the utilities to accumulate financial assets to pay for the stranded costs -- then it should not be continued. In particular, it should not be continued since it was operating in exactly the opposite direction, reducing the financial assets available to pay for stranded costs.

The requests for retail price increases (often referred to as "rate relief") were made primarily to be CPUC and secondarily, to Governor Davis. Through the challenge period, absolutely no rate relief was made available to the utilities. In fact, SDG&E, the only one of the three major investor-owned utilities that under AB 1890 would be no longer was subject to retail price controls, remained free of the controls only for a limited time. The California Legislature voted to reimpose those controls.

With the political institutions -- CPUC, the governor, the legislature -- turning their backs on the legitimate requests of the utilities, PG&E and SCE sued the CPUC in Federal District Court. The utilities relied on the federal "filed rate doctrine" that requires States to pass through to utility customers the costs of electricity that is purchased subject to Federal tariffs. The utilities interpreted Federal tariffs to include FERC-approved tariffs.

In addition, utilities argued, “the CPUC’s rulings also are unlawful in that they violate the Commerce, Takings, and Due Processes Clauses of the Constitution.”

“In particular, the Takings Clause requires the State to set retail rates that are not confiscatory. Rates are confiscatory if they fail to provide the utility a reasonable opportunity to recover its prudent costs of service and a fair rate of return commensurate with the risks undertaken. Confiscatory rates unlawfully interfere with reasonable investment-backed expectations.”¹¹⁰

However, legal proceedings seldom proceed quickly and this was no exception. The lawsuit remained in progress through the challenge period and through the crisis, until SCE finally settled the suit on October 2001. The PG&E case is still proceeding in U.S. District Court.¹¹¹

Although the challenge facing the investor-owned utilities could have been solved by early action of the Governor, the CPUC, or the Legislature, by the end of the November 2000 none of the appropriate policy responses had been forthcoming. Thus, by the end of the challenge period, they were facing a near-certain financial crisis, absent an abrupt State policy shift.

State Policy Responses during the Challenge Period

Soon after the June price spikes, on June 15 2000, Governor Davis requested that Michael Kahn, Chairman of the Electricity Oversight Board and Loretta Lynch, President of the CPUC examine the causes of the blackout that had occurred in the San Francisco Bay area and the associated wholesale price increases. Ms. Lynch and Mr. Kahn duly responded to Governor Davis’ request

¹¹⁰ Both quotations are from Southern California Edison Company v. Loretta M. Lynch, et al, Complaint For Injunctive and Declaratory Relief, November 13, 2000

¹¹¹ On May 2, 2001, U.S. District Judge Ronald Lew dismissed as premature the PG&E lawsuit that sought to overrule decisions by the CPUC that PG&E was not entitled to recover money it had spent to buy electricity for its customers during the crisis. The judge ruled that the CPUC orders were not yet final, but were only interim orders. Judge Lew stated that PG&E could refile its suit when the CPUC orders are finalized. PG&E has done so.

and issued a report, which they forwarded to Governor Davis and posted on the CPUC Web site¹¹². The cover letter of the report, dated August 2, 2000, began:

“Dear Governor Davis:

“In response to your letter of June 15th, included as Attachment 1, the attached report analyzes the electricity conditions facing California, including the Bay Area black-outs of June 14th and the circumstances giving rise to forced outages and related pricing problems. Your concerns have proved well-founded in light of recent retail price escalations in San Diego and the state-wide wholesale price upsurges. The Bay Area outages and the San Diego price increases are only the first manifestations of problems in our electricity system.”

The first paragraph of the executive summary of the report stated:

“California is experiencing major problems with electricity supply and pricing caused by policies and procedures adopted over the past ten years. This summer, California has seen both electricity price volatility – exemplified by huge increases in wholesale electric prices and increases in retail prices in San Diego – and supply and delivery system instability – culminating in unprecedented black-outs in the Bay Area. These serious, but thus far isolated, examples represent a precursor of what lies ahead for California’s economy over the next 30 months. California’s reliability deficits and retail price volatility may not improve in that time without a mid-course correction.”

Thus, very early in the process, Governor Davis was aware that there were important challenges facing California. Moreover, he was given, by two of his appointees, broad advice and a set of specific recommendations designed to address the problems they had identified. But even after that report, California policy responses during the period of growing electricity challenges were surprisingly limited, relying almost entirely on efforts to establish or strengthen price controls at both the retail and wholesale levels.

¹¹² *California’s Electricity Options And Challenges: Report To Governor Gray Davis*. The report is available online through the California Public Utilities Commission: <http://www.cpuc.ca.gov/published/report/Table%20of%20Contents.htm>

One policy framework, articulated by Governor Davis, provided the guidance for California's response to the challenge. Price controls at both the wholesale and the retail level seemed to be the one and only goal of the State's policy framework during the challenge period. The State could enforce and expand retail price controls, which they did very aggressively. However, they could not unilaterally impose wholesale price controls, since the Federal government, and particularly FERC, had the primary jurisdiction over wholesale markets. Thus, Governor Davis orchestrated a broad campaign to urge FERC to maintain and expand wholesale price controls.

Governor Davis articulated his overall strategy in a series of letters dated July 27, 2000 and summarized that strategy in a press release issued that day. Portions of that press release follow¹¹³:

“SACRAMENTO—Governor Gray Davis today called on federal and state regulators to take swift action to extend the caps on wholesale electric rates in California and provide San Diego ratepayers with millions of dollars in refunds.

....

“In letters to two state regulatory agencies and two California-based panels charged with overseeing California's power market, Governor Davis called for a coordinated state effort to urge federal regulators to take strong measures to reduce power rates in both the short- and long-term.

“The legislation signed into law in 1996 by Governor Pete Wilson to deregulate California's investor-owned electric utilities left state agencies and the Governor with limited options to regulate prices, Governor Davis noted. However, today's initiatives are designed to maximize the leverage of California's regulatory agencies with the Federal Energy Regulatory Commission

“In letters released today, Governor Davis:

- Called on the California Independent Systems Operator ... to immediately apply to FERC for extension of its authority to establish price caps for wholesale power

¹¹³ This and other press releases can be reached through Governor Davis' home page: http://www.governor.ca.gov/state/govsite/gov_homepage.jsp

Governor Davis also requested the ISO to reduce the "wholesale price cap to the lowest reasonable level,"

- Urged the California Public Utilities Commission (PUC) ... to "take all actions necessary to assure that electricity supplies are adequate and that prices paid by California consumers are just and reasonable." He called on the Commission to file a petition with federal regulators next week to support extending wholesale price caps. He also urged the PUC to ask FERC to declare that no competitive market for energy currently exists in California - action that would support wholesale price caps.
- Requested the Electricity Oversight Board ... to take three actions at its August 1, 2000 meeting. They include: urging the ISO to petition FERC for continued authority to impose wholesale price caps; establish price caps at the lowest reasonable level; and file a petition with FERC requesting a finding that no competitive market exists in California.
- Called on the California Power Exchange ... to apply for caps on the price bid for wholesale electricity in the day-ahead and day-of "spot markets" that it operates.

“In a separate letter to the PUC President Loretta Lynch, Governor Davis requested the PUC at its August 3, 2000 meeting to authorize the return of \$100 million in refunds from the California Power Exchange to San Diego Gas & Electric ratepayers.”

As discussed above, the PX and the CAISO both complied with the Governor’s request, submitting requests to FERC to establish or extend their price control authority.

In addition, although the California Legislature took only very limited actions, they were consistent with the Governors’ overall strategy. Several bills were introduced but never passed, to urge FERC to impose price controls on the wholesale market. Assembly Joint Resolution No. 77, a joint resolution of the California Senate and Assembly, did gather sufficient votes to pass.

It reiterated the wholesale price control strategy, resolving:

That the Electricity Oversight Board, working with the Public Utilities Commission, shall petition FERC to modify the Independent System Operator (ISO) tariffs to require that the prices in the energy and ancillary services markets are just and reasonable whether they result from the operation of these markets or other mechanisms.

It further resolved:

“The Electricity Oversight Board shall direct the Independent System Operator to show cause why the price caps in the ancillary services and real-time energy markets should not be lowered to \$100 per megawatt-hour immediately and continue until at least March 31, 2001.”

In September, the California legislature reestablished retail price controls in San Diego. AB 265, authored by Assemblywoman Susan Davis (D-San Diego) and Senator Deirdre Alpert (D-Coronado) imposed retail price controls on electricity for consumers and small businesses in San Diego at \$65/MWh (6.5 cents/KWh). The price control regime, slated to continue through December 2003, was made retroactive from June 1, 2000. This action, by reducing electricity prices could be expected to increase electricity demand and to exacerbate the electricity problems.

Gray Davis’s policy framework, focusing entirely on price control, thus was fundamental to almost all the steps the State took during the challenge period. The State continued to force the investor-owned utilities to rely on wholesale spot markets and thus the utilities were not able to begin to manage the wholesale price risks they faced. In addition to the reestablishment of retail price controls in San Diego, retail price controls were not relaxed for PG&E and SCE. No significant steps were taken to guard against the possibility of energy emergencies.

Only very limited positive steps were taken within California to go beyond Governor Davis’ policy framework. Some steps were taken to increase electricity supplies and to decrease electricity demands. Governor Davis signed an executive order that directed “all California

agencies involved in building new energy facilities to streamline the review process for siting new power plants without compromising environmental laws or public health and safety protections.” The Order required that “all state agencies involved in permitting new facilities must submit their review and findings within 100 days of receiving a completed application.” That Order could be expected to speed new construction but would have no impact on electricity supply during the challenge period or during the crisis. In September, Senate Bill 1388, authored by Senator Steve Peace (D-San Diego), was passed, providing for more rapid permitting of new power plants.

State-owned buildings were directed to reduce their use of electricity, but only during serious energy emergencies¹¹⁴. SB 1194, authored by Senator Byron Sher (D-Palo Alto) and AB 995, authored by Assemblyman Rod Wright (D-South Central Los Angeles), were signed into law. These extended in time the existing AB 1890 requirement of a separate electricity rate component, collected as a bypassable charge, to fund energy efficiency and conservation activities, public interest research and development, and development of renewable resources technology.

In short, other than imposing or urging others to impose electricity price controls, the State governmental bodies took remarkably few significant policy steps to avert the coming electricity crisis. Moreover, the State took no positive steps to avert the coming financial crisis but rather, by reimposing price controls in San Diego, threatened to exacerbate the problems.

¹¹⁴ The order was applicable only to Stage 2 and Stage 3 emergencies. See Chapter 4 for a discussion of these emergencies.

In Summary

Between 1997 and the autumn of 2000, the risk embedded in the restructured system, although perhaps not apparent to participants in that system, had become a reality. California consumption of electricity grew slightly faster than historically, available imports in California dropped sharply as markets became much tighter throughout the West, new California generation capacity was being constructed but was not yet operational, virtually all California electric generation units other than natural gas fired, were at full capacity, and as a result, production in California from existing gas fired units increased sharply. The increase in use of gas fired units implied that not only were the efficient ones online but the old inefficient plants were brought online as well. The inefficient ones used more natural gas and emitted more NO_x and SO_x than the newer more efficient units, thereby increasing the marginal cost of generating electricity. The increase in the use of natural gas pushed up its price. The RECLAIM market experienced a massive jump in the price of emissions credits as the available supply of credits decreased. These factors together would account for the challenge.

During the summer and fall of 2000, the severe challenge demanded leadership and wisdom of California's political leaders. Mastering the challenge would not have been easy once wholesale electricity prices had jumped during the summer of 2000. By that time, all meaningful solutions were likely to involve short-term economic sacrifices by many, including by the voters in California. Yet, as of the summer of 2000, there were important policy actions still possible that would have avoided a California electricity crisis and a financial crisis. However, California's political leadership never rose to the challenge. This failure of political leadership turned the challenge into a crisis.

Chapter 4: Through Crisis

By December 2000 or January 2001, there was no question but that California was in the midst of a crisis. Yet even then, statewide policy actions were available to avoid the long-term consequences of that crisis, although perhaps it was too late to avoid the short-term consequences. However, the failure of leadership persisted. And the crisis deepened.

This chapter examines the growth and subsequent remission of California's energy crisis and the evolution of State and Federal policy during that crisis.

The Nature of the Crisis

The California "energy crisis", like the challenge, can be seen as two crises – a Western electricity crisis and a financial crisis of the investor-owned utilities that turned into state budgetary crisis. Once the challenge reached crisis proportions, these two crises exacerbated one another. Conceptually, the two crises were separable from one another. There could have been a Western electricity crisis that did not lead to a financial crisis¹¹⁵ and there could have been a financial crisis without an electricity crisis. However, these two crises fed on one another during late 2000 and early 2001, spiraling California deeper into the dual crises.

The electricity crisis grew directly from the electricity challenge that was facing the Western states. Fundamentally, the challenge became an electricity crisis for the West because the basic

¹¹⁵ In fact, in the Pacific Northwest, as well as the remainder of the eleven western states, there was the same electricity crisis but it did not turn into a financial crisis, primarily because the utilities did not face the same risky posture as did the California investor-owned utilities. Most of the utilities in the west were protected through long term contracts for most of their electricity acquisitions.

problem – the increase in demand for electricity in California coupled with the decreases in electricity supply – was managed poorly by the State of California.

The financial crisis started primarily as a crisis for the investor owner electric utilities and turned into a crisis for the State budget. That the financial challenge turned into a financial crisis was the direct result of State regulatory, administrative, and legislative action or, more precisely, inaction.

Not only did the electricity crisis lead to the financial crisis, but also the financial crisis made the electricity crisis substantially worse. Since the investor-owned utilities did not receive adequate revenue to pay their suppliers, the utilities began delaying their payments, promising to pay later. This created significant uncertainty among suppliers. None could be sure they would ever be paid. The uncertainty of future payments would lead a rational supplier to increase the price at which it was offering to sell the supplies into the California market, therefore increasing the wholesale prices further. In addition, because the investor-owned utilities were delaying their payments to suppliers, some suppliers were not financially able to continue generating electricity. For the smaller companies, cash flow problems could be severe. In particular, many QFs were owned by relatively small companies that were not able to continue generating electricity without being paid. Therefore, some of these generators went off line, and stopped delivering electricity. This further reduced electricity supply and exacerbated the electricity crisis. The heightened electricity crisis made the financial crisis worse.

In what follows these two crises are discussed separately, even though they were tightly interrelated. Some policies are integrated into discussion of the crises. However, some crosscutting policy issues are discussed in separate section.

The Electricity Crisis

By December 2000, the challenge had grown into a crisis, with even greater increases in the wholesale electricity prices and with frequent energy emergencies as the operating reserves were at dangerously low levels. The crisis remained severe all winter. Not until late spring 2001, did the electricity crisis start to disappear, with wholesale prices falling, electricity consumption declining relative to 2000 levels, and decline in the frequency of energy emergencies. During the peak of the crisis, the standard belief was that the summer of 2001 would be even worse than December and January had been, since summer is California's period of peak electricity use. However, by summer 2001, the energy crisis had mostly subsided. By that time, new generating plants, whose applications for certification were filed in 1997 or 1998 (See Table 4), were first coming on line and electricity demand had declined relative to 2000. Wholesale prices had declined sharply from their peaks and the energy crises had all but disappeared. Moreover, by fall 2001, wholesale prices had declined to historical levels and energy emergencies had disappeared entirely. The crisis had passed.

The California energy crisis was a short-term event – one of but seven months duration – although an intensely painful event. Large amounts of the new generation capacity, mostly

initiated in the first few years after AB 1890 was passed, are projected to come on line during the next few years. Thus, it is unlikely that the electricity crisis will return soon, if at all.

Wholesale Prices

Monthly average data for electricity sales on the day-ahead PX market are shown in Figure 22, through¹¹⁶ December 2000, with data shown separately for Southern California (SP15) and Northern California (NP15). The average spot wholesale price of electricity reached a short-term peak in August 2000, declining during the next two months, as the days grew cooler and the demand for electricity decreased. However, even the \$100/MWh price in October was several times higher than normal. November and December showed new increases in the electricity prices. In December, the average PX price for electricity in Northern California slightly exceeded \$300/MWh while in Southern California that price was roughly \$225/MWh. Daily peaks were much higher than either these figures in December. For both Northern and Southern California, the maximum December price on the PX was slightly above \$1000/MWh. The minimum price of electricity sold on the PX for any one hour throughout the month of December in northern California was \$132/MWh!

¹¹⁶ Comparable data for subsequent months are not available, because the PX was shut down in January. The PX ultimately declared bankruptcy in March 2001.

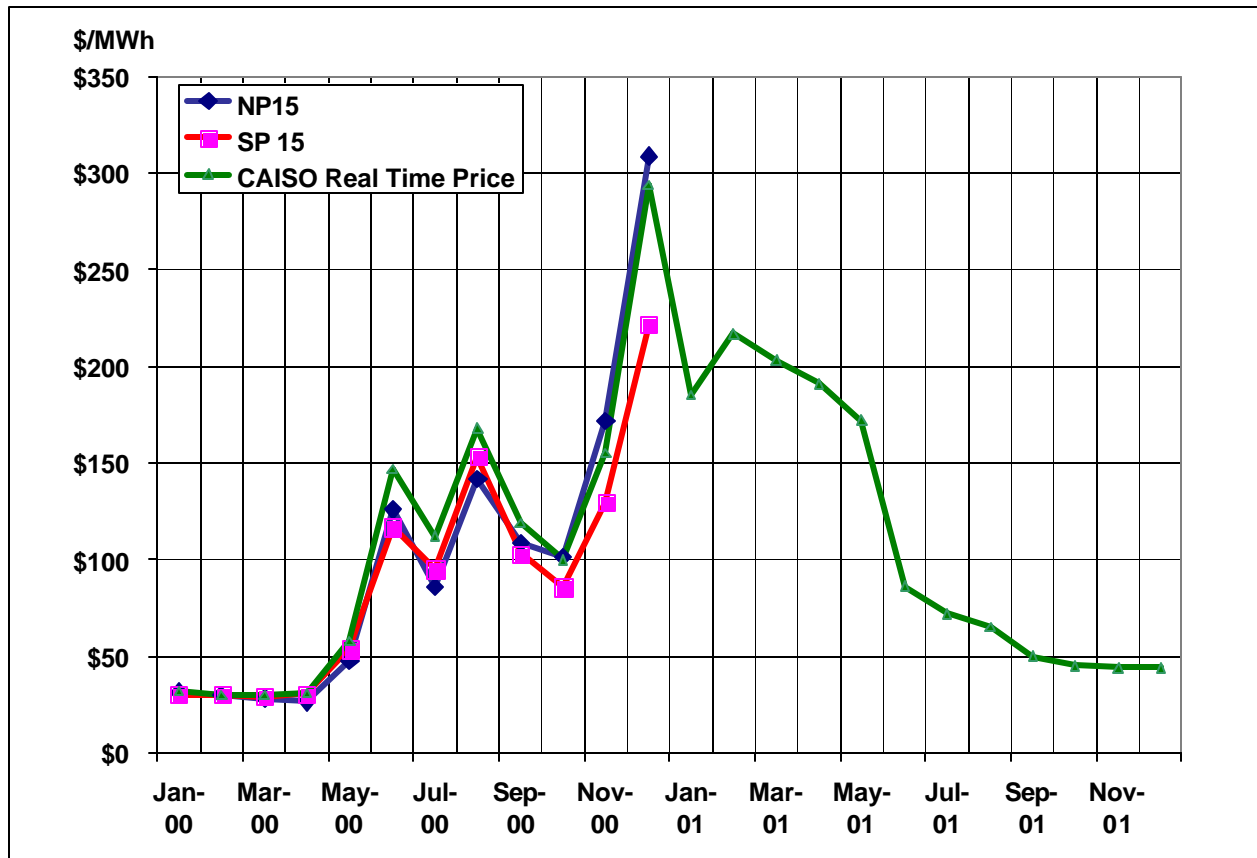


Figure 22 Spot Wholesale Prices, California PX (Day Ahead), CAISO Real Time

The longer series, in Figure 22, the “CAISO Real Time Price” is the weighted average of prices paid for all wholesale real time purchases of electricity scheduled through the CAISO. This includes electricity sold under the price cap (whenever a price cap existed), electricity transactions based on bids accepted over the price cap, plus out-of-market purchases scheduled in real-time¹¹⁷.

¹¹⁷ Source: Data from a sequence of CAISO monthly memos entitled “Market Analysis Report for”. The most recent available is “Market Analysis Report for December 2001”, a memo from Anjali Sheffrin, Director of Market Analysis, CAISO, to ISO Board of Governors. www.caiso.com/docs/09003a6080/12/50/09003a6080125047.pdf

These two price series differ in that the “CAISO Real Time Price” includes out of market purchases, purchases from entities that are not in the CAISO control area, such as out of state generators or from municipal utilities, e.g., the Los Angeles Department of Water and Power. These out-of-market purchases never went through the PX but were negotiated in real time. Whenever the price caps were in effect, the out-of-market purchases generally carried a higher price than those purchases transacted on the PX. Thus, the exclusion of these observations generally biases the PX prices downward, as can be seen in Figure 22.

To the extent data are available, prices were similar among the Western markets for most of the time, with the exception of two weeks in December 2000 (the week of December 11 and the week of December 18). During those weeks, the maximum prices during the peak period were \$5000/MWh at Mid-Columbia and \$4000/MWh at the California-Oregon Border, while the maximum prices recorded on the PX were \$1400 and \$950. Figure 23 shows the same type of data that were displayed in Figure 16, the average of the high and low prices during peak periods on a week-by-week basis, for the various market centers, although for a longer time period. Data are shown from April 1, 2000 to October 1, 2001. The top pane of the chart shows the full range of prices; the bottom pane is truncated at \$500/MWh.

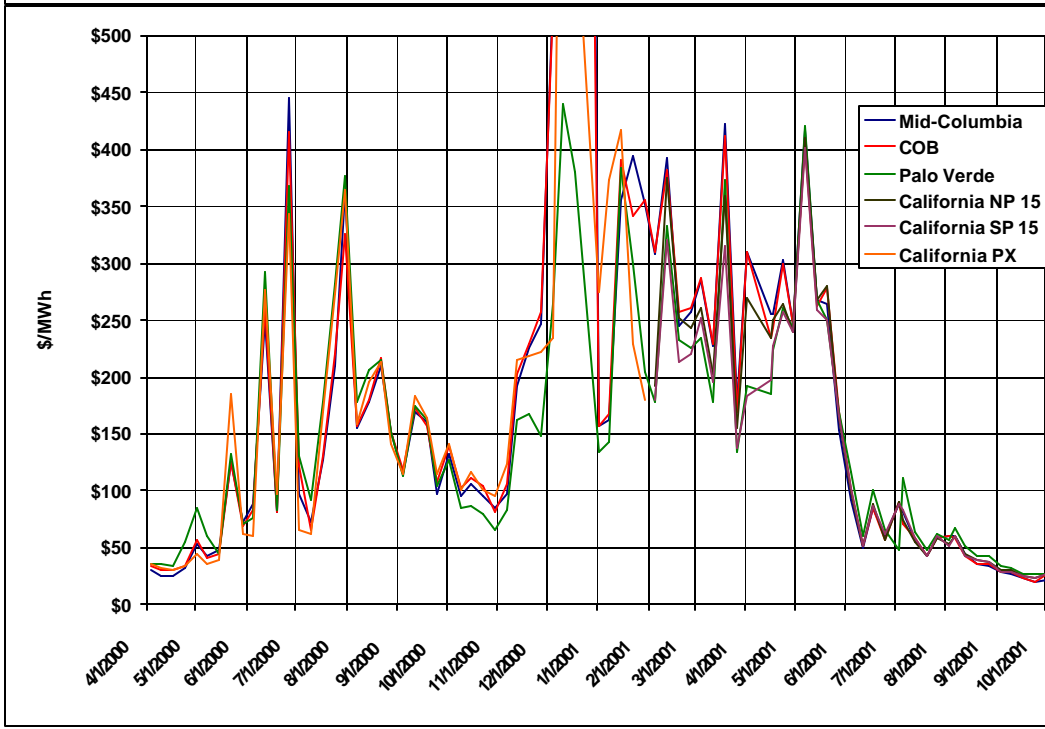
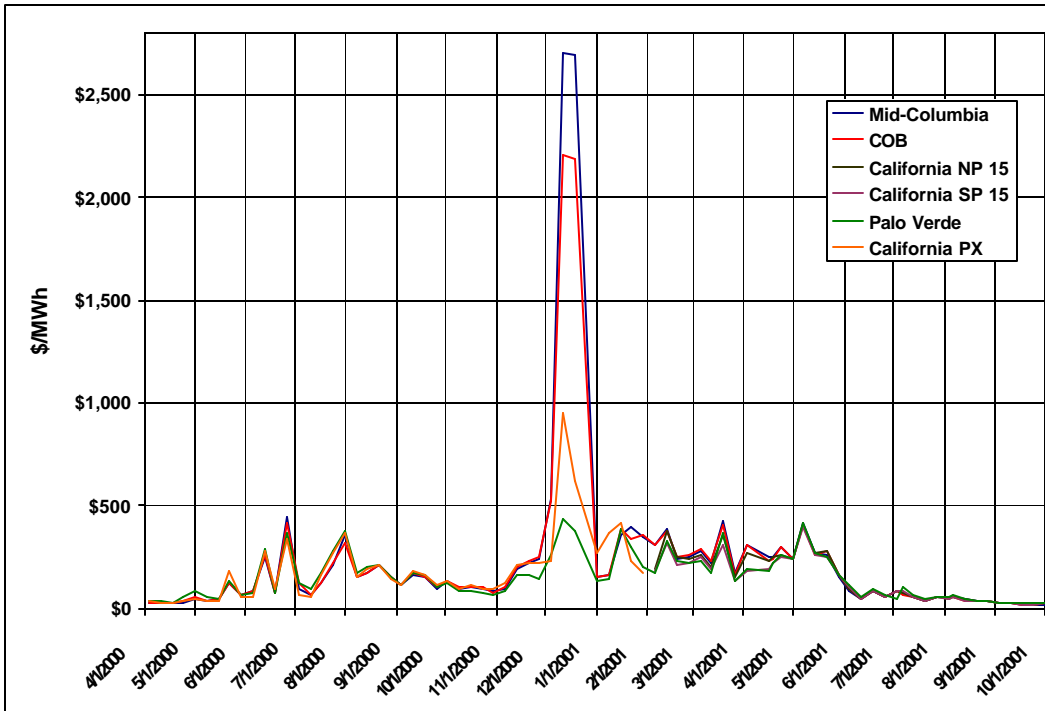


Figure 23 Non-Firm Power Prices: Average of High and Low Peak Prices, Various Western Markets

As Figure 22 illustrates, the wholesale price paid for electricity reached the maximum monthly average in December 2000, stayed high through May 2001, and has been falling ever since.

The sharp decrease in wholesale electricity prices had not generally been anticipated much in advance of the actual reductions. Expectations of future prices can be measured by observation of the futures prices prevailing at different times. Figure 24 shows the published futures prices for electricity averaged over the two markets centers, Palo Verde and the California Oregon Border, relevant for imports and exports of California Electricity. This figure shows that on May 4, the futures price for electricity to be delivered in August was \$550/MWh. Prices were near \$400/MWh for delivery in June, July, and September. However, by June 8, the August futures price had declined to \$240/MWh and prices for adjacent months had gone down to below \$200. By July 16, all futures prices had declined to below \$100/MWh.

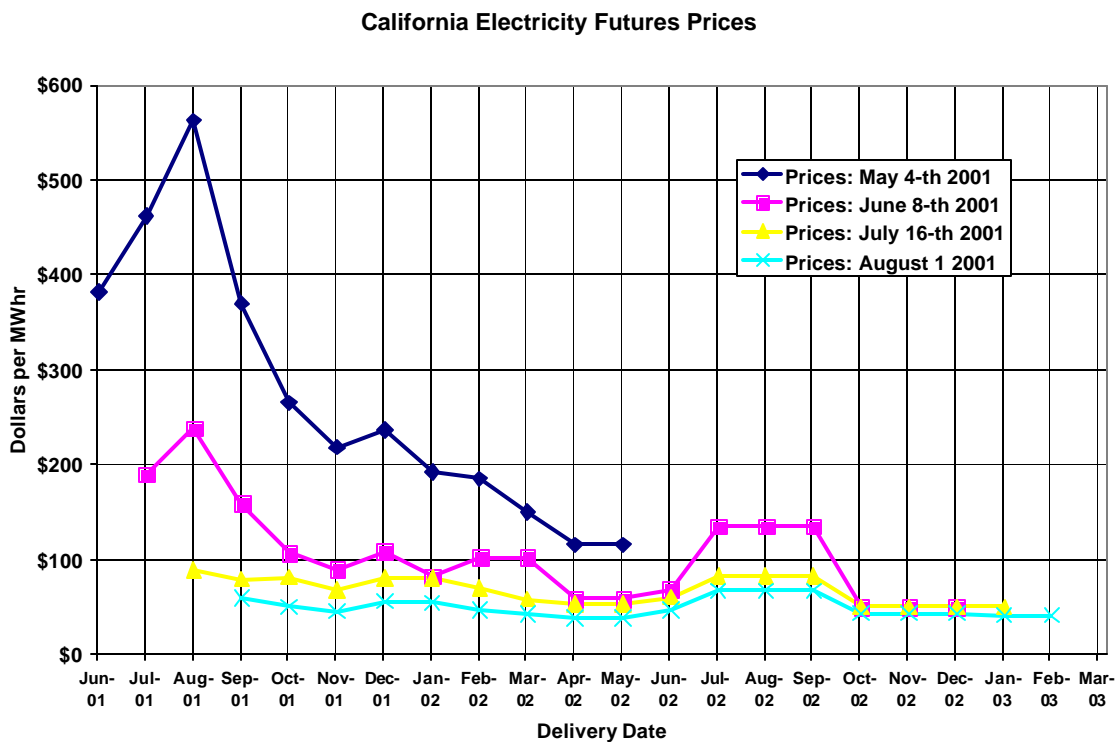


Figure 24 California Electricity Futures Prices at Several Different Times

These figures reflect very sharp changes in beliefs about the prices electricity would command in wholesale markets, sharp changes that were occurring between early May and early June. In addition, the beliefs seem to have continued to evolve downward through July and into August, consistent with the actual reductions in prices.

One can use either the time that wholesale prices sharply decreased or the time that beliefs about future prices sharply decreased in order to define the end of the California electricity crisis. Using those criteria, the crisis can be seen as beginning in late November 2000 and ending in June 2001, a seven-month event: short, but painful.

Electricity Supply and Demand

The basic economic forces underlying the price increases and their subsequent declines throughout the West were the same forces of electricity demand (particularly peak demand), available generating capacity, electricity generation costs, and possible market power described in the previous chapter. None of the difficulties had been overcome by the end of the challenge period. And some became worse as a result of the California financial crisis. This section describes only those factors that changed in important ways from the challenge period and during the crisis.

Electricity Imports and Exports

What, at first, might have seemed surprising was that prices were so high in winter, since demand for electricity in California typically peaks in summer and declines in the winter. However, Pacific Northwest utilities are winter peaking, declining in the summer. During the

winter when California typically needs less electricity and the Pacific Northwest needs more, California exports electricity to the Pacific Northwest.

During 2000, the low rainfall in the Pacific Northwest reduced the availability of water for hydropower generation and that reduction continued to reduce the available generation of electricity in the Pacific Northwest. Thus, the demands for exports of electricity from California during the winter 2001 increased.

In terms of Figure 19, California's demand for electricity is reduced during the winter – the demand curve shifts leftwards – but the import supply curve is also reduced – the supply curve also shifts leftwards.

Natural Gas Prices

Contributing to the increase in electricity prices during the crisis were even more dramatic increases in the natural gas price than had occurred earlier in 2000. In December, the California natural gas price jumped to about \$50 per million Btu, a factor of 10 higher than it had been. Although this price peak lasted for only two weeks, the spot natural gas prices in California remained above \$10 per million BTU until June of 2001 (see Figure 25, based on data from Enerfax.com). These high prices did not result from limitations in the availability of natural gas at the wellhead or at market centers, as shown by the prices of natural gas at Henry Hub, Louisiana, the major market center. Rather the price spike resulted directly from the large demand for natural gas to fuel electric generators during the winter when the demand for natural

gas naturally peaks, coupled by limitations in the pipeline capacity to transport natural gas within the State¹¹⁸ and the absence of natural gas held in storage from previous months.

The sharp increase in natural gas prices, coming just when investor-owned utilities were not paying generators for electricity they sold, provided strong incentives for generators either to stop producing electricity or to bid very high prices to sell the electricity they did generate.

Thus, these natural gas prices probably contributed substantially to the wholesale electricity price increases during the crisis, particularly to the December electricity price spikes.

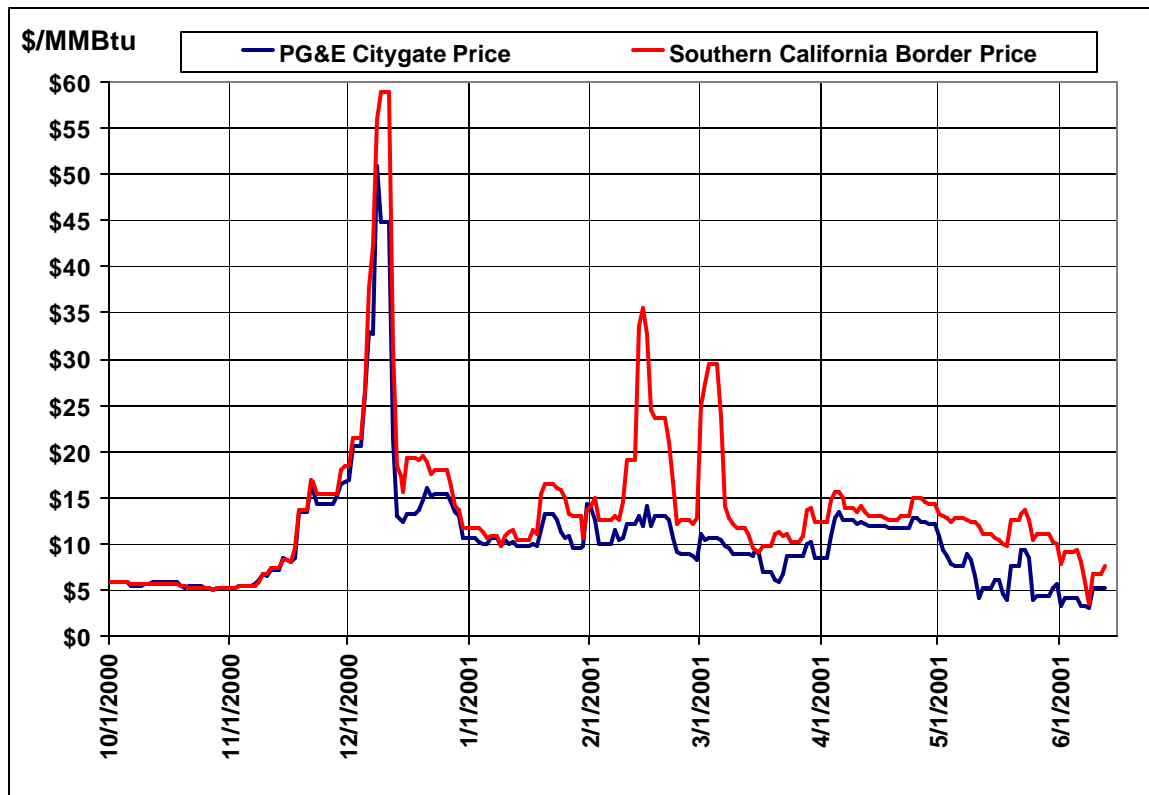


Figure 25 Natural Gas Spot Market Prices. Two California Transaction Points

¹¹⁸ The CPUC, SCE and PG&E brought suit in FERC against El Paso Corp., a Texas pipeline company, charging that it had withheld capacity to cause a gas shortage that would increase prices. In October, 2001, the chief administrative law judge of the FERC ruled in favor of El Paso, concluding that the California parties failed to prove the contention that El Paso had withheld capacity.

Risk Created by the Financial Crisis

Because of the financial crisis, as will be discussed in a subsequent section of this chapter, the utilities began delaying their payments to electricity generators, promising to pay later.

However, it was becoming clear that unless the State took appropriate policy measures, the utilities were unlikely to become capable of paying for the electricity in a timely manner, if at all. This created significant uncertainty among suppliers, most of whom would be able to sell their electricity out-of-state or the municipal utilities in California, if they were not compelled to sell to California's investor-owned utilities.

Uncertainty of future payments would lead a rational supplier to increase the price at which it was offering to sell supplies into the California market, therefore increasing the wholesale prices further. For example, if a supplier believed that there was only a 70% probability of receiving \$100/MWh for electricity and 30% probability of never being paid at all, then the sale of that electricity would be worth no more than \$70/MWh to the supplier. If the cost to that supplier of generating the electricity were \$77/MWh, that supplier would not be willing to sell the electricity for a promised price of \$100/MWh. A bid of \$110/MWh¹¹⁹ would represent a bid at exactly the expected value of the cost of generating the electricity. The uncertainty of payment alone would have had the direct effect of increasing the bid prices and thus the market clearing prices in the wholesale market.

¹¹⁹ \$110/MWh multiplied by 0.7 equals \$77/MWh.

This increase in bids to account for market risk would appear exactly as if the generator were trying to exercise market power to increase the wholesale price of electricity. Determining whether such bidding was based on an attempt to exercise market power or on responding competitively to the financial risk is very difficult, since it depends on the generator's assessment of the probability it would be paid.

This phenomenon was particularly obvious in the November 2000 through January 2001 period when the utilities were not paying for the electricity they were receiving and when their credit ratings were declining sharply. In January, however, the state of California stepped in as the credit worthy buyer, seemingly guaranteeing the payment for all electricity purchased on behalf of the utilities. Instead, California refused, despite repeated FERC orders, to pay its own spot market wholesale power bills. Until November 2001 the State Department of Water Resources (DWR) did not even allow itself to be billed by CASIO for its purchases. The investor-owned utilities still have not paid for wholesale electricity purchased before January 2000. During 2001, continuing nonpayment caused some suppliers to drop offline and continuing risk of nonpayment caused others to include a credit premium in their bids. FERC subsequently approved a 10% credit premium to compensate for continuing financial risks for sales to California. Thus, even though the State had seemed to guarantee payment for all electricity, the state-created financial crisis continued through 2001 to reduce supplies and to place upward pressures on wholesale prices. A subsequent section "Policies Impacting Risk to Electricity Suppliers" further discusses this continued risk.

Possible Exercise of Market Power

As will be discussed in a later section, in mid January 2001, the Governor ordered the State Department of Water Resources (DWR) to start purchasing wholesale electricity on behalf of the electric utilities, since the electric utilities were no longer considered as creditworthy buyers. Other than electricity self-generated or purchased through pre-existing contracts, the investor-owned utilities no longer acquired electricity other than through the DWR. This change fundamentally altered the market structure in California, shifting market power toward the State. Instead of several competing buyers of electricity, buying on an organized market, for all practical purposes, the DWR became the dominant buyer of electricity in California. The DWR was able to choose how much of the electricity it should purchase ahead of time and how much it should acquire on the real time CAISO market, thus, if DWR chose, it could acquire almost all its electricity through bilateral contracts outside the CAISO.

As the dominant buyer, the DWR was not able to change the total electricity consumption or the timing of that consumption -- those were passively determined by the load. Nevertheless, the DWR could negotiate short, medium, and long-term contracts with the various sellers. DWR was not required to pay the same price to each seller or to disclose the prices it paid for any particular transactions¹²⁰: it had the ability to price discriminate for purchases other than on the real time market.

Figure 26, based on data released by DWR, illustrates both the large number of entities from which DWR was buying electricity and the wide range of prices it was paying. Each bar on the

¹²⁰ Data on purchase prices ultimately had to be released, but the releases were enough after the time of transactions that the information would have little or no value to the generators trying to defend against discriminatory pricing by the state.

chart represents a private sector or public sector entity selling electricity to DWR during the first six months of 2001. Blue bars represent public entities – Powerex (a subsidiary of BC Hydro), Los Angeles Department of Water and Power (LADWP), DWR, Bonneville Power Authority (BPA), Sacramento Municipal Utility District (SMUD), and the City of Burbank. Red bars represent private entities – Mirant, Dynergy, Williams, AES, Duke Energy. Sellers are shown in order of their total electricity sales to DWR, with ones selling the most electricity furthest to the left. The height of the bars shows the cumulative fraction of electricity purchased, that is, the fraction of purchases represented by that seller and all larger sellers. Mirant supplied 26% of the DWR purchases. Dynergy supplied 8%; thus the cumulative supply for Dynergy and Mirant is 34%. Williams sold another 8% and thus the cumulative percentage is shown as 42%. The graph shows that four sellers accounted for almost 50% of the purchases by DWR, eleven sellers accounted for 75%, and twenty-one sellers together accounted for 90%. Thus the market structure was one in which a single dominant buyer, DWR, was purchasing electricity from very many competing sellers.

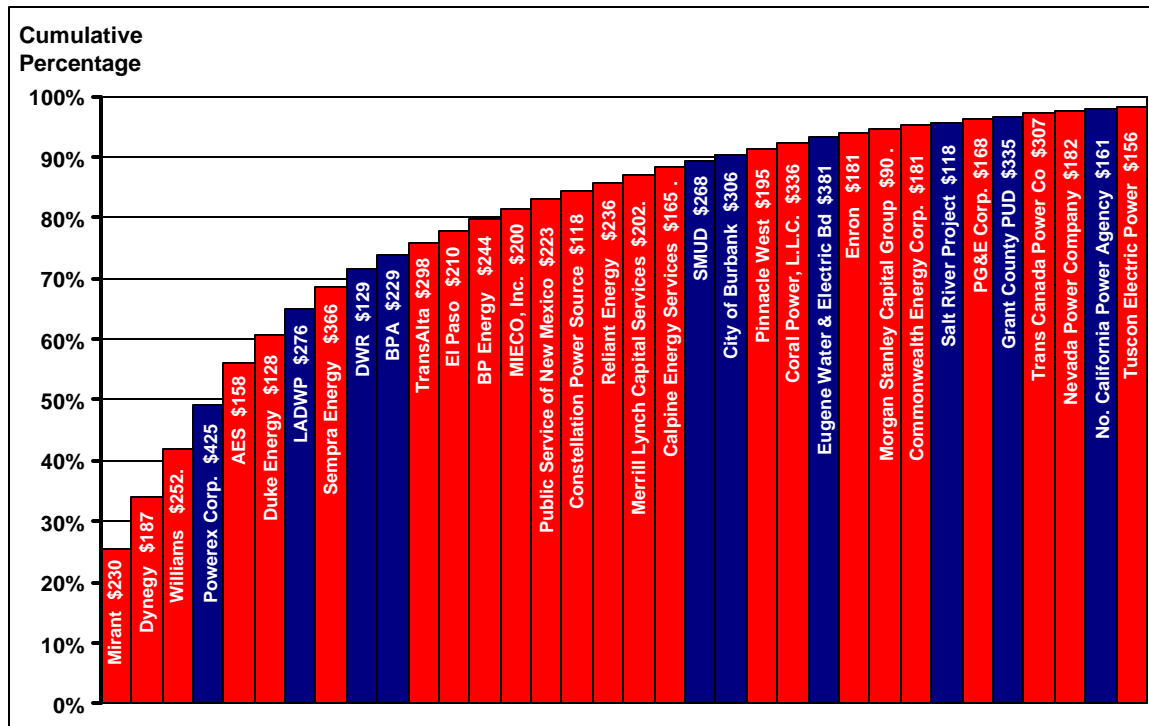


Figure 26 DWR Electricity Purchases, January through June 2001

The average prices of electricity sold to DWR are shown above the names of the sellers. Figure 26 shows that the prices negotiated by DWR varied widely across the sellers. Of the four largest sellers, DWR paid Mirant an average price of \$230/MWh, Dynegy an average price of \$187/MWh, Williams, \$252/MWh, and Powerex \$425/MWh. The highest price in the group was more than twice the lowest. Among the sellers accounting for 90% of the transactions, DWR paid prices ranging from \$128/MWh (Duke Energy) to \$425/MWh (Powerex Corporation), a greater than three-to-one difference. Monthly data show the same pattern of price discrimination among the sellers for each of the six months. These data thus show that DWR was willing and able to price discriminate among the sellers.

A skillful price-discriminating dominant buyer, purchasing from a number of competing sellers should always be able to reduce the total acquisition cost, even without reducing the total amount of electricity purchased, although it could not reduce the acquisition price below the prices at which the generators could sell electricity out of state, where there were competing buyers.

DWR's ability to price discriminate in its purchases reduced the incentives, if they existed, for sellers to attempt to exercise market power in the ways described in previous sections. For with DWR as the dominant buyer, if a firm offered a small portion of its output at a high price and the rest at a low price, the DWR could simply choose to buy the low price portions at the bid price, reject the high price offer and purchase that quantity from another supplier instead. Although a seller would have incentives to increase the price at which it offered the bulk of its product, as would be the case in an as-bid auction, the seller's lack of information about the cut off price created incentives against price increases. If it suspected that a seller was trying to manipulate market prices, the DWR could purchase from other sellers, even those offering electricity at higher prices, to discipline sellers it suspected were attempting to manipulate market prices. This possibility of strategic purchasing by the DWR implied that as of late January, any generator market power could be exercised only 1) for sales through the CAISO real time market and ancillary services markets or 2) through actual reductions of generation, say by taking plants offline. Even if the DWR chose not to operate in a proactive manner to exercise its new market power, at the minimum, the DWR had the power to block any maneuvers by suppliers attempting to manipulate markets.

Thus, to the extent that suppliers were exercising market power, that market power disappeared during the last half of January 2001, to be replaced by DWR market power as the dominant buyer. Therefore, if market power was an important force in increasing prices during the challenge period and into December and early January, it is unlikely to have been an important force keeping prices high in February through May.

Generators Off Line

A fundamental driving force for the supply reductions, and hence the wholesale price increases, during the winter of 2001 was the reduction in availability of electricity generated in California. Large numbers of generators went off line in during the late fall 2000 and winter 2001. Historically, between 1000 and 6000 MW average daily generating capacity would normally be off-line in a month. However in the period between October 2000 and May 2001, a monthly average of 12,000 MW generating capacity was off-line, reaching a peak out of 14,000 MW in April 2001. Figure 27 shows these data.

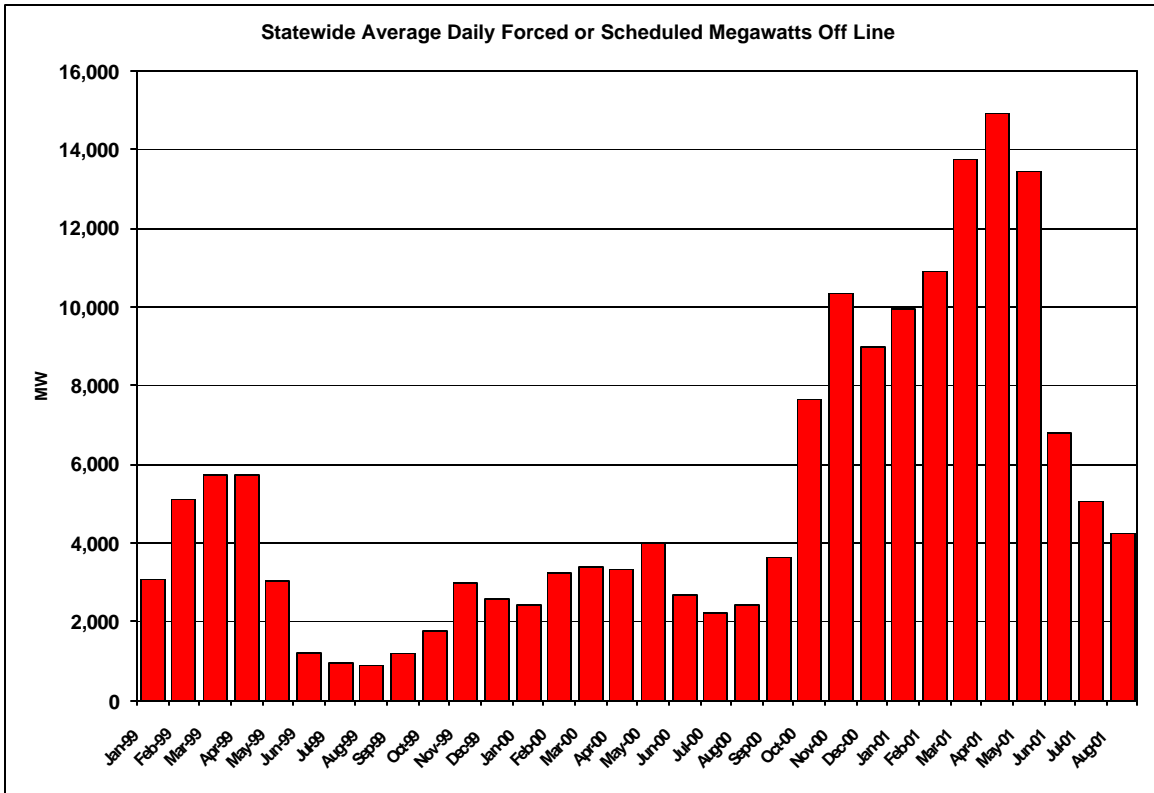


Figure 27 Average Generating Capacity Offline. Source: California Energy Commission

This large amount of generating capacity off-line resulted from a combination of causes but the greatest fraction of generators was off-line reportedly for repairs or maintenance. However, whether the maintenance and repairs were forced upon the generators, were part of a competitive cost minimizing solution, or were designed to increase wholesale price has not been fully resolved. This empirical matter most probably cannot be resolved without careful in depth assessment of facts that currently are not publicly available.

It is reasonable to believe that all or most of the generators were shut down for legitimate maintenance and repair needs. Many of the gas-fired units were old and, with age, had

deteriorated. California had just gone through a summer in which generators were being operated more intensively than they had been in many years and many had been cycled on and off, adding to the stress on these old plants. The firms operating the generators have asserted that a larger than average need for repairs resulted from running the plants at full capacity for the entire summer and that plants had been forced off line for needed repairs. One such outage has been very well documented: an accident at SCE's San Onofre nuclear power plant in February 2001 took over 1000 MW offline for several months. Since SCE was a buyer of electricity, it had an intense incentive to bring that plant back to operation as soon as possible.

It is also reasonable to believe that shutting down of some plants was largely a matter of choice, not of necessity. Whether some old plants can still be run, even though in need of repairs, is a matter of engineering and operational judgment. There were economic incentives to shut down some of the plants. Firms that owned a portfolio of generators had an incentive to withhold one of their plants from generating electricity, in order to increase the wholesale price of electricity sold by the remaining plants. Such an opportunity to exercise market power would be a financial motivation to take one plant offline for repairs, even though the plant could continue to operate if the owner had so chosen.

In response to the concern that the large number of plants offline could have been the result of deliberate withholding, FERC initiated an investigation. In February 2001, FERC issued a

report¹²¹ on the causes of the outages, with the following conclusion, based on its field and office observations:

“The telephone audits and the on-site inspections disclosed that the outages occurred at generating plants that were 30 to 40 years old. These generating facilities were operated at a significantly higher rate in 2000 than in previous years. Most of the generating facilities were out-of-service because of tube leaks and casing problems, turbine seal leaks and turbine blade wear, valve failure, pump, and pump motor failures.

“Staff did not discover any evidence suggesting that the audited companies were scheduling maintenance or incurring outages in an effort to influence prices. Rather, the companies appeared to have taken whatever steps were necessary to bring the generating facilities back on-line as soon as possible by accelerating maintenance and incurring additional expenses. Also, the outages did not necessarily correlate to the movement of prices on a given day.”

Other observers argue that these telephone audits could not have detected plants that were shut down for manipulating market prices. In addition, even field audits may not detect actions to slow down repairs. The United States General Accounting Office (GAO) reviewed the FERC analysis and concluded¹²²:

“FERC’s study was not thorough enough to support its overall conclusion that audited generators were not physically withholding electricity supply to influence prices. FERC’s study was largely focussed on determining whether or not the outages that occurred were caused by actual physical problems—such as leaks in cooling tubes—requiring maintenance or repairs. However, it is practically impossible to accurately determine whether such outages are orchestrated or not because plants frequently run with physical problems and the timing of repairs and maintenance is often a judgment call on the part of plant owners or operators.”

Neither the FERC study nor the GAO was able to assess quantitatively and definitively the genesis of the plant outages. FERC "did not discover any evidence" of strategic manipulation of

¹²¹ FERC “Report On Plant Outages In The State Of California” Prepared by: Office of the General Counsel, Market Oversight & Enforcement, Office of Markets, Tariffs and Rates Division of Energy Markets, February 1, 2001

¹²² “Energy Markets: Results of Studies Assessing High Electricity Prices in California”, USGAO, June 2001. “Energy Markets: Results of FERC Outage Study and Other Market Power Studies”, USGAO. Statement of Jim Wells, Director Natural Resources and Environment Thursday, August 2, 2001

outages but did not claim to have proved there were no strategic manipulations. GAO concluded that “FERC's study was not thorough enough” but did not claim to have evidence that there was strategic manipulation. Absent litigation, with discovery of internal documents and testimony under oath – and possibly even with a litigation – it is unlikely that we will ever know definitively whether these outages were uncontrollable or whether they resulted from strategic manipulation.

A smaller, but significant number of the offline plants – perhaps up to 3000 MW – were not the old gas fired units but rather were the QFs whose operators were not being paid for the electricity they were selling the investor-owned utilities¹²³. Thus, some portion of the reductions in capacity, but far from a majority, was the direct result of the uncertainty imposed on the QFs and the reduction in their cash flow, as a direct result of the financial crisis.

Figure 27 shows that May 2001 was the last month for which such a large amount of generating capacity was off line: in May almost 14,000 MW were offline while in June that figure dropped to 7,000 MW. The 7,000 MW increase in available supply of electricity was a very important component to loosening the market and driving wholesale prices down toward more normal levels in June.

The reasons for the sudden change in available supply are not altogether clear. As discussed in the subsequent section on FERC rulemaking, the FERC May and June Orders included "must

¹²³ On March 20, 2001, the *Los Angeles Times* reported, in a story entitled “Small Power Firms’ Cutbacks Contribute to Blackouts”: “Monday, about 3,000 megawatts of qualified-facilities generation went offline because the companies that operate the power plants can no longer afford to buy natural gas used to fuel the plants due to the utilities’ failure to pay money owed to the companies, said Jim Detmer, vice president of operations for the state’s Independent System Operator.”

offer" provisions. This Order may have had a significant impact. In addition, by June, QFs were being paid for the electricity they sold and they, for the most part, had come back on line.

Natural gas prices had dropped substantially and the costs of running the less efficient units had decreased substantially, thus making it more attractive for them to be kept operational.

New Generation Capacity

During the challenge period small amounts of new generation capacity became available. In May through July 2000, approximately 1000 MW of new generation capacity had come on line in Colorado, Nevada, and New Mexico. A 250 MW cogeneration plant went online in British Columbia at the beginning of October 2000.

However, during the last half of the crisis new generation capacity was rapidly becoming operational throughout the west, including California. A very small amount became operational in March 2001. But starting in late April, new plants came on line at the rate of around 1000 MW per month for the next six months. By June 1, 2001, almost 2000 MW had become operational, by August 1 over 5,000 MW had become operational, and by October 1, almost 7000 MW was online. Figure 28 shows the cumulative new generation coming online after August 2000, with data from ten western states plus British Columbia¹²⁴. Additional capacity was completed in the Mexican portions of WSCC, but these data are not included in that figure.

¹²⁴ These data were compiled from many different publicly available sources, including the California Energy Commission for plants in California.

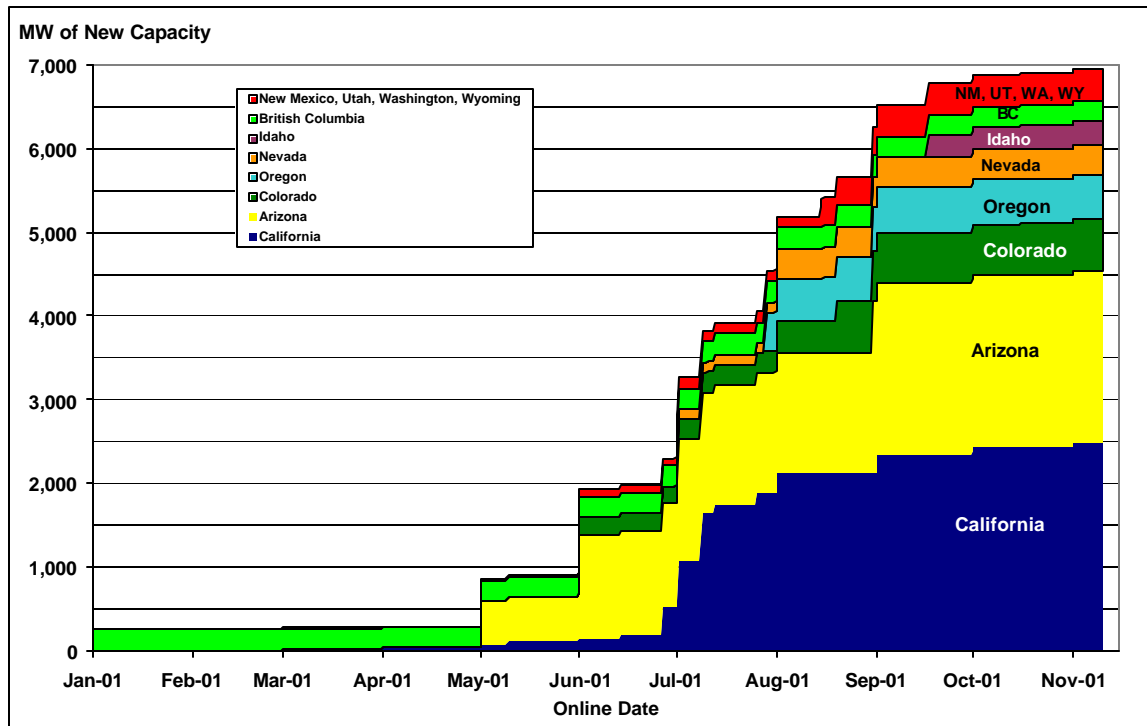


Figure 28 New Electric Generation Capacity Online in WSCC (excluding Mexico)

Figure 28 shows that about 800 MW of new capacity came online in British Columbia and Arizona around the beginning of May 2001 and that over 1000 more went online by June 1. The additions were primarily in Arizona, but smaller amounts also went online in Colorado and Wyoming. These increases in new generation capacity combined with the June reductions in the number of plants offline placed significant downward pressure on spot wholesale prices. The wholesale spot prices decline sharply around June 1.

In California, as of the beginning of the crisis, no new generation capacity had yet come on line, although much was in the construction pipeline. Not until late June and July 2001, after the sharp decline in wholesale prices, did any new generation capacity become operational. These

new plants, Sunrise Power, Sutter Power, and the Los Medanos Energy Center, contributing 1400 MW of capacity, had been initiated between December 1997 and December 1998, shortly after the restructuring legislation. However, they were completed slightly too late to have had any impact on electricity prices until after the crisis had ended.

Figure 28 shows that as of November 2001, of the new capacity in the west, 36% was in California. This fraction is comparable to California's 40% of the electricity consumption. And California's new capacity came online slightly after the first new capacity in Arizona and British Columbia. These data thus do not support a claim that California State governmental actions successfully brought a disproportionate number of plants online nor that the State's actions were particularly successful in speeding up the construction process for those plants already under construction.

The new generation capacity under construction in California and the rest of the west can be expected to assure against a near term repeat of the electricity crisis. Figure 29 provides estimates, published by the California Energy Commission, of the new California-only generation capacity projected to come online before the end of 2004. These data are based on electric generating plants currently under construction. Figure 29 shows the capacity additions both from large plants (greater than 300 MW) and from peaking units currently under construction¹²⁵. Figure 29 shows that by the beginning of the summer of 2002 there can be expected to be roughly 4000 MW of new capacity online and almost 6000 MW by the end of the summer of 2002.

¹²⁵ Because the construction time for peaking units is so short, there may be more peaking units online during this time horizon, if needed, based on plants for whom no application has yet been filed.

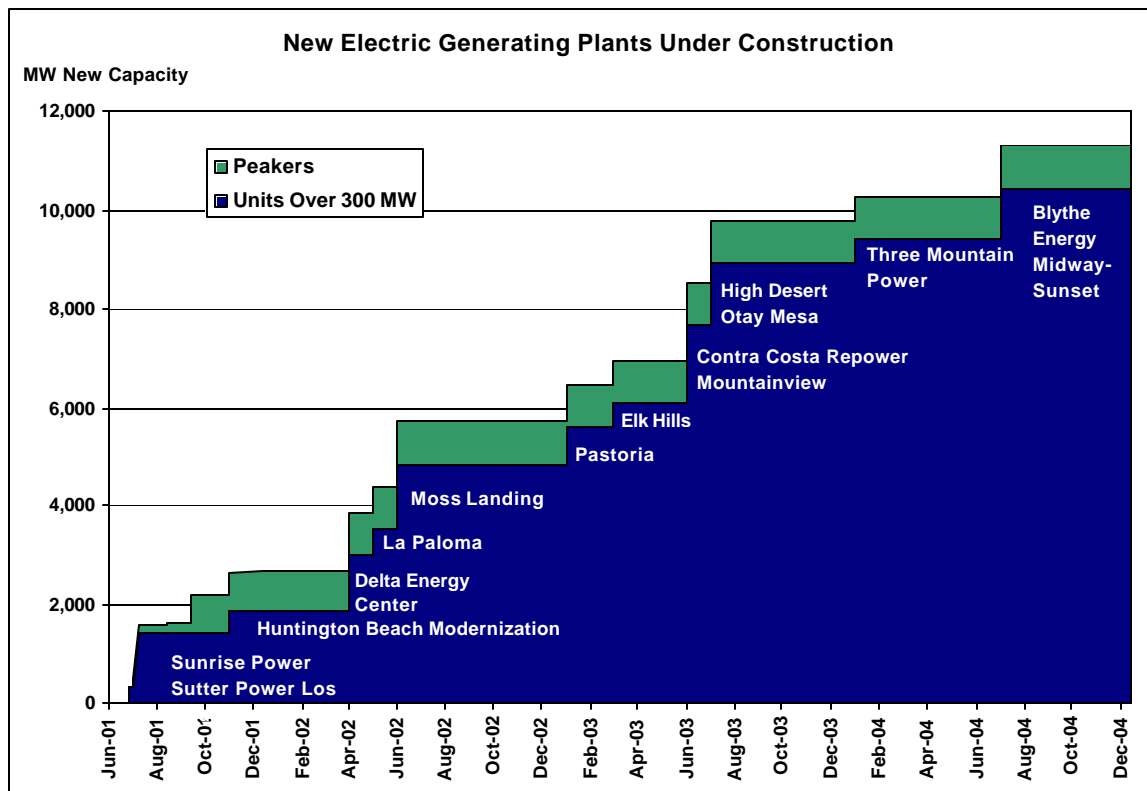


Figure 29 Expected New Generating Capacity in California from Plants Under Construction

Energy Conservation

Electricity demand, both measured in terms of peak demands and total megawatt hours of electricity, declined from 2000 to 2001. During the spring and summer of 2001, these significant reductions in the consumption of electricity and the peak demands for electricity started becoming apparent, thereby taking pressure off the tight electricity market. The reductions continue through the most recent times for which data are available.

Figure 30 shows the reduction in average electricity consumption and in peak demand, based on California Energy Commission data¹²⁶. The bars show the peak demand reductions on a month-

¹²⁶ Data are published by the California Energy Commission on its www page.

by-month basis from 2000 to 2001; the lines show the reductions in average electricity use. The monthly peak electricity demand was reduced, on average, by 1,900 MW (4.4%) and the monthly average use was reduced by 1,200 MW (4.3%). Although this demand reduction was substantially smaller than variations in the capacity of plants offline, it was comparable in magnitude to the new generation capacity online by the end of the period. Demand reductions, which generally can occur more rapidly than new construction, have been important in putting downward pressure on wholesale prices.

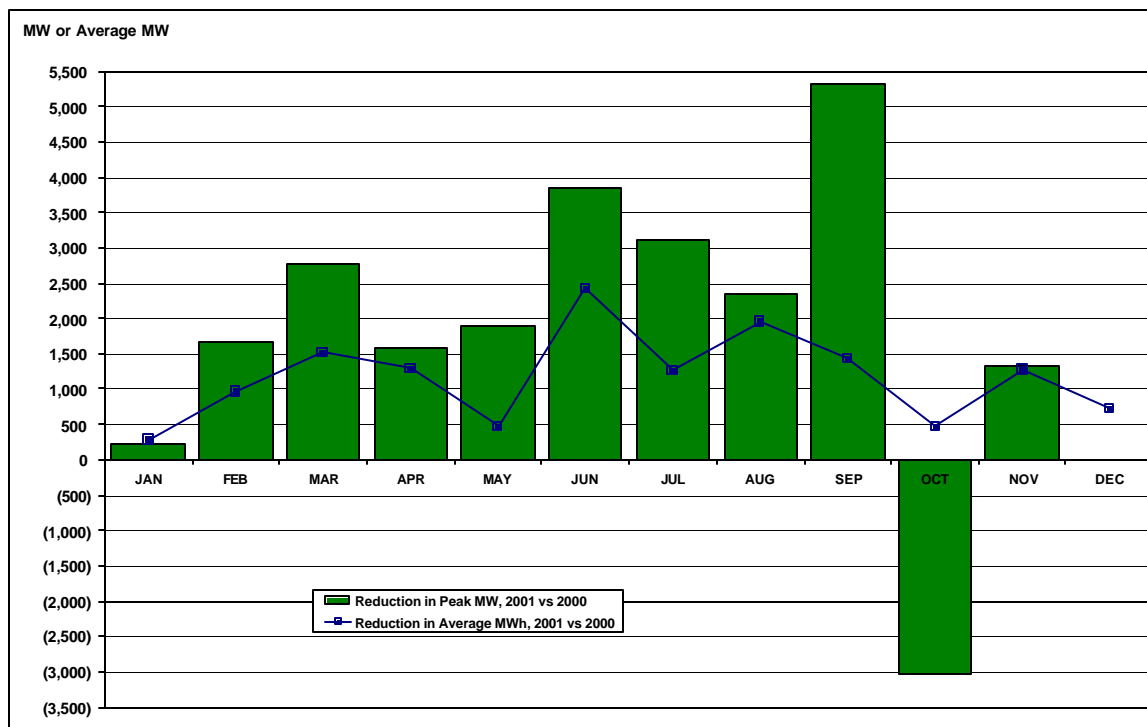


Figure 30 Reductions in Electricity Use, 2001 vs. 2000, Source: California Energy Commission

In addition, there were reductions in electricity use throughout the west. In the Pacific Northwest, in particular, there were significant numbers of industrial shutdowns, including in the aluminum industry, which together reduced the demand for electricity in the west.

These demand reductions stem from a combination of factors -- expectations of increased electricity prices, high retail natural gas prices¹²⁷, the energy demand management programs, energy efficiency and conservation programs, publicity about electricity problems, and the decline in the California economy. Subsequent empirical work will be needed assess the quantitative significance of these various factors.

Some of the demand reductions can be expected to be transient, for example, the significantly reduced lighting levels in large stores or parking lots in shopping centers or the changes in temperature settings of air conditioners. In addition, the demand reductions associated with the decline in the California economy will be reversed as the economy recovers and against starts to grow.

However, much of the demand reductions will be permanent¹²⁸. The reduction in public sector use through the substitution of light emitting diodes in traffic lights rather than conventional light bulbs will not be reversed. Buildings have been reroofed with light-colored materials, thereby

¹²⁷ Many customers, particularly in northern California, received one single bill for natural gas and electricity purchases. When the natural gas prices increased, newspapers carries storied about consumers whose energy bills had increased and who were finding ways of reducing their electricity consumption in response. Although a reduction in electricity use in response to an increase in natural gas price is not what economists normally predict, it seemed to be occurring in California. Perhaps subsequent empirical work will be able to examine whether this phenomenon in fact occurred in significant amounts. But the requisite empirical work has not yet been completed, or at least not yet been published.

¹²⁸ These reductions will be permanent, relative to the level of economic activity and to the population. But a growing population and growing economy will increase the overall level of electricity use even with these permanent reductions.

reflecting radiant energy rather than absorbing it, reducing the air conditioning load. Consumers and firms that have substituted compact fluorescent lights for conventional incandescent lights are unlikely to go back. The utilities are again promoting energy efficiency programs and these too can be expected to result in permanent reductions in electricity use.

California could still face electricity problems in the winter 2002, particularly if a large number of generating plants again goes offline or if a cold winter leads to large electricity demand in the Pacific Northwest¹²⁹. However, as time goes on, the probability of continuing problems declines. With the large amount of new capacity scheduled to come online within the next several years and continuing demand reductions, supplies of electricity are likely to remain adequate.

Energy Emergencies and Rolling Blackouts

The peak of the energy crisis was marked by energy emergencies and the profound fear of rolling blackouts. The crises were the result of supply and demand imbalances in which the supply of electricity was not sufficient to satisfy all electricity demand and keep a safe margin of operational reserves. Blackouts occurred when supply was so small that groups of customers had to be “blacked out” in order to avoid instability in the entire grid. Although blackouts came to symbolize the electricity crisis, energy emergencies were the norm at the height of the crisis and blackouts were the exception.

¹²⁹ Particularly in Washington electricity is used for space heating in many homes. Cold weather can greatly increase the space heating loads.

Figure 33 diagrams the various stages of energy emergencies and the demand responses, alerts, and warnings issued by CAISO at the various stages of energy emergencies. Blackouts occur only when CAISO has declared that a stage 3 emergency exists, that is, when operating reserves decline below 1.5%. During some stage 3 emergencies, rolling blackouts, although threatened, never are ultimately required.

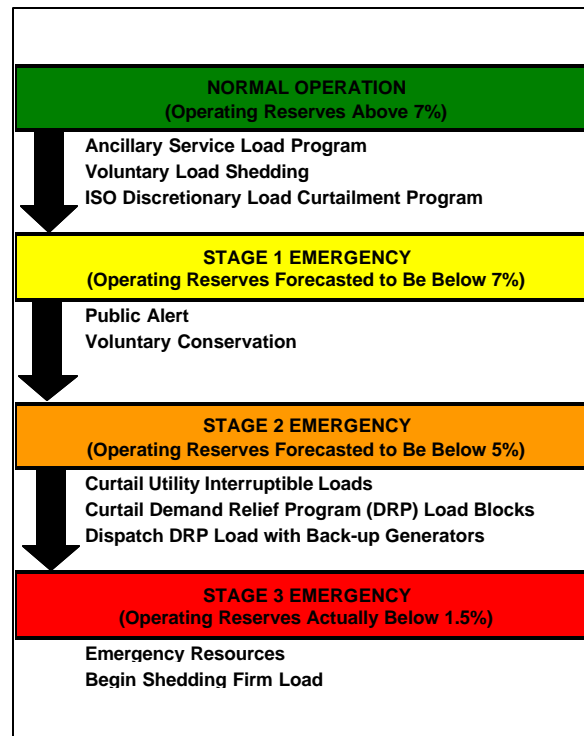


Figure 31 Electricity System Emergency Levels. Source: CAISO 2001 Summer Assessment, March 22, 2001, California Independent System Operator.

As Figure 33 indicates, in anticipation that Stage 3 emergencies might occur, several options would be taken, in turn. First, during a stage 1 emergency, when operating reserves were projected to fall below 7%, public alerts were issued with calls for people to reduce their use of electricity during the energy emergency, particularly during peak times. Commercial

establishments would be encouraged to reduce “unnecessary” lighting and to curtail use of air conditioning or other heavy uses of electricity.

During a Stage 2 emergency, when operating reserves were projected to fall below 5%, more severe measures were taken. Utilities had contracts with large users, particularly large industrial users¹³⁰, to reduce use of electricity significantly during stage 2 emergencies. The loads for these large users could be interrupted during energy emergencies, although such contracts included a provision limiting the number of such interruptions that could be required. Since these users had each voluntarily agreed to such contracts, this load shedding would be concentrated on firms whose operations would not be severely damaged by an interruption of electricity service. In addition, the CAISO established a demand relief program (DRP) under which energy aggregators agreed to reduce their aggregate demand when so ordered by CAISO. Under this program, load aggregators develop and market programs to their end-use customers willing to reduce electricity use in response to a CAISO curtailment order. Such orders could be issued during stage 2 emergencies, up to a limited number of curtailment hours in each month for a given participant.

These curtailments sometimes were not sufficient to avoid moving to a Stage 3 emergency. In a Stage 3 emergency, the CAISO calls upon emergency generating resources and orders utilities to begin shedding firm load, that is, orders blackouts. In rolling blackouts, shortages were allocated to the utilities. The utilities had been required to identify electricity “blocks”, or areas that could be blacked out simultaneously. During the emergency, utilities were required to shut down all

¹³⁰ Other large users could have such interruptible service. For example, the Claremont Colleges had interruptible electricity contracts and experienced such contractual blackouts.

electricity in those blocks for a limited time, typically one to two hours. If the shortage continued, other blocks would be blacked out in sufficient quantities to assure that the entire grid did not crash.

Alternatively, CAISO could have been willing to pay higher prices to obtain additional supplies, either from the generators participating in the California market or from out of market purchases. While the price caps were in effect, this option had been foreclosed. Upon the lifting of the price caps, however, such high price purchases were possible, to a limited extent.

The separation of the PX and the CAISO, and the resulting restrictions imbedded in the CAISO tariff, made this process of acquiring electricity to avoid stage 3 energy emergencies far more difficult than it need have been. As discussed above, when the PX and CAISO were established, the PX was given responsibility for all trading on the day ahead and the day-of markets. The CAISO was not allowed to buy or sell on those markets; that is, the CAISO was restricted to real time purchases and sales of electricity. “Real time” has been interpreted as during the hour that the electricity is needed. Thus, because of the early decisions to separate the PX and the CAISO, the CAISO tariff precludes it from acquiring electricity to meet emergency conditions earlier than during the hour that electricity is needed.

This restriction was in effect even when CAISO personnel were confident ahead of time that the electricity would be needed. Moreover, as discussed at another point, the utilities were typically greatly under-scheduling their loads, sometimes by as much as 35%. All under-scheduled loads

had to be covered by CAISO purchases with purchases occurring *during the hour that the electricity was needed*, thereby making the process far more hurried than it needed to have been.

Organizations other than the CAISO could make contractual commitments to purchase electricity well in advance of the time it would be used. Thus, when electricity supplies were short throughout the Western states, the CAISO, because of limitations in its tariff, would be the last entity to be able to acquire supplies to avoid energy emergencies. That restriction thus increased the likelihood that the blackouts would be concentrated in California.

Figure 34 plots the energy emergencies declared by CAISO during the challenge and the crisis period. Data are presented on a daily basis; each major division on the horizontal axis represents two weeks. Stage 1, 2, and 3 emergencies are indicated by the 1, 2, and 3 on the vertical axis. Rolling blackouts are shown as one level higher.

The first energy emergency was declared on June 14. This one day, Stage 1 emergency resulted from the heat wave hitting California and surrounding states while supplies were tight. During mid-July through August, Stage 1 and Stage 2 emergencies, including multi-day emergencies became common. Mid-September saw a brief return of energy emergencies. With the cooling autumn weather, there were no more energy emergencies until November.

Stage 2 energy emergencies returned in mid November. However, in December and January energy emergencies became the norm. December 4 began an eleven-day period of Stage 2 emergencies, a period in which the CAISO first declared a Stage 3 emergency. The emergencies

seemed to take a break for the holidays at the end of the year – a time of generally reduced commercial activities. After the first week of January, CAISO declared energy emergencies for 32 consecutive days. The first rolling blackouts, for two days, occurred January 17 and 18.

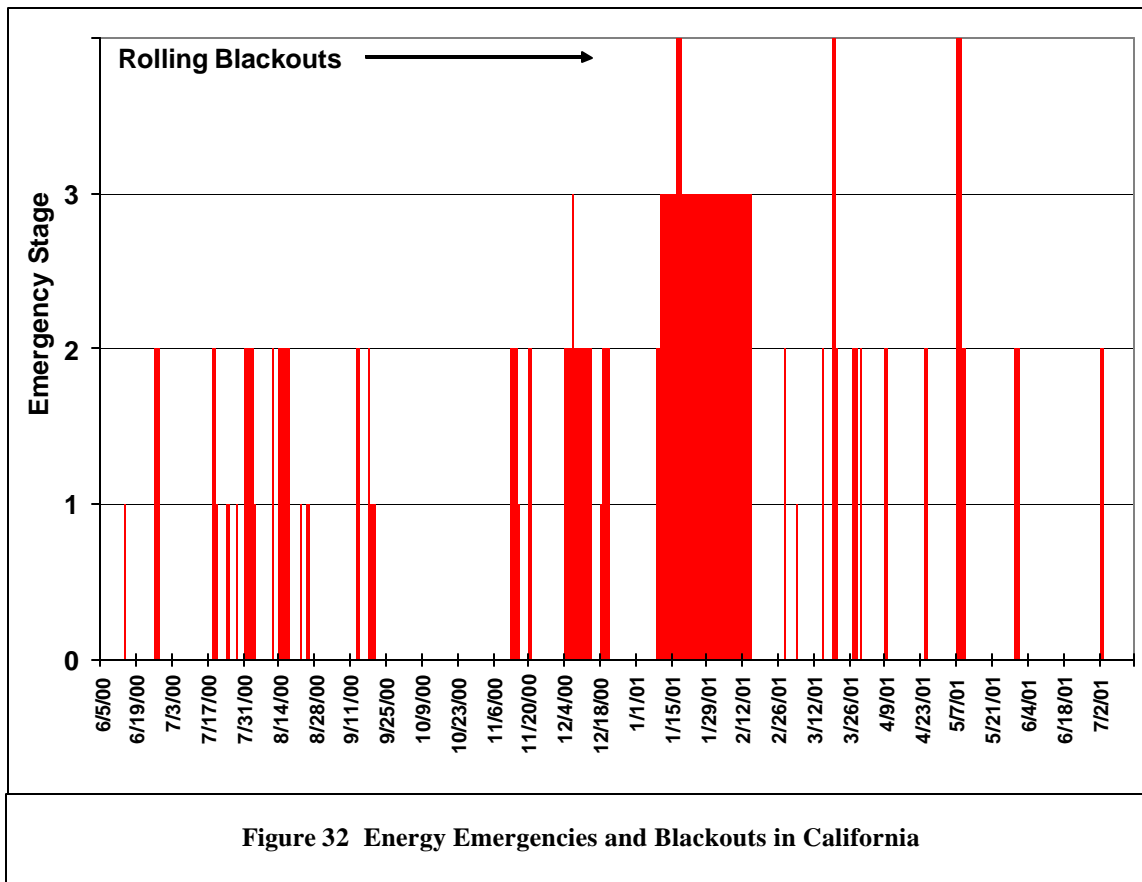


Figure 32 Energy Emergencies and Blackouts in California

Once the coldest part of the winter had passed and the heating loads in the Pacific Northwest had subsided, energy emergencies became less common. However, Stage 2 emergencies continued to recur, including two episodes of rolling blackouts, each two days long.

Although everyone in California was asked to conserve energy during each energy emergency, none of the demand reductions was mandatory unless a Stage 2 or 3 emergency was called.

During a Stage 2 emergency, conservation or load shedding was mandatory, but only for those organizations that had entered contracts allowing for such mandatory load shedding. Only when Stage 3 emergencies were severe enough to require rolling blackouts did the shedding of loads extend to individuals or organizations that had not agreed to allow such curtailments.

Blackouts came to symbolize the electricity crisis in California. Nevertheless, although blackouts were the symbol, and the threat of blackouts was frequent, actual blackouts were very rare. The CAISO ordered blackouts in fact on only six separate days, as shown in Figure 34 and in Table 6. Moreover, blackouts were called for only a small fraction of the load at any time, as shown in Table 6. The most severe was on January 18 in which 1000 MW of load was curtailed, accounting for 3.2% of the peak demand that day. Other rolling blackouts ranged from 300 MW to 500 MW, or 0.9% of the peak load to 1.7% of the peak load.

Date (all 2001)	Curtailed Ordered (MW)	% of Peak
January 17	500	1.6%
January 18	1000	3.2%
March 19	500	1.7%
March 20	500	1.7%
May 7	300	0.9%
May 8	400	1.1%

Table 6 Rolling Blackouts in California

Perhaps blackouts came to symbolize the electricity crisis in California because, for several months, the threat of blackouts was always real. Initially almost everyone was vulnerable to such interruptions, with the exception of hospitals and other emergency locations. Blackouts hitting industrial plants, on only short notice, could and did lead to very high costs. Blackouts

covering areas of street lighting and traffic lights raised the risk of traffic accidents. The fear of blackouts was expressed frequently in newspaper stories, editorial cartoons, and letters to editors. Thus, although there were many instances of very large costs incurred, particularly by industrial facilities, the fear of blackouts may have generally been greater than the direct consequences of the blackouts themselves.

The last rolling blackout was ordered on May 8; the last energy emergency was declared on July 3 during a heat wave. Since that day, the CAISO has not declared any energy emergency.

The Financial Crisis

As of December 2000, the financial challenge had become a crisis, a crisis that ultimately resulted in PG&E declaring bankruptcy and SCE teetering on the brink of bankruptcy for month. Once the financial limits of the utilities had been reached, this crisis moved to a hemorrhaging State budget. At this time, the State budgetary issues have yet to be resolved.

That the financial challenge turned into a financial crisis was the direct result of State regulatory, administrative, and legislative action. The State could have averted the financial crisis during the challenge period if it stopped forcing investor-owned utilities¹³¹ to deeply subsidize electricity use by their customers.

Had the State relaxed its price controls, the utilities would not have faced a financial crisis and the state budget would have retained a sizable surplus. Consumers and businesses would have faced higher prices of electricity but the price increases would not have been of crisis

¹³¹ As noted previously, California municipal utilities were not so required and were free to increase their prices, based on decisions by their governing boards.

proportions. Thus, the financial crisis was caused simply by the unwillingness of the State regulatory authorities, under the leadership of the Governor, to allow retail electricity prices to rise sufficiently to cover the cost of acquiring that electricity, or even most of the cost.

The significance of the regulatory controls is apparent from a comparison of the impacts on the investor-owned utilities with the impacts on the municipal utilities and investor-owned utilities throughout the other ten states and on the municipal utilities in California. During both the challenge period and the crisis, the increases in spot wholesale prices were very similar throughout the eleven western states. Therefore, other than electricity purchased under long-term or medium-term contracts, wholesale electricity prices increased by roughly the same amount for investor-owned utilities and municipal utilities throughout the entire eleven state region.

Yet only California, and only the investor-owned utilities of California, faced a fundamental financial crisis. Some investor-owned utilities in other states and some municipal utilities in California faced difficult financial problems but none was brought to the brink of bankruptcy, as were the investor-owned utilities in California.

There are two fundamental differences between California's investor-owned utilities and all the other entities. All the other entities acquired the vast bulk of their electricity either through their own generation or through a mix of medium-term and long-term contracts. All of the other entities faced regulatory bodies that could have increased the retail prices if needed to keep them creditworthy, although in many cases these bodies did not increase retail price by as much as wholesale price increased. Only the California investor-owned utilities faced the Western

electricity crisis with a requirement to purchase most of their electricity on spot markets and with a regulatory body that refused to raise retail electricity rates until it was too late. Therefore, only the California investor-owned utilities faced the devastating financial crisis.

The financial crisis did not end even when all financial assets of the utilities were depleted. The State took over from the investor-owned utilities the obligation to purchase sufficient electricity to satisfy electricity demand. As a result, over the course of roughly six months, this decision by the State decimated the State budgetary surplus. In essence, the State of California had put itself in the place of the investor-owned utilities as the only entity facing the Western electricity crisis without long-term contracts to purchase electricity and with price controls limiting the price at which the electricity was sold to its customers. Thus, the state of California started facing the same financial crisis that the CPUC and Governor Davis had imposed on the investor-owned utilities. However, as will be discussed at a later point, the CPUC had the power to raise retail electricity rates and the State had the power to enter medium-term and long-term contracts to purchase electricity. When needed to reduce the impact on the California State treasury, during the crisis, the CPUC and the State ultimately took these actions in had precluded the utilities from taking.

The Financial Crisis and the Utilities

Until January 2001, no retail rate increase was forthcoming and the investor-owned utilities remained trapped between soaring wholesale prices and the retail price controls rigidly enforced by the CPUC and strongly endorsed by the Governor.

A loud and clear warning came from the financial community on December 20 2000, when Standard and Poors warned that utilities would not be able to finance wholesale power purchases without clear and definitive action from California's regulators ensuring that costs could be repaid. Citing the likelihood of default, Standard & Poors asserted that unless such clear and definitive actions were taken within 24 to 48 hours, there would be a downgrade of credit ratings of the utilities to "deeply speculative" levels.

In a classic "too little, too late" move, on January 3 the CPUC proposed, and on January 4 agreed, to allow SCE and PG&E to raise rates by merely 1 cent/KWh (\$10/MWh). The increase was too small by a factor of at least three, to begin to compensate for average wholesale cost increases of over \$100/MWh. Moreover, the CPUC made it clear that the rate increase would be a temporary surcharge, to be in effect for 90 days, and subject to refund. The CPUC promised to investigate the rate issue further during the 90-day period, stating, "we do not yet have the facts to evaluate the utilities' claims of their dire circumstances". By that decision, the CPUC clearly signaled that they were willing to drive the utilities to bankruptcy.

The Governor only grudgingly accepted any price increase at all, stating in a press release: "If I had my way there would be no rate increase to consumers. But given the colossal failure of California's deregulation scheme, the PUC's decision was unfortunately necessary."

However, four days later, Governor Davis did offer the investor-owned utilities some hope. In his "State of the State" address, January 8, 2001 he stated unequivocally:

"To utilities and the financial community, let me say this: I reject the irresponsible notion that we can afford to allow our major utilities to go bankrupt. Our fate is tied to their fate.

Bankruptcy would mean that millions of Californians would be subject to electricity blackouts. Public safety would be jeopardized. Businesses would close. Jobs would be lost. Investment would flee the state. And our economy would suffer a devastating blow.”

Yet even with those dramatic, although overstated comments, the Governor remained opposed to the single most important action that he could take to solve the financial crisis -- a meaningful retail price increase consistent with the cost increases the utilities were facing. And, as it turned out, Governor Davis did nothing to back up his words with actions.

In order to keep buying electricity, both PG&E and SCE used their available cash and credit to pay for the massive financial shortfalls. However, the rate of net outflow was staggering. For example, the costs that PG&E faced exceeded their revenues by roughly \$1 billion per month. By PG&E estimates, the cumulative shortfall was \$3.4 billion by October 2000, \$4.5 billion by November, and \$6.7 billion by year-end 2000. By the end of the first quarter of 2001, the cumulative shortfall amounted to about \$9 billion. Similarly, SCE, by the end of the process, had incurred liabilities and indebtedness from procuring electricity, totaling approximately \$6 billion. Any company, including PG&E and SCE, faces limits on its financial reserves and its borrowing capacity. By January, SCE had reached those limits. PG&E reached its limits in a similar timeframe.

On January 16, SCE formally notified the US Securities and Exchange Commission (SEC) that it had suspended payment of some power purchase and debt obligations. Its public filing stated that the utility's cash reserves of approximately \$1.2 billion as of January 15 would be exhausted February 2 if it met all its financial obligations. This default meant that debtors would be entitled to exercise legal remedies to collect. Standard & Poor's and Moody's Investors Service

subsequently downgraded SCE's bonds to below investment grade. SCE would no longer be treated as a creditworthy buyer of electricity.

On January 19, Standard & Poor's downgraded the ratings on PG&E's bonds to below investment grade, reflecting PG&E's defaults on Jan. 17. Therefore, PG&E would no longer be treated as a creditworthy buyer. On February 1, 2001 announced that, it could not make full payment to CAISO and QFs for November CAISO energy purchase and December QF electricity deliveries. Of the somewhat more than \$1 billion due, it would make partial payments of \$161 million.

Before that time, the utilities had been able to purchase electricity even though they were delaying payment for it, because they were creditworthy. Some QFs with contracts to sell electricity to the utilities had attempted to break the contracts citing that the utilities were not paying for the electricity, but had the attempt usually been rebuffed in court. As long as a utility was deemed creditworthy, suppliers were obligated to continue supplying electricity.

However, once a utility was not creditworthy, sellers had a legal right to abrogate their electricity sales contracts with that utility. Moreover, there was strong motivation for these suppliers to break the contracts, because the spot prices of electricity at that time had so far exceeded the fixed prices in the long-term contracts and because the seller could no longer be assured it would be paid. The motivation coupled with the legal right to break the contracts made it clear that all the contracts were vulnerable.

The FERC chair, apparently anguished by the growing disaster, clearly communicated¹³² to the policymakers of California on January 18. Chairman Hoecker wrote:

“This year, energy is costlier in most regions of the country, but in California a cavalcade of misjudgments and bad luck have caused a genuine economic and social crisis. The situation has deteriorated further since early January. Negotiations over long term contracts have reached impasse, notwithstanding many hours of tough talk in Washington and the herculean (but ultimately inadequate) efforts of state legislators to buttress sagging utility creditworthiness and to find a sustainable retail rate compromise. California's reserves have evaporated this winter as recurrent plant outages continue and weather forced valuable units off line. Yesterday, the ISO had no choice but to order rolling blackouts in northern and central California in order to prevent a system collapse. So, to the financial crisis, we now add a serious threat to human welfare. With consumer rates frozen below cost (and below 1996 levels), with generators wary of making sales to entities probably unable to pay for power generated at unseasonably (and even historically) high cost, and with no plan to amortize existing utility arrearage, Southern California Edison and Pacific Gas & Electric stand at the brink of insolvency. For following the state's restructuring law, they may go bankrupt. Moreover, with only minimal forward contracting and utilities still subjected to high PX spot market prices for their "net short" position, the Commission's plan to diminish and discipline the spot market remains unrealized. Amidst a severe power shortage, conspiracy theories, resistance to more realistic rates, and calls for palliative price caps continue to obscure the issues and delay solutions.

“Perhaps bankruptcy can be averted.

“Urgency is a must. I am persuaded that California's utilities can still be withdrawn from the brink. But their descent into Chapter 11 does not materially alter the need to act to devise a coordinated plan of action. We have reached this stage of growing crisis through a series of acts of short-term thinking and now the desperation is palpable. We cannot, however, keep moving from one failure to the next, with no agreed-upon objectives. The Governor's stated plans are unrealistic and ours cannot be fully implemented without his help. Time to put down the guns.”

By mid January: the Governor had delivered reassuring words for public consumption but had taken no action to support those words; the CPUC had granted merely a temporary rate increase that was far too small; the Legislature had taken no meaningful actions to solve the financial crisis; wholesale prices remained well above the retail prices; utilities were rapidly running out

¹³² “Addendum to remarks of January 4, 2001”, by FERC Chairman Hoecker, dated January 18, 2001. http://www.ferc.gov/electric/bulkpower/Furtherconcurrency_Jan_18.pdf

of financial assets and borrowing capacity; utility bond ratings had been downgraded to a junk bond levels; electricity suppliers arguably were no longer legally required to sell electricity to the two utilities. The plight of the utilities was desperate and the Governor's "irresponsible notion" was promising to become a reality.

Then, and only then, was the Governor forced into action to begin to address the financial crisis, since absence of action could have resulted in large regions of the state without electricity, a condition that surely would have destroyed the Governor's chances for reelection. Several options remained at that time.

First, the State could stand by and allow the utilities to file for bankruptcy protection. The implications of this alternative were not completely known but various scenarios could be envisioned. Bankruptcy would put the future of the utilities under the control of a Federal judge who would have very strong powers. The judge could not force suppliers to continue selling electricity to the utilities unless the utilities could assure that those new obligations would be paid. Alternatively, the judge could order the generating assets to be sold to the highest bidders. However, if market power was being exercised, it was likely that the highest bidder would be the one most able to increase the value of the generating asset through the exercise of market power. One way or the other, a bankruptcy judge would be expected to assure that the utility's selling price for electricity would be no less than its purchase prices. Therefore, the judge would have the power to require the retail prices of electricity raised to cover the ongoing costs of purchasing electricity.

Alternatively, the judge could allow the utilities to stop supplying electricity to those customers whose prices were below costs for new purchases. However, it would have been highly unlikely that any judge would take such a harsh action; it would have such devastating consequences for all California. Thus, absent reduction in the wholesale price of electricity, it was reasonable to expect that retail customers would face greatly increased electricity prices one way or the other, if the Governor simply allowed the utilities to go bankrupt.

The second option would have been to allow what so many people had been urging, to increase the retail price of electricity for both consumers and businesses. The CPUC could have entered such an order. However, based on CPUC normal procedures, that would have been a slow process. Moreover, the CPUC had just affirmed that they were not willing to provide a rate increase of more than \$10/MWh. Thus, by the time the growing crisis forced the Governor into action, it was too late to depend entirely upon the CPUC, at least for the short-term solution.

However, the Governor of California does have almost unlimited powers that has been conferred by the State Government Code, including the ability to suspend both statutes and regulations. Explicitly included in the Code are almost unlimited powers to deal with sudden and severe shortages of electrical energy. Governor Davis could have used this emergency power, unilaterally, without approval by the Legislature, to suspend retail price control and could have unilaterally increased electricity prices. Then, while retail price controls were suspended, the Governor could have worked with the Legislature to modify the law and with the CPUC to set the basis for the appropriate retail price increases. The personal risk to the Governor would have

been that voters, knowing that he had raised electricity rates contrary to his previous public statements, might not support his reelection. He chose not to take that course of action.

Instead, on January 17, immediately after the credit rating downgrade implied that the utilities were no longer creditworthy buyers, Governor Gray Davis chose to use his emergency powers another way. He issued a Proclamation that a "state of emergency" existed within California, a Proclamation allowing him to take unilateral action. Governor Davis ordered the State Department of Water Resources (DWR) to assume responsibility for procurement of wholesale electricity for customers of California's three major IOUs. He ordered DWR to start purchasing electricity on behalf of the electric utilities. Subsequent legislation¹³³ extended and broadened the authority available to the Governor once he had declared the state of emergency.

Under the Governor's plan, the State would purchase the electricity on behalf of the utilities' customers and the utilities would sell the electricity on behalf of the State and reimburse DWR, based on the retail rates at which the electricity was sold. Essentially, DWR would sell the electricity it purchased to the utilities, charging a price equivalent to the utilities' retail prices. This plan allowed the State to avoid the consequences of power suppliers refusing to sell electricity to the California utilities.

In addition, DWR would ask the CPUC to increase retail rates to allow the utilities to begin fully reimbursing DWR for its electricity purchase costs. Apparently, the Governor saw rate increases as acceptable if implemented on behalf of the State Treasury.

¹³³ On January 19, 2001 he signed SB 7 which directed DWR to procure electricity for the next twelve days and appropriated initial funds for this purpose. On February 1, 2001, the Legislature enacted AB1X, which, among other provisions, authorized DWR to continue purchasing electricity through December 31, 2002.

Adding injury to insult, on January 19 the CPUC confirmed that, no matter how much the utilities were paying to buy electricity in the wholesale market relative to the regulated selling price of electricity, and no matter whether they were creditworthy, they were obligated to continue buying sufficient electricity to fully serve all their customers. The temporary restraining order¹³⁴ issued by the CPUC stated, in part:

In this interim decision, we are issuing a temporary restraining order (TRO) preventing Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (Edison) from refusing to provide adequate service to all of their customers. We affirm that regulated California utilities must serve their customers. This requirement, known as the "obligation to serve" is mandated by state law.

A bankruptcy filing or the threat of insolvency has no bearing on this aspect of state law. Even utilities that file for reorganization must serve their customers.

On January 23, the US Department of Energy extended for two weeks an emergency federal order directing electricity producers to sell to SCE and PG&E, even though they were not creditworthy. In doing so, however, Energy Secretary Spencer Abraham warned that there would probably be no further extensions.

State Payments to Buy Electricity

Under Governor Davis' order that the DWR purchase electricity on behalf of the utilities, the retail prices would remain low and the high cost of wholesale power purchases would be borne initially by the State treasury. The State would issue long-term revenue bonds to reimburse the State treasury. Repayment of interest and principal of these bonds would be a surcharge on retail electricity prices and thus ultimately the ratepayers would pay all of these costs. Although meant as a temporary measure until the utilities again became creditworthy purchasers, this was the first

¹³⁴ The entire text is available at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/4653.htm

of several steps taken by the government to interject the State squarely into the middle of the electricity system.

Once the state became the primary buyer of electricity, there were no longer any transactions on the PX and that institution had no way of raising money to pay its costs. The process of dismantling the PX began. The PX ultimately declared bankruptcy in March. One of the two market institutions established by AB 1890 was thus eliminated.

Governor Davis continued to assert that increases in the retail electricity price to meet the cost of electricity would not be in the interests of the consumers of electricity. However, his assertions failed to admit that the people of California would in fact pay the entire wholesale price of the electricity even though the retail prices would be kept low during the crisis. The high wholesale price of electricity represented the cost to the State of California, whatever the retail price. The entire cost would be paid by a combination of consumers, businesses, and taxpayers in California. The price of retail electricity determined which of these entities would be paying what fractions of the total cost, not whether the cost would be paid. Low prices to consumers would save those consumers money as purchasers of electricity but cost the taxpayers of the State the same amount saved by consumers. Low retail prices of electricity to businesses would save those businesses money in their role as buyers of electricity but cost the taxpayers of the State the same amount saved by the businesses. If the State issued bonds to pay the costs, as had been announced by Governor Davis, then future ratepayers would be responsible for paying the costs of current electricity purchases. None of that difference would be paid by the electric utilities because they had no financial assets left. Therefore, at best, low retail pricing was a zero

sum game among businesses, residential consumers, and taxpayers, many of whom, of course, were the same people.

However, the failure to raise retail prices did more than simply move the burden of payments from Californians as buyers of electricity to Californians as taxpayers or from current ratepayers to future ratepayers. The low prices eliminated the natural market incentives to respond to those high prices by reducing electricity use. Reducing electricity use would have lowered the wholesale price and therefore would have reduced the cost to California. So more than simply reallocating the high wholesale cost, the failure to raise retail prices greatly increased that cost. After all, why would corporations and individuals choose to go through the cost and difficulties of reducing their use of electricity to save costs for the State if people other than the firm or consumer reducing the use would capture much of the savings?

As of the beginning of 2001, it was generally projected that California would have an \$8 billion budgetary surplus during the year. This projected surplus was largely the result of a healthy California economy. However, Governor Davis' commitment for the State to become the wholesale purchaser of electricity changed that.

Once the State took over the purchasing of electricity on behalf of the utilities, purchase costs remained as high, just less visible. Rather than a transparent market -- the PX -- that was observable by the public, either directly through the web site, or indirectly through newspaper reports, the purchases by the DWR were hidden from public view. However periodically,

information would be issued about the purchase costs, often as press releases from the Governor's office and more recently from the DWR.

Table 8 shows¹³⁵ monthly data of DWR electricity purchases, including the price per MWh of electricity purchased under contracts, the price per MWh or electricity purchased on spot markets, the fractions purchased on spot markets versus under contract, and the overall costs during the month for January 2001 through January 2002.

	Spot Cost (\$/MWh)	Contract Cost (\$/MWh)	Average Cost (\$/MWh)	Fraction Spot	Fraction Contract	Total MWh (in 000s)	Total Cost (\$ millions)
Jan. 17-31	\$321	\$368	\$332	77%	23%	1,654	\$549
February	\$308	\$279	\$304	86%	14%	4,743	\$1,442
March	\$271	\$239	\$261	69%	31%	6,903	\$1,801
April	\$331	\$207	\$269	50%	50%	6,913	\$1,860
May	\$271	\$216	\$243	49%	51%	8,222	\$1,999
June	\$113	\$194	\$168	32%	68%	6,201	\$1,041
July	\$78	\$160	\$146	17%	83%	6,212	\$909
August	\$53	\$153	\$131	22%	78%	6,228	\$815
September	\$36	\$172	\$134	28%	72%	5,069	\$679
October	\$34	\$104	\$89	21%	79%	4,658	\$415
November	\$41	\$109	\$94	21%	79%	3,768	\$355
December	\$36	\$107	\$88	27%	73%	4,256	\$373
January	\$33	\$110	\$92	23%	77%	3,396	\$313
Total						68,223	\$12.5 billion

Table 7 State Costs for Electricity Purchases

These data show that beginning in June 2001, spot prices of electricity dropped sharply from the high levels during the peak of the crisis. By January 2002 spot prices had declined to \$33/MWh. However, the DWR cost for electricity purchased under contract remained above \$100/MWh for

¹³⁵ Data for price per MWh of electricity purchased on spot markets, overall purchases, purchases on spot markets versus under contract, and the overall costs are taken from DWR data. Average cost per MWh for electricity purchased under contract is backed out of these data. Data source: <http://wwwowe.water.ca.gov/newsreleases/2002/energy/02-02jan-cost.html>.

each month, including both medium term and long term contracts the State had negotiated while spot prices were high. However, from early 2001 through autumn, the fraction of electricity purchased under spot prices dropped sharply. Because spot purchases had been reduced to about one quarter of State acquisitions by the end of 2001, the State was not able to reduce its average acquisition cost by nearly as great a percentage as the spot price had dropped.

In the first quarter of 2001, DWR electricity purchases cost \$3.8 billion. At the then current retail price of electricity, these purchases would have returned about \$1.0 billion to the State, thus depleting the State budget by \$2.8 billion during this quarter alone¹³⁶.

Amid warnings by the State Treasurer that the State intervention to purchase electricity was decimating the State budget, at the end of March the CPUC agreed to do what it had been unwilling to do previously -- to raise the average retail electricity price another 3 cents/KWh or \$30/MWh, although the increase was not implemented until May. (See discussion in a subsequent section)

In the second quarter of 2001, DWR electricity purchases increased to \$4.9 billion. Although the wholesale spot and contract prices had declined from the first quarter, the total megawatts of electricity purchased by the State increased, resulting in the increased total purchase costs. The sale of this electricity by the State would have returned roughly \$1.8 billion to the State¹³⁷. Thus,

¹³⁶ The estimates of State revenues are given as the revenue ultimately recovered by the State for selling the electricity. There was a lag from selling the electricity to the time that the payments for the electricity were delivered to the State. This and subsequent State revenue estimates do not account for this lag and thus the estimates do not describe the month-by-month cash flows.

¹³⁷ This assumes an average selling price of \$75/MWh for April and May and \$105/MWh for June.

the State budget was depleted by another \$3.1 billion in the second quarter, bringing the cumulative state deficit to about \$5.9 billion.

During the third quarter the State budgetary hemorrhaging had greatly subsided. Retail prices of electricity had been increased and therefore the State was able to recover more revenue for each MWh of electricity it acquired on behalf of the investor-owned utilities. In addition, spot wholesale electricity prices had declined sharply so that by the beginning of the third quarter, the spot price had fallen below the retail electricity price. However, the State was purchasing over 70% of its electricity on medium term contracts. These contracts had been negotiated earlier and included prices well above the spot prices for electricity. Therefore, the average acquisition price of electricity purchased by the State remained above the retail price. During that quarter, the State paid a total of \$2.4 billion and was entitled to recover about \$1.8 billion, leading to an additional budgetary deficit that in the third quarter had decline to about \$0.6 billion.

By October, the average price of electricity purchased by the State on spot markets had declined to \$34/MWh and the average purchase price had declined to \$89/MWh (the average cost of electricity purchased under contracts was \$104/MWh). The retail price remained at about \$105/MWh for sales by the State. Thus, for the first month since the State began buying electricity, the State was able to sell the electricity it acquired at prices high enough to reduce the overall deficit, by roughly \$0.1 billion. The electricity-purchase-induced hemorrhaging of the State budget had ended.

The Governor's plan had been simply to borrow the money from the State treasury to cover the cumulative deficit and to pay the treasury back through issuance of DWR revenue bonds.

Although the amount of revenue bonds needed has grown over time, most recently the State has been attempting to sell \$12.5 billion worth of revenue bonds to cover the costs of purchasing electricity. The longer-term consequences of this bond sale will be discussed in the next chapter.

The Financial Crisis of the Utilities: the Saga Continues

In the months after the State had started purchasing electricity on behalf of the investor-owned utilities, the Governor and the legislature began addressing the financial plight of the utilities. Initially, rather than accepting a rate increase to allow the utilities to work their way back to solvency, the Governor started a process of negotiating with the utilities, offering to purchase the electricity transmission facilities, some generating facilities, and other assets. The colorful phrase characterizing the process was "I give you a dollar, you give me a hot dog"¹³⁸. The State Legislature and the Governor took the view that for the utilities to get financial relief from the controls imposed by the State, they would be required to sell significant proportions of their physical assets to California¹³⁹.

By late March and early April there had been little real progress in the negotiations. However, with much fanfare, Governor Davis announced he would deliver a live address to Californians on the electricity crisis. At that time the CPUC had proposed retail electric rate increases that could at least stabilize both the utility financial conditions and the State budget, although would not repair either. It seemed an appropriate time to lend his support to that plan. In addition, many

¹³⁸ The characterization originated with Senate leader, John Burton.

¹³⁹ This requirement was part of the policy framework developed by the Governor in January. See Section on State Policy.

expected to hear positive progress on his negotiations with the utilities. However, he did neither, but rather proposed an alternative and significantly lower set of rate increases. On his negotiations with the utilities and on his rate increase he stated: “Unlike the PUC, my plan includes funds to restore the utilities to financial stability -- if they agree to three main conditions: They must provide low-cost regulated power to the state for 10 years. Agree to sell us their transmission system. And dismiss their lawsuits seeking to double your electricity rates.”

After PG&E executives listened to Gray Davis’ live address, the next day, April 6, PG&E declared bankruptcy. Their filing for reorganization under Chapter 11 of the U.S. Bankruptcy Code cited¹⁴⁰ “unreimbursed energy costs which are now increasing by more than \$300 million per month, continuing CPUC decisions that economically disadvantage the company, and the now unmistakable fact that negotiations with Governor Gray Davis and his representatives are going nowhere.” Gray Davis had finally pushed the largest utility over the brink.

Later that day Governor Davis met with John Bryson, CEO of Southern California Edison, announcing, “We are determined to work out the few remaining issues that we have between us. ... But I am hopeful we will have a satisfactory result for the people of this state within the next few days, proving that negotiation, not bankruptcy, is the appropriate path.” SCE did not file for bankruptcy protection but continued the negotiations with the Governor and the State Legislature.

The Governor’s “next few days” became the next six months. By September, the issues with SCE had not been resolved. In September 2001, Governor Davis called for a special session of

¹⁴⁰ PG&E News Release, April 6, 2001

the legislature to examine a possible bailout plan for SCE. The financial crisis for SCE was finally resolved on October 2, 2001, through negotiations between SCE and the CPUC, before the special session was to begin.

In this settlement, SCE agreed to release the PUC from all claims under its Filed Rate Doctrine lawsuit and agreed to withhold payment of dividends to its stockholders for at least three years. By the time of the agreement, wholesale electricity prices had declined to pre-crisis levels and the second round of retail rate increases had been implemented, so that retail prices were by then well above wholesale prices. Under the agreement, the CPUC agreed to keep SCE retail rates at the elevated levels for several years, providing SCE with sufficient cash flow that it should be able to pay its debts. Thus, the agreement assures that the people of southern California will pay high electricity bills over the course of years. The CPUC expressed confidence the agreement would restore SCE to creditworthiness so it could, at some time, begin purchasing electricity for its customers. However, many creditors, including many electricity generators and traders, have not yet been paid. And the settlement terms still are purported to give CPUC significant control about which wholesale electricity purchase bill will ever be paid. The settlement did not reach any resolution on the filed rate doctrine. SCE withdrew the claim and the CPUC made no concessions about CPUC or State regulatory authority over SCE. However, SCE was able to keep all its physical assets, including its transmission and generation facilities.

Governor Davis rescinded his request for a special session of the legislature, officially signaling the end of SCE's crisis, stating, "Their settlement has protected the public interest and will allow the state's second-largest utility to return to financial health."

The terms of the settlement suggest that, had the CPUC been willing to raise rates in autumn of 2000 to the same rates to which they were raised in spring 2001, the entire financial crisis could have been avoided.

PG&E remains in bankruptcy court. On September 20, 2001, it filed a proposed reorganization plan, which promised to pay all creditors in full. The plan would separate PG&E into four separate companies, completing the vertical disintegration. One company would own and operate the retail electric distribution functions and operate as a regulated utility local distribution company¹⁴¹. It would sell most of its assets, including its electric generation and transmission assets to the other three companies. These companies would operate as deregulated entities, owned by its parent PG&E Corporation. Proceeds from the sale of assets would allow PG&E to pay all creditors. Under this plan, the state would have very few options to control retail prices well below wholesale costs since the retail entity would own none of the generation and transmission assets. The plan would allow PG&E to escape from much of the State's regulation of its activities and avoid legal restrictions imposed by the CPUC or the State legislature. Governor Davis, the CPUC, and several consumer groups opposed this change, citing the possibility that retail price increases could occur under this plan.

On February 7, 2002, the federal bankruptcy judge (Judge Dennis Montali) refused to approve PG&E's reorganization plan and rejected PG&E's argument that U.S. bankruptcy law must supersede state law. The judge's ruling allowed PG&E to attempt to establish "with

¹⁴¹ The natural gas components would be divided in a similar way with natural gas transmission going to the unrelated entity and the retail natural gas functions would stay with the regulated utility.

particularity" specific state laws and regulations that should be preempted by federal bankruptcy law. Nevertheless, he made it clear that PG&E must establish that the preemption is based on conflicts with particular provisions of federal bankruptcy law, not simply a general preemption.

On February 13, 2002, the CPUC submitted an alternate reorganization plan, one that would keep almost all PG&E activities under control of State regulators. The CPUC-proposed plan has many similarities to the one negotiated between SCE and the CPUC. Similar to the SCE situation, retail electricity rates significantly exceed costs of acquiring electricity (for quantification, see Figure 35 in a subsequent section of this chapter), now that wholesale prices have dropped. Thus, PG&E is now accumulating revenues well in excess of its costs. The CPUC proposal would keep PG&E retail rates at the elevated levels for at least several years, providing PG&E with sufficient cash flow that it should be able to pay its debts over the next few years. PG&E would not pay any dividends to its stockholders from 2001 through 2003. The PG&E proposal, if accepted, would assure that the people of northern California, like those of southern California, would pay high electricity bills over the course of years. The CPUC expressed confidence its proposal would restore PG&E to creditworthiness so it could begin purchasing electricity for its customers by January 2003.

The judge has not ruled on the CPUC proposal and PG&E has not yet filed a response to the judicial decision. However, it appears that the end of the PG&E crisis could be in sight, even though complete resolution may not come quickly. Nevertheless, until a full settlement is reached, PG&E is precluded from paying most of its debts, including the money it owes for

purchasing wholesale electricity in the pre-January-2001 time. Thus, more than a year after PG&E purchased the electricity, many generators and electricity traders still have not been paid.

State and Federal Policy Responses

The time of crisis, even more than the challenge period, was a time for strong, wise political leadership. Faced with the reality of the crisis at its peak, the California Governor and the Legislature made energy one of the highest priorities for communication and for policy development. However, as in the challenge period, much of the policy action seemed primarily intent on casting blame outside of California, hiding the short-term problems, and shifting the consequences to the future, even at the cost of greatly increasing the overall difficulties for California.

The policies favored by the California political leadership emphasized direct government intervention in the market place, reliance on retail and wholesale price controls, plus strong regulatory intervention. The CPUC, now with different leadership than when AB 1890 had been passed, stopped trying to improve markets, strongly enforced retail price controls (which the State could control), and lobbied for wholesale price controls (which the State could not control.) The California Governor intensified his public relations campaign of blaming California's electricity problems on the Federal government, including Federal regulators, on electricity generators, on "deregulation", all but on his own policy inaction. He continued his lead role in militating for strong price control regimes at both the retail level and the wholesale level. The Legislature failed to modify the most damaging problems of the system but did take leadership in

encouraging energy conservation and energy efficiency measures. When the Governor and Legislature were forced to respond to the financial crisis, their response relied on direct governmental wholesale purchases of electricity and negotiations to acquire assets of the utilities, therefore moving the State towards public power and direct State participation in electricity markets.

At the same time, Federal action, through FERC, though slow, sometimes misdirected, and inconsistent over time, seemed designed to address the underlying flaws in the market design and implementation, to avoid simple ineffective palliatives, and to strengthen the role of markets. Like the CPUC of the early through mid 1990s, FERC operated as a regulatory agency trying to move away from direct control of market transactions and market pricing. FERC policy actions, overall, had the hope of providing longer-term solutions to California's energy crisis by attempting to identify, analyze, and correct fundamental problems.

The ideological conflict was painful between State leadership that continued to favor dominantly public sector roles and the FERC that continued to favor dominantly private sector roles. The State and FERC each had jurisdiction over important parts of the restructured system so neither could fully impose its views on the other and each needed actions of the other to be fully effective. The fundamental ideological differences were never fully resolved and continue to this date.

Actions by the State Executive Branch and Legislative Branch

Public Relations and Rhetoric

First, starting during the challenge period and extending through the crisis, Governor Davis waged a public relations campaign in which he sought to assign blame for California's electricity problems on many organizations outside of his own office. Perhaps his most frequent target was the electricity generators and marketers. In speech after speech, press release after press release, Governor Davis made it clear that he believed the generators were engaging in wrongful and possibly criminal activities. Words and phrases such as "profiteering", "plunder", "unconscionable", "price gouging", "exorbitant profits", "market marauders", "pirate generators", "privateers", "obscene profits", and "outrageous wholesale prices" peppered his formal statements.

Governor Davis often associated these words with phrases such as "out-of-state generators". The "out-of-state" label, like so much of his rhetoric, was a distortion of reality: spot market electricity sales by in-state entities were at prevailing market prices, just as were spot market sales by out-of-state sellers (as would typically be the case in any markets.) In fact, the two largest municipal utilities in California, the Los Angeles Department of Water and Power and the Sacramento Municipal Utility District were selling electricity at market prices¹⁴², just like every

¹⁴² The DWR data for the first half of 2001, presented previously in Figure 26, show that DWR paid California sellers, including California municipal utilities, higher prices than it paid the out-of-state suppliers Governor Davis had so often accused of price gouging. DWR paid an average of \$276/MWh to the Los Angeles Department of Water and Power, \$268/MWh to the Sacramento Municipal Utility District (SMUD), and \$305/MWh to the City of Burbank. It paid San Diego based Sempra Energy an average price of \$366/MWh. Among the ten largest out-of-state sellers to DWR, only two (both Canadian entities) were able to negotiate prices higher than SMUD, private sector TransAlta, (\$298/MWh) and public sector Powerex Corporation (\$425/MWh). DWR paid an average of \$236/MWh to the ten largest out-of-state suppliers, less than to any of the in-state sellers (with the exception of DWR purchases from itself).

other seller. Yet it seemed politically expedient for the Governor to shift all blame to entities outside California, completely distorting reality¹⁴³.

The rhetoric included the Governor's well-publicized announcements that the State of California was initiating a criminal investigation into the actions by the generators and marketers.

However, to this date, the State has not announced it has ever uncovered such illegal activities.

The lack of any such announcement strongly suggests that the criminal investigation never uncovered any illegal activities, since, given the Governor's pattern of public rhetoric, he would have broadly publicized any evidence of wrongdoing that the State found.

Federal organizations, particularly FERC, were also subject to his biting attacks. A particularly vicious Gray Davis attack was prompted by FERC's decisive steps to deny California's various attempts to extend state-managed price controls¹⁴⁴. In a communication for public consumption, he stated:

The Federal Energy Regulatory Commission has abdicated its responsibility to the people in the West. Their responsibility is to ensure just and reasonable rates. Instead, they have chosen to ensure unconscionable profits for the pirate generators and power brokers who are gouging California consumers and businesses.

....

This is an inexplicable decision by armchair Washington bureaucrats fixated on economic ideology that has no practical application to the dysfunctional energy market in California and the West. Instead of acting in the best interests of consumers and businesses, the FERC commissioners have acted as pawns of generators and power sellers whose only interest is to plunder our economy.

....

¹⁴³ As of January 8, 2002, Governor Davis had shifted his rhetoric to focus attention on California municipal utilities. In his 2002 State of the State address he asserted: "Merchant generators, even some of our own municipal utilities - were gouging us unconscionably." Shortly thereafter, Governor Davis launched a daily series of political advertisements implying that Richard Riordin, former mayor of Los Angeles and a contender for the Republican gubernatorial nomination for California governor was responsible for the LADWP charging prices "twice as high" as the prices charged by other sellers of electricity. The pure political motivation for Governor Davis' changing rhetoric and his distortion of reality had become painfully apparent.

¹⁴⁴ Press release issued by Governor Davis on December 15, 2000.

The public health and safety of California's citizens and the economy of the State cannot be subject to the blackmail of a few greedy privateers working in concert with a handful of Washington bureaucrats.

Governor Davis became fond of labeling electricity deregulation as the villain, rather than his own leadership, or lack of leadership, in managing the challenge and crisis. He referred to FERC actions as a “reckless deregulation experiment” that would make “guinea pigs of California consumers”. He described California’s problems as the “ravages of a dysfunctional marketplace”.

Governor Davis’ language was colorful but did not serve the interests of the people of the State of California. The colorful language served only his personal political interests.

Regrettably, Governor Davis made threats that the assets of the generators would be subject to eminent domain procedures. Such threats, far from solving any of the real problems of the state, tend to chill the desire of other firms to invest in new generation in California and thus were counter-productive to electricity system solutions.

The low point of the rhetoric from the California Executive Branch came when California’s chief law enforcement officer, Attorney General Bill Lockyer, managed to utter one of the most offensive statements imaginable from a person charged with the integrity of the criminal justice system in California. Lockyer stated in a *Wall Street Journal* interview (May 2001) that he hoped to imprison – and more than simply to imprison – Kenneth Lay, the chairman of Houston-based Enron Corp, a person who was not charged with any crime in California, much less

convicted: "I would love to personally escort (Enron Chairman Kenneth) Lay to an 8-by-10 cell that he could share with a tattooed dude who says, 'Hi, my name is Spike, honey.'"

The State Framework for Policy

In addition to the rhetoric that emanated from the Executive Branch of the California government, there did emerge an overall framework for policymaking. Unlike Governor Davis' policy framework from the challenge period, this framework, developed in combination with the leaders of California's legislature recognized both the electricity crisis and the financial crisis. In addition, unlike the governor's price control policy framework from the challenge period, it recognized the importance of electricity supply and demand to the electricity problems.

Announced on January 26, 2001, as a "rough consensus reached with bipartisan leadership of California's Senate and Assembly", the policy framework was stated¹⁴⁵ as:

1. Aggressively promote energy efficiency, conservation, and demand reduction among consumers, businesses and public entities.
2. Increase the supply of electrical generation in California through continuing efforts to streamline permitting and construction of new plants, while protecting the environment, and remove obstacles to the development of distributed generation.
3. Authorize the state to purchase the "net short" electricity needed to serve investor-owned utility customers. The "net short" is the power needed beyond that generated by the utilities themselves or available to them from "qualifying facilities" (QFs) and other long-term contracts. It is anticipated that most of this power will be purchased through long-term contracts with power suppliers.
4. Provide that the state will sell power directly to ratepayers with the investor-owned utilities collecting and remitting a dedicated portion of rate revenues to the State.
5. Reduce the price of power delivered by QFs to the utilities by changing the contracts between the utilities and QFs through action by the PUC and/or the Legislature to a reduced rate agreed to by the QFs.

¹⁴⁵ Can be accessed through http://www.governor.ca.gov/state/govsite/gov_homepage.jsp

6. Provide ratepayers with an asset of value such as stock warrants as equity participation in the financial recovery of the utilities. This equity participation will be used either to help retire bonds or otherwise provide tangible benefits to consumers.
7. Continue negotiations with the investor-owned utilities and others on a plan to deal with the unrecovered costs that threaten the economic viability of the utilities while protecting the ratepayers.
8. Resolve outstanding regulatory and legal actions initiated by the utilities to recover all their undercollections.
9. A public authority that could assure adequate power supply and adequate transmission capacity.

This overall framework included five major points – Numbers 3, 4, 6, 7, and 9 – that, as implemented or negotiated by the State, would increase the public sector direct participation in the energy markets as a buyer or seller of electricity. One major point – Number 1 – would involve increases in direct governmental regulation in energy markets. One point – Number 5 – would require the State to use its regulatory or legislative power to alter the long-standing contracts QFs had with utilities. One point – Number 8 – would involve resolving the legal challenges brought by the utilities challenging the right of the California to maintain retail price controls. Only one point – Number 2 – would involve increasing the ability of markets to work effectively.

Elements missing from the framework were significant. There was no part of the framework designed to move the State away from the price controls imposed on investor-owned utilities, only a point to resolve the challenges to the price controls. There was no part of the framework proposing to allow the utilities to participate in a much broader range of contracts to buy electricity. Nothing in the framework addressed the dangers of energy emergencies, including

blackouts. There were no points about working constructively with Federal agencies to improve the operations of electricity markets.

Moreover, the subsequent policy actions taken or attempted by the state were roughly, although not completely, consistent with this policy framework. And similarly, the omissions in the policy framework remained omissions in state policy implementation. Some policies have already been discussed; some will be discussed in what follows.

Governor Davis called two concurrent extraordinary sessions of the Legislature, the first on January 3, 2001 and the second on May 17 at the expiration of the first session. The work of these special sessions proceeded in parallel to the work during the (simultaneous) regular sessions, but served to focus Legislative policy attention on the electricity and financial crises.

Policies Impacting Energy Demand

Most beneficial of its policy actions in terms of loosening the supply/demand balance were the policies designed to reduce electricity demand, in both the short run and the long run. Although only the short-run programs would reduce the severity of the energy crisis, the long-run programs could help assure there would not be a repeat of the crisis.

One of the most publicized was the "20/20 plan". Under this plan, all residential and small commercial purchasers of electricity were encouraged to reduce their use of electricity by 20% from the previous year. Those that did so would be rewarded not simply with the reduction in the electricity bill based upon less usage but also would enjoy a 20% reduction in their overall electricity bill. The "20/20" plan accomplished two objectives. It was effective in dramatizing a

goal for reducing electricity consumption and making it clear that goal was achievable. In addition, the plan had embedded in it a significant financial incentive that essentially increased the marginal price of electricity to consumers without increasing the average price¹⁴⁶.

The State, with help of the Advertising Council, launched the "Flex Your Power" campaign featuring the image of a light switch and a finger turning off the switch. This campaign further sensitized people to the public value of reducing electricity use.

The Governor issued an Executive Order¹⁴⁷ requiring retail business to reduce substantially “unnecessary outdoor lighting wattage” during non-business hours. Failure to do so would subject the commercial establishments to fines. Police were authorized to search out those companies using too much electricity and cite them. Whether this had any real effect or simply served to dramatize the goal of reducing electricity use was unclear.

AB 1890 had included a component of the retail electricity price to pay for public benefit programs, including \$228 million per year to pay for energy efficiency and conservation activities and other demand side management programs. However, the particular expenditures of these funds, earmarked for these specific purposes, needed State approval, which was forthcoming during the crisis. These funds paid for costs incurred by utilities in promoting energy efficiency improvements throughout California’s economy. Perhaps the most successful was the subsidy offered for the sales of compact fluorescent lights at through high volume

¹⁴⁶ The incentive was a discontinuous one. There was a benefit for meeting or exceeding the goal, no benefit for almost meeting the goal, and no further benefit for exceeding the goal. Thus this plan increased the marginal cost only for reductions of 20%, not for increases.

¹⁴⁷ Executive Order D-19-01, February 1, 2001.

discount retail stores, such as Costco. PG&E alone reported around 3.5 million sales of compact fluorescent lights under its 2001 incentive programs¹⁴⁸. This initiative reduced electricity usage very quickly and can be expected to have a continuing impact on consumption.

In January 2001, effective in July 2001, the California Building Standards Commission adopted comprehensive emergency modifications to California's statewide building efficiency standards, giving California the toughest building efficiency standards for new construction in the nation. Among other features, the standards require more efficient air conditioning and heating ducts in new homes and impose standards on new windows designed to reduce solar radiative heat transfer. These modifications had no effect on the immediate crisis but can be expected to have a longer-term impact on electricity demand.

The legislature passed two major bills that to reduce electricity use during the time of the crisis: SB 5X and AB 29X. AB 29X allocated \$35 million to acquire and install real time meters for industrial customers using more than 200 KW of power, many of which have been installed. However, to this date, the CPUC has yet to approve a tariff that would allow electricity to be sold at real time prices and thus this investment had no beneficial effect during the energy crisis.

AB 29X also allocated \$20 million to distribute compact fluorescent lights through the California Conservation Corps. SB 5X allocated about \$430 million in general fund revenues to emergency energy efficiency incentives and \$220 million in funds to reduce electricity prices for low

¹⁴⁸ A typical compact fluorescent light (CFL) uses about 20 watts to produce the same light as a 75 watt incandescent bulb. Thus, a CFL substituted for an incandescent light reduces electricity consumption by 55 watts during times either light would be on. If 50% of the PGE-subsidized CFLs were lighted at a given time, that would reduce electricity use by about 100 MW ($0.5 \times 3.5 \text{ million} \times 55 \text{ watts} = 96 \text{ MW}$), roughly equivalent in to the maximum output of two typically sized peaker generating plants.

income households. The latter could be expected to increase slightly the usage of electricity while easing the financial impact of high electricity prices on low-income families.

Policies Impacting Electricity Generation Capacity

In February 2001, Governor Gray Davis signed six Executive Orders to expedite the review and permitting process of power generating facilities in California. One order allowed small peaking plants to be quickly approved and constructed and was limited to those that could be completed before September 2001. The other Orders envisioned a four-month and a six-month licensing process, where the time period was based on expectations of permitting time after all data to the California Energy Commission were deemed to be adequate, a process that itself could take months. The four-month licensing process was limited to simple cycle, thermal power plants. They had to be able to be on line by December 31, 2002 and would be required to convert from a simple cycle mode to combined cycle mode or cogeneration within 3 years. The Orders do have the longer run potential of increasing the supply responsiveness by reducing the time for new plants to be approved and ultimately to come on line.

The Governor negotiated with those companies who were in the process of constructing new generating plants to provide them with an incentive to come online earlier than they would have otherwise. The financial incentive offered for coming online early may have moved the online date for plants by a small amount but did not result in any plants coming online during the crisis. These incentives were politically valuable, however, since press releases from Governor Davis continued to suggest that his actions were responsible for construction of those plants, even though they had already been under construction when he took office.

Policies Impacting Risk to Electricity Suppliers

Throughout 2001, State actions continued to create financial risk for sellers of electricity and thereby reduced the supply of electricity from generating units within California. Those risks also discouraged those generating electricity outside California from selling into the California market. Such California electricity supply reductions could be expected to raise the wholesale price of California electricity. Financial risks stemmed from four classes of California actions (or inaction) continuing through much of 2001: change of the CAISO board composition, failure of DWR to pay for spot electricity purchases through CAISO, CPUC refusal to allow investor-owned utilities to pay challenge-period bills, California's continued demands that FERC order large refunds.

First, by the end of January 2001, Governor Davis had replaced the CAISO stakeholder board with a new five-person board, three of whom were closely associated with the Davis administration¹⁴⁹. Control of the CAISO board had moved to the State. Once the PX stopped operating, DWR was purchasing all its spot market electricity through the CAISO. Thus, the state of California had become the largest market participant and had gained control of the CAISO. The harsh rhetoric by Governor Davis castigating the electricity generators and marketers was continuing. Thus, it was reasonable for all generators and marketers to believe that CAISO would not treat them fairly but rather would act to favor the State of California and electricity buyers whenever possible. This rational belief could be expected to increase significantly the perceived risks facing generators and marketers.

¹⁴⁹ Governor Davis appointed Maria Contreras-Sweet (California Secretary of Business, Transportation and Housing), Tal Finney (Director of Policy, Governor's Office), Mike Florio (Attorney, The Utility Reform Network), Carl Guardino (President and CEO, Silicon Valley Manufacturing Group), Michael Kahn (Attorney; Chairman of Energy Oversight Board). Maria Contreras-Sweet left the board after the September 11 terrorist attack.

Second, from January through November 2001, DWR purchased about \$1 billion worth of spot market electricity through CAISO. However, during this time, the DWR did not pay any of its obligations for purchasing electricity through the CAISO. Since the CAISO had no resources of its own to pay for purchases, as of November, CAISO had not paid the generators. Nor could the generators be sure that either DWR or CAISO would ever pay them.

It appeared that CAISO had established policies that encouraged DWR to not pay, or at least did not discourage DWR's non-payment. CAISO had argued in a sequence of FERC filings that sellers were required to supply electricity for CAISO's real time markets whether or not they are paid. DWR and CAISO argued to FERC that DWR might not be required to pay for all electricity it purchased on behalf of the investor-owned utilities. Until November, the CAISO and DWR had not even reached a satisfactory agreement on how CAISO would bill DWR and thus CAISO never even billed DWR for its electricity purchases until that month.

FERC repeatedly ordered CAISO to enforce its tariff provisions requiring all buyers of electricity to be creditworthy. Finally, on November 7, 2001, FERC found CAISO in violation of its tariff and ordered that it pay all overdue amounts within three months¹⁵⁰:

“We have repeatedly directed the ISO to enforce its creditworthy standards under the Tariff.... Although DWR represents that it is the guarantor of transactions for the non-creditworthy UDCs [utility distribution companies] DWR has yet to pay for these net short positions.... Moreover, a creditworthy party pays its bills when they are due.”

¹⁵⁰ FERC “Order Granting Motion Concerning Creditworthiness Requirement and Rejecting Amendment No. 40”, Issued November 7, 2001. Available at <http://www.ferc.gov/electric/bulkpower/er01-889-008-11-7-01.PDF>

Only after FERC had issued the November 7 Order did CAISO begin to bill DWR for the power it had been purchasing since January. Until that time, the failure of DWR to pay for its purchases created significant risk for the generators and traders that were selling to CAISO.

FERC has quantified the risk to sellers resulting from DWR and CAISO business practices. On June 19, 2001, FERC issued an order outlining the methodology that should be used for calculating any non-competitive overcharges in sales through the PX and CAISO. FERC determined that a competitive price estimate could include a 10% “creditworthiness adder” for transactions after January 5, 2001, reflecting increased credit risks in California. As late as December 19, 2001, FERC ruled that this 10% creditworthiness adder is still justified.¹⁵¹

“In the June 19 Order, the Commission instituted the 10 percent adder to recognize both the larger risk of nonpayment in California when compared with that in the larger West-Wide market, and the longer payment lag in the ISO spot markets when compared with that in the Western bilateral spot markets. The Commission also pointed out that questionable business practices have sent negative signals to future supplies, credit rating agencies, and investors. ... However, despite our repeated instructions to the ISO to ensure that there is a creditworthy party backing up each and every transaction, we have continued to receive complaints that suppliers are not being paid. Under these circumstances, we continue to believe that the circumstances that justified institution of a creditworthiness adder have not abated. Until the risk of nonpayment by purchasers in California has been relieved, the adder is still justified.”

Third, the State has taken actions to block the investor-owned utilities from paying their pre-January 2001 wholesale electricity acquisition bills. PG&E’s bankruptcy and SCE’s extended pre-settlement negotiations with CPUC have assured that the two investor-owned utilities have not paid the generators and traders for their pre-January 2001 electricity purchases. (See discussion in the section: “The Financial Crisis of the Utilities: the Saga Continues”.) The CPUC proposal for the PG&E restructuring would significantly delay PG&E payments to the

¹⁵¹ FERC “Order On Clarification And Rehearing”, issued December 19, 2001.
<http://www.ferc.gov/electric/bulkpower/el00-95-001-12-19-01.PDF>

generators even after PG&E emerges from bankruptcy. Although SCE now has large cash balances, the CPUC is still not approving complete payments of SCE debts for purchases from the generators. The total unpaid amount is greater than \$10 billion. California seems to link blocking of payments to California's inflated \$8.9 billion estimate of the refunds due from generators. This payment delays not only creates risks of non-payment, but also has created cash-flow problems for the relatively small electricity generators. Some of implications of this refusal have already been discussed in the section entitled "Generators Off Line".

Fourth, the State has continued to press FERC for aggressively large refunds, asserting that the generators had overcharged California and continued to overcharge. FERC initiated settlement hearings to reach an agreement on the appropriate amount of the refunds. However, attempts by FERC Chief Administrative Law Judge Curtis L. Wagner, Jr to bring the parties to a settlement were not successful. They were blocked by California's unwillingness to budge in its refund demands. On July 12, 2001, Judge Wagner issued a report and recommendation in which he made it clear that California's claims were far too large¹⁵²:

"That very large refunds are due is clear.... While the amount of such refunds is not \$8.9 billion as claimed by the State of California, they do amount to hundreds of millions of dollars, probably more than a billion dollars in an aggregate sum."

"The State of California has publicly made it clear that the refund amount claimed by the State of California is \$8.9 billion. It has not moved from that position and Governor Davis makes it publicly clear that it will not.... However, it is the opinion of the Chief Judge that the amount claimed by the State of California has not and cannot be substantiated."

Because California was never able to reach agreement with any other parties, the actual amount of refunds will be settled by evidentiary hearing, unless the parties are able to come to agreement

¹⁵² FERC. "Report And Recommendation Of Chief Judge And Certification Of Record". (Issued July 12, 2001)

before hand. The schedule contemplates a sequence of hearings scheduled March through July 2002. Absent settlement, the refund amounts will not be determined until after all hearings have been completed. The uncertainty about the outcomes of these hearings further increases the risk for market participants.

Policies Related to Energy Emergency Responses

That State took no leadership in mitigation of energy emergencies, including the rolling blackouts until after the last of the blackouts had occurred. After the last of the blackouts had occurred, the rules for managing blackouts were modified to reduce costs if blackouts were to continue. For example, large industrial users were allowed to enter contractual relationships in which they agreed, when requested during energy emergencies, to reduce their use of electricity by 20 percent from then current levels. In exchange, they were assured that they would be spared from rolling blackouts. However, as more and more electricity users became exempt from blackouts, the more those blackouts would be concentrated on the remaining users. By late spring, 2001, an estimated 50% of electricity use had been exempted from blackouts and therefore the remaining non-exempt users faced a doubled risk of being blacked out themselves. This plan had another drawback. For many companies, the easiest way of assuring they could reduce demand by 20% at short notice was to keep demand at least 20% above their minimum needs for electricity. Thus, there was an incentive on companies to avoid reducing demand by as much as they might otherwise to assure their ability to cut back from then current levels¹⁵³ when needed. Although this system did enhance the demand reductions during emergencies, it

¹⁵³ This incentive comes about because the cutback was to be measured from consumption levels in the few weeks before they were called upon to cut back. If the cut back was measured from consumption levels at some base time, say at the time the rule was passed, then there would not have been this perverse incentive.

probably increased the use of electricity in non-emergency times and thereby increased the probability of energy emergencies.

In addition, in a change from the practice during the early blackouts, in which the area being blacked out was given only a very short warning, a plan was developed to provide more advance warnings about forthcoming blackouts. This change was intended to allow emergency personnel to be positioned more effectively during rolling blackouts and to allow companies to make some plans to cope with anticipated blackouts. However, no blackouts occurred after the decision was made to provide the warnings and thus it is unclear how well the system would have worked.

These actions, for the most part, were useful, but other than the energy conservation and efficiency programs, did nothing fundamental to help solve the energy crisis.

Retail Electricity Pricing

Most needed to address the energy crisis (and the financial crisis) was for retail electricity prices to adjust to the changing wholesale prices. Increases in retail prices would have more sharply reduced electricity demand and therefore would have reduced wholesale prices. Nevertheless, that was the action most strongly opposed by the Governor. Instead even during the crisis period, the pervasive message from the Governor and the other State institutions was the demand for expanding wholesale electricity price controls as a companion to continued retail price controls.

However, after many months of refusing to approve retail electricity price increases, the CPUC accepted the idea that it could keep the retail base prices of electricity and could add

“surcharges” on to the retail rates to start bringing retail rates up toward the wholesale prices. On January 4 2000, the CPUC took the first small step, approving a 1-cent/kWh, 90-day surcharge on customer bills (equivalent to \$10/MWh), an amount far smaller than desirable for encouraging the needed electricity demand reductions, but a step. This surcharge would increase residential rates about 9%, small business customers, 7%, medium commercial customers, 12%, and large commercial and industrial customers 15%.

Using conventional estimates of the elasticity of demand¹⁵⁴ for electricity, the average retail price increase of 10% could be expected to motivate a roughly 1% - 2% reduction in demand over a short run, starting almost immediately. Although this demand reduction was smaller than desirable with the very tight market, even the 1% - 2% reduction in demand could have some impacts on the wholesale price. Using the previous assumption that a 1% change in supply or demand leads to a 10% change in wholesale price, such demand reduction could motivate a 10% - 20% reduction in wholesale price. On the other hand, if a 1% change in supply or demand leads to a 2% change in wholesale price; such demand reduction could motivate only a 2% - 4% reduction in wholesale price. Thus, although this surcharge was far too small to solve the financial crisis facing the utilities, it contributed somewhat to the demand reductions that were observed during that time.

Perhaps more importantly, the principle had been established that retail price increases could be a viable response to the energy crisis.

¹⁵⁴ The elasticity of demand is defined as the percentage reduction in demand motivated by a 1% increase in price. Here, and for other numerical examples, a short run elasticity of demand for electricity will be approximated as 0.1 - 0.2. Long run elasticities have typically been estimated to be as large as 1.0 and possibly larger.

Governor Davis seemed well aware that allowing retail prices to increase sufficiently would have been fundamental to addressing the energy problems. However, he still refused to allow that step. In one well-publicized February press conference, he stated¹⁵⁵: “Believe me, if I wanted to raise rates I could have solved this problem in 20 minutes. But I am not going to ask the ratepayers to accept a disproportionate burden.¹⁵⁶” And he did not raise the rates. At least until the State was threatened with budgetary chaos.

By early March, with the California DWR purchasing the electricity, the economic realities of the high wholesale price and low retail price were now falling most sharply on the State, not on the utilities. The state budget had been decimated. Political leaders began seeing the wisdom of increasing retail electricity prices to compensate the State treasury for the costs of its wholesale electricity purchases. Even Governor Davis grudgingly accepted retail price increases. On March 27, 2001, the CPUC voted to increase retail electricity rates by 3 cents/KWh for SCE and PG&E customers and to make permanent the 1 cent/KWh temporary surcharge. It was estimated at the time of its passage that this increase would be sufficient to allow revenues collected from the sale of electricity to cover the cost of DWR purchases of wholesale electricity but would do little or nothing to bring the utilities back to financial health.

Even then, Governor Davis worked to reduce the rate increase. During a live address to the people of California, on April 5 Gray Davis proposed an alternative to the CPUC increase, proposing an average residential increase of 2.4 cents/KWh for PG&E residential customers, 2.2

¹⁵⁵ Transcript of press conference, Governor Gray Davis, February 16, 2001.

¹⁵⁶ By the time he had made this statement, Governor Davis had already developed the plan for selling state revenue bonds to pay for State purchases of electricity and for requiring ratepayers to pay all of the interest and principal of these bonds. Under this plan, the ratepayers would be forced to accept the entire burden, completely contrary to the public statement he was making.

cents/KWh for SCE residential customers and between 2.6 and 3.0 cents/KWh for commercial/industrial customers.

Although the CPUC announced that the increase would be effective immediately, the promised tiered-rate proposal had yet to be designed. It was widely reported in the media that, although the actual charges may not appear on consumer bills right away, the customer billings would be implemented retroactively to the end of March. Thus, even before the price increase was implemented, the belief by individuals and companies that there would be a hefty price probably motivated as significant reduction in electricity consumption.

On May 15, the CPUC adopted the specific rate structure, which would appear on June bills.

The two retail rates together increased retail rates roughly 30% - 35%. Using the same estimates of elasticity of demand, these price increases could be expected to motivate short run demand reductions of 3% to 7%, reductions large enough to affect significantly the tight electricity markets.

As implemented, the rates adopted by the CPUC are highly tiered, with households that use low amounts of energy paying prices slightly lower than the cost of delivery services plus acquisition cost of electricity and those using larger amount of electricity paying almost twice the cost of that electricity for additional units purchased. Figure 35 illustrates¹⁵⁷ the rate structure for PG&E in December 2001. The line shows the marginal price of electricity at various levels of monthly

¹⁵⁷ These particular data are for a home in the San Francisco Bay area, not using electricity as its primary source of space heating. These price data are included in bills PG&E sends to its residential customers.

electricity consumption, ranging from zero electricity use through 2000 KWh per month. For reference, the average use of electricity per residential customer in California (548 KWh) is noted.

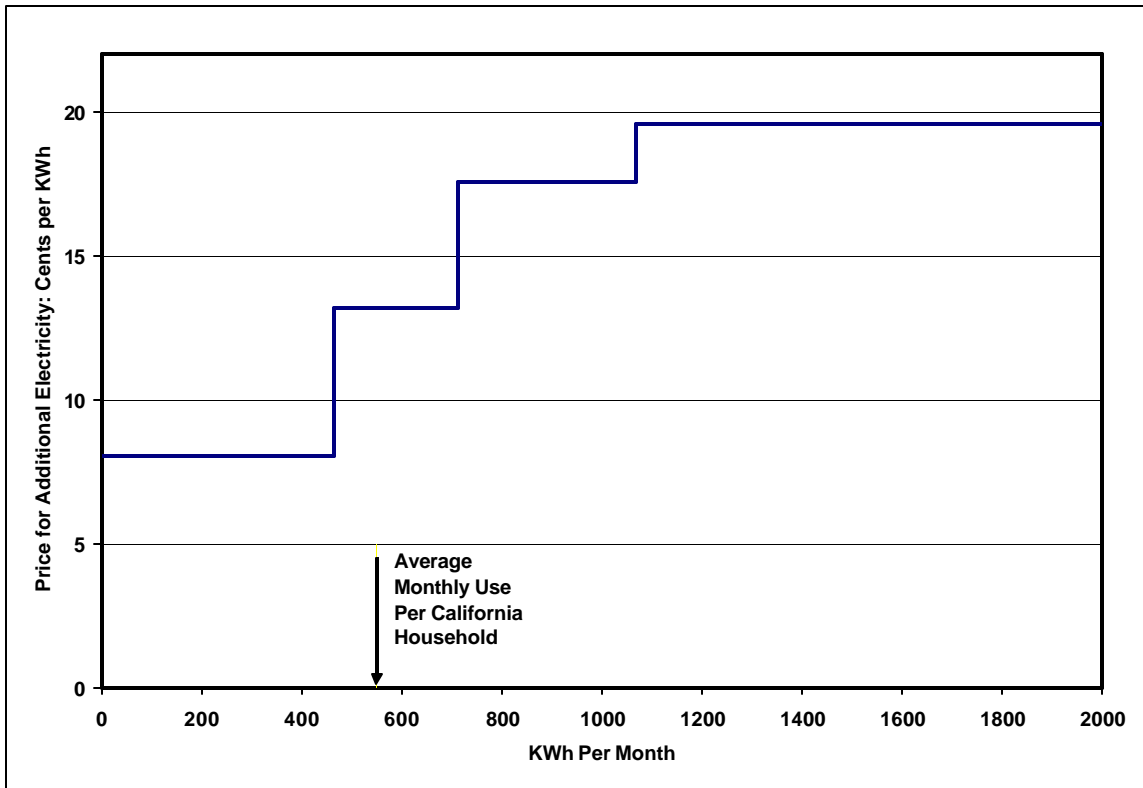


Figure 33 Electricity Prices for PG&E Residential Customers, December 2001

For those who use less than 130% of the “baseline” quantities per month (the winter baseline for the San Francisco Bay Area is 356.5 KWh), the customer pays 8.0 cents/KWh; for those that use more than 300% of the baseline, the marginal price rises to 19.5 cents/KWh.

These figures can be compared with the pre-restructuring price of about 9 cents/KWh, the current spot cost of wholesale electricity plus service fees (transmission, distribution, and public

purpose programs) totaling about 6 cents/KWh, or the cost of the DWR electricity purchases plus service fees, totaling about 13 cent/KWh. By any of these measures of cost, this rate structure greatly over-charges those residential customers that use a large amount of electricity relative to the baseline. The retail price for the greatest users of electricity (more than 300% of the baseline) is over twice as high as the 9 cents/KWh average price of retail electricity prior to restructuring. Thus, even though the electricity crisis is over, those customers that use over 300% of the baseline quantities of electricity pay twice the rate they faced before the crisis.

FERC Rule Making

Early in the challenge period, FERC started to examine carefully problems of wholesale electricity markets throughout the United States. On July 26, 2000, FERC ordered its staff “to conduct an investigation of electric bulk power markets so that it can determine whether markets are working efficiently and, if not, the causes of the problems.” The commission asked its staff to “investigate the markets, including volatile price fluctuations, and report their findings by November 1, 2000.” After San Diego Gas and Electric filed a complaint with FERC in August 2000, the commission directed staff to accelerate its analysis in California and the western region of United States.

Federal policy implemented through FERC was necessarily more limited than State policy could be, since FERC did not have jurisdiction over any retail market operations, electricity consumers, plant siting, or utility electricity purchases. It did have primary authority over wholesale markets, although it had allowed California institutions to take the lead in designing the

wholesale markets within the State. Those wholesale markets commanded most of the FERC attention.

In November 2000, FERC released the staff report and simultaneously issued a market order proposing remedies for California wholesale electric markets. Through that November Order proposing remedies and the subsequent December Order directing those remedies to be implemented, FERC had started the process of taking control of market design from California institutions and of providing that leadership itself. Governor Davis and other California political leaders strongly resisted that shift in control. The painful process of wresting control over wholesale markets from California officials and of California leaders fighting to retain control continued throughout the entire crisis.

FERC for the most part was pursuing a market approach, attempting to repair defects in the California wholesale markets rather than controlling prices. However, as an organization that operated for the most part as a judicial body, with operational procedures comparable to those in litigations, FERC decision-making, with one exception, was typically slow and laborious. Moreover, FERC decision-making depended not only on judicial rules but also on the beliefs of FERC commissioners. Because the composition and leadership of FERC changed during the process, that change in itself implied that FERC decisions were not necessarily consistent over time. Ultimately, FERC implemented temporary wholesale price controls, primarily in the form of bid caps, initially California-wide and then Western-region-wide controls, as the crisis was nearing its end.

November 1 and December 15, 2000 Orders

On November 1, 2000, FERC issued a market Order that proposed a set of remedies for California's wholesale electricity markets. The remedies were, for the most part, to take effect at the end of 2000. The Order provided a three-week period during which anyone could comment on the various proposals. FERC followed, on December 15, with an Order directing the remedies. Except for the more extensive discussion, the December 15 Order was very consistent with the November 1 Order.

In these Orders, FERC reiterated its earlier conclusion that the wholesale prices were not “just and reasonable” and identified problems of market design as fundamental to the problem¹⁵⁸:

“the existing market structure and market rules, in conjunction with an imbalance of supply and demand in California, have caused and, until remedied, will continue to have the potential to cause, unjust and unreasonable rates for short-term energy during certain time periods.”

FERC went on to propose measures designed to repair the defects in the wholesale markets and, for a limited time while the defects were being repaired, to keep prices lower than they would otherwise be. FERC had started the process of removing from California any formal leadership in wholesale electricity market design.

A first goal was to reduce the over-reliance in California on the spot markets for wholesale electricity.

¹⁵⁸ Language from the November 1 Order.

FERC eliminated the requirement that the investor-owned utilities buy and sell all power on the PX or CAISO. This change, in principle, permitted utilities to participate in bilateral markets and forward markets, not simply in spot markets. It allowed them to use the electricity they had generated without selling the electricity and buying it back. This was an important long-term change, but given the precarious financial situation of the utilities by that time, its short-term impact was probably limited to allowing the utilities to use directly the electricity they generated.

However, for this order to have any significance, it was necessary for CPUC to eliminate the requirements it had set on the utilities. FERC noted¹⁵⁹ that without the CPUC cooperation, this portion of the Order would be ineffectual:

“We cannot emphasize enough that the California Commission must act decisively and immediately to eliminate the requirement for the IOUs to buy the balance of their load from the PX. This is the most serious flaw in the market design created by AB1890 and the California Commission's implementing orders. In addition it is crucial that the California Commission move quickly to provide the IOUs with approval of their forward purchases. The specter of after-the-fact disallowance for transactions other than PX purchases has certainly chilled the decision making process and continues to subject California's ratepayers to the volatility of spot prices.”

In addition, FERC imposed strong incentives on utilities and generators to complete almost all scheduling of load and generation with CAISO ahead of time, rather than in real time transactions. These incentives were designed to move electricity transactions away from the real time market. FERC required all California market participants to pre-schedule all resources and loads with CAISO and imposed a large penalty on all real time energy transactions greater than 5 percent of the prescheduled amount.

¹⁵⁹ FERC “Order Directing Remedies For California Wholesale Electric Markets” Issued: December 15, 2000

CAISO's Replacement Reserve capacity market rules were modified so that a supplier bidding into this market would receive only the energy payment if it were called upon to deliver energy, not the capacity payment in addition. These modifications could be expected to make market scheduling more rational, the acquisition process more deliberate, and energy emergencies less frequent.

In addition to reducing the reliance on spot markets, these Orders rejected a central component of the Governor's policy framework from the challenge period. The FERC Orders decisively rejected the proposal that the PX be given authority to implement wholesale price caps and denied the request that CAISO continue its authority to manage price caps. However, in order to keep continuity, FERC ordered that CAISO implement a \$250 price cap on its purchases, without modifying the \$100 price cap it had imposed for replacement reserves, until the end of December. Thus, CAISO was precluded from further changing these price caps during that period without the express permission of FERC. Thus, after the end of December, the State would no longer have the authority to manage or modify any wholesale price controls.

However, the FERC substituted its own price mitigation measures to begin at the end of December. FERC ordered that all single-price auctions run by the CAISO or the PX be temporarily modified to a hybrid system, often described as a "soft price cap". Under this system, a single market clearing price would be used if that market clearing price were no greater than \$150/MWh. However, if the market did not clear at \$150/MWh or below, any accepted bid above \$150/MWh would be paid the bid price, but this bid price would not be used to set the

market-clearing price. Typically, suppliers bidding less than \$150/MWh would be paid an amount at or near \$150/MWh and those bidding above would be paid their actual bid.

This rule changed optimal bidding strategies for those times participants expected that the market would not clear at a price at or below \$150/MWh. Under these changed rules, it was no longer optimal for independent firms to bid at their marginal cost but rather it became profitable to guess the cut-off price and to bid a little below that price, as in any as-bid auction system. Thus such a “soft price cap” system leads to lower total cost of purchases for a fixed set of bids but motivates firms to increase sharply their bid prices. Thus, it is dubious whether the partial move to an "as bid" system would in fact have led to expenditure reductions. It could have increased total costs.

In addition, the PX and CAISO were required to report confidentially to FERC all bids in excess of \$150 and each seller was required to file bid price, electricity quantity, and marginal generation cost of each such transaction. The expressed intent was for FERC to monitor the market and to observe attempts to exercise market power. Those bidding above \$150/WHh would be asked to justify their bids and lack of justification could result in the supplier being forced to refund the higher price.

Such a requirement for bid justification could provide strong motivation if generators believed that price bids above costs would be detected and that the refunds would include a penalty in addition to the difference between price and marginal cost. However, if generators believed that bids well above costs were unlikely to be detected and that, if detected, the only penalty would

be a requirement to refund the difference, then this requirement would provide little or no motivation for limiting bids.

In addition to changes in the market rules, FERC required changes in the governance of the PX and CAISO. FERC rejected stakeholder boards and required that the boards of the PX and CAISO be replaced with independent non-stakeholder boards. FERC promised to give further guidance on the selection of these boards.

The State seemed to agree with the last of the requirements, subsequently passing its own legislation that would eliminate the stakeholder boards. However, in another test of state vs. Federal authority, the Governor pointed out to FERC that he had the power to make appointments within the State of California. The California legislation made it explicit that the Governor would appoint the CAISO Board of Governors.¹⁶⁰ He subsequently appointed a new board to govern CAISO, apparently without consulting FERC about its composition.

The Board of Governors consisted of Maria Contreras-Sweet (California Secretary of Business, Transportation and Housing), Tal Finney (Director of Policy, Governor's Office), Mike Florio (Attorney, The Utility Reform Network), Carl Guardino (President and CEO, Silicon Valley Manufacturing Group), Michael Kahn (Attorney; Chairman of Energy Oversight Board).

Although unquestionably each board member was highly talented, the board composition led

¹⁶⁰ This legislation is AB 5X, by Assembly member Fred Keeley (D-Boulder Creek). It replaces the existing governing board of the Independent System Operator (ISO), composed of 26 so-called "stakeholders," with a governing board composed of five members appointed by the Governor. Board members were required to be independent of any ISO market participant but could be members of the State Administration.

immediately to the appearance, if not the reality, that CAISO – the California *Independent* System Operator – would no longer be independent.

FERC had ordered that CAISO be governed by an “independent non-stakeholder board”. A California state agency was the largest buyer of electricity in the State and thus the State was clearly a market stakeholder. Two members of the new CAISO Board of Governors were members of the Davis Administration. One was chair of Governor Davis’ Energy Oversight Board. Thus a voting majority of the Board was clearly associated with the State government, in particular, with the Davis Administration. It would be difficult to characterize this as an “independent non-stakeholder board”.

However, other than the last issue of who had the authority to appoint the members to the PX and the CAISO boards, these Orders very clearly wrested control from the State and moved it to the Federal level. However, with members of the PX and CAISO boards appointed by the Governor, and with board members having authority to implement the FERC rules, this structure promised to prolong the ideological conflict.

CAISO Tariff Amendment No. 33

Shortly before CAISO’s authority to maintain price caps had expired, it requested FERC to allow a change of its purchase rules (tariff Amendment No. 33, Issued December 8, 2000). In what may have been its only very fast response on an important policy issue, FERC agreed immediately. CAISO replaced the cap on imbalance energy bids with a “soft price cap” system with the interim break point set at \$250/MWh (rather than the \$150 in the November 1 Order). Under this interim procedure, CAISO stopped rejecting bids priced above the then current

\$250/MWh price cap, and began evaluating those bids in merit order, from low price to high price. Bids in excess of the \$250 break point would not set the market-clearing price for imbalance energy, but rather would be paid as bid.

CAISO's reason for this change underscored the difficulties of the price cap system under which California had been operating¹⁶¹. CAISO noted that it had been forced to declare Stage 2 Emergencies for the previous four days, and saw no immediate relief. The change was designed to allow CAISO to compete for more needed electricity. Terry Winter, chief executive officer of CAISO explained,¹⁶² "I couldn't keep the system working if we didn't get relief." It is very likely that the new plan did accomplish the end of making more electricity available and reducing the severity of energy emergencies. It is also likely that the plan allowed wholesale prices to increase in California, by essentially eliminating the price cap in the real time market several weeks before FERC's order would have done so.

These were intended as interim plans, to remain in effect while FERC led the process of developing more comprehensive price mitigation plans and systematically improving market operations.

However, the FERC Orders did not stop the drumbeat of demands from the Governor and the CPUC that more rigid price controls be imposed on the wholesale markets. The pressure operated through press releases and press conferences, through communication by members of the California delegation in the US legislature, and through direct appeal to other decision

¹⁶¹ FERC Docket No. ER01-607-000, "Order Accepting Tariff Amendment On An Emergency Basis", (Issued December 8, 2000)

¹⁶² Nancy Vogel, *Los Angeles Times*, Nov. 7, 2000.

makers in Washington. Finally, on April 26, FERC did issue an Order that accepted wholesale price controls, or in FERC vocabulary "price mitigation".

April 26, 2001 FERC Price Mitigation Order

This Order established a prospective "mitigation and monitoring" plan for the California wholesale electric markets, scheduled to become effective May 29, 2001. The plan included several central elements, FERC described as intended to strike a balance between market-determined prices and controlled prices¹⁶³.

The plan included provisions designed to control the number of generating plants that would be offline at any time (See Figure 27), since by then the problem of plants offline was well recognized. It required that all planned outages by units with Participating Generator Agreements¹⁶⁴ (PGAs) with CAISO be coordinated with, and approved by, CAISO. Such a requirement would presumably make it easier to assure that any outages of generating units were for legitimate reasons, not simply to increase market prices. Perhaps more importantly, it would allow CAISO to develop a central body of information that would give early warning of tight markets.

The price mitigation plan moved a step back from the hybrid auctions of the November 1 and December 15 Orders and toward restoring single-price auctions. Rather than keeping the "soft cap", which was set at a fixed, somewhat arbitrary level, all price caps would be removed.

Replacing the "soft caps" would be "bid caps", limitations on the prices that given generation

¹⁶³ See www.rtowest.org/Doc/FERCOrder_April262001_EL00-95-012_CalISOMktMitigation.pdf

¹⁶⁴ A Participating Generator Agreement is a legal agreement between a generator and the CAISO that establishes "the terms and conditions on which the ISO and the Participating Generator will discharge their respective duties and responsibilities under the ISO Tariff". The agreement allows the Participating Generator to schedule energy and submit bids to CAISO through a Scheduling Coordinator.

units could bid. Each generation unit would be required to bid a price no higher than an administratively determined estimate of the marginal cost of operating that plant. The estimated marginal cost would be based on the unit's heat rate and emissions rate, the price of natural gas and of emissions credits, plus a \$2/MWh fee for operation and maintenance costs. These bids, limited by bid caps, would be processed in a single price auction to give the market-clearing price, a price each generator would receive, if its bid were below that level.

There was an opportunity for an exception to the bid caps. If a firm could establish that its cost was in fact above the calculated bid cap, that firm could submit a higher bid. However, that bid would not be used to determine the market clearing prices. In addition, these firms would be required to justify their costs or pay refunds. Similarly, resources located outside California could bid, but their bids would not be used in setting the market-clearing price during mitigated periods.

The bid caps would not always be imposed. Rather they would be imposed whenever any energy emergency had been declared. No caps would be imposed in the absence of an energy emergency, in the theory that competitive forces would be sufficient in those times.

However, this structure left open the possibility that the bid caps would limit prices during an emergency at levels lower than the market clearing prices in non-emergency situations. Whether this would occur, however, depended on whether the competitive forces would be sufficient during non-emergency times.

In addition to the bid cap requirement was a rule designed to stop generators from exercising market power by simply not bidding at all, rather than just bidding a high price. The plan imposed a “must offer” requirement, a requirement that all sellers with PGAs offer all their available power to the ISO in real time if it is available and not already scheduled to run. This rule would apply to all sellers with PGAs as well as non-public utility generators located in California that use any CAISO facilities. The requirement would not be imposed on hydroelectric plants.

The Order prohibited other bidding practices if they were seen as potentially allowing anti-competitive market manipulation. The Order prohibited any bids that vary with the output of a unit in a manner not related to the known cost characteristics of the unit. This would exclude the types of bids described in a previous chapter in which the last MW of electricity is bid at a very high price relative to most of the electricity from the same unit. Similarly, a single unit in a portfolio could not be bid at a very high level compared to the remainder of the portfolio unless there was a clear performance or input cost basis. Bids that appear to change only as electricity demand goes up, independent of the operations of the generating unit, would be outlawed.

Finally, the Order made it clear that demand response should be part of the market response. Load- serving entities were required to establish demand response mechanisms in which they identified the price at which load should be curtailed.

This mitigation plan was conditioned on CAISO and the three investor-owned utilities filing a regional transmission organization (RTO) proposal by June 1, 2001. This requirement was meant to develop further regional responses to regional problems. However, otherwise, the plan was a California specific plan.

FERC June 19 Order Broadening the Scope of Price Mitigation

Ultimately, after comments were received, a more comprehensive plan was adopted on June 19, extending the price control regime to all of the western states and to all times, including times in which there was no energy emergency. The Order primarily extended the scope of the April 6 Order. It was scheduled to remain in effect until September 30, 2002.

As opposed to the April 6 Order, the June 19 Order set rules to be implemented in a common manner¹⁶⁵ across all of the markets in the Western region. As in the April 6 Order, whenever there is an energy emergency, it forces the generators to offer bids at some estimated marginal cost¹⁶⁶. In addition, however, in non-emergency times the mitigation order sets price controls based on the market-clearing price in the last Stage 1 emergency. Moreover, it further attempts to eliminate California's reliance on spot markets.

In addition to the "bid cap" system of the April 6 Order, the June 19 Order imposes price caps on bilateral sales. These bilateral transactions would be based on whatever prices are negotiated

¹⁶⁵ In price control times a 10% price premium was allowed for sales to California, ostensibly to compensate for market risk. However this premium seems larger than needed to compensate for market risk and may have given California a significant advantage over other states in obtaining limited supplies of electricity during periods of energy emergencies.

¹⁶⁶ FERC: "Order On Rehearing Of Monitoring And Mitigation Plan For The California Wholesale Electric Markets, Establishing West-Wide Mitigation, And Establishing Settlement Conference" (Issued June 19, 2001)

between the buyer and the seller, but the market-clearing price in the single price auction would set an upper limit on the allowable prices for these transactions.

Different bid caps were applied to generators and marketers. During energy emergencies, the bid by a generator could be no higher than an administratively derived estimate of marginal cost of electricity from that generator. The estimate of marginal cost would be equal to the marginal cost of the gas used (with that gas purchased at that moment on a spot market for gas) plus variable operations and maintenance costs.

The costs of emissions credits or other emissions costs and start-up fuel costs would not be included in setting the market-clearing price. Rather these costs would be directly billed to CAISO. Such a system would no longer assure that the lowest cost units would have their bids accepted. In particular, emissions and start-up costs would not count in determining which plants would be dispatched. Unfortunately, this would create a bias toward selecting the plants with less good environmental performance if their costs otherwise were low.

In addition, generators would be given an opportunity to justify costs higher than the administratively determined bid caps, but these higher costs would not be used in setting the market-clearing price.

Marketers, as opposed to generators, would not be allowed to bid higher than the market-clearing price. That is, they must act as a price taker.

Simple price caps would be imposed for spot market sales in times other than energy emergencies. The price for spot market sales could be no greater than 85% of the highest CAISO hourly market clearing price established while the last Stage 1 emergency (not Stage 2 or 3) was in effect. When the next Stage 1 emergency is declared, the new price cap would be set for the subsequent time. That could be higher than or lower than the one that had been set before.

This FERC Order currently sets all price mitigation rules throughout the Western region. As such, it sharply changed the California system from one that uses blunt price caps in California markets, markets viewed in isolation from the rest of the interconnected region, to one that uses caps on bids tailored to generation costs and that fully reflects the interconnected nature of the Western region. Moreover, its lifetime is limited to one additional year.

Some Impacts of the Current FERC Price Mitigation Rules

It is difficult to access definitively the impacts of the FERC April 26 and June 19 Orders. Just before they became into effect, wholesale prices fell to below the maximum prices allowed under these mitigation rules and soon fell to well below the maximum prices. Although it is conceivable that FERC price control rules caused a sharp decline in prices, price controls typically do not cause prices to fall to well below the controlled levels. Therefore, it is unlikely that either the bid caps or the non-emergency price caps can account for the observed reduction in prices.

However, it is possible that the rule prohibiting anticompetitive bidding practices changed the pricing dynamics in the market. However, the impact of this rule could not be assessed without

careful evaluation of the confidential CAISO data on the nature of bids before and after this change. These confidential data, if ever made available to researchers, might provide some information about the significance of that rule.

The price mitigation rules do have one troubling feature. The non-energy-emergency price caps for the entire West are fundamentally controlled by a California organization, the CAISO. This price cap is set equal to 85% of the highest CAISO hourly market clearing price established while the last Stage 1 emergency was in effect, but only if that emergency was in effect for a full hour. However, the CAISO itself declares energy emergencies and in some circumstances can control whether the Stage 1 emergency lasts for more than one full hour, and thus resets the level of the price cap or is terminated in less than one hour, and thus does not reset the level. While there has been no evidence this power has been misused, the potential is troubling.

California Policy during the Crises: A Critique

The sad history of a challenge that grew into a full-blown crisis need not have occurred. At every step of the way, there were alternatives that the State could have taken to address the financial crisis, the electricity crisis, or both. However, the steps would have taken leadership at the gubernatorial level.

The first alternative that could have been taken, but was not, would have been to allow the utilities in spring 2000 to start purchasing electricity on medium-term or long-term contracts. This action could have been taken by the CPUC, since by that time, the purpose being served by the restrictions were no longer valid. Presumably, the Governor, having appointed the President

of the CPUC, could have worked with her to accomplish that action if he had chosen.

Alternatively, if the CPUC had been unwilling to cooperate with the Governor (an unlikely possibility) the Governor could have taken action by exercising his broad emergency powers. Neither the Governor nor the CPUC ever took this first crucial step.

This single step would have had a large direct impact on avoiding the financial crisis. Since the financial crisis was exacerbating the electricity crisis, that step would have also reduced the severity of the electricity crisis. If the utilities had entered into long-term contracts for a large share of their electricity supplies, then they would have remained financially viable throughout the time. If the utilities had remained financially viable, the generators of electricity could have remained confident of being paid for electricity sold. Without uncertainty about whether they would be paid, their bid prices would have been lower. Since they would have been paid, suppliers would not have been forced to shut down plants because they could not pay for generating electricity. Although wholesale prices would have risen, it is very doubtful whether they would have risen to as high levels, had there not been the financial crisis.

With the failure to authorize long or medium-term contracts, the Governor and the CPUC kept the investor-owned utilities facing a high risk. Ironically, this solution initially denied to the utilities, was an action taken by the State at the height of the crisis. Thus rather than the utilities entering into long-term contracts at relatively low prices, the State entered into long-term contracts later, at much higher prices.

Second, the political leadership failed to allow the retail price to move with the wholesale price. This failure was fundamental to the financial crisis and as discussed above, was a fundamental reason the energy crisis remained as severe as it did.

Although the leadership failure must rest squarely with the Governor, the failure was fundamentally bipartisan. Neither the Republicans nor the Democrats in the California Legislature were as a whole demanding increases in the retail prices. Some isolated exceptions were pointing out the importance of retail price increases¹⁶⁷. Nevertheless, legislators of both parties, fearing adverse voter reaction to any dramatic increases in retail prices, acquiesced to the Governor's position, a position seen by Democratic legislative leaders as the “bookends” of Governor Davis’ policies. At least a high cost to the State was less visible to voters than would be the high cost of increased utility bills, if retail prices had been allowed to increase. In addition, if the State were able to issue bonds to cover the cumulative State shortfalls, the high cost would be seen by ratepayers over the long distant future and would not be as obvious during the next election. The political calculus seemed very strong and neither party took leadership by fighting to bring about retail price increases until the State budget had been decimated.

Given that the actions actually undertaken by the Governor were primarily politically expedient actions and those that he avoided were more difficult, politically riskier actions, the question arises whether the Governor understood the seriousness of the problem that California was facing.

¹⁶⁷ For example, early in the crisis, Representative Joseph Simitian, a Democrat, was calling for retail rate increases, at least in the marginal prices of electricity.

If there was any doubt that Governor Davis was aware the State faced a serious challenge, the report¹⁶⁸ he received on August 2, 2000 from two of his key energy appointees -- Michael Kahn, Chairman of the Electricity Oversight Board (EOB) and Loretta Lynch, President of the CPUC -- confirms that he had been fully informed early in the challenge period and that he had been advised by people whom he trusted that strong actions were needed. However, even with this advice, he soon afterwards developed a policy framework relying exclusively on price controls. He sent letters to the CPUC, the PX, CAISO, and the EOB strongly urging them to take actions following the strategy he had developed¹⁶⁹. In addition, Governor Davis did his part to communicate his perspectives on the energy situation externally, as was discussed in a previous section. Thus, it is clear that Governor Davis was very personally involved from the early days of the challenge period, that he felt comfortable exerting his power as Governor to direct these California agencies, and that it was he determining the central policy choices taken by the California government.

Throughout the entire emergence, growth, peaking, and remission of the California electricity crisis there was a frequent stream of advice to the State from FERC. This advice came in the form of FERC responses to California requests, of orders initiated by FERC in response to complaints filed by participants in the California markets, of FERC studies and other reports, and of direct communication by FERC members and staff with Governor Davis and with other California state or private agencies. This advice made it clear that FERC was willing to work in a cooperative manner with the state of California, but that California had much to do in order

¹⁶⁸ Report discussed more fully in previous section "State Policy Responses during the Challenge Period"

¹⁶⁹ More complete discussion appears in previous section "State Policy Responses during the Challenge Period"

to correct its internal policies. Although much of this advice may not have been welcome by Governor Davis, the information was brought forcefully to his attention.

In addition, advice to Governor Davis was not limited to advice from Washington, but was forcefully communicated both personally and publicly. One of the more public communications was issued in late in January 2001 by an ad-hoc group of energy and public policy experts¹⁷⁰ convened through University of California, Berkeley. This group, including university faculty, former public officials, and energy consultants, issued a call to action, entitled “Manifesto On The California Electricity Crisis”, outlining a set of public policy solutions designed to help California solve the energy crisis¹⁷¹.

The Manifesto made it clear that the financial crisis:

“must be dealt with immediately before it gets further out of hand. If the credit worthiness of the investor-owned utilities can be restored, California can both solve the

¹⁷⁰ Signed by: Sanford Berg (Director, Public Utility Research Center; University of Florida); Tom Campbell (Professor, Stanford Law School); John Chandley (Principal, Law & Economics Consulting Group); Carl Danner (Former Chief of Staff to the President of the CPUC); Harold Demsetz (Professor Emeritus, Economics, UCLA); Roger Farmer (Professor, Economics, UCLA); Lee Friedman (Professor Of Public Policy, UC Berkeley); Richard Gilbert (Professor, Economics, UC Berkeley); William Hogan (Professor, John F. Kennedy School of Government, Harvard University); Paul Joskow (Professor, Economics and Management, Director, MIT Center for Energy and Environmental Policy Research, MIT); Paul Kleindorfer (Professor of Operations & Information Management, Professor of Public Policy & Management, The Wharton School, University of Pennsylvania); Amartya Lahiri (Assistant Professor, Economics, UCLA); Robert Lawrence (Professor, John F. Kennedy School of Government, Harvard University); Tracy Lewis (Professor, Economics, University of Florida); Chris Marnay (Staff Scientist, Lawrence Berkeley Nat'l Laboratory); Daniel McFadden (Nobel Laureate, Professor of Economics, UC Berkeley); Phil McLeod (Principal, Law & Economics Consulting Group); Robert Michaels (Professor of Economics, California State University, Fullerton); Lee Ohanian (Associate Professor of Economics, UCLA); Shmuel Oren (Professor of Industrial Engineering and Operations Research, UC Berkeley); Joseph Ostroy (Professor of Economics, UCLA); Larry Ruff (Consultant); Richard Rumelt (Professor of Business and Society, UCLA); Pablo Spiller (Professor of Business, UC Berkeley); Robert Solow (Nobel Laureate, Professor of Economics, MIT); James Sweeney (Professor of Management Science and Engineering, Stanford University); David Teece (Professor, Director, Institute of Management, Innovation & Organization, Haas School of Business, UC Berkeley); Phillip Verleger (PK Verleger LLC); Mitch Wilk (Former President and Commissioner CPUC); Oliver Williamson (Professor, Haas School of Business, UC Berkeley); Janet Yellen (Professor, Haas School of Business, UC Berkeley)

¹⁷¹ The complete document is available at http://www.haas.berkeley.edu/news/california_electricity_crisis.html.

immediate supply shortage problems resulting from credit risks and then look to proper long-term solutions to its electricity problems.”

The Manifesto urged four key elements to these long-term solutions:

“freedom to engage in long-term contracts, retail price flexibility, competition at both the wholesale and retail levels, and more effective cooperation between federal and state regulators to fix a variety of market imperfections and resulting market performance problems.”

The Manifesto stressed the importance of avoiding actions that would make matters worse:

“In particular, a State takeover of the business would make matters worse, as would turning the State into a permanent electricity purchasing authority. It would also be unfortunate if the State were itself to commit to long-term contracts for a large portion of California's electricity needs. The State's credentials as an astute player in the electricity market aren't impressive, and there is no reason to expect major improvement in the future. Accordingly, emergency state contracts should be avoided if at all possible. Nor would the State buying up existing generation assets add to supply. In the end, new power plants are needed, and the State should focus on creating a supportive environment for necessary new private investment. State ownership is not a solution at all – merely a guarantee that the taxpayers will be saddled with additional obligations for decades to come.”

The advice from within California was clear, forceful, and well publicized. It could not have been missed. Unfortunately, Governor Davis chose to reject this advice, as he continued to reject the advice of Federal authorities, doing almost exactly the opposite on every count. California suffered the consequences of his decision-making.

Chapter 5: From Crisis to Blight

Although the electricity crisis itself was a short-term event, the policy actions – or inaction – during the challenge period and the crisis have left a continuing harmful legacy, a legacy that threatens to remain for years or even decades to come. This legacy can be seen in terms of the fundamental financial problems with which investor-owned utilities are struggling, in terms of deep financial obligations incurred by the State in purchasing electricity, obligations the State intends to transfer to purchasers of electricity within the service areas of the two investor owned utilities, and in terms of financial obligations ratepayers will be forced to meet if they wish to remain in California.

Pacific Gas and Electric remains in bankruptcy court. Its most recently proposed restructuring plan has been opposed by the State of California but is under consideration by the Court and, as such provides the possibility that PG&E will ultimately return to financial health. Southern California Edison has agreed with the CPUC on a retail price structure that promises but does not guarantee that SCE will return to financial health, although not quickly. Although the peak of the crisis has passed for these two firms, they face a continued high risk.

The state has been purchasing electricity on behalf of the investor-owned utilities since January and has accumulated a short-term net financial shortfall exceeding \$6 billion as a result. In addition, the State has signed long-term contracts to purchase electricity, with contractual commitments to pay prices around twice as high as the expected future market prices. These contracts together represent long-term financial obligations to pay more than \$40 billion in order to purchase electricity that is likely to be worth around \$20 billion. The difference between the

contractual price and the value of the electricity represents an expected future net shortfall of roughly \$20 billion. Thus, because of its actions, the State of California has accumulated a combination of short-term and long-term financial losses exceeding \$25 billion. These near term and long term financial obligations are the basis of the blight the State now faces.

However, who will pay these financial losses is still an issue. If these losses are added to the future retail prices of electricity in the service areas of the investor-owned utilities, retail electricity prices in those areas will be elevated for many years above prices in surrounding states or prices in parts of California served by the municipal utilities (Los Angeles and Sacramento are the two major locations.) If these losses are paid by California taxpayers, taxes must be increased in California or State-supported public services must be diminished. Either allocation of the financial obligations would be damaging to the people of California.

The legislature and the Governor have made their intentions clear that these financial losses must be paid, not broadly by the California taxpayers, but by the families and companies that will remain as or will become customers of the investor-owned utilities. These financial obligations were incurred by the State “on behalf of” those families and companies that were customers of the investor-owned utilities during the crisis. A large majority of these families and companies can be expected to remain as customers of the investor-owned utilities during the next decade or so. Thus, imposing the financial obligations on the future customer of the investor-owned utilities would result in a rough correspondence between those who would be forced to pay the costs and those families and companies on whose behalf the state incurred the obligations.

However, this allocation of the costs will not lead to an anywhere near perfect correspondence between those who would be forced to pay the costs and those families and companies on whose behalf the state incurred the obligations. Families and businesses moving into the service areas of PG&E and SCE would be required to pay costs of these past mistakes. Those moving out of the service areas, either to other parts of California or away from California will avoid paying the costs¹⁷². This allocation of costs thus embodies incentives for families and businesses to move out of areas served by the investor-owned utilities to other states or to areas served by the municipal utilities. In addition, it penalizes families moving into the service areas of investor-owned utilities.

Another perspective, one not adopted by the Governor or the legislature is that the financial obligations resulted not from the mistakes of the electricity ratepayers, either those purchasing electricity from the investor-owned-utilities during the crisis or those that may be located in the service areas of the investor-owned utilities in the future. Rather they resulted from the decisions made by the Governor, the CPUC, and the legislature prior to and during the crisis. The Governor and legislators were elected by the voters; the CPUC members were appointed by governors. It was the entire electorate, or at least the majority voters of the electorate, who had empowered the Governor and the Legislature. Thus, the alternative perspective is that these costs should be distributed broadly among the California voters, and that these financial responsibilities should be paid over a period of years through the State Treasury. However, to date the Governor and the legislature have definitely not adopted this perspective. Moreover, it is unlikely that the voters who purchase electricity from the municipal utilities would welcome a

¹⁷² To some extent this will be mitigated. The future obligation may reduce the value of real estate in the service areas of the investor-owned utilities decreasing the price of real estate and imposing costs on those leaving the area. But one cannot expect this capitalization process to be anywhere nearly perfect.

solution involving their contribution to paying for electricity they did not use. This solution would not embody the same incentives for families and businesses to move out of the service areas of the investor-owned utilities.

Which groups should or will ultimately pay the costs of these State obligations is a long-term issue, one that need not be fully resolved during the next year. Currently the State has incurred the obligations and is taking steps to delay payment of the short-term obligations and steps to assure that the financial obligations are ultimately paid by future customers of the investor-owned utilities.

In the short-run, perhaps California has no choice but to defer the payments. Because of the economic slowdown, California is now facing a State budgetary deficit exceeding \$10 billion, not counting any financial shortfalls from electricity purchases. Unless the state can find a way of recovering the electricity-related shortfalls from the retail electricity consumers, or can find a way to defer payment for years, the State budgetary deficit would increase sharply, to levels unlikely to be untenable. Thus, the State has little choice but to assure that the financial shortfalls from electricity purchases will not become short-term obligations for the State Treasury.

The California Legislature has authorized the state to defer payments of the shortfall and to shift obligations to ratepayers in the service areas of the investor-owned utilities. First, the State has authorized the issuance of \$12.5 billion of revenue bonds. These revenue bonds would be financial obligations, not of the State, but of retail electricity purchasers within the PG&E,

SDG&E, and SCE service areas¹⁷³. The retail electricity purchasers in California would be obligated to pay back the principal and interest on those bonds through increased retail prices of electricity. In addition, the State has requested the CPUC to provide long-term guarantees that the retail electricity price will be kept high enough to assure that ratepayers will pay the entire cost of the long-term electricity contracts plus the costs of repaying any revenue bonds the State is able to market. However, to date, the CPUC has been unwilling to make such a commitment, citing very legitimate concerns that the various obligations made by the State “on behalf of” electricity purchasers could result in unreasonably high retail prices over many years.

Absent the guarantee the State plan to sell revenue bonds was in limbo. The long-term electricity purchase contracts include clauses that obligate the State to pay for that electricity prior to all bonds, notes or other indebtedness. Therefore, if the State were to issue revenue bonds, the payment of their interest and principal would be subordinated to payments for the long-term contracts. This subordination would not create particular risks if the CPUC guaranteed that the retail electricity prices would always be kept high enough to cover adequately both obligations. However until the CPUC agreed to the guarantee, it was highly unlikely that the bonds could have been issued as investment-grade instruments.

The State had financed its electricity purchases using a short-term bridge loan, anticipating that it would be able to market long-term bonds. However, because the bonds have not yet been sold, the bridge loan has now rolled over to become a medium term loan, at a higher interest rate. It remains an obligation of the State of California. Now that the CPUC has agreed to keep retail

¹⁷³ Under current plans these bonds would not be obligations of anyone purchasing electricity within the service areas of the municipal utilities because electricity was not purchased on behalf of these consumers.

rates high enough to assure payment of the long-term contractual commitments and the bond repayments, the state should be able to market the bonds as investment grade instruments and can repay the medium-term loans.

These continuing financial ramifications of the dual crisis are major components of the blight that threatens California, but they do not encompass all long-term adverse consequences of the State's policy choices.

One of the important provisions of AB 1890 was direct access by electricity consumers to wholesalers, generators of electricity, or other electricity aggregators so consumers would have the ability to bypass utilities. Although the option of going directly to generators was unlikely to be taken, at least at first, by residential consumers, the option could be important for commercial or industrial users. The option promised to create legitimate retail competition that, over the course of years, could be expected to reduce retail markups and could be expected to increase the range of electricity supply services available to all consumers.

But the California legislature has now voted to repeal all provisions allowing direct access: companies and individuals are now precluded under State regulation from entering contracts to purchase electricity, except from their local utilities, utilities that are obligated to pass revenues on to the State to cover the State's financial obligations. The legislation repeals direct access during the time that the State continues to purchase electricity on behalf of utilities. The purchase contracts extend for the next twenty years and the legislative intent seems to be that

direct access would be abolished during that entire time. Thus, unless the current legislation is changed, meaningful retail competition will not be a reality for a very long time in California.

Although elimination of retail competition is a restrictive step backward, the State's financial obligations provide a strong motivation for such a step, since the Governor and legislature have decided pay for the financial obligations of purchasing electricity through increases in the retail electricity prices to be paid by future customers of the investor-owned utilities. That allocation of costs provides strong incentives for customers, particularly large customers to stop purchasing electricity from these utilities. The easiest alternative for most would be to bypass the utilities, thereby avoiding payment of some portion of the State-incurred financial obligations¹⁷⁴.

Since the total amount of the obligations is fixed, the more customers are able to avoid paying a share of these obligations, the greater will be the remaining share to be paid by the rest of the customers. Such a restriction therefore helps to assure that the State's financial obligations for electricity purchases will be borne broadly within the service areas of the investor-owned utilities.

In addition, California has created a State Power Authority that would develop and operate new electric generation plants, selling State generated electricity in competition with private sector generators. This agency has the potential for moving California even further down the path to becoming a public power state and pressuring consumers to purchase the State-generated electricity in preference to possibly lower cost electricity generated by private sector firms.

¹⁷⁴ For most large firms the other two alternatives – move to areas of California that will not face these high prices or move out of California – are more difficult and may not be economically viable for some.

Collectively, these long term consequences of the State actions threaten to leave California with more severe versions of the problems that motivated restructuring in the first place – high retail prices, no consumer choice, and pervasive government control in electricity supply. This, then, is the blight toward which California is being led. The long-term blight is the focus of this chapter.

Long Term Electricity Purchase Contracts

At the height of electricity crisis, Governor Davis announced that the State would not limit its wholesale electricity purchases to the quantities needed during the crisis period but rather would enter long-term contracts to buy electricity over the next two decades. The State subsequently requested bids to sell large quantities of electricity to California through long-term contracts. This was the first of several policy actions under which State would start becoming a long-term direct participant in the electricity markets, substituting State direct control for private sector control. Ironically, entering long-term contracts was one of the actions proposed by the utilities but precluded under State regulations.

As had been pointed out in the “Manifesto on the California Electricity Crisis”, during the height of the crisis was not the time to lock the state into long-term contracts. Long-term contracts, negotiated by anyone, including the utilities, could have been expected to result in many years of high electricity prices. Yet the Governor chose a time shortly after the peak wholesale prices to

start negotiating the long-term contracts. Rather than the State entering long-term contracts at that time, several alternatives were available.

First, the State could have waited until the crisis had subsided and negotiated long-term contracts only after spot prices had fallen significantly. This option would have left the State vulnerable to even higher wholesale prices during the crisis and to even larger budgetary deficits. In hindsight it would have avoided many years of elevated wholesale prices, although at the time the State entered the contracts it could not have known with certainty whether spot prices would increase or decrease.

Alternatively, the State could have encouraged the investor-owned utilities to negotiate medium-term or long-term contracts appropriate for their needs. This option would have left the long-term control of these purchases with the private sector, not with the State. However, once the utilities were not creditworthy, sellers would have been unwilling to enter such contracts or, at best, would have required very large risk premiums. In order to counter that problem, the State could have provided guarantees to the sellers that the State would provide a guarantee to those obligations. In that way, the State could have reduced the risk without taking on the purchase obligation itself.

The State could have waited until the crisis had subsided and allowed the utilities, once they were again creditworthy, to themselves negotiate medium-term and long-term contracts. This solution, however, depended upon the State allowing increased retail electricity rates so that the utilities could have become creditworthy within a reasonable time. However, during early 2001,

the Governor was still opposing any retail price increases beyond the \$10/MWh temporary surcharge. Thus, given the Governor's opposition to retail price increases, this option was not realistic, although the State could have still guaranteed payment of the financial obligations under the contracts and thus could have facilitated private sector contracting.

In short, at the peak of the crisis there were no good alternatives for California to assure lower wholesale prices. The time for the State to sign long-term contracts or to let the utilities sign those contracts was gone by the end of the year 2000.

However, Governor Davis continued on the path of establishing the State as the direct buyer of electricity, rather than following the other alternatives. He chose to do so at the peak of the electricity crisis. He authorized a team to negotiate long-term contracts for the State to buy electricity and the team did so.

During the negotiations, both the generators and the State were well aware that there were many generating units under construction. Therefore, the Governor could rationally expect that the negotiated long-term contractual prices would be well below the then current spot prices. This expectation made it possible for Governor Davis to assure the voters that, although the contract negotiations and terms would be confidential, the contracts would specify electricity prices well below the spot prices they were hearing about daily. In fact, the negotiated prices are lower than the then current spot prices but much higher than the wholesale prices that could reasonably be expected during the life of these contracts.

Figure 34 shows the total MW under these contracts for each month up to the year 2011. One contract continues beyond this point, to the year 2021, providing 1000 MW of electricity. These long-term contracts obligate the State to purchase roughly 8000 MW over the peak usage times each month (typically 16 hours per day, 6 days per week), for each year between 2004 and 2010, about 20% of the total generating capacity in California.

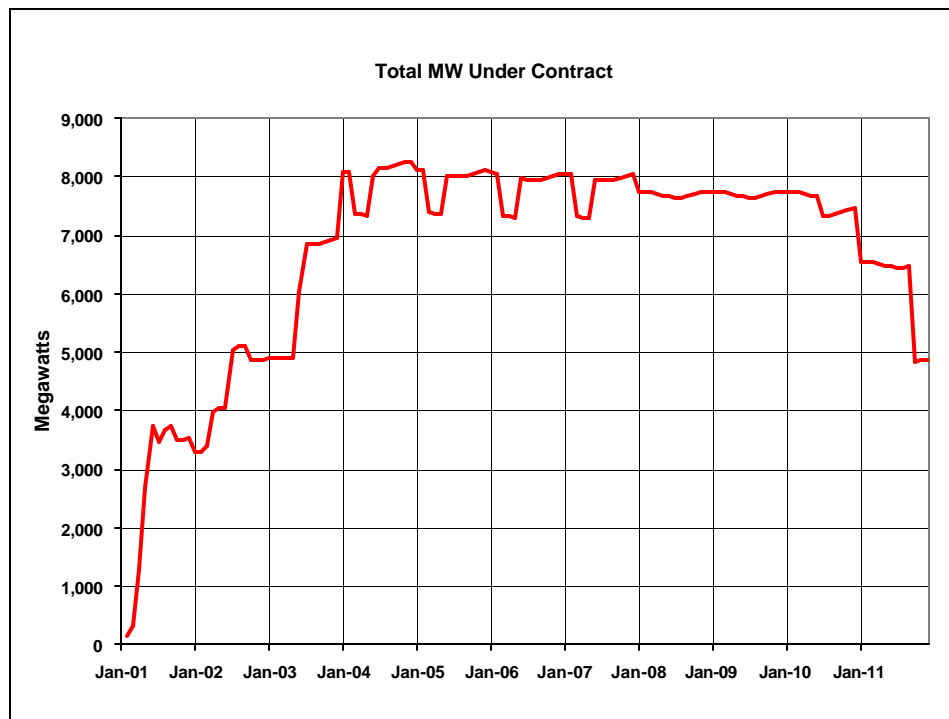


Figure 34 Total MW Under Long Term State Contracts

Some of the contracts specify the source of the electricity. In each such case, the source is electricity from California plants that already had been under construction before the challenge period or crisis had developed.

The total contract quantity does not reach its peak until January 2004. Fully half of the contracts do not promise to deliver electricity until January of 2002, seven months after the end of the crisis. And some do not begin delivering electricity until January 2004. Thus, the Governor's justification for the contracts – that they were being used to solve the crisis – seems to be not consistent with the timing of several contracts. Since observers at that time generally believed that the biggest difficulty would be during the summer of 2001 and that California would be past the crisis by the fall of 2002, long-term contracts that do not begin until January 2004 are not consistent with the goals announced by the Governor.

These contracts are consistent with California moving along the path to becoming a public power state, with fundamental control of electricity supply resting with the state government, rather than with the private sector. Thus, the timing of these contracts suggests that part of the purpose of entering these contracts may have been to help transform California into a public power state.

It would be easier to justify the contracts if the contractual prices were low. But they are not.

Figure 37 graphs the contractual prices under these contracts to the year 2011. For 2001 and 2002, the price varies on a month-to-month basis but averages over \$90/MWh¹⁷⁵. During 2003, the prices decline from an initial \$90/MWh to \$75/MWh. The price from the year 2004 through the end of the contracts averages slightly above \$70/MWh.

¹⁷⁵ These prices include not simply the price stated in the contract but also the capacity payments obligated under these contracts.



These prices are significantly higher than the expected market clearing prices for electricity, once the new generating plants come on line. Figure 37 illustrates an estimated range of average electricity prices that could be expected to characterize the market, once new electric generating capacity comes online, under the assumption that delivered natural gas prices range¹⁷⁶ between \$3/mcf and \$5/mcf. These natural gas prices would result in wholesale electricity prices ranging between about \$30/MWh and \$45/MWh. While these are simply predictions about an expected range, they would have been very reasonable projections at the time the long-term contracts were being negotiated. These predictions suggest that the contracts negotiated by the State will require California to pay between \$25/MWh and a \$40/MWh higher than the market prices that

¹⁷⁶ This calculation assumes new generating plants have a heat rate of 8.6 MMBtu/MWh plus a fixed cost of \$3 per MWh.

could have been projected at the time the contracts were negotiated. This additional cost applies to roughly 20% of California's electricity supply during the next ten years and 10% over the subsequent ten years.

In addition to the high contractual prices are more subtle problems of delivery location and risk bearing provisions of the contracts. Each contract includes a firm guarantee that the State will purchase the contractual quantities. For the most part, they are take or pay contracts in which the State guarantees to pay for the contractual quantities whether or not the State actually takes the quantities. The risk bearing issues were examined by California State Auditor Elaine Howle, who, on December 20, 2001 reported that the contracts did not include adequate protection from price spikes and outages. Most of the contracts provide little or no penalties to suppliers if they fail to deliver the contractual quantities.

Some defenders of the contracts have argued that the prices in the long-term contracts should not be criticized without taking into account the short-term contracts that were tied to the long-term contracts. The assertion is that the State agreed on prices higher than fair-market prices for the long-term contracts in exchange for receiving electricity during the spring and summer of 2001 at a price lower than the market price.

Sempra Energy Resources is one of the sellers cited as agreeing to contracts that would exchange future costs in place of costs during 2001. In a November 5 article in *Utility Spotlight*, Sempra Energy Resources, CEO Stephen Baum was quoted as saying: "To complete the long-term deal and to help stabilize prices during the state's energy crisis, (we) sold this summer's power to

California at a discount-to-market basis, creating a loss in the second and third quarters”

Sempra, in fact did contract to sell California 250 MW of power for peak periods in the four months from June 2001 through September 2001, at \$80/MWh. This sale occurred at a time when futures prices for electricity during the summer of 2001 were around \$400/MWh. Thus, for Sempra, it may be true that the State agreed on prices higher than fair-market prices for the long-term contracts in exchange for receiving electricity during the spring and summer of 2001 at a price lower than the market price. However, in the same contract, Sempra agreed to sell California electricity for the six-month interval, April 2002 through September 2002 at high prices. The contract committed California to buy 300 MW of power during peak periods in those six months at a price of \$160/MWh and 150 MW during all hours (peak as well as off-peak) for those six months at a price of \$100/MWh. These sales at above market prices helped to compensate Sempra for sales at below market levels, leaving very little justification for substantial increases in the long-term contractual prices. The long-term contractual quantities vary from 1200 MW to 1900 MW from June 2003 through September 2011, at prices¹⁷⁷ averaging \$67/MWh.

On the other hand, some firms, such as Calpine did not have any short term contracts with the State of California and thus could not have reduced the short term prices in exchange for above-market long-term prices.

Thus, it is possible that some energy generators did link the prices for short term sales to the terms for long term sales. To the extent that did happen, the long-term contracts should be evaluated in the context of linked short-term sales. However, the State was ordered by the Court

¹⁷⁷ All the Sempra prices, including the year 2001 prices are included in Figure 33.

to release the terms of the long-term contracts, which the State did. If low prices in linked short term contracts were part of the considerations the State received for signing the long term contracts, the State was probably obligated to release information about those linkages. Since the State did not release information about explicit linkages, it is reasonable to conclude that there were no linkages other than those embedded in the contracts released by the State, and whose prices are summarized in Figure 37.

Figure 36 estimates the financial obligations to be paid by the State of California for these long-term contracts. For the years between the 2004 and 2010 California will be obligated to pay somewhat more than \$4 billion per year.

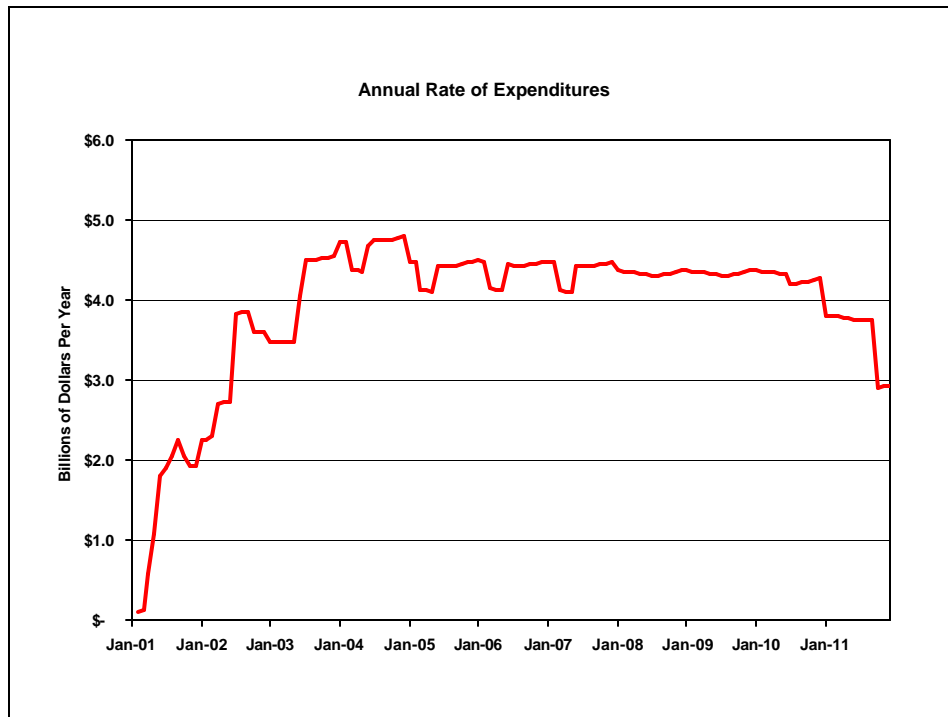


Figure 36 State Financial Obligations for Long Term Bonds

Currently the State of California does not sell retail electricity directly to customers, but only sells it through the utilities on whose behalf the State purchases the electricity. In doing so, the State could choose either of two very different options about the pricing of this electricity.

First it could charge the utilities a price for this electricity consistent with the market price for electricity. Under a belief that the market price will be much less than the contractual price the state has negotiated, the State would lose money on each such transaction. The difference would come directly from the State budget and the State budget would be burdened by about \$2 billion per year for the next ten years. Under such a pricing policy, the costs of contractual mistakes would be distributed broadly among the California voters, as suggested in the introduction to this chapter. Retail electricity prices would not be elevated and these contracts would not lead to incentives for families and businesses to move away from service areas of the investor owned utilities.

This has not been the announced intention of the State. Rather the State has announced that the utilities would be required to purchase the electricity from the State at a price equal to the contractual prices that the State negotiated. This would imply that for the next ten years the utilities would face an annual \$4 billion financial obligation based upon decisions made by the State “on their behalf.” This financial obligation would provide electricity worth about \$2 billion annually. If the investor-owned utilities were to pass that cost on to their customers, the financial loss would increase their retail prices of electricity by about 10% for the next ten years and perhaps 5% for the subsequent ten years¹⁷⁸.

¹⁷⁸ These calculations assume that the revenues these utilities receive during the next ten years will be about \$15 billion per year.

The CPUC initially voted against guaranteeing that DWR would be allowed to cover all of these costs from future retail electricity rates. However, the CPUC has now agreed that all State-negotiated contractual costs will be charged to consumers through electricity rates.

There is now a broad recognition in California that the contracts were mistakes, or at least that the terms negotiated by the State were too unfavorable to the State. This recognition has led to efforts by the State to “renegotiate” the contracts. The State has been in or has scheduled contract revision discussions with at least five holders of major contracts (Calpine Corp., Coral Power, Dynegy, PacifiCorp, Sempra Energy, and Williams) and has brought legal actions as well, requesting FERC to invalidate the contracts or reduce the prices in them.

The position taken by the electricity generators is well summarized in a statement by Williams Cos. spokeswoman Paula Hall-Collins¹⁷⁹: “Our position has been clear from the very beginning. We do have a contract and we feel it was fairly negotiated. But as with any of our long-term deals, we're interested in developing a relationship.”

The State position is summarized by two statements¹⁸⁰, one by Loretta Lynch, President of the CPUC – “We can do it easy or we can do it hard, but it will be done” – and one by state Sen. Richard Alarcon¹⁸¹, D-San Fernando – “Everything short of extortion that we can do ... we should.” The State seems to be pursuing a wide variety of approaches to the renegotiation that go beyond attempting to find mutually advantageous contractual changes. The attorney general

¹⁷⁹ Quoted from article by Carrie Peyton, The Sacramento Bee, Jan. 10, 2002.

¹⁸⁰ Also quoted from Carrie Peyton, The Sacramento Bee, Jan. 10, 2002.

¹⁸¹ Statement from hearing by the Joint Legislative Audit Committee.

has continued the investigation to find improper actions in the wholesale electricity markets and appears to be trying to make that investigation a component of the renegotiation talks. The CPUC has challenged several of the contracts in complaints to FERC and has recently filed a comprehensive complaint to FERC.

Electricity Revenue Bonds

As discussed in the previous chapter, central to the Governor's plan to buy wholesale electricity on behalf of the investor-owned utilities' customers was the plan to issue bonds, also on behalf of those customers, to finance the purchase of that electricity. The bonds, currently proposed to total \$12.5 billion, would be sold as DWR revenue bonds, not as State general obligation bonds¹⁸². The \$12.5 billion would cover, after discounts and other costs of marketing the bonds, about \$6 billion borrowed from the California general fund and the \$4.3 billion bridge loan the State negotiated during the electricity crisis. If the sale were successful, it would be the largest government bond sale in U.S. history.

Under the current plan, the revenue bonds when (and if) sold, would represent an obligation to the future buyers of electricity in California, in particular the customers of the investor-owned utilities. This obligation would be in addition to the obligation stemming from the State's long-term electricity purchase contracts¹⁸³.

¹⁸² Under the California Constitution the State cannot issue bonds backed by the full faith and credit of the State of California unless the voters of California vote to do so. However, neither the ratepayers nor the California voters need to vote on these revenue bonds.

¹⁸³ This obligation is particularly ironic in light of the Governor's statement on February 16: "Believe me, if I wanted to raise rates I could have solved this problem in 20 minutes. But I am not going to ask the ratepayers to accept a disproportionate burden." This obligation seems to have been part of the Governor's intention from January 19 when he first authorized DWR to start buying electricity. He apparently planned even then to require ratepayers to accept the entire burden, since he never formally proposed any alternative means of paying the interest and principal on the revenue bonds other than asking the ratepayers to pay the entire amount.

If they were sold as 15-year bonds, with an interest rate between 4% and 5%, they would require an annual payment of roughly \$1.2 billion per year over the next 15 years. This amount would correspondingly increase the average price of electricity sold by the investor-owned utilities. Annual payment on the bonds would increase the price of electricity to these consumers by about¹⁸⁴ 6%, in addition to the price increase associated with the long-term contracts signed by the State.

However, whether these bonds would be marketable as investment-grade instruments was, for a long time, questionable. As revenue bonds, the guarantee of repayment would be based only on revenues from future sales of electricity. The State's long-term contracts to purchase electricity obligate the State to pay for the electricity it purchases using monies collected in the DWR's Electric Power Fund (Fund) established in the California State Treasury. These contracts have clauses that state: "payments under this agreement shall constitute an operating expense of the Fund payable prior to all bonds, notes or other indebtedness." Therefore, if bonds were issued as obligations of the Electric Power Fund, payment of the interest and principal of these bonds would be subordinated to payments for the long-term contracts. Thus, the principal and interest might not be paid unless retail prices for electricity sold by the investor-owned utilities will be high enough to pay costs of the State-issued long-term electricity purchase contracts and the costs of continued electricity purchases, in addition to the debt service on the bonds.

¹⁸⁴ In 1999, investor-owned utilities sold 153 Million MWh of electricity (see Table 1). If that electricity were to sell at a bundled average price of \$130/MWh (including distribution services) total revenues of the investor-owned utilities would be \$20 billion per year. \$1.2 billion is 6% of \$20 billion.

As discussed in the chapter introduction, subordination would not create risks if the CPUC guaranteed that the retail electricity prices would always be kept high enough to cover adequately both obligations. However, the CPUC initially explicitly rejected such a guarantee. Therefore, absent changes in the CPUC decision, it seemed likely that the bonds could not be issued as investment-grade instruments.

If the bonds were not issued, the state could continue with its current \$4.3 billion loan, which it would be obligated to pay back over several years, unless it is refinanced. The State budget would remain in deficit from its past electricity purchases but ratepayers would not necessarily face the additional 6% increase in the retail electricity price over the next fifteen years. In any event, the state of California currently has incurred a debt that it will be obligated to pay one way or the other. Either it will cause a long-term drain on the electricity ratepayers or it will cause a shorter-term drain on the State Treasury. Either adds to the blight.

On January 31, 2002, the CPUC announced that it had reached a tentative agreement with the DWR and was negotiating with offices of the governor and the treasurer about the amounts and provisions of a bond issue. The agreement would make it possible for the state to sell the revenue bonds as investment grade instruments. The bond proceeds, after marketing costs, would repay the \$4.3 billion short-term loan and the remainder would replenish the state's general fund. Under the agreement, the DWR would put in best faith efforts to renegotiate the long-term contracts and would allow the CPUC to take legal actions to try to overthrow the contracts.

Inclusion of the Utilities' Past Crisis Costs in Future Electricity Rates

Retail electricity prices can be expected to remain elevated above wholesale electricity costs for a third reason. The utilities incurred massive losses during the challenge and crisis periods and there remains a legal argument that they be allowed to recover some significant share of those losses. The CPUC has made such agreement that would allow Southern California Edison to earn back in the future some portion of losses incurred during the challenge and crisis periods. As part of the agreement, SCDE agreed to drop its “filed rate doctrine” lawsuit. PG&E still is proposing that it be allowed to recover some share of the losses. Whether such an option will be allowed for PG&E is not clear, but the decision is likely to be part of the final plan to allow PG&E emerge from Chapter 11 bankruptcy proceedings.

The Southern California Edison agreement with CPUC would allow it to recover much of its losses over the next several years. In particular, the agreement would allow SCE to keep charging its customers the current level of retail electricity prices even though the wholesale price has decreased to pre-challenge-period levels. The current price includes an average increase in retail electricity rates of \$40/MWh. This is an average increase of 33% above the historical average retail prices charged by SCE. Thus, if wholesale prices of electricity remain at their current levels, then, because of the need to recover the past losses, the retail price of electricity purchased from SCE will be 33% higher over the next several years than it would otherwise be.

Whether the 6% increase in electricity prices associated with the electricity bonds plus the 10% increase associated with the State long-term contracts would be added to the 33% increase

associated with SCE recovering its past losses is not clear. However, what is clear is that customers of SCE will be paying a significant increase in electricity prices over and above the wholesale cost of electricity and over and above the price of electricity in other states.

Paying Sunk Costs through Future Electricity Prices

There is little doubt that, absent very large refunds from the electricity generators and absent complete renegotiation of the long-term contracts, the State faces many billions of dollars of electricity purchase costs beyond the future wholesale costs. These are sunk costs, costs that have already been incurred (although they may not have to be paid until some future times) and whose magnitudes will not depend on whether Californians buy much or little electricity in the future.

There is no easy way to pay these large sunk costs. However, some ways of paying them are likely to be more damaging than others. The current State plan –increasing retail electricity prices for many years in the future – is likely to be one of the more damaging options. The damage will come about because the elevated prices of electricity will motivate consumers to take actions that would not be economically justifiable given the future wholesale electricity costs and the costs of distributing electricity. Those actions can increase the blight facing California.

The introduction to the chapter has discussed how elevated prices may distort locational decisions of businesses and families, both within California (from the service areas of investor-

owned utilities and to the service areas of municipal utilities) and between California and other states. For businesses, the locational distortions may be more subtle than decisions to move away from areas of high electricity prices. Rather firms may simply shift some fraction of their electricity-intensive activities away from California or away from service areas of the investor-owned utilities. They may compensate by moving back same fraction of their non-electricity intensive activities or they may choose not to compensate at all.

Businesses will face incentives to self-generate electricity since self-generation will allow them to avoid paying some share of the sunk costs. This incentive to self-generate will remain even though self-generation costs exceed costs of electricity delivered by investor-owned utilities. This will occur if the inclusion of sunk costs makes the price of electricity delivered by investor-owned utilities higher than the per-unit cost of self-generation. Businesses will look for ways of substituting other energy such as natural gas or petroleum in place of electricity.

In addition, there may be incentives for municipalities, such as San Francisco, to municipalize their utilities, if the sunk-cost allocation rules are written so that the newly created municipal utility can avoid paying its share of sunk costs. This possibility seemed to be part of the debate as San Francisco residents were voting in 2001 whether to create a municipal utility and to take over PG&E distribution assets¹⁸⁵.

¹⁸⁵ This proposal was defeated by a very narrow margin. During the debate, S. David Freeman, head of the California State Power Authority, speaking to a rally of those supporting municipalization, promised that the State Power Authority would sell the new municipal utility electricity at a low cost. Perhaps he meant that the electricity would be sold at a low cost but that San Francisco would still pay the same share of the sunk costs, but newspaper reports of his speech never suggested that caveat.

The inclusion of sunk costs in future electricity prices can also distort capital investment decisions by businesses and families. Electric vehicles currently represent only a very tiny fraction of the personal passenger vehicles on the road today. With the advance of hybrid electrics and of technologies needed for dedicated electric vehicles, it is likely that more dedicated electric vehicles will be introduced into California markets. However, elevated electricity prices would create incentives against purchase of these vehicles. At a less esoteric level, elevated electricity prices would provide incentives for families to buy clothes dryers and water heaters fueled by natural gas rather than those fueled by electricity. Although these individual distortions are each unlikely to be important to the California economy, their cumulative impacts can add to the blight.

Elimination of Direct Access

One of the important and very positive elements of the restructuring under AB 1890 was a provision for direct access by users of electricity-to-electricity generators. Electricity users and generators were allowed to negotiate bilateral contracts directly for the purchase and sale of electricity. Although it is not reasonable to expect small users would negotiate such contracts, the ability for large users to do so is a step to creating retail competition.

In addition, direct access created the possibility for retail aggregators to compete with one another and with the utilities. A retail aggregator could enter agreements with many users of electricity to supply their electric needs and possibly additional energy needs. An aggregator would contract with generators to supply electricity that it would in turn provide to its customers.

The opportunity for such aggregators to enter the market potentially provides an element of retail competition, although it is most likely that such aggregators would initially participate only in niche markets. Direct access is a potentially useful step towards retail market competition, although, in itself, it is far from sufficient to create that competition.

However, direct access would conflict with the intention of the State to pay for the sunk costs through increased future electricity prices. The price elevation is creating an incentive for large users to enter bilateral contracts directly with generators to provide the electricity, rather than purchasing electricity through investor-owned utilities. Whenever a large electricity user bypasses utilities, or otherwise avoids purchasing electricity from the utility, more of the sunk costs would fall on the remaining customers, further increasing the retail price of electricity.

Members of the California Legislature understand this phenomenon and have voted, as part of Assembly Bill 1X (AB 1X) to eliminate direct access. AB 1X adds Section 80110 to the Water Code:

"After the passage or such period of time after the effective date of this section as shall be determined by the [Public Utilities] commission, the right of retail end use customers ... to acquire service from other providers shall be suspended until the department [the Department of Water Resources] no longer supplies power hereunder."

The CPUC most recently ruled that the suspension shall begin as of September 20, 2001, but kept open the possibility for setting that date retroactively to July 1, 2001. The DWR has entered contracts to purchase power extending until the year 2021. Thus, under AB 1X, direct access would be suspended for the next twenty years, absent legislative or contractual changes.

State Power Authority (California Consumer Power and Conservation Financing Authority)

The most recent and most explicit step towards turning California into a public power state was the creation of the new State power authority, established by Senate Bill 6X (SB 6X). This authority, headed by S. David Freeman, has broad authority to construct new electric generating facilities and to acquire existing facilities by use of eminent domain procedures.

Governor Davis first proposed creating a state power authority during his January 8, 2001 State of the State speech. During that address, he proposed: "... either a joint powers authority among the state and our 30 municipal utilities to develop the additional power we need, or a California public power authority that can buy and build new power plants." SB 6X, passed in May 2001, created the state power authority, more formally known as the California Consumer Power and Conservation Financing Authority.

The State power authority has broad powers to construct, own and operate electric generation and power facilities and finance energy conservation programs. It "will be able to finance natural gas transportation or storage projects; issue up to \$5 billion in bonds; have the power of eminent domain; and make loans and grants."¹⁸⁶ The State power authority "will be authorized to build, own and operate new power plants on behalf of consumers."¹⁸⁷ Although the State power authority has a \$5 billion current limitation on its bond-issuing authorization, the authorization can be expected to increase once the initial \$5 billion has been spent.

¹⁸⁶ Press release issued by Governor Davis, 05/16/2001.

¹⁸⁷ Idem.

The Authority initially signed¹⁸⁸ 48 signed letters of intent with 19 separate bidders allowing it to begin negotiations to have constructed 2,271 MW of renewable energy. As of October 4, 2001, it signed 31 letters of intent from 16 separate bidders for 3,214 MW of natural gas-fired gas fired peaker units to be on-line for next summer.

Had the State power authority continued on this path, it would have spent large amounts of State money without achieving any long-term increase in California generation capacity. To the extent the State power authority were to build new generating units, these units can be expected to substitute explicitly for generation, transmission, and contractual activities by private corporations.

The expected displacement of private investment is most obvious for gas fired peaker units that would be owned by the Authority. Peaker units can be constructed rapidly by private sector firms. However, corporations will do so only if such construction is profitable. The State Power Authority has indicated that it will sell electricity from its peakers at “cost”; thus, no profit margin would be included in the wholesale prices of electricity generated by these units. Private sector owners of peaker units would expect some profit margin. Thus, if the State Power Authority generates electricity as efficiently as would private sector firms, the Authority would be willing to sell electricity for a lower price than would private sector firms. This would not reduce the equilibrium price of electricity (that would be set by overall supply/demand balance), but it would assure that the State Power Authority would operate its peaker plants for a greater fraction of the time than would private sector firms. For every MWh of electricity the State Power Authority generates, some private sector firms will generate one MWh less. With less

¹⁸⁸ See: www.cpowerauthority.ca.gov/projectlist/main.asp

opportunity to sell power, private sector firms will invest in fewer peaker units. In general, then, it can be expected that the investments by the State Power Authority would displace private sector investment on a one for one basis.

In addition, California Power Authority projects would be exempt from franchise fees and property taxes, even though they would impose as much cost on cities and counties as would equivalent private sector projects. This subsidy to California Power Authority projects implies that there even if the State Power Authority generates electricity less efficiently than would private sector firms, the Authority could still sell electricity for a lower price than would private sector firms, with cities and counties bearing financial losses. Thus there would be less pressure for the California Power Authority to manage its projects efficiently, even though its projects would displace more efficient private sector generators.

Now that it is becoming clear that California is likely to have sufficient capacity before next summer, the California Power Authority has been backing away from its intention to build new gas-fired peaking plants. It has now issued a draft request for bids for microturbine, solar photovoltaic and fuel cell projects. Its current investment plan emphasizes renewable forms of energy such as wind, biomass, and solar. Currently there is very little private sector investment using these emerging technologies and thus there is little private sector investment to be replaced. As such, the current investment plan of the California Power Authority plan can be expected to increase the number of plants in California that use renewable energy of the means of generating electricity.

The, the creation of the State Power Authority and its initial activities were moving California down the road toward public power generation. However, that path seems to have changed, somewhat, with the emphasis on harnessing renewable energy as the source of the public power generation. Whether the authority will revert to its initial direction of investment or remain on its current path is not obvious at this juncture, but will be very dependant on the policy options encouraged by the next California governor and legislature.

Chapter 6: Policy Options: What Next?

Now that the crisis has passed, blight is threatened, but public attention has subsided, California and all the western states still face important policy issues. These issues relate both to the electricity system and to the financial implications of the dual crises. Some of the decisions may be driven at the Federal level, through FERC. Others involve state regulatory or other policy decisions. However, most involve opportunities – or requirements – for cooperation at the state, regional, and federal levels. In the remainder of this chapter, these policy issues are discussed in terms of a series of prescriptive recommendations.

Improve Regional Integration

Integrated physically through an extensive grid of electricity transmission capacity, the electricity systems of the eleven western states are highly dependant on one another. The electricity crisis made it clear that long run supply and demand trends and short run variations in those trends in any part of the region can have important ramifications throughout the entire region. Regulatory policies in one state can influence electricity markets throughout the region. Information about new capacity development in one state can influence decisions about whether new capacity development will be profitable in other states. Yet the regulatory policies, information flows, and market management rules of the eleven western states have not been well integrated. Thus, there are opportunities for mutual gain among the states through actions that increase regional integration of decision making and information flows.

Publicly available supply/demand information

Many decisions made by either public sector or private sector entities depend largely on good information about regional electricity supply, demand, and prices in addition to state-specific information. For example, decisions to invest in generation capacity, made by either public sector or private sector entities depend on beliefs about future supply and demand balances and/or future wholesale electricity prices. If potential investors – in either the public sector or private sector – believe there will be surplus generating capacity for many years, they tend to avoid making new capacity investments, recognizing that it is unlikely that they will recover costs of the investment, much less earn a profit. If they believe there will be shortages over the relevant future, potential investors are likely to choose to invest in new capacity. Thus, good information about historical and current conditions and reasonable projections of future conditions throughout the region can help to avoid “boom and bust” cycles in the electricity markets. Monitoring to detect exercise of market power can be more effective if based on information from throughout the interconnected region rather than information from simply one state. Evaluation of the relative impacts of energy conservation programs, retail price changes, and reductions in economic activity would be improved by high quality state-specific and regional data and such evaluations would be helpful in improving policy interventions in response to possible future electricity challenges or crises.

The nature and extent of publicly available electricity information vary radically among the various states. California, the largest state, provides a rich array of information through CAISO and the California Energy Commission; much of these data are readily available through the Internet. The California Energy Commission periodically publishes projections of electricity supply and demand. The Northwest Regional Planning Council develops periodic estimates of

electricity demand and supply for the Northwestern states. However, some of the states provide relatively little information through readily available sources.

The Energy Information Administration, an agency of the US Department of Energy, regularly publishes state-by-state electricity data on a comparable basis. However, these data are too limited to guide private sector and public sector decision making. The Western Governors' Association and FERC have both published studies that examine the entire region, as have several researchers¹⁸⁹. Yet these sources do not provide information for continued decision-making.

Cooperative efforts among the states to coordinate either information development or information communication could provide mutual gains. Whether such cooperative efforts would best be organized through direct cooperation among state agencies, through the Western Governors' Association, through a regional transmission organization, through the Western Systems Coordinating Council, through research institutes, or through some federal agency is not clear. What does seem clear, however, is that better publicly available region-wide data could improve private sector and public sector decision making and could allow the general public better opportunities to evaluate the policy decisions being made and communicated by public officials.

Regional Transmission Organization

In December 1999, FERC issued Order 2000, calling for the formation of regional transmission organizations (RTOs), spanning large geographic regions, organizations that would be

¹⁸⁹ E.g. Jolanka V. Fisher and Timothy P. Duane have published such a study.

responsible for providing reliable, nondiscriminatory and efficient transmission service for regional competitive wholesale electricity markets. In Order 2000, FERC expressed its belief that the creation of such RTOs could reduce any remaining transmission-related impediments to competitive wholesale electric markets, in particular, any remaining engineering and economic inefficiencies in the operation and expansion of transmission grids and any opportunities for transmission owners to discriminate to favor their own (or affiliated companies') wholesale market purchases and sales.

In April 2001, FERC accepted the proposal for the creation of RTO West, a RTO that would control all transmission within eight western states (Washington, Oregon, Idaho, Montana, Nevada, Arizona, Utah, and parts of California not controlled by CAISO). FERC noted, "RTO West can serve as an anchor for the ultimate formation of a West-wide RTO¹⁹⁰." RTO West will serve as the independent system operator for its entire area and "will operate more than 90 percent of the high voltage transmission facilities from the U.S.-Canadian border to southern Nevada¹⁹¹."

An important issue for California is whether to combine the functions of the CAISO and RTO West into one RTO that could more efficiently control transmission services over almost all, if not all, of the interconnected western region of the United States. Such an integration of RTO West and CAISO could remove any problems of transmission coordination between California and the rest of the West. However, in principle, any remaining problems could be eliminated without creating a single organization but rather by sufficient coordination between the two

¹⁹⁰ FERC press release April 25, 2001, re Docket Nos. RT01-35-000 and RT01-15-000.

¹⁹¹ Ibid.

existing organizations. In practice, however, as long as operational rules of the two entities remain different from one another, such coordination is likely to be imperfect. If California wholesale electricity purchases and sales return primarily to spot market transactions while bilateral contracts continue to characterize most of the transactions in the other areas, the structural differences in wholesale electricity markets may make integration of the two entities more difficult. In addition, the integration would take the power to appoint the members of the governing board out of the hands of the California governor and may therefore reduce the degree of political control over the transmission system.

Whether CAISO should remain as its own RTO and simply cooperate with RTO West or the two entities should become one is not clear. However, by the California governor and legislature need to address this issue in the near future.

Improve California Electricity Markets

Redesign Wholesale Markets for Electricity

In examining causes of the energy crisis in California, this book has focused most attention on issues of regional energy supply and demand, issues of California price regulation of the retail and wholesale markets, issues of risk management, and long-term problems stemming from decisions made by California's political leaders. Issues of California market design have been important but not central to understanding the fundamental causes of the crisis. No matter how perfectly the wholesale market had been designed in California, the fatal flaws in the regulation of the investor-owned utilities coupled with the "perfect storm" leading to supply/demand

imbalances would have created a challenge and the failure of the political leaders to address meaningfully the problem would have led to the crisis.

However, the wholesale markets in California remain severely flawed. They are unnecessarily complex and uncoordinated. Although the degree to which market power has been exercised, generating capacity has been strategically withheld, or that market rules created inappropriate incentives may never be fully resolved, it is clear that the currently flawed markets continue to create risks that costs will be increased and prices will be elevated above the appropriate levels. There is a great need to modify these markets to reduce the chance that another garden-variety storm will produce “perfect storm” symptoms.

Restructuring Principles

Many authors have addressed means of restructuring the market. A clear and cogent statement of some of the principles is incorporated in Hogan’s statement to Congress¹⁹², from which the following passage is taken:

“The experience is now sufficient for FERC to go beyond its previous deferential approach to markets created by stakeholders without regard to a set of detailed standard design principles. The good experience is concentrated in New York and in PJM, which serves the Mid-Atlantic region. These two markets now function under independent system operators (ISO) who employ a standardized spot market design for system coordination. The common elements of this standard design include a bid-based, security-constrained, economic dispatch with locational prices, bilateral schedules, financial transmission rights, license-plate access charges and a broad scope for market-driven investment. Efficient pricing consistent with the ISO coordination functions then permits maximum commercial freedom without undermining reliability. The market monitoring and market power mitigation rules follow from the design.

These principles would include:

¹⁹² “Statement Of Professor William W. Hogan Before The Subcommittee On Energy Policy, Natural Resources And Regulatory Affairs, United States House Of Representatives”, August 2, 2001

1. The ISO must operate, and provide open access to, short-run markets to maintain short-run reliability and to provide a foundation for a workable market.
2. An ISO should be allowed to operate integrated short-run forward markets for energy and transmission.
3. An ISO should use locational marginal pricing to price and settle all purchases and sales of energy in its forward and real-time markets and to define comparable congestion (transmission usage) charges for bilateral transactions between locations.
4. An ISO should offer tradable point-to-point financial transmission rights that allow market participants to hedge the locational differences in energy prices.
5. An ISO should simultaneously optimize its ancillary service markets and energy markets.
6. The ISO should collaborate in rapidly expanding the capability to include demand side response for energy and ancillary services.

CAISO's Wholesale Market Redesign Efforts

The CAISO has recently taken policy leadership by developing proposals for fundamental improvements in the wholesale market design, through its “Market Design 2002” project. A team within CAISO has been assigned the responsibility of developing a program of market changes that would address the most fundamental of the whole sale market problems. On January 8, 2002, CAISO issued a preliminary draft of its proposed market changes.¹⁹³ Although the draft is still explicitly a “work in progress”, it proposes substantial changes to repair some of the most troublesome aspects of the current wholesale markets in California and represents an excellent step toward adopting restructuring principles consistent with those outlined above.

Central elements proposed by the CAISO include the following¹⁹⁴:

- Available Capacity (ACAP) Obligation on Load Serving Entities

¹⁹³ California Independent System Operator, “Market Design 2002 Project: Preliminary Draft Comprehensive Design Proposal”, January 8, 2002. <http://www.caiso.com/docs/09003a6080/13/58/09003a6080135879.pdf>

¹⁹⁴ Each of the following elements is a direct quote from “Market Design 2002 Project: Preliminary Draft Comprehensive Design Proposal”. Quotations in the paragraphs that follow are from this document as well.

- Day-ahead Congestion Management
- Firm Transmission Rights (FTRs).
- Forward Spot Energy Market.
- Residual Day Ahead Unit Commitment.
- Real-time Economic Dispatch Using Full Network Model.
- Real-time Bid Mitigation for Local Reliability Needs.
- Damage Control Price Cap on CAISO Markets.

Most of these proposed elements represent much needed and appropriate reforms to the well-identified market flaws. Under the day-ahead congestion management proposal, the CAISO would start using a “fully accurate model of the CAISO grid for the purpose of adjusting generation and load schedules to mitigate transmission overloads and ensure local reliability, instead of today’s simplified three-zone model.” This change will allow the CAISO to move toward nodal pricing and control, pricing and control recognizing that economic conditions at various nodes of the grid may vary significantly from one another even within a given geographic zone.

Firm transmission rights are financial instruments that would allow market participants the right to assure their electricity would be transmitted at particular time between particular generator locations and load locations. These would allow participants to hedge risks of possible high congestion charges.

The proposal for a forward spot energy market would replace the now-defunct PX with an organized short-term futures market for electricity. However, rather than a market run totally separate from the CAISO, the new forward spot energy market could and should be integrated into the CAISO operations (although CAISO believes the market could be operated by another

entity). As the CAISO team has recognized, under the proposed congestion management changes, there will be spot market transactions among electricity market participants; creation of a formal forward spot market would improve the efficiency of these trades.

The proposal for residual day ahead unit commitment would allow the CAISO to assess whether the day-ahead schedules include enough resources to meet the next day's demands. If needed, CAISO could make commitments to pay electricity-generating resources that have long start-up times for both the times they are generating and for the costs they incur for start-up and for remaining in operation even when the electricity may not be needed.

Under the proposal for real-time economic dispatch using full network model, "every 10 minutes during each operating hour the CAISO would run a 'security-constrained economic dispatch' program to determine which resources to dispatch at what operating levels to meet real time needs." Such an approach would allow CAISO to use cost-minimizing, modern optimization models, taking into account the relevant constraints facing the system ("transmission constraints, local reliability needs, and generator operating constraints, as well as system imbalance energy needs"). This proposal would be consistent with the move toward nodal real time pricing in the wholesale market. In addition, this proposal would eliminate the requirement for scheduling coordinators to submit balanced loads. The overall optimization program would perform the balancing function and thus individually balanced loads would not be important.

Finally, the proposal for real-time bid mitigation for local reliability needs would allow CAISO to mitigate locational market power that could be exercised by generators that are the only units operating at a constrained location on the grid.

Although the detailed implementations of these plans undoubtedly have not yet been completed and, once completed, will be subject to much debate, these proposed changes together represent a very strong and useful movement towards improving the design of California wholesale markets.

Two of the proposals, however, may not be appropriate in their current form, or at least require significantly more design. The proposal for an available capacity (ACAP) obligation on load serving entities would place on the utilities (and other load serving entities) the responsibility “to procure adequate capacity to meet their expected peak monthly loads plus reserve requirements.” This proposal would move the California wholesale markets sharply away from spot markets and is likely to lead utilities to enter into a mix of long-term, medium-term, and short term contracts to purchase electricity. This allocation of responsibility would be a very positive step, as would the shift away from spot markets. However, it is not yet clear whether the CAISO proposed mechanisms for accomplishing this end would be workable. Under this proposal, each load serving entity would be required to have contractually available to it electricity generation capacity equal to “a fixed margin above the next month’s forecast peak load (e.g., in the area of $(1.15) * \text{forecast monthly peak load}$)”. This obligation could be met “by a combination of own generation, firm energy contracts ..., capacity contracts, and physical demand management.”

Before the beginning of each month, each load serving entity would be required to demonstrate to the CAISO that it has procured adequate capacity for the following month. Those entities that had shortfalls would be assessed a substantial penalty.

Whether such a plan will improve the market operations is unclear. It would increase the demand for electricity contractual commitments and, at least in the short run, would increase the wholesale price of electricity. The CAISO would be required to evaluate demand forecasts of each utility and substituting its own forecasts for the utility forecasts if they differed from one another. The proposed incentive structure is likely to lead to more unused generating capacity in times of short supply than would be desirable. The plan might encourage somewhat more capacity development than would otherwise be the case and might reduce the degree of price volatility. In short, while this plan has many desirable characteristics, more design and analysis is still required.

Finally, the proposal for a damage control price cap on CAISO markets has been designed to “limit the adverse cost impacts of an unusually severe price spike.” However, this proposal cannot be evaluated until the level of that price cap, the conditions under which it is applied, and the structure of prices under the cap are specified. Whether price caps, bid caps, or no controls at all are more appropriate to deal with severe price spikes has not been settled.

CAISO has clearly communicated its intention to use the preliminary draft as a starting point in the redesign process, not as the ending point. As such, the CAISO is now taking a very

appropriate and much needed leadership position in working to improve the California wholesale electricity markets.

Assuring Competition in Wholesale Markets

The California experience suggests that particular attention must be paid to assuring that there is true competition and only a minimum chance for the exercise of market power. Because there are so many constraints on the electricity system, based upon the non-storable nature of electricity, based upon the locational structure of electricity generation and use, based upon limitations associated with transmission capacity, enforcement of antitrust laws and other pro-competitive laws is important. However, in doing so, the empirical rules that have been developed for other industries may be difficult to apply directly¹⁹⁵.

Public visibility of actions taken by the various participants in the system – generators, local distribution companies, traders, and governmental agencies – is also crucial for appropriate policymaking and enforcement of market rules. Thus, reliable publicly available data would allow analysts and members of the public to see more clearly actual workings of the system. Appropriate data include both the regional supply and demand data described above plus more detailed data (possible made available only after several months) about actions by individual market participants.

¹⁹⁵ For example, given the almost vertical demand functions and the supply functions (when capacity is low), empirical rules based on conventional measures of market concentration are likely to understate the opportunities for exercise of market power.

Finally, given the possibility of complex bidding structures, it is important that the system be designed to reduce the possibility that firms with relatively small market share can exercise market power. Some of the market redesign issues discussed above can be important for this goal.

Promote Retail Competition by Restoring Direct Access

As discussed above, retail competition for serving small residential customers may be problematical. However, retail competition for serving large industrial loads is feasible and would have several important benefits. If industrial customers can negotiate contracts with electricity generators, absent requirement for CPUC intervention, those contracts can provide appropriate risk sharing mechanisms mutually beneficial to the generator and the user of the electricity. For example, such contracts could implement a real time pricing system, with real-time prices varying along with some objective measure of spot wholesale prices. The real time pricing system could be implemented as a two-part system so that marginal prices can vary along with wholesale prices while the average payment for the electricity varies only by a much smaller amount.

Direct access could allow those companies that need a much higher degree of supply reliability than normal and are willing to pay for additional reliability to be able to acquire such reliable electricity supplies. Direct access could also promote the development and installation of micro turbines or fuel cells that were located very close to point of electricity use¹⁹⁶.

¹⁹⁶ It is possible however that the lack of direct access could encourage distributed generation located on the facilities of the customer wishing to purchase electricity, if that customer were precluded from the opportunity of directly negotiating an appropriate contract for electricity generated off of its premises.

Finally, direct access for large industrial customers could be the starting point by which we begin to experiment with the possibility of more complete retail competition.

As discussed above, however, current law precludes direct access for all customers. The California legislature recognizes that direct access would conflict with the intention of the State to pay for the sunk costs it has incurred through increased future electricity prices.

There are viable alternatives for recovering the sunk costs, alternatives that do not require elimination of direct access. For example, the State could impose a tax on electricity sales, either for sales in service areas of the investor-owned utilities or throughout the State. Alternatively, the CPUC could adopt an exit charge, under which any industrial customer choosing to bypass utilities would be obligated to pay into a fund designed to cover the State's sunk costs.

An even better alternative would be to recognize the nature of the problem -- the State of California agreed to a large number of unwise financial obligations. Those unwise obligations were the responsibility of the Governor and the Legislature, as representatives of the California citizens. The State could keep these mistakes as State financial obligations through the State Treasury. The State of California would still pay the financial burden of the errors made by the Governor and the Legislature but the payment, over many years, would remain strictly a financial problem rather than creating restrictions on the freedom of California's economy to operate effectively.

Thus, it is both desirable and possible to restore direct access at least for large electricity customers. The failure to do so is a step backwards towards governmental direct controls rather than market operations.

Improve Pricing in Retail Markets

Markets for electricity, like markets for other commodities, can allow people the freedom to choose the goods and services they wish to consume while, at the same time, assuring that the quantities they purchase are economically efficient. Markets can encourage consumers to buy goods and services whenever those products are more valuable to the consumer than their cost and can discourage purchases whenever the value to the consumer is less than the cost. However, markets can function in such an efficient and free manner only if prices correspond to costs, in particular to marginal costs.

One of the fundamental problems during the challenge period and the electricity crisis was that retail electricity prices were not allowed to follow marginal costs, even approximately. Retail prices were artificially constrained to well below marginal costs of electricity production and distribution during the entire challenge and crisis periods. When retail prices are kept well below cost, consumers are not naturally encouraged by market forces to reduce their use of electricity. The resultant over-use of electricity provides motivations for governmental organizations to impose restrictions on personal freedom to choose how much electricity to use. Now retail prices charged by the investor-owned utilities remain well above marginal costs and promise to remain at elevated levels for decades to come. When retail prices are kept well above cost, consumers find ways of using less electricity than would be optimal from their own perspectives and incur too large costs to reduce their use of that electricity. Thus, both the under-pricing of electricity

during the challenge period and the crisis and the over-pricing of retail electricity now cause economic inefficiencies.

The functioning of retail electricity markets could be significantly improved if retail prices were allowed to track costs of providing that electricity to customers. Tracking of costs could be improved in two dimensions. First during times of particularly high wholesale prices, average retail prices should be elevated to correspond to the high average wholesale prices and during times of low wholesale prices, average retail prices should decline: the retail price level should correspond on average to costs. Second, during the course of the day, as wholesale prices fluctuate between high levels during peak times and low levels at off-peak times, retail prices should follow this daily variation in wholesale costs.

The problems of failing to allow the retail prices to increase during times up exceptionally high wholesale prices have been extensively discussed in previous chapters of this book. The discussion need not be repeated here. However, the problem of failing to allow retail price variations during the course of the day to correspond to cost variations has not been adequately discussed and will be the subject of what follows.

Allow Real Time Retail Pricing

Wholesale electricity prices vary sharply over the course of a day, week, or month, with high prices during times of high demand and low prices during times of low demand. Figure 37 illustrates this price variation, using data on wholesale prices and transactions volume on the California PX during July 1999, a normal period. The volume, shown by red lines, has a scale

from zero to 40,000 MWh. Wholesale price, shown by blue lines, has a scale from \$0 to \$160/MWh.

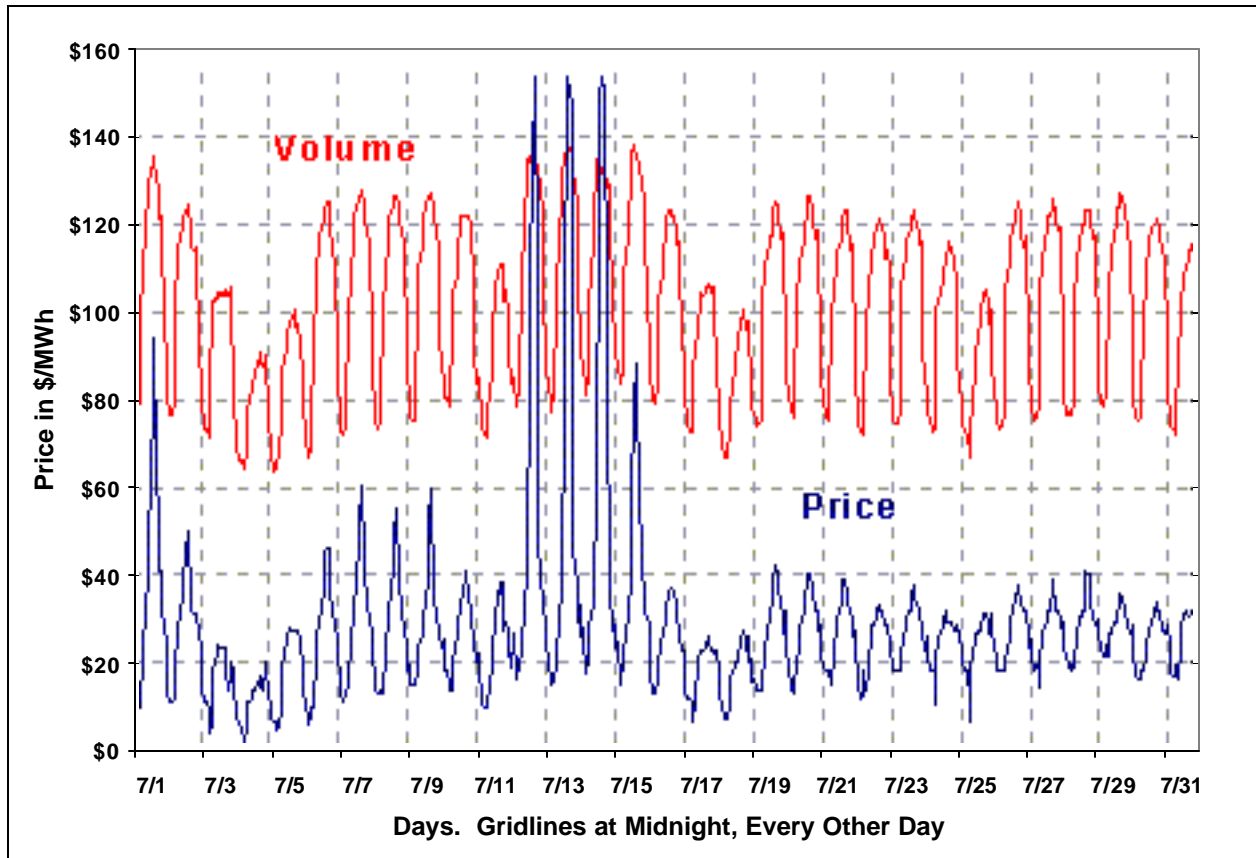


Figure 37 PX Price and Volume during the Course of a Month: July 1999

Figure 37 shows that during the course of the month, wholesale price varied from a low of \$2/MWh to a high of \$155/MWh, roughly an 80-fold variation. During the days with least variation, the high price was roughly twice the lowest price and during days of medium price variation, the high price could be six times as high as the lowest price.

Figure 37 also shows that prices were high during periods of high volume, times when demand reductions would be appropriate and prices were low during periods of low volume, times when there is no particular need for demand reductions. If consumers could be motivated to shift the timing of their electricity use away from the peak times towards off peak times, wholesale price increases during peak periods could be substantially alleviated, inducing only small increases in the off-peak prices.

Even in the face of these large normal variations in wholesale prices, and thus in costs of acquiring electricity, regulated retail prices for all but the largest customers remained constant. For example, for PG&E, the retail price of electricity during this time was \$125/MWh, including \$60/MWh for delivery services and \$65/MWh for electricity. Thus, for most times during that interval the retail price of electricity itself exceeded the marginal cost of electricity but for some times the price was much lower than marginal cost.

Efficiency in the use of electricity could be significantly improved if customers faced retail prices that varied on a real time basis, corresponding to marginal cost variations. Such a time varying system is generally referred to as "real time pricing". In principal, real time pricing would promote economic efficiency since it could be designed to assure that retail prices closely tracked marginal costs of electricity, on an hour-by-hour basis or more frequently.

In practice, however, installing meters, designing and operating the communications systems, and managing the billing system would be costly, even though the meters are currently being installed for the largest customers. For the largest customers and those most able to change their

electricity purchases in response to time-varying prices, the costs of metering will be smaller than the economic gains from real time pricing and, on net, real time pricing would lead to net economic benefits. For the smallest customer and those least able to adjust electricity purchases in response to changing prices, the costs of metering would exceed the economic gains from real time pricing and real time pricing, on net, would not be attractive. Thus, although real-time pricing is an attractive option for many electricity users, it is not economically attractive for all.

Real time pricing is likely to grow as a contractual structure for the larger users if retail competition, particularly direct access, is restored. Under such a competitive system, electricity users who would, on net, benefit from real time pricing would be free to choose such a pricing arrangement and those who would not benefit would be free to remain with prices that remain constant within a given day. In addition, for those under CPUC tariffs, real time pricing should be made broadly available.

Under a pure system of real time pricing, the price of all electricity purchased by large customers would vary on an hourly basis with the wholesale market price. Such a system is referred to as a "one part real time pricing" system. The difficulty of a one part real time pricing system is that the total expenditure for electricity by large electricity user could vary radically from week to week or month-to-month. If an electricity user wishes to avoid large fluctuations in electricity purchase costs, one-part real time pricing may be unattractive.

An alternative, especially for large industrial customers, is a "two part real time pricing system". Under this system, a historical base load quantity of electricity purchased by the large user is

made available at some more stable price. For increases or decreases in the quantity of electricity used, around that level, the price for incremental increases in use of electricity or incremental decreases in use of electricity would be set equal to the real time price. Under such a two-part system, the large customer bears less risk of price variations but still faces incentives to reduce demand during high price times, since the marginal retail price of electricity would move with the wholesale price. Two part real time pricing would allow a balance between stability of average expenditures and variability of marginal prices responding to changing conditions.

The disadvantage of a two-part real time pricing system, however, is that if the base load quantity is set at a price lower than expected for the future, then each user will fight to have a large base load quantity. The allocation of the baseline in that case becomes a difficult political process.

Even this problem can be solved if the price of the base load is set equal to or slightly above the expected price of the electricity in the future. In that case, the customer can freely choose the base load quantity for the future and sign a binding contract to that effect¹⁹⁷. However, the problem cannot be readily solved if the base load is made available at a subsidized price, as was the case during the electricity crisis. Thus, although real time pricing would have been useful during the challenge period and the crisis, those times would have been the most difficult to introduce such a system. Thus, it perhaps should not have been a surprise that, although the

¹⁹⁷ Pricing of mobile telephone service is organized that way. The buyer decides how many “free” minutes to have available each month and pays a fixed cost for the fixed availability of these free minutes. Additional minutes, purchased as spot transactions, are at a much higher rate.

California Legislature voted \$35 million dollars to install real time meters, no real time pricing system has yet been approved by the CPUC and implemented within the State.

Improve Risk Management

Risk management for the electricity system involves identification and appropriate reduction of both the physical risks in the system and the financial risks and involves improving the response of the system to reduce the consequences of adverse events. Physical risks are discussed first. A subsequent section addresses financial risk protection.

Reduce Infrastructure-Related Risks

Improve Fuel Supply Infrastructure

In California, the infrastructure to transport natural gas both into the State and within the State has been a bottleneck causing natural gas prices to soar and this infrastructure should be expanded. With these pipelines at or near capacity, whenever there is a short run a significant increase in the use of natural gas to run generating plants, we can expect the possibility of sharp increases in natural gas price, with a consequent increase in wholesale costs of electricity.

High prices for infrastructure services provide market signals that greater amounts of that infrastructure would be economically efficient and would be profitable for investors. The price for natural gas transportation services within California can be measured by the difference between the delivered natural gas price and the price at the California border, a difference that rose to \$50/mcf. Although this price persisted for only a short time, transportation services

prices exceeding \$5/mcf persisted for months. These high prices strongly suggested the need for additional pipeline capacity.

Now that the crisis is over and the very inefficient gas-fired generating plants are not being used, natural gas pipeline capacity currently appears sufficient. However, the new gas-fired electric generating plants soon coming on line will again increase the use of natural gas and will thus require increasing natural gas pipeline capacity. In order to minimize the risk of similar natural gas price spikes, California's natural gas pipeline system needs expansion. The California Public Utilities Commission needs to support, and even encourage, future proposals for pipeline expansion.

Improve Transmission Infrastructure

The infrastructure for electricity transmission is currently too limited at a few important bottlenecks on the grid. Significant increases in the electricity price in Northern California, relative to the Southern California price, were associated with the inability to move adequate quantities of electricity from Southern California to northern California when needed, along Path 15. An expansion of the transmission capacity between northern and Southern California would be a significant infrastructure improvement, but a very costly investment.

In October 2001, Secretary of Energy Spencer Abraham announced that a power transmission line would be built to relieve congestion along Path 15. Estimated to cost about \$300 million, the line will be built by a consortium of private companies and public agencies.

In addition, the crisis made it painfully clear that the western United States is electrically virtually isolated from the rest of the country. The west had very high spot wholesale electricity prices while prices to the east of the Rockies remained much lower. The construction of new tie lines connecting the western part of United States with the rest of the nation would allow a sharing in either direction as needed and would reduce the likelihood of regional electricity shortages. On the other hand, transmission facilities are expensive. Costs of such investments would likely dwarf the \$300 million expected for the Path 15 upgrades. In addition, investment in new gas fired electric generators is relatively cheap. Whether investment in such new transmission capacity would be economical, relative to the alternative of new generation capacity, remains to be seen, but the assessment of that option is needed.

Make Energy Infrastructure More Secure from Terrorism

The infrastructure serving California's electricity system, including natural gas pipelines and electricity transmission systems is vulnerable to terrorist attacks. Successful attacks have the potential of creating another electricity crisis, although of shorter duration than the 2000-2001 events.

The natural gas pipelines that serve California cover long distances, in many places above ground. The above-ground sections could be vulnerable to terrorist attack although the below-ground sections are likely to be difficult to attack. Successful attacks could reduce California's ability to generate electricity using natural gas, the energy source for 50% of California's electricity generation. Pipelines coming into California have capacity to each supply on average less than 10% of California's electricity generation. Unless the system is near full capacity, only

successful attacks on multiple pipelines can create such a crisis. Moreover, a decrease in natural gas availability would cause the least efficient gas fired generating units to be taken off line, not the most efficient. Thus, although California is vulnerable through the natural gas pipeline system, the potential for damage is smaller than the potential for damage through the electricity transmission system.

Electricity transmission lines remain very vulnerable to terrorist attacks, although successful attacks on most lines themselves could be repaired relatively quickly. In addition, local transmission grids are designed to operate effectively if one transmission line is out of operation. However, there are several transmission lines essential to system operation. Given the large fraction of electricity moved along Path 15, between Northern and Southern California, and the large fraction moved on the two interties from the Pacific Northwest, successful terrorist attacks at these parts of the grid could precipitate a short-term physical shortage of electricity.

Even more damaging than attacks on transmission lines would be attacks on substations. Substations typically cannot be repaired quickly because the large transformers within these substations and the switching equipment typically cannot be made available quickly.

How one can best protect this vulnerable infrastructure is not clear. However, the solution should involve some combination of protection, redundancy of infrastructure, and equipment stockpiles allowing rapid facility repair. Each of these strategies adds costs to the electricity system.

Improve System Response to Adverse Events

One approach to improving risk management involves reducing the likelihood that adverse events, such as supply shortages, will occur. That approach, discussed in the previous section, may lead to a focus on reduction of the infrastructure-related risks. There is another complementary approach: reducing the harm that results from adverse events, should they occur.

Typically, harm can be reduced by making the system more flexible, more responsive to changing economic conditions. The responsiveness then allows, even encourages, individual consumers and producers to adjust in ways that reduces the harm they face and, in so doing, reduces the harm to the entire system. Generically such approaches involve increasing the electricity demand responsiveness and increasing the electricity supply responsiveness to changing conditions.

Increase Electricity Demand Responsiveness

As has been discussed in previous chapters, one of the fundamental causes of price volatility in the wholesale electricity markets was the lack of responsiveness of electricity demand to wholesale prices. Figure 19 and Figure 18 illustrated that if the demand for electricity were more responsive to wholesale price changes, the wholesale price changes caused by variability in supply and demand would be greatly reduced. Thus, price-spike-related economic damages would be reduced if electricity demand were to be more responsive to wholesale price increases.

A significant factor ending the electricity crisis has been the reduction in use of electricity. Some of the underlying demand reductions are transient and some are permanent. The permanent reductions in demand, although beneficial, will not provide the “shock absorbers” needed to increase the demand responsiveness of the system. Market participants and

governmental agencies will take into account these permanent demand reductions as they evaluate or forecast future electricity demand. Such expectations of future electricity demand strongly influence new generation capacity¹⁹⁸. Therefore, permanent demand reductions will ultimately lead to equivalent reductions in electricity generation capacity, just compensating for the demand reductions. Therefore, once all adjustments are completed, permanent reductions in electricity demand will not enhance the ability of the State to respond to future price volatility¹⁹⁹.

Policies that lead to greater demand reductions, occurring quickly, in response to wholesale price increases could significantly reduce future wholesale price spikes. Policies implemented in California would be good. Those implemented throughout the west would be much better.

One strategy would make retail prices quantitatively more responsive and more quickly responsive to wholesale prices, counting on consumers in their own interest to reduce electricity purchases when retail electricity prices increase. This strategy could involve many different approaches.

At the most basic level, this strategy would require electricity regulators to abolish fixed-price retail price controls. California's dogged maintenance of retail price controls in the face of skyrocketing wholesale prices was the single most harmful California policy failure. If Governor

¹⁹⁸ The influence may be direct, in that firms estimate the future generating capacity needed to satisfy future demand. Or it may be indirect, in that firms evaluate the supply/demand balance and assess the likely future market prices of electricity. Through either route, expectations of future demand influence capacity investment decisions.

¹⁹⁹ One should remember that California has had a long tradition of successful policies designed to reduce electricity demand. In 1999, California per capita residential electricity use was 37% below the national average. This history of relatively low electricity intensity did not save California from the crisis.

Davis and/or the CPUC had allowed retail rates to increase appropriately during the challenge period, demand would have dropped enough to allow California to avoid the crisis²⁰⁰.

Even without such retail price controls, most utilities, municipal or investor-owned, charge retail rates to approximate the cost of delivery services plus the average cost of acquiring electricity. Moreover, most utilities acquire the vast majority of their electricity through long-term fixed-price contracts or their own generation (incurring costs not closely related to the wholesale price.) Thus, the average acquisition cost of electricity increases by far less than does the spot wholesale price²⁰¹. Therefore, under average cost pricing, retail prices increase by only a small fraction of the increase in spot wholesale prices. The magnitude of the resultant retail price increase is much smaller than the magnitude of the spot wholesale price increase.

In addition, regulated retail electricity prices generally respond only slowly to whole sale price increases. Typically, regulators calculate average cost in a backward-looking manner, based on many months of historical experience. Regulator agencies seldom, if ever, calculate the average of current acquisition costs. Therefore, calculated average costs respond only slowly to changes in spot wholesale prices. As a result, the retail price increase is often delayed for many months.

²⁰⁰ One might reasonably conclude that, after observing the great harm caused by California's maintenance of retail price controls into the crisis, no state would ever make such a fundamental mistake in the future. But price controls have been a resort of political leaders in the United States before and they are likely to be again. And Governor Davis seemed to understand fully the great damages his policy was causing. Moreover, because the economic factors underlying California's restructuring are common across many electricity systems, the reasons underlying California's initial imposition of price controls may be relevant elsewhere. However, even if retail price controls are imposed during times of relatively stable wholesale prices, California's plight should make it clear that such controls must be eliminated during times of sharply rising wholesale prices.

²⁰¹ As an example, if a utility acquires 90% of its electricity on long-term fixed-price contracts and 10% on the spot market, then a \$100/MWh increase in the spot wholesale price would lead to a \$10/MWh increase in the average wholesale price.

The speed of the retail price increase is much slower than the speed of the spot wholesale price increase.

Regulatory agencies could take steps to make the speed and magnitude of retail price increases correspond more closely to the speed and magnitude of changes in the spot wholesale market. Regulatory agencies can quickly add surcharges onto the standard retail rates in times of rapid wholesale price increases. These surcharges can be larger than the increase in average acquisition cost and yet may be smaller than the increase in the spot wholesale price. Such surcharges would increase the net revenues of the utility during wholesale price spikes. Regulators could require the utility to accumulate these excess revenues in a special account that could be drawn upon during times of sharp reductions in spot wholesale prices²⁰². In this way, state agencies could still regulate utilities so that prices, *averaged over time* corresponded to average costs while varying retail prices by more than the variation in average acquisition cost.

In addition, retail pricing could include two part tariffs, either with or without real time pricing. Such two-part tariffs would allow the marginal retail prices – that is, the prices for increases or decreases in the quantity of electricity purchased – to increase or decrease by as much as wholesale spot prices while keeping average retail price equal to average acquisition costs. Such a system – if one could transcend the problem of customers fighting to increase their low-priced base quantity – would enhance the efficiency of retail markets and would greatly increase the responsiveness of demand to wholesale market conditions.

²⁰² This statement assumes that regulators allow retail prices to fall by more than the decrease in average acquisition cost during times of sharp drops in spot wholesale prices.

A further step would be for utilities to institute real time pricing broadly, as discussed in a previous section. Real time pricing, with variations in marginal prices corresponding to wholesale price variations, would give the fastest, most complete incentives for demand to respond to wholesale price movements.

The farther utilities move along this sequence, the more responsive will retail demand be to wholesale prices. The more responsive is retail demand to wholesale prices, the less volatile will be the wholesale price. However, the farther utilities move along this sequence, the more volatile will be the retail prices and the greater will be the political impetus to re-establish retail price controls.

Retail price variations are not the only means of increasing energy demand responsiveness. Utilities could introduce a system of demand-side bidding, in which large users of electricity could agree to reduce their use of electricity, while being compensated financially for those reductions. Utilities could establish a formal auction to allow such demand-side bidding to proceed efficiently. CAISO's "Market Design 2002" project envisions such a system of demand-side bidding.

In addition, utilities could increase the currently existing programs of direct control by the utility of some loads, for example, air conditioning loads. Many uses could be set under computer control and utilities could exercise that control in times tight electricity markets. The equipment for that communication and control is available now. The utility and the customer would enter a contractual relationship that allows the utility to cycle the appliances, or to reduce the use of

those appliances during hours of the day in which prices of electricity were particularly high. The utilities would need to negotiate ahead of time the contractual agreements to allow such widespread load shedding in times of need. Under such a system, the customer would not pay large increases in electricity price but would still be motivated to reduce demand when needed.

Increase Supply Responsiveness

The most fundamental long-term solutions to the California electricity crisis were initiated four years ago with the boom in construction of new electric generating facilities. Including the plants that were completed this summer, 11,000 MW of new generating capacity is under construction. Of this total, about 6,000 MW can be expected to come online within the next year or is already generating electricity. Another 11,000 MW of new generating capacity is under review by the California Energy Commission.

A fundamental requirement for avoiding “perfect storm” problems is adequate electricity generating capacity. However, “adequate” must be defined in a regional context, not simply a California-specific context, since the regional markets are so tightly interconnected. Thus, there needs to be incentives for new generation capacity throughout the region, including in California. Thus, in California, the issue is how not to discourage development of generation capacity. In the other states, the issue is how to encourage the appropriate amount of new construction.

Since the restructuring legislation of 1996, which included a significant deregulation of electricity generation, there has been a boom in construction of new generating plants in California. Nevertheless, it is important not to get in the way of this process. Threats to take over these plants by eminent domain, threats to return to the old regulated system, or a long-term

system of wholesale electricity price control could each dampen enthusiasm for new construction. These threats create large uncertainties for those considering investing in new electric generation facilities. Similarly, actions by the State Power Authority to use state funds to compete with private sector investment would be contrary to the goal of allowing the private sector to develop new generation capacity. State-created investment uncertainty is neither in the long-run interests of the citizens of California nor in the interests of investors in the electricity system.

Given the long lead-time from decisions to invest in new generating units until the time the new generation is on line, increasing supply responsiveness must account for the responsiveness of investment decisions to forecasts of future market needs. However, future supply and demand conditions in electricity markets are not perfectly predictable. Hydroelectric generating capacity is very dependent upon the amount of rainfall. Increased costs of natural gas can make some generating facilities uneconomical and thereby reduce supply. Construction of new generating facilities can be delayed for a host of different reasons. Prediction of the growth in electricity demand is at best an imperfect art. Air conditioning loads are very dependent on weather so that consumption of electricity can vary greatly on a daily basis. And for states, like California, that count on other states to supply a significant amount of electricity demand, supply and demand conditions in those other states also may be unpredictable. For that reason, improvements in the quality of prospective market information, including improvements in the breadth and quality of current and historical regional electricity market data, could be important contributors to the goal of increasing electricity supply responsiveness.

In addition, financial incentives could encourage utilities or generators to assure that there will be reserve capacity in the system. The existence of reserve capacity would increase the short-run supply responsiveness and would thus help reduce the damages associated with adverse supply and demand conditions. One approach would be creation of capacity markets. However, capacity markets are very difficult to develop and manage and thus may not be a viable means of increasing capacity to increase the short-run supply responsiveness. Another approach might be the implementation of something like the “available capacity obligation on load serving entities” currently being proposed by the CAISO.

Distribute Financial Risks Appropriately

California’s electricity crisis made it clear that the financial risks associated with rapid increases of wholesale prices were felt very unevenly by the various utilities in the west. Those that had secured all or almost all of their electricity needs through long-term fixed-price contracts faced little or no financial risk. On the other hand, those, such as California’s investor-owned utilities, that were required to purchase more than one half of their electricity on the volatile spot markets faced tremendous financial risks. In addition, those utilities that could respond by increasing retail electricity prices were able to avoid risks by passing them on to their customers while those utilities whose retail rates remained fixed bore all risks of wholesale price increases themselves while their customers bore none.

Each utility and their customers will typically wish to reduce the risk of price spikes associated with short supplies of electricity. One method of any single utility reducing its risk and those of its customers would be to enter long-term contracts to purchase electricity at fixed prices. If a utility covered all of its electricity needs this way, variations in spot wholesale prices would have

no necessary financial consequences for the utility. If the utility's retail rates were based on its average acquisition price of electricity, then its customers would also not be subject to financial consequences of wholesale price increases. In this way, the utility and its customers could avoid all risk of wholesale price variations.

However, long-term fixed-price contracts may reduce the risk facing the utility holding the contracts while increasing the risk to other utilities (and their customers) buying electricity at spot market prices. In some sense, long-term contracts do not reduce the overall market risk but simply transfer that risk to other market participants. This occurs because utilities typically sell electricity to their customers at prices based on the average acquisition price of that electricity. If, when wholesale prices increase, the average acquisition price does not change, utilities typically keep retail electricity prices constant. Constant retail prices imply that the electricity users have no incentives to reduce their demands as wholesale prices increase. Therefore, long-term contracts tend to substantially reduce the electricity demand responsiveness and imply that larger wholesale price increases are needed to balance supply and demand after a given reduction in electricity supply or increase in demand.

The role of contracts in distributing the financial risk, rather than reducing the overall risk can be illustrated by a group of five identical utilities each purchasing 10,000 MW of electricity, under one assumption that none uses any long term contracts, compared to another assumption that each covers 80% of its initial purchases using long term contracts. Assume that in either case, some event reduces the electricity supply by 5,000 MW. Then, each firm, being identical to every other firm, would ultimately reduce its consumption by 1,000 MW.

Assume now that every \$2/MWh rise in the retail price of electricity reduced the demand for electricity for a given firm by 100 MW. Therefore, the retail price of electricity would need to increase by \$20/MWh in order to motivate the 1,000 MW demand reductions for each firm. This required retail price increase would be \$20/MWh, no matter whether no utilities or all utilities used long-term contracts.

If no firms had any long-term contracts and all priced retail electricity at the average wholesale cost, then in response to the 5,000 MW reduction of supply, the wholesale price would increase by \$20/MWh. This price increase would apply to all 9,000 MW each utility was still purchasing. Thus the cost increase for the 9,000 MW ultimately purchased would be \$180,000 per hour of purchases (9,000 MW x \$20/MWh)

If each firm had long-term contracts covering 80% of its initial electricity needs, and all priced retail electricity at the average wholesale cost, then in response to the 5,000 MW reduction of supply, the wholesale price would now increase by \$180/MWh, not \$20/MWh. The \$180/MWh increase in price would apply to the 1,000 MW the utility would continue to purchase on the spot market; there would be no price increase for the other 8,000 MW under long-term contract. A \$180/MWh increase in price applied to 1/9 of the purchases would increase the average wholesale price and the average retail price by \$20/MWh. Thus the cost increase for the 1,000 MW ultimately purchased on the spot market would be \$180,000 per hour of purchases (1,000 MW x \$180/MWh), identical to the increase that would occur if no firms had long-term

contracts. A similar equality would hold for increases in electricity supply leading to reductions in wholesale electricity price.

Thus, although each individual utility could use long term contracts to protect itself from the risks of wholesale price increases stemming from supply reductions, it could do so only if the other utilities continued to purchase on the spot markets. If all utilities tried to protect themselves using long-term contracts, none ultimately would be any more protected than was the case when all electricity was being purchased on the spot markets. Long-term contracts simply protect those that have entered long-term purchase contracts and transfer the risks to the other utilities.

Equal distribution of the financial risk among utilities, therefore, requires that each utility be given an equal opportunity to protect itself with long-term contracts²⁰³. If most utilities are so protected, but some are required to purchase the majority of their electricity on spot markets, those purchasing on spot markets will bear a disproportionate share of the risk. A similar phenomenon would occur if utilities were not allowed to increase retail prices when wholesale prices increased, as was the case in California.

To keep the example simple, assume that public utility commissions, to protect consumers, allowed only 10% of the wholesale price increase to be passed on to retail customers. Assume

²⁰³ A numerical example illustrates different firms having different contractual protection. Assume three utilities had long term contracts for 80% of initial electricity needs and two had no contracts. In response to the 5,000 MW reduction of supply, wholesale price would increase by \$42.86/MWh. The \$42.86/MWh price increase would apply to 1,000 MW of 9,000 MW for utilities with contracts, would increase average price by \$4.76/MWh, and would reduce demand by 238 MW for each of these three utilities, for a total reduction of 714 MW. The \$42.86/MWh increase in price applied to all purchases of the other two utilities would increase average price by \$42.86/MWh and would reduce demand by 2143 MW for customers of these two utilities, for a total reduction of 4286 MW.

that utilities purchased all electricity on the spot market, as in the first case. Then, in response to the 5,000 MW supply reduction, wholesale prices would increase by \$200/MWh, not \$20/MWh. Since 10% of this \$200/MWh increase in wholesale price would be passed through to consumers, consumers would face an increase in retail price of \$20/MWh, just enough to motivate the requisite demand reduction. Consumers, although protected by the public utility commission, would face exactly as much of a price increase as they would with no such protection. However, now the utility would lose \$180/MWh for each of the 9,000 MWh it purchased, for total losses of \$1,620,000 per hour of purchases²⁰⁴.

The examples illustrate the fundamental point. Every restriction that keeps wholesale price increases from translating to retail prices will result in greater increases in the wholesale prices, since each such restriction reduces the electricity demand responsiveness. If some utilities are allowed to enter long-term contracts while others are denied that opportunity, the latter group will face increased financial risk just compensating for the reduced financial risk of the former group. If wholesale price increases are only partially passed through to retail price increases, wholesale prices will go up even more to motivate the requisite demand responses, therefore harming the utilities without in fact protecting the customers.

This fundamental nature of the markets implies that if some utilities throughout the region are allowed, even encouraged, to cover most of their electricity acquisitions through long-term fixed-price contracts, then all utilities must be allowed to do so. If wholesale prices increase, these utilities must be allowed to increase the retail prices correspondingly. Any restrictions on the

²⁰⁴ If consumers were ultimately required to pay some share of these losses, through long term bonds, then the efforts to protect consumers would make those consumers strictly worse off, since they would save no money during the crisis but would be burdened by high prices after the crisis, as in the California case.

ability of a utility to enter long-term contracts or to pass wholesale cost increases to retail prices will lead to an uneven distribution of risk among those utilities.

However, the simple examples do not give the complete story, since utilities differ in the financial agreements they have with their customers. Therefore, a wide array of contractual structures should be open to the participants in the system, so they can each choose appropriate contracts depending on their particular circumstances. Electric utilities that have fixed obligations to serve customers are likely to want electricity supply contracts whose time horizon is consistent with the longtime scale of the obligation to serve. Risk sharing arrangements between the utilities and their large customers or between generators and large customers should be allowed or encouraged. Risk sharing arrangements may include obligations to provide fixed amount of electricity at a predetermined price with additional quantities of electricity or reductions in the use of electricity priced at a real-time price. With such contracts in place, the utilities could make long-term contracts to acquire the electricity in sufficient quantities to cover such retail contracts and could thus be free to set up risk sharing arrangements that are consistent with preferences of their customers.

Manage California's Financial Obligations

California has acquired massive financial obligations primarily because of the State's mismanagement of the electricity crisis. The total dollar value of these obligations is still not clear. The FERC has yet to rule on how large are the refunds to which California will be entitled from generators that charged more for electricity than allowable under FERC price mitigation rules. Moreover, how large will be the bond offerings and under what terms are still

outstanding issues. Whatever the ultimate magnitude of the obligations, the State still needs to resolve two issues: how it should treat financial obligations to electricity generators under the long-term contracts and in what ways it should pay for these obligations. These will be the final two issues of this chapter.

Long Term Electricity Contracts

Now that it has become widely apparent that the State's long-term electricity purchase contracts are at prices well above the current and expected future electricity prices, there is a strong pressure among governmental officials to "renegotiate" the contracts. There seems to be a broad recognition in the State Administration and legislature that these contracts are not now and never were in California's interest. Yet how the State should proceed is not obvious, since many options involve tradeoff between the credibility of the State as a contractual partner and the depth of the electricity blight.

Renegotiation of many contracts can be valuable for both contractual parties when economic conditions change. However, legitimate renegotiation implies the identification of contractual changes that are preferable for both parties. "Renegotiation" typically does not imply changes that are preferable from one party's perspective and disadvantageous from the perspective s of the other party. Nor does it mean unilateral renegeing on commitments. Yet these distinctions are not apparent from California's policy pronouncements, where "renegotiation" seems to have lost the concept of mutual gain or mutual agreement.

Attempts by California to achieve unilateral gains can have long-term adverse consequences for California. The continuing ability of the state of California to negotiate contracts on reasonable

terms with a wide variety of contractual partners depends largely on its not developing a pattern of attempting to avoid its contractual obligations. Thus, California must recognize that even though the long-term contracts are very costly to the State, unilateral attempts to avoid this obligation would be harmful to California's credibility. Thus, it is important that any renegotiations of the contracts be truly bilateral agreements rather than unilateral attempts by the State to force the generators to provide lower prices to the State.

Similarly, the State should not try to overthrow the terms of the contracts by legislation. In particular, one legislative proposal, no longer active, would give repayment of state electricity bonds, if issued, higher priority for payment than the electricity contracts would have. This provision would be in direct conflict with terms included in the long-term electricity price contracts negotiated by the state of California. Passage of this bill would be just such a unilateral change in the essential contract terms. Not only would such a change reduce California's credibility as a contractual partner, it is likely to be subject to years of litigation. Given the litigation threats, such a legislative solution would not accomplish its end of assuring that the bonds would be marketable as investment-grade instruments.

Paying for Long-Term Financial Obligations

Currently, Governor Davis has made it clear he intends that the elevated costs of long-term electricity purchase contracts and debt service costs of the long-term bonds (once issued) will be obligations of future retail purchasers of electricity in California. These obligations would keep electricity prices elevated for decades above the marginal costs of electricity acquisition. Such

long-term electricity price elevations will lead to long-term distortions within electricity markets unless this method of payment is changed. Two possible changes would reduce the distortions.

The first alternative would be for Californians to pay for these contractual obligations in their role as taxpayers rather than as electricity purchasers. This change would not reduce the direct costs to California for these contracts. But it would reduce the long-term electricity market distortions and thus would reduce the depth of the blight. Such a change would allow the State to return direct access as an option for large electricity users.

Fairness issues associated with such a plan could be seen through several different perspectives. The obligations were incurred for purchases of electricity on behalf of the customers of the large investor-owned utilities. From one perspective, it thus seems unfair that all taxpayers should pay the costs. However, the California governor and members of the legislature made the fundamental mistakes. These were officials elected by all of California. Thus, from a second perspective it seems unfair that only a portion of the taxpayers should incur the costs of their mistakes. In addition, the mistakes were made in the years 2000 and 2001. Thus from another perspective, it seems unfair that new firms or consumers entering California after the crisis should be responsible for the mistakes made before they moved to California. In addition, some people and firms will move to or from service areas of the investor owned utilities. One perspective suggests that it would be unfair for these to avoid the costs or pay the costs of the past decisions, simply because they chose to or are required to relocate within California.

It is highly likely and extremely unfortunate that such fairness debates will be central to any state policy debates about whether to convert the contractual obligations from an electricity ratepayer obligation to a taxpayer obligation.

Alternatively, a non-bypassable fixed charge could be assessed to electricity users, with that charge sufficient to pay for the financial obligations of the long-term contracts plus the debt service on the bonds. Utility customers who continue to purchase their electricity from investor-owned utilities would simply pay the elevated price. However, those who no longer chose to purchase their electricity from the investor-owned utility would be required to pay an exit fee calculated to cover their share of the financial obligations. Firms and consumers who were not customers of the investor-owned utilities in 2001 would be entitled to a price reduction, the opposite of the exit fee.

In principle, this approach would allow the State to allocate the financial obligations of the long-term contracts and the long-term bonds to those customers who purchased from the investor-owned utilities in the year 2001. In practice however, such a plan would not be simple. It could create a set of incentives for firms and customers to take actions to avoid the fee, for example, by reducing their scale of operations within the service area of an investor owned utility, but not actually leaving. Hence, while in principle such an approach would be viable, in practice the difficulties may be too great.

Between the two options, considering the difficulties of implementation and the remaining distortions, conversion of the obligations from ratepayer obligations to taxpayer obligations is

likely to be the better course of action. However, it is likely that the fairness concerns will dominant the debate and the current California governor and legislature will take no action. If that is the result, California's electricity system could remain in blight for decades to come.

Chapter 7: Some Reflections

The story of the California electricity and financial crisis is far from finished. At the time of this writing Pacific Gas & Electric is still struggling to develop a plan to emerge from bankruptcy, a plan acceptable to both the judge and its creditors. Southern California Edison is regaining financial health but still faces obstacles. Various state agencies are attempting to renegotiate the long-term contracts and/or to challenge the contracts in court or through FERC. The California Public Utilities Commission and the Department of Water Resources are discussing options for issuing long-term revenue bonds. FERC-established wholesale price mitigation measures are scheduled to expire in September. Litigations spawned by the crisis are working their way through the courts. The fall of Enron has brought into question the viability of some electricity contracts. In addition, Enron's fall has led commentators to blame that corporation for its roles in electricity market restructuring and in the crisis. FERC recently initiated a fact-finding investigation into whether Enron or any entity manipulated electricity or natural gas prices (or "otherwise exercised undue influence over wholesale prices") during the crisis. The California Independent System Operator is developing proposals for correcting flaws in California electricity markets. The Federal Energy Regulatory Commission continues to promote and support Regional Transmission Organizations. Other regions, including the Northeast, are successfully operating restructured electricity systems. Texas is moving forward with its deregulation. The House Energy and Commerce subcommittee is working on legislation to promote deregulation. Researchers are striving for deeper understanding of Western electricity markets, further sorting out the underpinning of the crisis, and working to design better electricity market structures.

Even though the story is far from final, it may be valuable at this point to reflect on lessons that emerge from the sad history, even though any lessons will be, by necessity, somewhat subjective.

Unfortunately, one message repeatedly communicated is that the California experience proves that electricity deregulation has been a failure in California, and by extension, is likely to be a failure elsewhere. For example, Governor Davis stated²⁰⁵ “But we must face reality: California's deregulation scheme is a colossal and dangerous failure. It has not lowered consumer prices; it has not increased supply. In fact, it has resulted in skyrocketing prices, price-gouging and an unreliable supply of electricity. In short, an energy nightmare.” Governor Davis has even used the California experience in Mexico to condemn any move towards privatization of the Mexican electricity system. Governor Davis during early December, 2001, speaking in Mexico, urged Mexican authorities to keep complete governmental ownership and control of the electricity system²⁰⁶: “Don’t hand over your electricity infrastructure to private interests, unless you have 15 percent more energy than you need. In private meetings, [Mexican] President [Vicente] Fox and I agreed on this.”

Yet a fair assessment of the California experience cannot reach such an anti-private-sector conclusion. Nor can it lead to a negative conclusion about the viability of electricity system deregulation.

²⁰⁵ January 8, 2001, State of the State Address.

²⁰⁶ Quote from UPI wire: <http://www.upi.com/view.cfm?StoryID=14122001-070000-9884r>. Story by Ian Campbell, UPI Economics Correspondent.

First, as has been well documented by researchers such as William Hogan²⁰⁷ and by Robert Crow²⁰⁸, electricity system restructuring, including deregulation, has been very successful in other nations and in other regions of the United States. Successful deregulation has been proven possible, even though California's particular system is flawed and California's system has been managed terribly.

In California, deregulation has set the stage for widespread wholesale market competition and adequate electric generation capacity. California's restructuring has resulted in a dramatic increase in the number of a new electric generating plants proposed, approved, and under construction. Deregulation is having the desired impacts on wholesale electricity supply.

The contention still seems to be that deregulation caused the electricity crisis. However, a fair examination of the western electricity crisis shows this contention to be invalid. The crisis stemmed primarily from two factors. For over a decade, population growth and economic growth in the western states steadily increased electricity consumption but very little new electric generating capacity was added. As a result, by the year 2000, western electricity markets had become very tight even under normal conditions. But 2000 and early 2001 were not characterized by normal conditions. Exceptionally low rainfall in the Pacific Northwest and in Northern California led to sharp temporary reductions in hydroelectric generation, reductions

²⁰⁷ For example, "Electricity Market Restructuring: Reforms of Reforms", by William W. Hogan, May 25, 2001, Harvard University.

²⁰⁸ "Not Invented Here: What California Can Learn from Elsewhere about Restructuring Electricity Supply", Robert Thomas Crow. Stanford Institute for Economic Policy Research Working Paper, December 2001; Available at <http://siepr.stanford.edu/papers/pdf/01-10.html>.

that triggered the electricity crisis. California deregulation played only a minor role, if any role at all, in creating the crisis.

The financial crisis, on the other hand, was the direct result of California regulatory actions. However, the financial crisis was not the result of deregulation, but rather of overly stringent regulation. Even though all municipal utilities and investor-owned utilities throughout the entire West faced the electricity crisis, investor-owned utilities located in California were the only ones that experienced the financial crisis.

Two regulatory rules forced California investor-owned utilities into a financial crisis. First, these utilities had been precluded from using long-term electricity purchase contracts to protect themselves financially from wholesale market price spikes. This lack of protection was in stark contrast to practices of other utilities: investor-owned utilities in the other western states and municipal utilities throughout the west, including California. The regulatory-imposed absence of financial protection set the stage for the financial crisis.

Second, once electricity prices on wholesale spot markets skyrocketed, the California governor and the California Public Utilities Commission refused to allow the retail price increases needed to keep the investor-owned utilities financially viable. The legislature even reestablished retail price control for San Diego Gas and Electric. The regulations forced the investor-owned utilities to purchase electricity at very high wholesale prices and to sell the same electricity at retail prices controlled to be far below purchase costs. These utilities were required to sell as much electricity as their customers wanted to buy, even though utilities were losing money on all their sales. The California Public Utilities Commission never allowed any increases in retail

electricity prices until after the largest two utilities had been drained of all financial assets and of all borrowing capacity and were on the verge of bankruptcy. Only then did the Commission approve any retail price increases. However, the initial increase was far too small to balance sales price and purchase costs. Thus retail price regulation, not deregulation, was fundamental to creating the financial crisis for the utilities.

Once these utilities had become so credit unworthy that generators and marketers were no longer willing to or required to sell them electricity, the State stepped in to buy electricity on their behalf. The State itself began buying electricity at high wholesale spot prices and selling it at the low regulated retail prices. Buying high and selling low was just as costly to the State as it was to the investor-owned utilities. During the winter and spring of 2001, this program completely drained the State Treasury of its \$8 billion projected surplus. This ill-conceived scheme was not the result of deregulation, but was the deliberate choice of the State of California.

In short, the financial crisis was not the product of deregulation, but rather was the product of overly aggressive and inappropriate regulation.

The California experience should make it clear, once again, that actions that economically isolate the supply side of markets from the demand-side create major problems. In California, retail price control was the primary regulatory mechanism that isolated the demand side from the supply side of the electricity markets. Such price controls typically reduce system responsiveness and eliminate incentives for consumers to adjust to changing economic conditions. The lesson had been brought home forcefully to the United States during earlier

energy crises, including 1973-74 and 1980-81 when gasoline price controls and governmentally imposed oil allocation controls led to hours-long gasoline lines. Yet California political leaders, ignoring lessons of the past, maintained rigid retail electricity price controls until the bitter end.

Maintenance of retail price control thus discouraged energy demand reductions – energy conservation – by consumers. However, energy conservation was California’s best hope for forcing wholesale prices to decrease. Thus, California’s decision to keep retail prices at artificially low levels allowed wholesale prices to remain at painfully high levels. Consumers did save money in the short run through lower rates, but will pay most, if not all, of the high wholesale costs through long-term increases in the retail rates. Therefore, public officials, by isolating consumers from wholesale market conditions, did not help these consumers. These actions have brought long-term harm to California consumers of electricity as well as to California taxpayers.

The California experience also brought into sharp focus the importance of managing risks associated with implementation of any policies, especially policies that radically change the system. California electricity restructuring was just such a policy. It radically changed regulation, altering an electricity system that itself has never been free of economic risk. The history of the electricity system should have made it clear that one cannot confidently predict changes that significantly influence generation costs. Cost of fuels change, as has occurred for natural gas, oil, and coal. Public acceptability of generating technologies can vary over time. Hydroelectric generation depends entirely on rainfall, the amount of which can vary sharply from year to year. Prediction of electricity demand growth is at best an imperfect art. And understanding

circumstances in which market power might be exercised -- in fact, even determining whether market power is being exercised -- is fraught with error. Risks exist and they must be managed.

Given the significant economic risks, the regulatory system should distribute those risks appropriately. However, the restructuring left investor-owned utilities bearing a disproportionate share of the risk. Subsequent regulatory implementation made matters worse. Thus, with reductions in available hydropower, the financial consequences of soaring wholesale spot market prices were borne disproportionately by the California investor-owned utilities.

It is impossible to expect that policy choices will eliminate system-wide risks. Risks will always remain. Nevertheless, one can expect that good policy choices and regulatory implementation will fairly distribute those risks. One can expect that the regulatory system will not disproportionately concentrate risks on a limited number of companies, particularly if those companies are incapable of bearing the entire risk. Unfortunately, that was not the case in California.

The California experience highlights something that is well known to everyone who has managed, participated in, or observed large-scale changes in complicated organizations or economic structures. Any major restructuring of such important systems will continue to require modifications well after the initial changes have been implemented. System operation requires monitoring and may require wise and strong leadership to identify and implement changes that are needed after unintended adverse consequences of the system change become apparent.

California's electricity system includes both complicated organizations and complex economic structures. The restructuring was fundamental and sweeping. No one was able to predict with complete certainty how all the changes would work. Thus, it was important that State carefully monitored important features of the system operation.

No one should have been surprised to find important unintended adverse consequences of the electricity system restructuring. No one should have been surprised to find system flaws that required changes. And no one should have been surprised to hear that the chief executive of the state needed to provide the leadership to assure that the appropriate changes were implemented.

In California, the Governor is the Chief Executive Officer of the state and thus had the leadership responsibility to assure that flaws in the changed electricity regulation system were identified and corrected early enough to avoid a crisis. At least, the Governor could have corrected flaws enough to avoid the most damaging consequences of the crisis. The California experience shows the real lasting harm that can befall a state when the Governor fails to take the appropriate role.

The California experience also highlights the dangers of failing to differentiate between short-run issues and long run issues. California, like all of the western states, faced a short-term electricity crisis. The crisis was severe but relatively short. Although during the crisis it was impossible to predict its exact duration, available information about new generation capacity under construction made it clear that the supply shortage, at the root of the crisis, would be of relatively short duration. During the crisis, it was also possible to foresee that any problems of market

rules would become far less important once the anticipated new generating capacity was on line. Thus, the short-term nature of the electricity crisis was predictable even during the crisis.

It was also predictable that the financial crisis, if allowed to proceed, could have long-term ramifications for the State. It was predictable that long-term contracts for electricity purchases at prices far exceeding the expected electricity prices would have long-term adverse financial ramifications. Thus, there were foreseeable long-term problems.

It is commonplace to note the need for careful differentiation between short-term problems and long-term problems. Careful differentiation between short-term and long-term helps assure that new long-term problems are not created as “solutions” to short-term problems. Unfortunately, the California State government did not seem to so differentiate. Thus, the State negotiated long-term contracts ostensibly aimed at the short-term crisis; these contracts quickly became long-term problems. The failure to implement rational short-term solutions, such as temporary retail price increases, implied that the State missed those solutions that could act quickly over a short time period. This failure allowed the short-term challenge to become a crisis and led directly to the long-term financial problems.

Although reasonable people can disagree about the appropriate policy measures, appropriate matching of the time scale of the solutions to the time scale of the problems would have been far superior to those actions taken in California.

As a final reflection, it is important to recognize that California has had severe economic and policy problems in the past and will have problems in the future. But California has a robust economy, boasts a diverse and vibrant population, provides technological leadership for the world, and remains a wellspring of new ideas. California will survive the problems, both the short-term and the long-term problems, associated with the electricity and financial crises. And in decades to come, perhaps the lessons learned from this crisis will help California to avoid similar mismanagement.