RETROSPECTIVE REPORT ON CALIFORNIA'S ELECTRICITY CRISIS

A REPORT PREPARED FOR
THE CALIFORNIA ENERGY COMMISSION

BY
THE CALIFORNIA COUNCIL ON SCIENCE AND TECHNOLOGY

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INTRODUCTION

In 2000, severely limited energy supplies and extraordinarily high energy prices significantly impacted California. To better enable California's policymakers to plan for the future, the California Energy Commission requested the California Council on Science and Technology to provide a detailed history of the energy crises, using objective data. The report was to include an overview of California's energy situation, the role of the state and federal agencies, the impact of supply and demand on resources, the impact of deregulation, and lessons learned. The report was also to include chapters analyzing the resources, institutions, and regulatory controls that contributed to the problems in the supply of electricity.

As the report describes, the electricity industry was dominated by large, investor-owned utilities before 1970, most of whose activities were regulated by state authorities. During the next twenty years, a combination of changed political and economic priorities, different technological opportunities, and changes in both costs of and demand for electricity undermined this structure. By the time California's electricity industry was restructured, neither the private companies, nor the state regulators, nor the federal regulators could effectively respond to industry challenges. Understanding the problems faced at that time is important for formulating and evaluating proposals today that will change the way the industry is governed.

Under the guidance of Dr. Terry Surles, PIER Program Manager for the California Energy Commission, Linda Cohen, Professor of Economics at the University of California, Irvine and Carl J. Weinberg, Principal of Weinberg Associates, prepared this report with contributions from Stephen Peck, President of Fléche and Paroma Sanyal, Assistant Professor of Economics at Brandeis University. The project execution and the reviewing process have been under the control of CCST's Large Science Project Committee.

Chapters in the report cover the evolution of federal electricity regulation and the process of restructuring in California. The supply and demand of electricity is reviewed. California electricity rate regulation, resource regulation and restructuring legislation is put in context with federal deregulation trends. The California "Crisis" is described in terms of the restructured electricity market. Price volatility and market manipulation were also factors contributing to the crisis. The current reforms and the roles of state agencies are then discussed. Finally, and most importantly, what are the lessons to take home from this experience?

While not claiming to be a fully comprehensive report, we hope that the details presented in this document can serve the state as it plans for the future.

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CHAPTER 1: THE EVOLUTION OF FEDERAL ELECTRICITY REGULATION PRIOR TO RESTRUCTURING IN CALIFORNIA

1.0 Overview

For most of the twentieth century the electricity industry was dominated by large, investor owned utilities (IOUs). These firms had regional monopolies and were vertically integrated, providing generation, transmission and distribution services. The companies were also subject to a wide range of federal and state regulatory oversight.

Prior to 1970, the governance structure of the firms in the electricity industry and the structure of the industry's government regulation meshed fairly well. Technological opportunities and economics supported the regulatory and industrial institutions. Under the so-called "regulatory compact," regulators provided the utilities with stable rates of return on their investments. For their part, the IOUs accommodated increases in demand for services with prices that declined over time. In addition, the IOUs cooperated with a wide range of federal and state initiatives, from subsidizing politically salient services, like lifeline rates and energy efficiency programs, to investing in security-relevant nuclear power technology.

Around 1970, the truce broke down. A combination of changed political priorities, different technological opportunities, and changes in both costs of and demand for electricity undermined the governance structure of the industry. During the next 20 years, the federal government substantially modified both its regulatory philosophy and framework. By the time California passed its restructuring legislation, the regulatory compact had been breached. Investor-owned utilities were no longer guaranteed rates of return adequate to encourage further investment. Retail prices had increased sharply and capacity investment appeared inadequate. Federal and state regulatory regimes were at odds. Restructuring in California responded to a set of difficult economic and political challenges.

The purpose of this section is to review the key features of this history. This background is useful to understanding choices made in California in the past ten years and the problems that have surfaced in our restructured environment. We proceed in three stages: first, we look at the evolution of the IOU industry in the first half of the twentieth century. Second, we review the reasons that the structure became dysfunctional during the 1970s and 1980s. We then consider the restructuring legislation by the federal government.

1.1 The Investor Owned Utility Industry

The IOU structure resulted from interactions of politics and technology. We consider these in sequence, starting with a stylized view of an entirely private electric utility industry. At their peak, vertically integrated IOUs served about 80 percent of retail customers in the United States and generated around three-quarters of the nation's electricity. Federal projects, rural cooperatives, firms generating electricity for their own use and municipal power companies provided the balance. These additional actors proved important to changes in the electricity industry. They are discussed in the Exception to IOU-PUC Hegemony section below.

The Legal Framework

State regulations, the 1935 Federal Power Act and the 1935 Public Utility Holding Company Act shaped the basic structure of the electric utility industry in the United States.

Initially, primary control for regulatory policy rested with state and local authorities, and the federal government filled in gaps when necessary. This philosophy is consistent with the notion that the purpose of electricity regulation is to promote service by the grant of intra-state monopoly franchises, and then to limit exercise of monopoly power through rate of return regulation.[1]

That electricity is, in part, an interstate business was apparent by 1927. The test case establishing the inadequacy of state regulation involved, not surprisingly, the small state of Rhode Island, whose electric utility sold power both within the state and to a Massachusetts distributor. When the Massachusetts firm disputed a rate increase, the U.S. Supreme Court ruled that no rate set by a state commission was valid in this circumstance. Neither Rhode Island nor Massachusetts had any rate-setting authority over interstate sales of electricity.[2] Congress responded with the 1935 Federal Power Act, which gave the Federal Power Commission authority to regulate "the sale of electric energy at wholesale in interstate commerce," but explicitly left to the states authority over power plant siting and retail distribution.[3] (The Federal Power Commission later became the Federal Energy Regulatory Commission, or FERC.)

The federal interest in financial securities justified passage in 1935 of the Public Utility Holding Company Act (PUHCA). Congress passed PUHCA in response to financial failures and accounting scandals in the electric utility industry. The Act imposed on public utilities a mind-boggling number of reporting requirements, accounting and securities regulations and business restrictions. One way to become exempt from the most onerous restrictions of PUHCA (although by no means all of its requirements) was for electric utilities to confine essentially all their assets and operations to a single state and to focus exclusively on electricity operations. By 1991, most private U.S. electric utilities qualified for exempt status. Only nine were registered electric utility holding companies.[4]

Any firm would become a PUHCA public utility if it owned even a modest share (ten percent) in an electricity facility. Of course, most businesses that contemplated involvement in some aspect of electricity generation, transmission or distribution responded to PUHCA by avoiding the electric utility business altogether.[5]

The Act had a profound impact on the structure of the industry. It supported IOU vertical integration both by foreclosing entry of independent power producers and by limiting alternative investment opportunities of utilities. Moreover, PUHCA restrictions simplified relations between FERC regulators and state PUCs. Because PUHCA inhibited both interstate activities by a single utility and all wholesale transactions between utilities and independent power producers, the Act reduced the scope of FERC's activities. In consequence, it lowered the potential for conflicts between the state and federal regulators.[6]

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[1] The earliest regulation of electric utilities in the United States was at the municipal level. For an analysis of the early state regulation of electric utilities, see Christopher Knittel, "The Adoption of State Electricity Regulation: The Role of Interest Groups," POWER working paper PWP-048, UC Berkeley.

[2] "Plainly, ... the paramount interest in the interstate business carried on between the two companies is not local to either state, but is essentially national in character. The rate is therefore not subject to regulation by either of the two States in the guise of protection to their respective local interests; but, if such regulation is required it can only be attained by the exercise of the power vested in Congress." *Public Utilities Comm. Of Rhode Island v. Attleboro Steam & Electric Co.,* 273 U.S. 83 (1927).

[3] 16 USC § 824.

[4] Watkiss, Jeffrey D. and Douglas W. Smith, "The Energy Policy Act of 1992 – A Watershed for Competition in the Wholesale Power Market," *10 Yale Journal on Regulation 447,* Summer 1993, footnotes 81 and 82 and accompanying text. This article contains an excellent discussion of the complex provisions of PUHCA and the changes instituted in the 1992 Energy Policy Act.

[5] Another consequence of the Act was that electrical supply firms that conducted research and development, like Westinghouse and General Electric, were discouraged from owning or sharing any substantial part of the risk of demonstration plants. PUHCA thus plausibly contributed to the limited scope of R&D investment in the industry, particularly prior to the formation of the Electric Power Research Institute in 1972.

[6] Even during the first part of the century such conflicts arose regularly over such issues as what constituted interstate trade. These disputes were typically resolved in favor of Federal Power Commission jurisdiction. E.g., *Federal Power Comm. v. Southern California Edison Co.,* 376 U.S. 205 (1964).

Technology Cooperated

Until around 1970, technology cooperated with the governance scheme outlined above. Technological advances drove costs down at central station generation plants. Both the basic technology and the technological advances favored very large fossil-fuel plants so that costs declined when demand within utility service areas became large enough to support big, efficient generating units. Prior to 1970, demand for electricity grew rapidly, averaging over seven percent per year. Thus, more utilities could take advantage of the scale economies in generation, and inflation-adjusted retail prices between 1945 and 1970 dropped by more than two-thirds. (See Table 1.1)

Year	Average Electricity Prices Cents per Kilowatthour
1940	28.67
1945	21.60
1950	16.03
1955	14.54
1960	11.70
1965	10.10
1970	7.60
1973	7.40
1974	8.50
1975	8.70
1976	8.80
1977	9.10
1980	9.50
1985	10.03
1990	9.05
1995	8.56
2000	7.68

Table 1.1 – Average Electricity Prices, 1940-2000, Cents per Kilowatthour, 1996 Dollar (Deflated using gross domestic product, implicit price deflators, chained 1996 dollars.)

Source: U.S. BEA

Source for prices: 1960-2000, U.S. Energy Information Administration at www.eia.doe.gov/emeu/aer/txt/tab0815.htm 1940-1960, Energy Data Report: Typical Electric Bills – January 1, 1980, U.S. Department of Energy DOE/EIA-0040 (80), p.6.

The growth in demand and reduction in costs meant that regulators were routinely faced with lowering prices to consumers, on the one hand, along with expanding operations and increasing profits to the regulated industry, on the other. Public utility commissions faced few tough decisions or trade-offs.

The changes in technology supported the federal/state regulatory split as well. The nature of the technological improvements legitimized vertically integrated, centralized utilities, as these could take advantage of scale economies. Growth in demand meant that scale economies could be exploited within smaller geographic areas. Thus the PUHCA restrictions for within-state operations and centralized production appeared to cost little in efficiency losses. Within the boundaries established by PUHCA, state regulators remained the dominant regulatory authorities over day-to-day activities of the electric utilities.

Exceptions to IOU-PUC Hegemony

The early 1960s have been termed the "heyday" of investor-owned utilities.[7] But even at that time, the industry departed significantly from a vertically integrated model or even from a set of regional vertically integrated monopolies. The IOUs obtained increasingly larger amounts of power and other energy services, such as reserve capacity, from other entities. In addition, they sold substantial amounts of electricity to wholesalers for final distribution. Furthermore, their control of the transmission system weakened steadily, albeit slowly, during the 1960s and 1970s.

On the generation side, electrical systems were interconnected and, starting in the early 1960s, utilities increased their participation in power pools. The interconnections stemmed in part from the increase in the size of the utilities' generating units, which required greater reserves for system reliability. Pooling activity increased with the establishment of the North American Electric Reliability Council (NERC) in 1968, following disruptive blackouts on the East Coast in 1965 and 1967. NERC, a non-profit organization whose members include the IOUs as well as other participants in the electric utility industry, sets transmission requirements, reserve capacity and other standards to "promote electric system reliability and security." [8] One of its early initiatives to improve system reliability involved bringing together the hundreds of small power companies for coordination purposes. Through NERC membership, the small companies took advantage of some of the scale economies of the big IOUs. NERC thus provided an important counterexample to the claim that utilities had to have a monolithic structure to provide reliable service. Furthermore, its regional model constituted a counterpoint to the within-state operations of the public utility commissions.

The retail end of the industry has always been populated by a variety of organizations. In the second half of the 20th century, the private, vertically integrated companies were responsible for about three-quarters of all retail customers. Municipal systems (primarily distribution companies) accounted for about 15 percent and rural cooperatives the remainder.[9] The municipal power companies were not regulated by state PUCs, but interacted with the federal authorities that regulated their wholesale transactions with the IOUs and the terms of their access to the IOU-owned transmission lines. Large IOUs owned nearly all the transmission lines, through which federal power and some of the state power flowed. But while transmission access existed prior to 1970, little wheeling occurred. A more common transaction involved IOU purchasing power from different generation sources, and then satisfying all the needs of the municipal utility within its service area.

The existence of a fairly large municipal sector was important to the deregulatory movement in several respects. First, their continued survival in the industry (albeit on occasion with subsidies) demonstrated the technical feasibility of separating distribution from transmission in the industry. The widespread existence of protocols for wholesale purchases and development of technology to enable transactions at the transmission/distribution interface provided evidence for the viability of more widespread vertical separation in the industry.

Second, the municipal sector was responsible for demonstrating the feasibility of wheeling, and thus additional vertical separation in the industry. Prior to 1979, many municipal utilities had obtained limited permission to wheel power on the IOU transmission system. Their success was unanticipated fallout from nuclear projects. In a compromise between public and private power proponents, the Atomic Energy Act of 1954 endorsed development of nuclear generating plants by the IOUs, but required the Atomic Energy

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[7] Richard F. Hirsh, *Technology and Transformation in the American Electric Utility Industry*, Cambridge University Press, Cambridge: 1989. This book contains an excellent discussion of technological and management changes in the industry between 1960 and 1980.

[8] See *About NERC* at www.nerc.com/about/.

[9] Statistics in text are for 1992. Watkiss and Smith, *op. cit*., fn 14. In 1980 IOUs provided 78 percent of all retail energy sales. Joskow, Paul L. and Richard Schmalensee, *Markets for Power: An Analysis of Electric Utility Deregulation*, MIT Press, Cambridge, Mass: 1983, p. 12.

Commission (later the Nuclear Regulatory Commission, or NRC) to consider antitrust issues in its licensing procedures. In 30 of the 100 construction permits issued by the NRC during the 1960s and 1970s, the Commission imposed some conditions to relieve alleged anticompetitive activities by licensees. These typically took the form of allowing municipal systems within the IOU's service area some participation in the nuclear project (e.g., partial ownership) and transmission access adequate to participate in the nuclear project. The result was that these IOUs had to publish a transmission tariff, which in some cases subsequently served as a wedge to more extensive access.[10]

Municipal power companies obtained additional wheeling rights from antitrust suits brought under the Sherman Act. In *U.S. v. Otter Tail*, the most prominent of these cases, [11] the Supreme Court found that the Otter Tail Power Company used its monopoly over transmission to impede municipalities within its retail area from establishing viable distribution companies when their contracts with Otter Tail expired. The Supreme Court ordered Otter Tail to wheel power for the municipalities from a generation project run by a rural electric cooperative. In its decision the Court carefully distinguished a wheeling order to correct for anticompetitive practices from any interpretation that FERC had authority to order wheeling to promote competition. Following what became known as the "Otter Tail doctrine," courts ordered wheeling services in a series of subsequent, similar cases, but only as remedy for anticompetitive practices. [12]

Between NERC-mediated power pools, sales to municipal power systems, wheeling for municipal power systems and power purchases from federal projects, by 1980 the electric utilities were in fact far from a classic vertically integrated business. As Table 1.2 shows, IOUs both bought and sold at wholesale a lot of the power flowing over their grids. The ratio of the quantity of power purchased (watt-hours) to power sold at retail ranged from 15 percent in the Southeast to nearly 60 percent in Ohio, Indiana, Kentucky and West Virginia (the East-Central Area), with a U.S. average of 30 percent. (See Figure 1.1 for a map of the NERC Regions) The ratio of power delivered for resale, e.g., to other utilities and to municipal companies, to power generated by the IOUs varied from ten percent in Illinois and Michigan (the Mid-America Interconnected Network) to over 60 percent in the East-Central Area, with a U.S. average of 26 percent. Of the resale transactions, about one-third of the power went to municipal utilities and most of the remainder to other IOUs. [13] The Western States Coordinating Council, which includes California, was about average for purchases. Its receipts-to-sales ratio is high, and is heavily influenced by purchases from the federal hydroelectric projects on the Columbia and Colorado rivers. In 1980, utilities in the WSCC region were relatively integrated at the distribution level, but even here the ratio of deliveries to generation was 15 percent.

By 1970, FERC had become an agency that focused its electricity portfolio on regulating and overseeing reliability activities rather than economy exchanges. While the Commission had jurisdiction over the details of the wheeling tariffs and conditions, it was much more prominent in regulating the power pools run by NERC than in the wheeling agreements ordered by the federal courts. The choice is understandable since most interstate commerce was, at least in name, conducted for coordination rather than economy purposes. Much effort at capacity pricing or any semblance of a market did not accompany the extensive capacity sharing on transmission lines.

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[10] See J. Pfeffer, "Policies Governing Transmission Access and Pricing: The Wheeling Debate Revisited," *Public Utilities Fortnightly*, Oct. 31, 1985, p. 26. In some cases the Sherman Act suits followed Atomic Energy Commission settlements. A combination of both brought about the first "competitive" spot market experiment in the United States, the Florida Energy Broker, which got underway as part of an antitrust settlement in 1978. See Linda Cohen, *"A Spot Market for Electricity: Preliminary Analysis of the Florida Energy Broker"*, Santa Monica, CA.: Rand Corporation, February 1982. On the other hand, IOUs often provided wheeling services at best grudgingly. Florida Power and Light, in particular, has not ceased litigating access issues with the municipal power companies within its retail area.

[11] 410 U.S. 366 (1973).

[12] *Otter Tail* and subsequent cases are discussed in Watkiss and Smith, *op. cit.*, fn 32 and accompanying text.

[13] Joskow and Schmalensee, op. cit., pp. 14-15.

Region*	Ratio of Receipts to Final Sales**	Ratio of Deliveries to Generation***
U.S.	0.30	0.26
ECAR	0.61	0.64
ERCOT	0.26	0.28
MAAC	0.26	0.17
MAIN	0.14	0.10
MAPP	0.59	0.44
NPCC	0.44	0.25
SERC	0.15	0.20
SWPP	0.37	0.35
WSCC	0.32	0.15

Table 1.2 – Bulk Power Transaction Data: Weighted Average Transactions by U.S. and NERC Regions, 1980 (power measured in watthours)

*See Figure 1.1 for a map of the NERC regions

**Receipts = purchases plus interchanges in

***Deliveries = sales for resale plus interchanges out

Source: Energy Information Administration, U.S. DOE, Interutility Bulk Power Transactions, DOE/EAI-0418, October 1983, p.37.

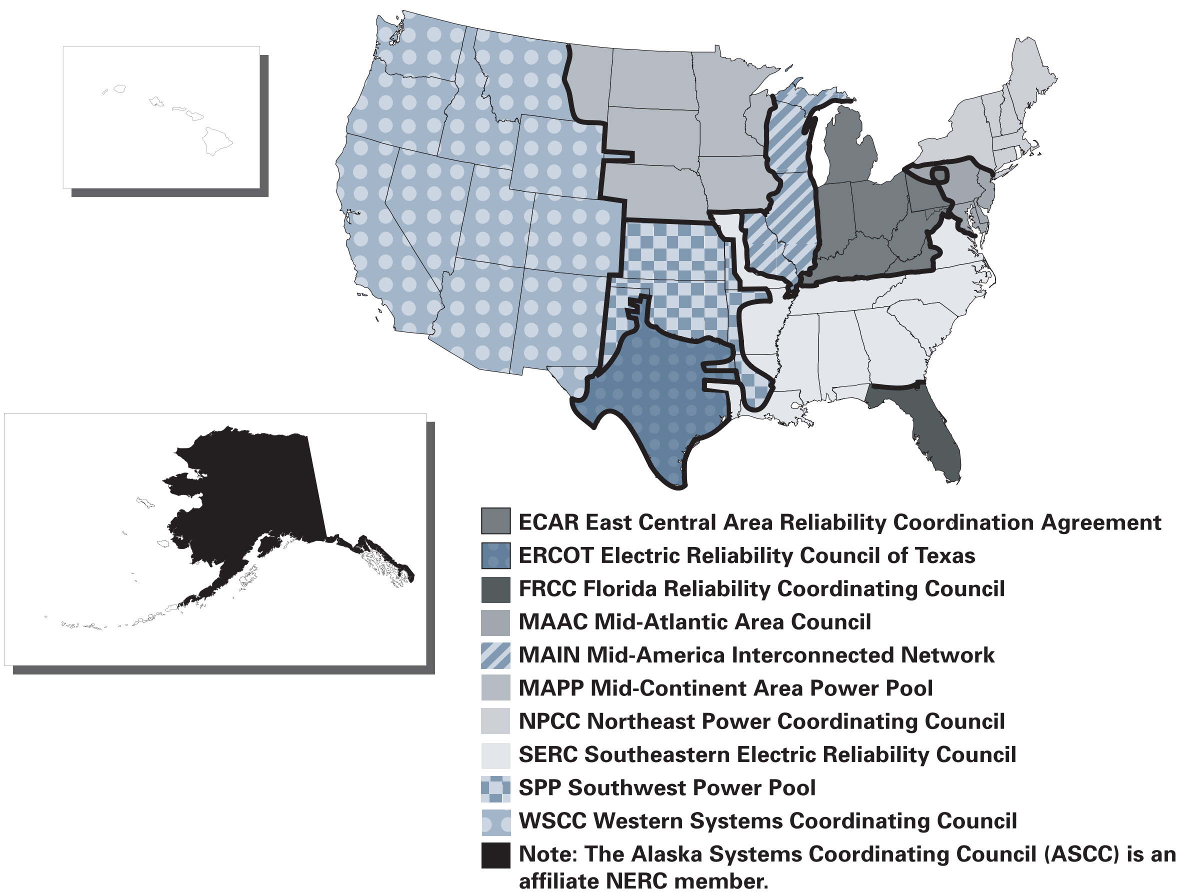

Figure 1.1 – North American Electricity Reliability Council Regions for Continuous United States, Alaska and Hawaii

Source: North American Electric Reliability Council http://www.eia.doe.gov/cneaf/solar.renewables/ilands/appd.html

In general, FERC had less rate-setting business during this time period than its legislative authority might suggest. While the Federal Power Act clearly contemplates a FERC role controlling monopoly prices for interstate commerce (e.g., the *Attleboro* case), the structure of the industry supported a difference in emphasis between federal and state regulators over network coordination versus pricing of services. This difference in focus remains evident in the restructuring activities 20 years later, as is discussed below.

1.2 The Breakdown

The early 1970s were marked by the rise in the environmental movement, increased production costs and sharply curtailed demand growth. Accompanying and contributing to these trends was a dysfunctional state regulatory structure. This section discusses the attempts to deal with the changes in the industry, culminating in the passage of the 1979 Public Utilities Regulatory Policy Act (PURPA).

Hard Times

In the early 1970s input costs increased sharply for electricity production. The oil crises of 1973 and 1978 translated directly into higher costs. Inflation during the decade raised interest rates on construction. The environmental movement, in full swing, resulted in numerous expensive operating and construction modifications for the industry. The cost increases were not offset by productivity gains. Service sector demand had grown enough over the previous 20 years to exploit all scale economies in production in nearly all parts of the country.[14] Finally, the improvements in thermal efficiency were played out: the large generating facilities favored by U.S. utilities were technologically mature.[15]

Exacerbating the problems for utilities, and causing problems for themselves, was the structure of the state regulation.[16] State regulation had been based on rate-of-return principles that only work properly in a world where input costs and demand are stable, or at least predictable. When costs decline, the system works, although not as advertised. When costs increase, the system collapses.

Rate-of return regulation works as follows: PUCs hold periodic rate hearings. They set rates using the four step rate-of-return process. First, they value the rate base of approved plant and capital. Second, they calculate the revenue required to provide a fair return on the rate base plus pay for estimated operating costs. Third, they estimate demand; and fourth and finally, they set retail prices (rates) to generate revenues sufficient to cover the revenue requirements. The process requires good estimates of future costs and future demand. Originally, rate bases included only "used and useful" plants and facilities. Rate payers did not finance projects during construction; rather, PUCs "allowed" the expenditures into the rate base following a "used and useful" demonstration. PUCs could "disallow" inappropriate expenses from rate-base recovery but before the late-1970s disallowances were merely a theoretical possibility.

As long as prices were declining and revenues acceptable to the utilities, neither the precision nor the pace of regulatory review were critical. Consumers were happy with the state of affairs, and delays worked to the advantage of utilities.[17] But when costs rose, the delays caused utilities to earn less than

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[14] An influential study of electric utilities found that while in 1955 significant scale economies existed at most U.S. electric companies, most firms were larger than necessary to take advantage of the scale economies by 1970. See Christensen, Laurits and William Greene, "Economies of Scale in U.S. Electric Power Distribution," *Journal of Political Economy* 84 (4), October 1976.

[15] See Hirsh, op. cit., Part II.

[16] One of the best discussions of the transformation of public utilities commissions in response to the changes in the environment for electricity remains Paul Joskow's seminal piece, "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation," *Journal of Law and Economics*, 17 (2), Oct. 1974, pp 291-327.

[17] According to some analyses, delays worked to the advantage of everyone by circumventing incentives for inefficient production that arise from effective rate-of-return regulation. Delays introduced slack, during which time utilities would directly profit from, and hence engage in, efficient production.

the allowed rate of return – a whole different ball game. With return on equity suddenly more risky and high inflation driving up interest rates, both bond and equity financing costs for construction projects increased, exacerbating the costs of regulatory delays. Consumers, of course, were unhappy with increasing prices, so regulators were besieged from all sides.

The environmental movement had a profound, negative effect on the regulatory and industry electricity institutions in the 1970s. It is important to distinguish this observation from an assessment of its economic or social impact. The record of energy efficiency during the past 20 years in California clearly demonstrates its value to the state's economy. Electricity use and conservation in California are discussed further in Chapter 2.

The environmental movement unquestionably raised the short run cost of the utility business in the 1970s. Part of the cost increase came from pollution mitigation requirements.[18] But the more visible impact arose from its impact on the governance and regulation of the industry. In the late 1970s, demand growth was far less than what utilities and regulators had expected based on their projections made a decade earlier. The environmental movement itself bears at most modest responsibility for this early decline in electricity demand. Important factors include the economic recession and high-energy prices. But whatever the reason, actual growth in national electricity consumption averaged 2.5 percent per year between 1973 and 1986, while many utilities had based their 1970s construction plans on forecasts for five percent growth or higher.[19] Consequently, they found themselves with a long-term construction projects – most notably the nuclear projects – whose need had become questionable. In many cases, schedules were extended, and in some the projects were cancelled. While these decisions may have minimized the damage of the inaccurate forecasts, the immediate impact was to raise production costs, drive the utilities back to rate hearings, and give credibility to the claims of the environmental movement.

The environmental movement obtained standing in the regulatory process. New agencies (e.g., the California Energy Commission) as well as old agencies, like the Nuclear Regulatory Commission, changed requirements and procedures to accommodate the new interest groups, and delayed, modified, and sometimes even rejected siting permits. Moreover, the actions of regulators became increasingly controversial. Not only were consumers unhappy over higher prices and producers unhappy about lower profits, but this new group thought much of the new construction was better handled by conservation rather than production, leaving little room for compromise

State regulators responded initially with a variety of regulatory fixes, intended both to restore the utilities to economic health and to distance themselves from the unpopular rate increases. Regulatory innovations included automatic rate pass-through for the cost of fuel and power purchases; rate recovery of interest payments during construction; allowances of some rate-base treatment for plants under construction; and various so-called "incentive regulation" schemes, that allowed retail prices to fluctuate within specified ranges without a rate hearing. Notwithstanding the efforts of state regulators, the utilities reduced capacity expansion, and prices rose sharply. In sum, by the late 1970s virtually everyone was unhappy with the state of the electricity industry. Reliability appeared to be deteriorating, prices were up, profits were down. The issue appeared on the national agenda in 1978 when President Carter and Congress took up the first major electricity legislation since the 1930s.

The Public Utility Regulatory Policies Act

The 1978 Public Utility Regulatory Policies Act (PURPA) is considered a landmark in the evolution of the electricity industry. Passed as part of a package to address energy conservation in the wake of

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[18] Dennison credits aggregate environmental equipment expenditures in the U.S. with a __ percent slowdown in measured economic productivity during the 1970s. Utilities contributed the largest share to the aggregate.

[19] Rosenfeld and Ward, 1992.

the 1970s oil crises, the act is considered a watershed in three respects. First, it opened up the electric utility industry, albeit narrowly, to non-utility generation. Second, it contained policies and in some cases requirements for electricity prices that were not based on the cost of service. Third it allowed FERC to order interconnections for wholesale transactions. In this section we consider these provisions and their importance to the national restructuring movement.

A central goal of PURPA was to encourage electricity production from cogeneration facilities and from renewable fuels.[20] In order to qualify for PURPA benefits, cogeneration plants had to produce some other commercial energy output in addition to electricity. The model PURPA cogeneration plant was a gas-fired unit that produced steam used in commercial processes as well as electricity. PURPA renewable plants had to be small – less than 80 megawatts – and they had to use a renewable fuel such as biomass or waste. (Under some conditions, temporary substitution of conventional fuels was allowed in these plants.)

The key component for industry structure of PURPA's cogeneration and renewable policy is that the Act encouraged these plants to be built by non-utilities. Non-utility ownership fits the technologies: companies with access to renewable fuel sources, or those that would use the cogenerated non-electric energy had strong incentives to develop the technology.[21] Moreover, industry had experience with some of the cogeneration technologies, although in the past the electricity generated in the plants was consumed entirely within the plant or factory where the cogeneration facility was located. PURPA allowed these companies to engage in limited commerce in electricity. In most cases, they had no choice about who to sell to: the interconnecting utility purchased any output. Moreover, the price was fixed by the state regulatory commission.[22]

In order to allow non-utility participation, the Act amended PUHCA to exempt from its regulations these plants. The Act also exempts them from state reporting regulations, giving their owners a bureaucratic advantage over utility generators. These favored facilities became known as "qualifying facilities," or QFs.

PURPA departs from the traditional cost-of-service basis for prices in two areas. It specified that QF power would be bought by the local utility not at the cost of QF production but rather at what the utility would have had to pay for power had it not purchased the QF output. This counterfactual price is called the "avoided cost." Avoided cost in principle is the marginal cost of generation for the electricity system. Introductory microeconomics teaches that marginal cost equals price in a competitive market, and confers all kinds of efficiency benefits. But as with rate-of-return regulation, which in theory generates profits to participants equivalent to what they would have gotten were the industry competitive (the "fair return"), implementing an avoided cost policy in a regulatory framework is a far cry from an actual market. PURPA left the precise determination of avoided cost to the state PUCs.

Second, noting that most rate structures at the time favored consumption, PURPA required all states to consider a range of pricing policies that would promote conservation such as increasing block structures for rates and time-of-use prices. The states had to consider conservation rates, but did not

[20] Like all major legislation, PURPA reflects compromises between different interest groups and goals – in this case, lowering oil consumption via methods attractive to the environmental movement. Nuclear power and coal (a domestic resource in little danger of exhaustion) were not on the list.

[21] Clearly the same could have been said about coal plants two generations earlier or electrical suppliers of any of the plants. In this case, the policy also was championed by PURPA supporters who subscribed to "small is beautiful" principles.

[22] One of the less "competitive" characteristics of PURPA was that some factories that cogenerated power found that they could sell the power they generated on site at the regulated "avoided cost," but purchase power at a lower, wholesale cost. They became what was known as "PURPA pumps," both buying and selling power (at least, on the books) and pocketing the difference.

have to implement them. As is discussed below, California embraced these provisions of PURPA to plausibly significant ends.

A number of states viewed PURPA as an outright power grab by the federal government. They challenged the Act in court, claiming that it violated the Tenth Amendment rights of states and was an unconstitutional incursion of the federal government in state affairs. The Supreme Court upheld PURPA.[23] The Court found that PURPA did not legislate state action, but rather the provisions that exempted QFs from state regulations cleaned up conflicting regulations between the federal and state governments. The federal versions held sway because of federal jurisdiction over the regulation of wholesale electricity. Furthermore, the Court noted that PURPA merely gave state PUCs the opportunity, rather than requiring them, to set avoided cost rules for QFs. FERC was prepared to set the avoided cost rates under its own wholesale regulatory authority if a state PUC did not wish to do so.

The importance of PURPA as an example for subsequent, more comprehensive deregulation has probably been overstated. The avoided cost rates were not market prices, and QFs were by no means the first incursion into a vertically integrated industry (see discussion above). But it was significant in at least three respects. First, it was the first crack in PUHCA in over forty years. Second, the non-utilities that built QFs became a vocal interest group and lobbied to allow more flexibility in the types of plants that would qualify for PUHCA exemptions.[24] Third, the cogeneration opportunity probably greatly spurred the adaptation and diffusion of modern gas turbines to electricity generation.

The new gas turbines are a substantial departure in technology from the thermal generation units that had dominated the industry during the previous forty years. These gas turbines are now the base-load plant of choice. The technology is of particular value to a competitive generation market for several reasons. First, it exhibits scale economies in manufacturing (e.g., when General Electric produces multiple units), but not in at-site construction experience: they can be more or less purchased as turnkey units (that is, relative to the previous technology). Operating companies have less need for the kind of large engineering and construction divisions maintained by major utilities in the 1960s. Second, the modern plants are efficient at sizes that are half the size or less of modern coal or nuclear plants, and the installation is relatively rapid. For both reasons, they are less risky investments. Of course, less risk is always desirable, but its reduction is even more valuable to non-utilities that cannot count on guaranteed cost recovery through a regulatory rate case.

PURPA had another consequence important to the later state restructuring movement. The variation among states' avoided cost definitions and QF contracts resulted in dramatic variation in prices a decade later, which added another straw to the traditional regulatory camel's back in high cost states. This unintended consequence is discussed further below.

Summary: The Regulatory Compact Breakdown

By the end of the 1980s, the structure of the electricity industry and the structure of its regulation were at odds. In part due to delays in construction, nuclear projects that came on line during the 1980s did so at enormous cost. Under pressure from consumer groups, PUCs were unwilling to grant sufficient rate increases to cover costs, and disallowed some construction expenses from rate base treatment. Utility equities suffered.[25]

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[23] *FERC et al. v. Mississippi et al.,* 456 U.S. 742, 102 S.Ct. 2126, (1982).

[24] A thoughtful discussion of PURPA and deregulation is contained in Paul Joskow, *"Deregulation and Regulatory Reform in the U.S. Electric Power Sector,"* in Deregulation of Network Industries: The Next Steps (S. Peltzman and Clifford Winston, eds.), Brookings Press, 2000.

[25] See Oakridge National Laboratory, *Prudence Issues Affecting the U.S. Electricity Industry* (July 1987); Idaho Power Stock Slumps after PUC Denies Equity Return on Valmy-2 Share, *Elec. Util. Wk.,* July 26, 1986, at 11; Watkiss and Smith, op. cit. at fn 16 and accompanying text.

Moreover, utilities were no longer providing new capacity. During the 1980s, independent power producers, operating under PURPA, accounted for half of all capacity additions in the United States. By the mid-1990s, ten percent of the U.S. capacity was in qualifying facilities. California's generous terms and enthusiasm for the program, combined with its distaste for central station generators, meant that virtually all capacity additions between 1986 and 1992 were QFs. These sources ultimately amounted to 23 percent of the installed capacity in California.[26]

Finally, notwithstanding the best efforts of state PUCs, rates increased. The largest increases occurred in states, including California, that had set up generous QF terms and made heavy investments in nuclear power starting in the late 1970s. The stage was set for restructuring legislation.

1.3 Federal Restructuring Legislation

By 1990, energy policy was back on the national agenda. Federal legislative activity culminated in the 1992 Energy Policy Act (EPAct). State agencies in California started considering restructuring legislation a year later, calling for "cooperative federalism" as regulatory changes at both the federal and state level were necessary to establish more competitive markets for electricity. The Federal Energy Regulatory Commission (FERC) issued two rules important to electricity restructuring in April 1996, known as Order 888 and 889. The California Legislature also acted in 1996, passing Assembly Bill 1890 (AB 1890). This section considers the federal legislation. The subsequent chapter reviews the background and primary components of AB 1890.

The Energy Policy Act of 1992

As with PURPA, energy security and conflict in the Mideast motivated EPAct. But where PURPA focused on administrative incentives to develop new sources of electricity and encourage energy conservation, EPAct sought to enhance efficiency in energy use through competition and market forces. Nevertheless, like most legislative initiatives, the bill moderates its goals to cater to the beneficiaries of previous policies. Its main provisions for electricity restructuring involve ownership of generation and access to transmission lines. In both cases, the policies reflect prerogatives of state regulators and existing public utilities. As is discussed below, FERC was far less gentle to these stakeholders in its subsequent rulemaking proceedings.

EPAct greatly expanded PUHCA exemptions for generators.[27] "Exempt wholesale generators," or EWGs, are not limited by size or fuel type. They can be new facilities. Also, a utility can sell a generator to a wholesaler who can qualify as an EWG.[28] EWGs are not limited in ownership structure, and can be virtually any company, including a utility affiliate. The only important limitation on an EWG is that it produces wholesale power only. An EWG can sell no power at retail. This provision of EPAct was justified as necessary to protect public utilities from "cherry-picking," that is, to preclude EWGs from selling exclusively to lucrative industrial customers and avoid serving the retail customers who benefit from the states' retail rate scheme. More precisely, it protected both the distribution business of utilities and the states' redistributive ratemaking options.

Unlike PURPA qualifying facilities, EWGs are not guaranteed a price or market. Instead, EPAct expected their output to be sold in a competitive wholesale market, either to the interconnecting utility or some other retailer, at a "market" price. By 1992, FERC had substantial experience with this kind of ratemaking. EPAct does include restrictions on wholesale rates when the EWG is owned by a utility

[26] 1999 estimates, drawn from Dept. of Energy, Electric Power Annual Vol. 2, Table 55; Jolanka V. Fisher and Timothy P. Duane, *"Trends in Electricity Consumption, Peak Demand, and Generating Capacity in California and the Western Grid 1977-2000,"* U.C. Berkeley, UC Energy Institute working paper PWP-085, Sept. 2001.

[27] For greater details on the provisions of EPAct, see Watkiss and Smith, *op. cit.*

[28] EPAct specifies that any utility sales of generators are subject to state regulatory review and regulations.

affiliate and sells to the parent utility, but, like the California restructuring legislation, EPAct does not contemplate the possibility that an independent generator might be able to exert market power on its own.[29] However, all wholesale transactions, including EWG transactions remain subject to FERC jurisdiction.

Second, EPAct gave FERC the authority to order wheeling in response to an application from an EWG or distribution company customer of an EWG. By contrast, PURPA only specified that FERC could order utilities to interconnect with a qualifying facility and purchase its output (at avoided cost) at the point of interconnection. During the 1980s, FERC's position was that PURPA prohibited it from "wheeling orders that have a significant procompetitive effect." [30] In fact, FERC regularly ordered wholesale transmission deals, including wheeling orders during this period, but not on its PURPA authority. Rather, it requested utilities to file wheeling tariffs as a quid-pro-quo for certain requests the utilities had made of FERC. These included actions that FERC argued might otherwise lessen competition, such as a merger or consolidation. Another basis for quid-pro-quo wheeling was when utilities requested permission to purchase or sell power at market-based rates rather than cost-of-service rates. These circumstances, however, did not provide a basis for the transmission services contemplated for a competitive EWG industry.

As it turned out, EPAct did not provide a reasonable basis for transmission services. The Act only allows FERC to respond with a wheeling order for a specific transaction: that is, in response to an application. EPAct does not give FERC authority to order a public utility to file a general wheeling tariff. Instead, each EWG would have to enter separate wheeling negotiations and separate appeals, if necessary, to FERC. Second, EPAct makes no provision for coordination among the transmission systems owned by adjacent public utilities. Thus, an EWG might have to negotiate wheeling agreements with multiple systems whose wires lay between the EWG and a distributor, and appeal each to FERC. Finally, wary of state regulatory jurisdiction, EPAct prohibits FERC from ordering wheeling for retail customers.[31]

FERC Orders 888 and 889

Between 1992 and 1996, FERC issued twelve EPAct wheeling orders, in individual proceedings it characterized as costly and time consuming.[32] In the interim, several states had initiated restructuring activities (see Table 1.3 for a summary of restructuring actions in different states), and the hearings in California in particular suggested that the EPAct protocols would be inadequate to deal with probable demand for wheeling services. FERC initiated rule-making hearings in 1995 that led to the 1996 Orders.

Order 889 requires that utilities post information about the transmission system – involving use, congestion, and demand conditions – so that all users of the system have identical information about access. This provision is important in California for the way that the Independent System Operator works, and is discussed in the next chapter.

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[29] For example, Watkiss and Smith, *op. cit.,* in an otherwise excellent and prescient treatment of restructuring, state, "In no current or currently foreseeable market do generators that are neither utilities nor utility affiliates possess generation dominance, ownership or control of transmission or any type of a monopoly franchise. Consequently, under FERC's analysis, these generators should routinely receive authority to wholesale at market based rates." (p. 486).

[30] *Southeastern Power Admin. v. Kentucky Utils. Co.,* 26 F.E.R.C. 61,127 at 61,323 (1984), cited in Watkiss and Smith, *op. cit.* at 457.

[31] *Energy Policy Act of 1992* 106 Stat. 2776, §212.

[32] FERCs experience with wheeling under EPAct authority is discussed in the Supreme Court's decision in New *York et al. v. Federal Energy Regulatory Commission et al.,* No. 00568 and 00-809, decided March 4, 2002. (2002 WL 331835 (U.S.), p. 4). (Cited below as *New York v. FERC.*)

Restructuring Legislation Enacted	**Arizona, California, Connecticut, Illinois, Maine, Massachusetts, Montana, Nevada, New Hampshire, Oklahoma, Pennsylvania, Rhode Island, Virginia**
Comprehensive Regulatory Order Issued	**Maryland, Michigan, New Jersey, New York, Vermont**
Commission or Legislative Investigation Ongoing	**Alabama, Alaska, Arkansas, Colorado, Delaware, District of Columbia, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nebraska, New Mexico, North Carolina, North Dakota, Oregon, South Carolina, Tennessee, Texas, Utah, Washington, West Virginia, Wisconsin, Wyoming**
No significant Ongoing Activity	**Florida, South Dakota**

Table 1.3 – Status of Electricity Deregulatory Activity, December 1, 1998

Order 888 is revolutionary in its impact on industry structure. The FERC order turns on the extent to which electricity is bundled. Utilities that sell only bundled intrastate services – that is, all its sales are to retail customers – are not covered by the Order. FERC decided that regulating such sales would lead to jurisdictional issues with the states.[33] Order 888 requires utilities that have unbundled retail sales to functionally unbundle the generation and transmission services. Specifically, each utility is required to state, "separate rates for its wholesale generation, transmission and ancillary services, and to take transmission of its own wholesale sales and purchases under a single general tariff applicable equally to itself and others." [34]

FERC considered the state versus federal jurisdictional issue involved in this apparent regulation of retail rates. But FERC decided that it was "irrelevant to the Commission's jurisdiction whether the customer receiving the unbundled transmission service in interstate commerce is a wholesale or retail customer." The Commission asserted federal jurisdiction whenever "a public utility voluntarily offers unbundled retail access… or if the State requires [it]." [35]

Order 888 goes well beyond the EPAct wheeling authorization, requiring general wheeling tariffs and extending to retail wheeling in most states. FERC asserted authority for the Order not under EPAct, but under sections 205 and 206 of the 1935 Federal Power Act, which give FERC power to remedy "unduly discriminatory practices." FERC found that the utilities were discriminating in the bulk power markets by providing either "inferior access to their transmission networks or no access at all to third-party wholesalers of power." [36] Thus, it was on its historical *Otter Tail* authority rather than a new EPAct authority that FERC ordered the wheeling requirements.

As with PURPA, some states saw Order 888 as yet another federal power grab. When combined with repeal of PUHCA limitations on independent generators, the open access requirements in Order 888 shift the bulk of the electricity business from bundled retail sales (regulated by the state PUCs) to wholesale transactions (regulated by FERC). The shift critically weakens state PUC control over retail prices. The federal filed rate doctrine, established in a series of federal judicial cases involving natural gas as well as electricity, requires state public utility commissions to allow a utility to pass through

[33] This discussion of Order 888 is drawn from the opinion in *New York v. FERC*.

[34] *New York v. FERC*, p. 4.

[35] *FERC Order 888* at 31,689.

[36] *New York v. FERC*, p. 4.

– that is, charge customers – expenses occurred subject to an approved federal rate.[37] In this case, the doctrine means that expenses accrued by utilities for wholesale purchases (set according to approved federal rates) are automatically charged to retail customers. State PUC control over retail rates thus diminishes as the component of utility costs due to wholesale purchases increases.

In addition, the Order allows FERC to encroach further on retail operations, by regulating transmission for unbundled retail sales. The Order thus challenges the redistributive ability of state PUCs in the electricity sphere. Finally, Order 888 shifts jurisdiction over the transmission lines, historically within the states' purview, to the federal government. This last chance may ultimately prove the most important, as the transmission lines are the businesses. FERC, along with the multitude of industry participants, are now formulating regional transmission policies, and the outcome of the negotiations is likely to be a fundamental component of future industry structure.

Together with a long list of utilities, consumer groups, electricity marketers, EWGs, and municipal utilities, these states challenged Order 888 in federal court on both statutory and constitutional grounds. The Supreme Court issued a decision March 4, 2002 upholding all parts of the Order.[38] California was not part of the original suit (the state was still in a "cooperative federalism" mode in 1996). However, the state filed a friend-of-the-court brief supporting New York's position in the Supreme Court appeal in 2001. In it, the state claims that the federal authority asserted in Order 888, "has severely limited California's alternatives for pulling back from the precipice of the state's electric utility disaster." [39] We return to this claim in Chapter 4.

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[37] Of course, the filed-rate doctrine has exceptions and subtleties. "In its simplest form, this doctrine says that if someone pays for services at a rate that has been filed with and approved by the proper regulatory agency then the legality of that rate should not be subject to being reopened in later proceedings." Fred Bosselman, Jim Rossi and Jacqueline Lang Weaver, *Energy, Economics and the Environment: Cases and Materials*, New York: Foundation Press, 2000, p. 589. State PUCs could possibly still challenge the expense by claiming that the utility's wholesale purchase was imprudent. The file-rate doctrine was at the heart of the lawsuits entered by Southern California Edison and other California utilities against the California Public Utility Commission during their financial melt-down following restructuring in California. See chapters 3 and 4, below.

[38] *New York v. FERC*. A unanimous court upheld the functional unbundling provisions of Order 888 based largely on the *Chevron* doctrine that deference was due the regulatory agency in the case. This part of the Order had been appealed by the states. Enron objected to the provision of Order 888 that exempts bundled retail sales from the Open Access provisions. This too was upheld by the majority, but three judges dissented. The dissent, written by Justice Thomas argues that FERC's reasoning was unpersuasive.

[39] The case and California's concerns are discussed in Carrie Peyton, "Power play for control of grid," Sacramento Bee, Jan 3, 2002.

CHAPTER 2: THE ROAD TO RESTRUCTURING IN CALIFORNIA

2.0 Overview

The development of the electricity industry in California paralleled that of the rest of the country, moving from a rate-of-return regulated, vertically integrated IOU structure to a hybrid system with independent power producers and multiple strategies for regulating prices, costs and investments. However, the trends that are discussed in the previous chapter that challenged the regulatory structure of the industry were exaggerated in California. Rather than modify the regulatory structure, the state decided in the early 1990s to pursue fundamental regulatory reform.

This chapter focuses on the development of some of the more distinctive features of the California electricity system, and how these features contributed to both the decision to restructure the industry and specific aspects of the state's restructuring plan. The first section reviews the overall structure of the industry in California and discusses the regulatory emphasis in the state on energy conservation policies. We then consider the status of rate regulation and resource planning in California in the early 1990s. The final sections review the main features of Assembly Bill 1890 and compare its provisions to the federal restructuring legislation.

2.1 California Energy Resources

Energy advocates in California were among the first in the nation to recognize and exploit the potential of demand side resources, conservation and energy efficiency. The regulatory structure in California recognizes energy efficiency and conservation as "resources," treating them for many purposes as symmetric to, say, a gas turbine plant. This section provides an overview of energy resources in California, considering first the "supply" resources and then the "demand" resources.

The Supply Side

California's electricity system proved particularly vulnerable to the economic and political changes in the 1970s. In the 1960s, generation in California, and resource plans emphasized oil and nuclear fuels. (See Figure 2.1) Furthermore, the environmental movement has a long, distinguished history in California, dating from the establishment of the Sierra Club in the 19th century. By the 1970s, environmental groups were deeply involved in state regulation of the electricity industry. Consequently, the oil price shocks, increased inflation and regulatory shocks associated with major construction projects hit both the economics and politics within the state with particular force in the 1970s. For the first time electrical utilities asked for rate increases. The average price of electricity for the three investor-owned utilities in California rose from less than \$0.02/kWh in 1965 to \$0.08/kWh in 1982. Moreover, capacity expansion slowed dramatically. In 1978, the PG&E reserve margin dropped to eight percent, and then fell even further in 1981 to a low of 6 percent – levels that today would trigger a power alert. In the summer of 1979, the Company alerted industrial customers to prepare for rolling blackouts.

Not surprisingly, PURPA was well received in California, where pro-environmental politics and electricity capacity shortages created fertile ground for its goals. Indeed, California policy anticipated PURPA, as in 1976 the legislature passed the Small Power Producers Act of 1976, which relieved small power producers from state regulatory oversight. The state did not join the lawsuits against the Act.

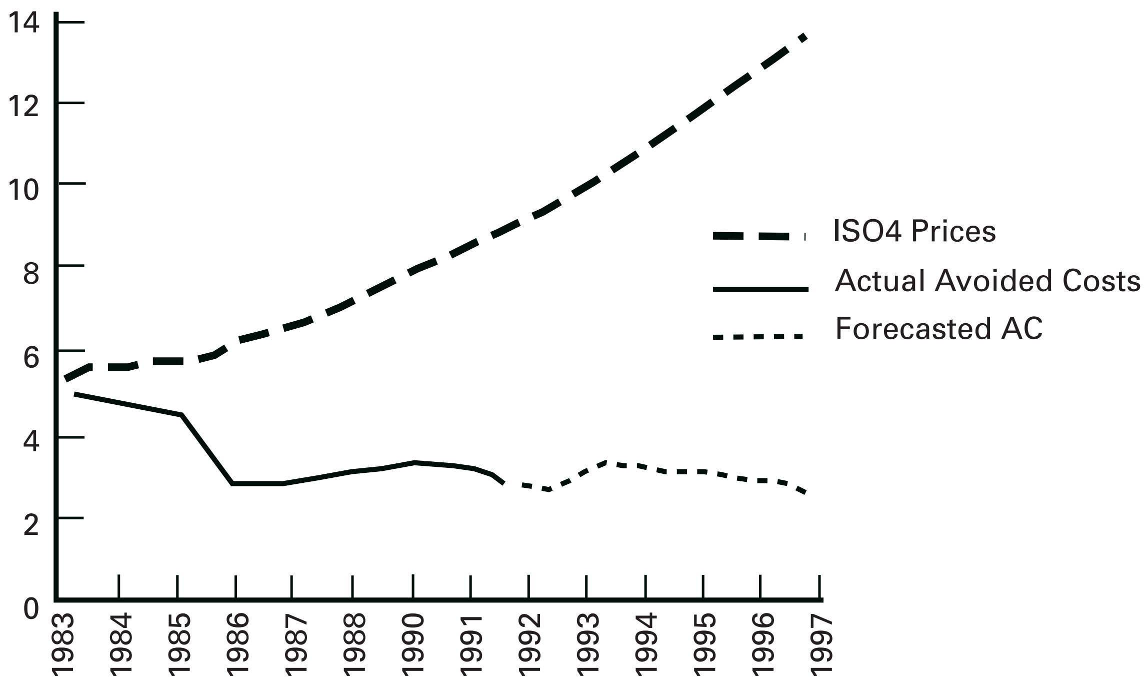

Figure 2.1 - QF Prices - SCE

Source: CPUC

The California Public Utility Commission (CPUC) took an active role in setting attractive avoided cost rates for QFs.[40] In 1982, the CPUC ordered utilities to provide proposals for five different types of contracts, known as standard offers. The standard offers, each applying to a different set of QF arrangements, would be known in advance by prospective QFs, and did not require individual negotiation. The existence of standard offers were intended to mitigate the ability of the large utilities to prolong negotiations. The utilities initially proposed, and the CPUC approved, three standard offers for QF pricing based on short-term avoided costs. Standard Offer 2 was particularly attractive as it provided fixed prices for capacity for up to 30 years. The utilities signed up 1,500 MWt of QF capacity under these contracts.

QF proponents argued that to encourage greater investment, long-term QF contracts should be based on estimates of future energy prices. Under heavy pressure from the CPUC, the utilities proposed the "interim standard offer 4" (ISO4) contract, which was approved in September 1983. This was a 15 to 30 year contract, and prices were based on forecasted prices of fuel and capacity needs. The contract was wildly attractive. By 1985, QF projects exceeded 15,000 MWt and, under petition from both PG&E and the CPUC's own staff, the Commission suspended the ISO4 option in April 1985. The SO2 contracting, which had also attracted subscribers, ended in 1986. Eventually about 9.5 gigawatts of capacity was installed in California in qualifying facilities.[41]

[40] An excellent discussion of the QF program in California is contained in Jeffrey Dasovich, William Meyer and Virginia Coe, California's Electric Services Industry: Perspectives on the Past, Strategies for the Future, A Report to the California Public Utilities Commission by the Division of Strategic Planning. San Francisco, CA, Feb 3, 1993. ch. 4. (Cited below as The Yellow Book.)

[41] California Energy Commission, *"1999 Operational Capacity of California's Three (Major) Investor-Owned Utilities,"* at www.energy.ca.gov/electricity/operational_capacity.html.

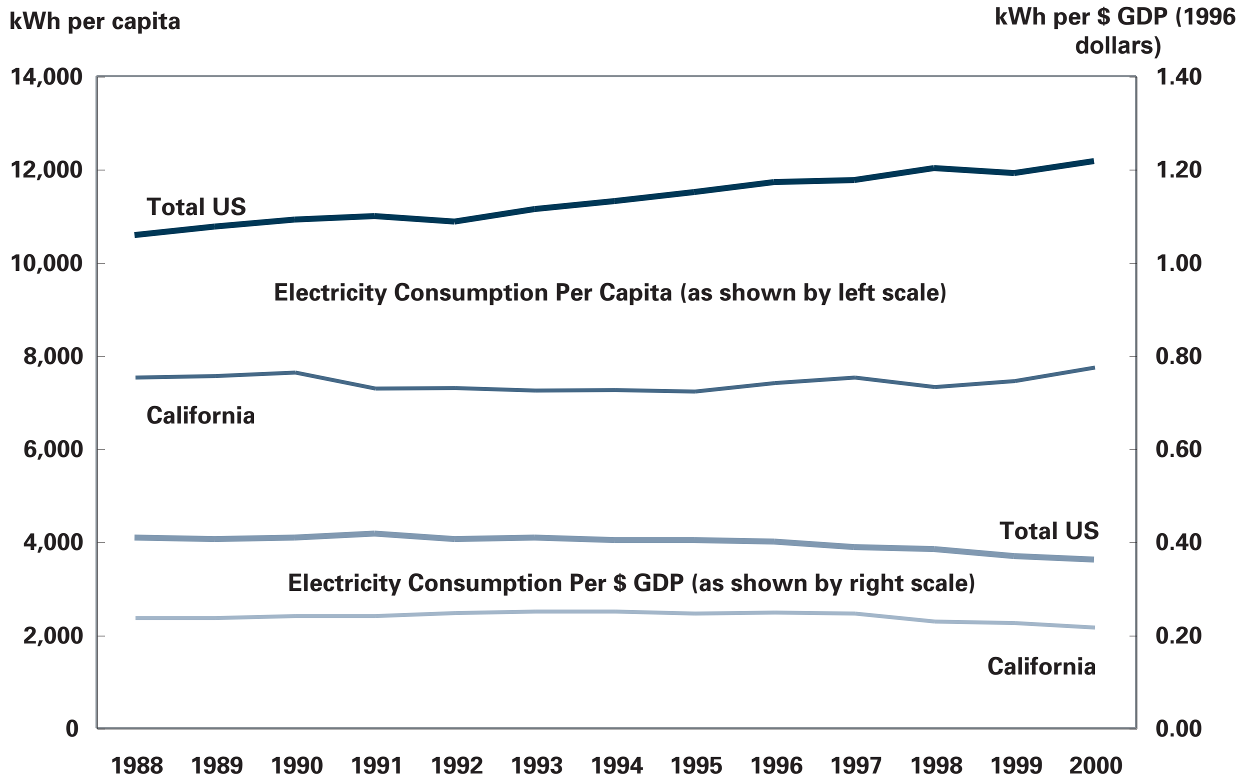

Figure 2.2 - Trends in U.S. and California per Capita Electricity Consumption and Consumption per Dollar of Gross Domestic Product

Source: CPUC

The ISO4 contracts incorporated beliefs about rapidly escalating gas and oil prices. It became apparent within several years that the contracts specified avoided costs that were substantially in excess of the actual cost of alternative generation opportunities for the utilities. (See Figures 2.2 and 2.3) Indeed, the Congressional Budget Office later estimated that the QF contracts were responsible for a majority of stranded costs in California following restructuring.[42] The contracts played an important role in the increase of electricity prices in California. In 1980, California had the ninth-lowest residential rates per kilowatt in the country; by 1990, average residential per-kilowatt rates in California were the seventh highest in the country (above Alaska) and fifty percent higher than the national average. [43]

The Demand Side

In California, regulators chose to deal with the projected demand shortages of the late 1970s in part by encouraging the utilities to become involved in conservation or energy efficiency. [44] These strategies had consequences for the restructuring plans in California, as is discussed below. It is notable that in 1982,

[42] Congressional Budget Office, *Electric Utilities: Deregulation and Stranded Costs*, October 1998.

[43] In 1980 the average residential bill in California for a household using 250 kwh was $11.59, which was the ninth lowest bill in that category in the country. *Energy Data Report: Typical Electric Bills - January 1, 1980,* DOE/EIA-0040 (80). In 1990 the average per kwt charge in the country for residences was 7.83 cents; in California the rate was 11.43 cents. *Electric Sales and Revenue - 1994*, DOE/EIA-0540 (94).

[44] In this paper, “conservation” means reducing the use of a service, such as turning off a light, and “efficiency” means getting the same service using less electricity or energy—in this example, replacing an incandescent with a more efficient compact fluorescent bulb.

electricity demand in California dropped for the first time since 1931. Of course the decline was only due in part – if at all – to the regulatory conservation strategies undertaken in California. Unfortunately, we know of no study that allocates credit for increased energy efficiency between state programs and other "market" forces, and whether, for example, the standards would have emerged absent the government program. These programs are part of the political landscape in California and hence relevant to our analysis here, but their impact on outcomes is critical for an assessment of the long-term impact of restructuring. In this section, we review consumption patterns in the state and some of the studies of the conservation programs.

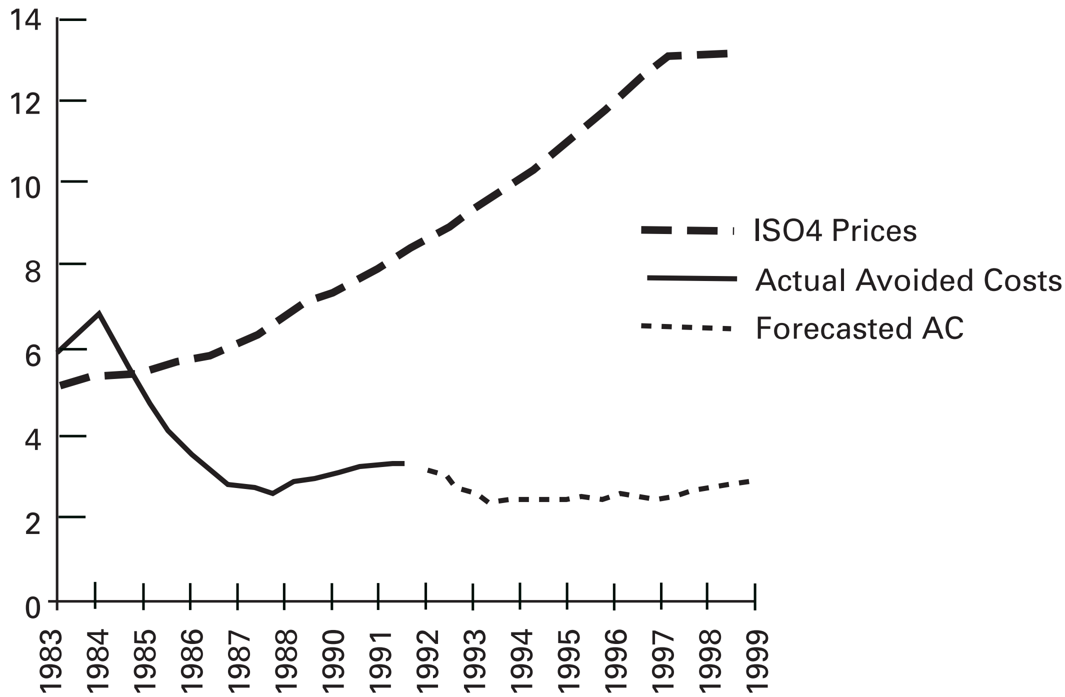

Figure 2.3 - QF Prices - PG&E

Source: CPUC

Electricity use in California is low. On a per capita basis, the state uses less than 8,000 kWh as compared to the national average of 10,500 kWh. (See Figure 2.2) Per dollar of gross domestic product (1996 dollars), the nation's use is twice as high as the state. Of course, improving energy efficiency is one of a number of components affecting these measures of energy intensity. The nature and structure of the economy as well as the climate are obvious contenders for the patterns of use in California.

To what extent are the state's favorable energy ratios caused by its efficient use of energy? There is no comprehensive study evaluating the effects of the state's energy efficiency programs, although there are numerous studies evaluating specific state and utility demand-side management programs.

In the most comprehensive available study on energy efficiency in California through 1993, Lee Schipper and James McMahon [1995] note that energy use is influenced by a number of effects, some natural and some artificial.[45] Moderate climates reduce the energy required for heating and cooling. A

[45] Schipper, Lee, and James E. McMahon. 1995 *Energy Efficiency in California: A Historical Analysis*. American Council for an Energy-Efficient Economy, July.

state's industrial make-up can strongly influence its energy use—heavy industry uses more energy than light manufacturing and service occupations. Higher energy prices, policy incentives and availability of energy efficiency programs reduce energy use.

Schipper and McMahon's study examined energy use in California by sector. From 1970 to 1993, energy demand per household in the state declined 27 percent. In the commercial sector, the study found that electricity use per unit of floor area increased electricity use by five percent, while gas use decreased 26 percent—an overall net decrease in energy intensity. They attribute electricity increases to the increase in the size of the state's commercial sector and the increasing use of electrical appliances.

California's manufacturing and industrial sector decreased its energy intensity 32 percent from 1978 to 1990. Schipper and McMahon attribute two-thirds of the decrease (22 percent of the total) to improvements in energy efficiency, and one third (the remaining ten percent) to changes in the mix of materials and goods produced. Combining the three sectors, final energy use per unit of economic output declined by 28 percent between 1978 and 1990. They estimate that one-third of the decline was caused by structural changes in the economy (shifts in what the state produces) and two-thirds by reductions in the state economy's energy intensity. Their evidence suggests that electricity intensity in the state fell more rapidly than in the U.S. as a whole during the study periods.

California has a long history of state-mandated energy efficiency programs. It pioneered the incorporation of efficiency in building codes — today the efficiency provisions are known as Title 24 — and it established standards for appliances that subsequently stimulated the highly effective U.S. national standards. The California Energy Commission, of course, promotes efficiency through a variety of expenditure and standard setting programs.[46] The state has also mandated extensive demand side management programs. These programs are of particular relevance to this discussion because they were funded out of regulatory-mandated electricity rates, and hence were a component of the state's utility regulatory policy prior to restructuring.

The utility demand-side management programs (DSM) are utility-administered programs that offered rebates and other payments, as well as technical assistance to homes, developers and builders, businesses, and industrial and agricultural enterprises to build or retrofit energy-efficient buildings, and install energy-efficient equipment. These programs range from rebates for the purchase of energy-efficient home appliances to assisting large industrial customers replace aging HVAC system components with more energy-efficient models. Investment in DSM programs grew steadily from 1980 to 1984, fell after the collapse of energy prices in 1986, and recovered in the late 1980s, rising to more than $400 million in 1993.[47]

Like other "public interest" utility investments, levels of support for the DSM programs were greatly reduced in the mid 1990s. The California restructuring legislation includes provisions for funding the programs through a surcharge on retail bills. The program is discussed in the subsequent chapter.

2.2 California Electricity Rate Regulation in the Early 1990s

In 1993, the CPUC issued a report that became known as the Yellow Book.[48] The report states that its purpose "is to provide a foundation on which the Commission and interested parties can examine a

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[46] Examples of the CEC's programs include: channeling state funds to improve the efficiency of state and local government buildings, schools, hospitals, state colleges and university facilities; developing model energy retrofit ordinances for local jurisdictions; developing a California Home Energy Rating System; and working with the utilities to effectively implement demand-side management programs.

[47] See Messenger, Michael, 1996, Recent Trends in Utility Program Funding and Design in California. *The Electricity Journal*, July, 1996, Pp. 50-57. Energy Efficiency Working Group. 1996. *Funding and Administering Public Interest Energy Efficiency Programs.* California Energy Commission. P300-96-004. August.

[48] See footnote 47 above.

range of regulatory strategies designed to better align the state's regulatory program with California's dynamic and increasingly competitive electric service industry." This report gives a fascinating and detailed picture of changes in the California industry during the 1980s. One of the more stunning consequences of regulatory policy changes in the previous decade was the extent to which cost-of-service regulation – the cornerstone of public utility regulation – had been superceded by other price-setting criteria. Energy from PURPA qualifying facilities, by then accounting for over 20 percent of the generating capacity within the state was sold according to one of several "avoided cost" formulas that were divorced from the cost of service from those specific facilities. Energy imports, which accounted for an important share of California's electricity consumption, were priced by federal tariffs. FERC was promoting "market-based" rates wherever it could plausibly claim competitive wholesale conditions, and a market for wholesale purchases had been an active component of the western region (the Western States Coordinating Council, or WSCC area) for a decade.[49] The Diablo Canyon nuclear power plant, the six hundred pound gorilla in PG&E's portfolio, was so expensive that the rate shock prospect caused even the utility to back off from the usual "used and useful" certification and rate base treatment. The CPUC established a special "performance based" schedule that delayed associated rate hikes to future years when (it was hoped) savings elsewhere might blunt the full impact of the project.

Finally, the incentive regulatory schemes instituted during the 1980s attenuated prices from estimated costs, and largely decoupled them from actual costs. For example, the Electric Revenue Adjustment Mechanism, adopted for PG&E rates in 1982, set targeted revenues based on estimated costs for a hypothetical demand level. If the utility succeeded in selling less power because of demand side management strategies, it could make up any shortfall in revenues from the forecast by a surcharge in the next period. The policy was intended to promote conservation activities by the utility as well as save on arguments over demand projections at rate hearings, and has been judged a success on both counts.[50]

One consequence of these regulatory policies was that, despite capacity investment strategies that ex post proved exceptionally expensive, the California public utilities became very profitable. From their low points in the mid-1970s, when rates of return on equity dropped to about three percent for PG&E, return on equity for the major utilities was in the 14 percent – 15 percent range through the 1980s. For most of the decade, their return on equity exceeded the level authorized by the CPUC.[51]

A second consequence of the policies, this time because of the capacity investments, was that California had among the highest retail electricity rates in the country. Adding insult to these injuries was that neighboring states had among the *lowest* rates in the country. Econometric studies show that the best predictor of which states restructured their electricity systems in the early 1990s was the conjunction of high internal rates and low neighboring rates.[52] Several causal factors were probably at

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[49] While the state had determined how to calculate avoided cost for QF contracts, the QF tariffs, like tariffs for energy imports and other wholesale purchases by the IOUs were technically federal, not state tariffs. According to the "filed rate doctrine," state PUCs must pass through to utility customers the costs of power purchased under a federal tariff unless the PUC rules that the wholesale purchases were imprudent. *Nanatahala Power and Light C. v. Thornburg*, 476 U.S. 953 at 970, 90 L. Ed. 2d 943; 106 S.Ct. 2349 (1986). Retail pricing history in the past few years in California is somewhat puzzling in light of the filed rate doctrine. It is credited with limiting the ability of the CPUC to unilaterally cap retail rates in San Diego when wholesale prices soared in the summer of 2000. It would presumably have had a much greater impact on the rate freezes still in effect for the other California utilities during 2000 and 2001. See Michael Kahn and Loretta Lynch's *Report to Governor Davis on the Electricity Conditions Facing California*, August 2, 2000, p. 25.

[50] *Yellow Book*, p. 57.

[51] *Yellow Book*, p. 64.

[52] See Matthew W. White, "Power Struggles: Explaining Deregulatory Reforms in Electricity Markets", *Brookings Papers: Microeconomics, 1996*, pp. 201-250; A. W. Ando and K.L. Palmer, "Getting on the Map: The Political Economy of State-Level Electricity Restructuring", Discussion Paper 98-19-REV, Resources for the Future, 1998.

work. First, of course, the differential rates were embarrassing, and underscored regulatory failure. A second factor was that the regulators and other policy-makers within the high-cost states hoped that facilitating markets would allow within-state consumers access to the cheaper power in neighboring states at cheaper prices. But probably the least legitimate, but most important reason for the correlation is that proponents of competitive electricity markets in the high-cost states with low-cost neighbors claimed the differential was evidence that restructuring would lower electricity costs. The projected increases in efficiency became collateral for compensating or bribing stakeholders into agreeing to a change in the status quo. As is discussed below, the belief that electricity prices would fall after restructuring was critical to both the validity of the California plan and to its political acceptability.

2.3 California Resource Regulation in the Early 1990s

Resource planning has traditionally been the province of utilities with public utility commission oversight and approval. California's procedure for approval of new power plants involves substantially more public input than most states, and certainly far more than a regulatory capture theory would predict. In 1971, in response to ambitious utility plans for nuclear power expansion, the California Legislature established a new agency: the State Energy Resources Conservation and Development Commission, now called the California Energy Commission (CEC). The CEC was to provide an independent forecast of electricity needs in California that would be the basis for approval of new power plants. As a sweetener for utilities, the agency was also to address the growing difficulties in siting and serve as a one-stop-shop for siting new thermal generation plants over 50 megawatts. Relative to siting agencies in most states, the CEC has provided effective opportunities for environmental proponents to participate in electricity resource planning.[53]

Public interveners also participated extensively in the PUC hearings. In 1976, the Environmental Defense Fund (EDF), which had become proficient at using the legal system to bring technical evidence into the public domain, intervened in a rate case where PG&E had requested permission to build new nuclear plants. Using its own computer models of future resource scenarios, EDF demonstrated that the utility demand forecast could be satisfied and customers would benefit more from increased energy conservation and renewable resources. The group then convinced the CPUC to order PG&E to release its computer program for resource expansion, which PG&E considered proprietary, so that comparisons could be made using equivalent expansion models. This decision was significant in several dimensions. It served as a model for integrated resource planning methods used in California, demonstrated a method for taking environmental concerns into account in resource planning, and allowed public input in the resource expansion planning. It also marked the end of aggressive expansion plans by the major California utilities, which subsequently embraced PURPA's provisions for interconnection with non-utility generators in the state.

During the 1980s, the CPUC, CEC, and utilities, together with interveners, followed "least-cost planning" (LCP) principles in resource planning.[54] LCP starts with a philosophy that energy efficiency and generation are equivalent ways to address energy needs. Under this approach, managers and regulators are required to consider demand reduction alternatives as well as traditional supply options to meet increased demand projections. If it were cheaper to employ some demand side management strategy and save a kWh than to produce it, the resource plan would adopt demand reduction in preference to new generation resources. LCP, an obvious favorite of environmentalists, was also held up as a more flexible approach to risk management in resource planning. The strategy gained legitimacy when demand shortfalls undermined the profitability of the very large plants ordered in the 1960s and early 1970s.

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[53] It is also no coincidence that, while PURPA allows "small producer" qualifying facilities to be up to 80 megawatts, the largest QF in this category in California is 49.9 megawatts.

[54] The various alphabet-soup resource planning policies that California followed in the 1980s and early 1990s are discussed in detail in *The Yellow Book*, op. cit.

The LCP concept evolved into a more comprehensive Integrated Resource Planning (IRP) approach. The fundamental principle of IRP is to identify, analyze and acquire cost-effective resources, namely resources that lower the long-term cost of energy services. IRP considers all feasible supply and demand-side resource options and selects a mix that minimizes overall costs. IRP extended the LCP concept to include environmental impacts, safety, national security, reliability and public involvement into calculations of future electrical demand and resource planning. IRP opened the planning process to other stakeholders and considered demand resources, renewable resources as well as fossil resources.[55]

The final round of the IRP in California was for the 1993 Biannual Resource Planning Update (BRPU). The BRPU determined each investor-owned utility's need for resources, the potential costs of those resources and the rules under which each utility would be compelled to acquire power from independent power producers to meet some portion of those needs. The CPUC and the CEC concluded that additional supply resources would be needed by the end of the decade, and that the utilities would competitively bid for "clean" resources. Clean included wind, geothermal, solar, biomass and high-efficiency gas fired cogeneration. The CPUC approved bids for 1200-1400 MW of capacity. The auction itself would yield "avoided cost" for PURPA purposes.

The California utilities revolted. Led by Southern California Edison, they appealed to FERC. They argued first, that they did not need the power. Second, they claimed that even if they did need the power, California did not have the authority under PURPA to set an avoided cost that required them to pay a higher price than the conventional wholesale market price. SDG&E claimed its ratepayers would pay millions of dollars of premiums over the life of the contracts. The Federal Energy Regulatory Commission, in a scathing opinion, voted 5-0 to halt the auction. FERC found that the California program violated PURPA as it had based avoided costs on an auction limited to "clean" resources. The basis for the decision is ironic, given California's claim that its energy policy was based on full consideration of all options and resources.[56] In March 1995, the CPUC halted the auction and authorized approximately $100 million for the utilities to buy out the previously executed contracts.

The importance of the BRPU decision may have been lost in the restructuring debates going on at the time in California. The state argued before FERC that its limited auction and "avoided cost" were valid under PURPA, since the state's previous calculation during the IRP had shown that among this set of "clean" plants were the least cost options. The state, of course, defined costs to include environmental and other social costs, as well as the economic costs measured in the market. FERC rejected the argument, and agreed with the utilities that the costs that mattered were those incurred by the utilities, which were only the market costs and not the imputed social costs taken into account in the IRP process. FERC's decision meant that the wholesale expenditures of utilities could not be used to subsidize state initiatives.

This is only one avenue by which the state could influence resource mix. Alternatives would be taxing polluting sources within the state so that the "clean" electricity sources were in fact, rather than in theory, the least cost option. Of course, that would not deal with out-of-state electricity sources, so the effectiveness of the strategy depends on the strength of the interstate transmission system. A second option (adopted in

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[55] Clearly the data requirements for ideal IRP analysis are huge. In theory, IRP allows very different resources – from lighting retrofits to photovoltaic units to a utility-owned and operated gas fired turbine to a non-utility biomass facility – to be compared in order to decide which are most cost-effective for a given utility at a given time. Because of the disparate nature of these resources, an analysis must include all related costs for each potential alternative. When conducted in this manner, an IRP analysis reveals which resources offer the greatest value, net of costs, to a utility and its customer. In the former, regulated, environment, the end result of IRP was (again in theory) a combination of approval for utility or independent power producer generation along with demand-side management programs to induce consumers to engage in the conservation parts of the plan. One argument for markets is that data demands are too large for IRP ever to be successful. In an deregulated environment, prices (in theory) induce consumers to adopt appropriate demand side management and provide information and incentives for appropriate generation investment. But note that the (theoretical) market outcome is identical to the (theoretical) IRP analysis only if environmental and social costs are included in market prices.

[56] *Southern California Edison Company v. San Diego Gas & Electric Company*, 70 FERC §61,215 (1995).

California after restructuring) is for the state to subsidize the clean sources, again so that their (monetary) cost is competitive. The subsidy is paid for by a retail rate charge, which has not been challenged. But the FERC decision closed a politically attractive mechanism to affect resource mix since it allowed direct state control of all electric plant construction and avoided state tax policies and spending policies, both of which are subject to influences outside the regulatory structure.[57]

The immediate impact of the FERC decision was to vacate California's resource planning process. The resulting uncertainty further demonstrated the non-viability of the state's regulatory structure in the evolving structure of the electricity industry. In consequence, for some participants, it added to the attraction of restructuring.

2.4 California's Restructuring Legislation

The plan that emerged in Assembly Bill 1890 (AB 1890) after several years of discussion and workshops, closely followed the CPUC proposals, whose subsequent rulings supported the policy laid out in the bill. This section considers both the Assembly Bill and the initial CPUC rules as the state's "restructuring plan." Several components of the plan follow directly from federal policies and national trends. Provisions for utility divestiture of plants, compensating utilities for financial consequences of the market change ("stranded cost recovery"), unbundling of different electricity products and centrally coordinated transmission for the state continue federal policies underway for a decade. However, as is discussed in the next chapter, the greater degree to which these policies were adopted in California had important implications for the performance of the industry. Like other states and the federal restructuring of telecommunications, the California plan attempts to compensate the beneficiaries of cross-subsidization policies in the prior regulatory regime. Relatively unique features of the California plan were the structure and importance of the power exchange market, restrictions on the public utilities about participating in the PX market, and a plan for phasing in retail competition that now looks as if it will be put on hold. The remainder of this section considers each of these components.

Assets: Divestiture and Stranded Costs

The California plan envisions a generation sector that competes for wholesale sales to distribution companies. One component of the plan was for the investor owned utilities to divest their generation capacity. They would then become utility distribution companies (UDCs), and would purchase power from competing generation plants. As a first step, AB 1890 provides incentives for the utilities to divest their thermal generating plants. Special considerations governed ownership of nuclear and hydroelectric facilities, and utilities in California have retained ownership of these facilities.

Divestiture served several purposes in the restructuring plan. First, it was intended to jump-start a competitive generation sector by facilitating entry into California by other firms. These firms would obtain a toehold in the generation sector without going through the lengthy siting and permitting licensing processes and the rather shorter construction process. The restructuring plan also anticipates that these companies would then participate in building new capacity within the state.[58]

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[57] Legal scholarship has produced a considerable literature on the extent to which state governments can constitutionally accommodate environmental goals within the constraints of dormant commerce clause jurisdiction. Two excellent papers that address issues closely related to those of concern in electricity restructuring are Kristen H. Engel, "The Dormant Commerce Clause Threat to Market-Based Environmental Regulation: The Case of Electricity Deregulation," *26 Ecology L. Q. 243* (1999) and Richard L. Revesz, "Federalism and Interstate Environmental Externalities," *144 U Pa L.R. 2341*. See also Bosselman et al., *op. cit.*, Ch. 13 B.

[58] The plan probably got this right. Nearly all entry into restructured markets by independent power producers has been firms that bought, rather than built, plants. More recently they have started plans to add additional capacity. For an analysis of the buy versus build decision see Jun Ishii and Jingming Yan, "The 'Make or Buy' Decision in U.S. Electricity Generating Investments," UCI Economics Department Working Paper, March, 2002.

Second, the legislative coalition and the CPUC believed that divestiture would reduce the incidence of monopolistic abuses in the market. The logic of the argument was that the more utilities retained their generating capacity, the greater likelihood of self-dealing in wholesale markets.[59]

During the legislative and rule-making phase of restructuring in California, nearly all of the discussion about monopolization centered on restraining the large distribution companies. As is discussed below, in the past few years, the focus has shifted to the firms that purchased the divested plants and other energy traders in the system. The possibility that single plants could exert monopoly power was in fact discussed in the hearings, although the extent of the problem was not recognized. The CPUC stated that some units are "located relative to the transmission system such that they have an inherent potential for abuse of market power. Some areas … may not be susceptible to immediate entry of lower priced competitors. Entry of competing generation in the near term may not be an option because of the need to upgrade transmission or build new generation in that area. We are concerned the mere divestiture of such units to entities other than investor-owned utilities will not decrease the potential market power or exercises of that power that lead to excessive prices." [60] The restructuring plan provided for such units to enter into "reliability must run" contracts with the Independent System Operator (see below) so that their prices would in principle be capped under the "market power" conditions. It is notable that even the initial analysis of congestion and ancillary markets concluded that the problem that single plants might provide critical reliability services was far from unusual. Severin Borenstein and James Bushnell report in 2000 that "over half of the 288 generating units in the California ISO system has been designated as 'must run' for reliability purposes under some conditions." [61]

A third argument for the divestiture was that it facilitated stranded cost calculations. One of the most complex legal issues involved in the restructuring movement at both the federal and state levels is how to compensate utilities for investments they undertook, or, in the case of PURPA qualifying facilities, long-term contracts they signed, subject to regulatory approval or requirement. Under the terms of rate-base regulation, the utilities had been guaranteed cost recovery for these assets over an extended period of time (up to 30 years). Competitive prices did not guarantee a return; indeed, it was expected that prices would be inadequate to recover costs of many of the recent investments, particularly for nuclear power plants and qualifying facility contracts. Investments stranded by virtue of regulatory change are known as stranded costs, and no consensus exists about the proper way to calculate their extent and assign their incidence.[62] FERC Order 888 sets out some standards and policies for full recovery of costs stranded as a result of its unbundling and transmission orders. The California plan obtained support from the utilities by proposing full recovery of stranded costs, conditional on sale by the utilities of at least 50 percent of their thermal generating capacity within a fairly short period of time. The divestiture

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[59] See Before the Public Utilities Commission of the State of California: Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation, R.94-04-031, Decision 95-12-063 (Dec. 20, 1995), as modified by D.96-01-009 (January 10, 1996), pp. 65-72. (Cited hereafter as CPUC Restructuring Order.)

[60] CPUC Restructuring Order, p. 68-69. The possibility that the mid-merit order plants might also possess monopoly power under some conditions was raised by both the FTC and Paul Joskow in these hearings, but their discussion of how to think about concentration measures in such circumstances seems to have fallen on deaf ears. The mitigation measures included in the CPUC Order all reflect classical ways of measuring concentration. See ibid, pp. 68 et seq.

[61] Severin Borenstein and James Bushnell, "Electricity Restructuring: Deregulation or Reregulation?" PWP-074, U.C. Energy Institute Working Paper, Feb. 2000; forthcoming in Regulation: The Cato Review of Business & Government.

[62] A detailed discussion of the main controversies and issues surrounding stranded cost issues is contained in Fred Bosselman, Jim Rossi and Jacqueline Lang Weaver, *Energy, Economics and the Environment: Cases and Materials*, New York: Foundation Press, 2000, chapter 12. An excellent, succinct discussion is provided in Timothy Brennan and James Boyd, "Stranded Costs, Takings and the Law and Economics of Implicit Contracts, RFF Discussion Paper 97-02, October 1996. Washington, DC: Resources for the Future.

provided market valuation of some resources, and the difference between market and book value offset calculated stranded costs for the qualifying assets that were not sold.

Total stranded costs in California are estimated at between 28 and 30 billion dollars. The market-to-book value for the divestitures by the California utilities was 1.86 for PG&E, 2.65 for SCE and 3.78 for SDG&E, netting a handsome sum for the stranded cost account.[63] Utilities were to receive compensation for remaining stranded costs from two sources. Customers who chose a different electricity provider from the utility would pay a non-bypassable fee to the stranded cost accounts. Retail customers of the utilities had their rates frozen at the 1996 levels until the stranded cost account was paid down or December 2001.[64] The plan was that these customers would pay for stranded costs through a variable surcharge on their electric bills that would be the difference between the competitive market price and the applicable 1996 rate. Once the accounts were paid up, retail rates would be deregulated. Of course, the plan depended on the 1996 rate exceeding the average market price by a reasonable margin. In the CPUC planning documents, the AB 1890 hearings, and the bill itself, this assumption was unquestioned.

Trading and the Market Brokers: The PX and the ISO

This section gives a very simplified description of the trading and markets plans in AB 1890 and the CPUC Order.[65] The restructuring plan set up two new market institutions, the California Power Exchange (CalPX) and the California Independent System Operator (CAISO). Both institutions trade wholesale power, and are regulated by FERC as EWGs. FERC approved wholesale tariffs filed by the PX and CAISO that specify the manner in which auctions will determine "market based" wholesale prices. FERC also approved the transfer of transmission management from utilities to CAISO and other restrictions and details of the proposed wholesale market plan in California.

The California restructuring plan specifies that the California Power Exchange will run single-price, public auctions for energy for delivery during one hour for the next day (the day-ahead auction) and for the next hour (the hour-ahead auction).[66] Generators or power marketers submit bids giving a quantity of energy they are willing to sell and a minimum sales price acceptable for the sale. (Bidders may enter multiple bids for different generator output.) Purchasers of power similarly submit bids giving a quantity they wish to purchase and a maximum sales price they are willing to pay. The PX aggregates sell bids into "supply" curves by ranking the bids from lowest to highest (a "merit order") and forms a demand curve using the reverse algorithm on the buy bids. A single price emerges from the market at the intersection of the curves (that is, where "supply" equals "demand"). All suppliers who submit bids below the price, and buyers who submit bids above the price, are notified that their bids have been accepted. Winning suppliers are then required to tell the PX which generators will be generating the contracted energy. Trading takes place at a single price.

The public utilities – PG&E, SCE and SDG&E – are required to bid all of their non-divested generation capacity into the PX. This requirement was intended to serve in part as the "functional unbundling" mechanism – the utilities' own energy would be treated like everyone else's – and in part to insure liquidity in the market. The utilities were not formally required to purchase all their requirements from the PX, but the CPUC indicated that the PX price would serve as the standard

[63] Paul Joskow, "Deregulation and Regulatory Reform in the U.S. Electric Power Sector," op. cit., p. 146.

[64] AB 1890 sweetens the deal for consumers by legislating at ten percent rate reduction until the end of 2001, paid for out of state bonds. AB 1890, §1 (b) 2.

[65] For a thorough discussion of the market and trading details see James Sweeney, The California Electricity Crisis, The Hoover Institution, 2002, especially ch. 2. See also Paul Joskow, "Deregulation and Regulatory Reform," op. cit.

[66] For a brief time near the end of its operation, CalPX ran block auctions for periods of time further than one day ahead. See Sweeney, op. cit.

for allowable expenditures. Thus, if the utilities had entered longer-term contracts that were more expensive on average than the PX price, the contracts would be disallowed. The utilities responded to the CPUC incentive in a rational manner, and purchased all energy requirements from the short-term markets through 2000.

The California Independent System Operator operates the transmission grid. AB 1890 allows the large utilities to retain ownership of their transmission facilities, but they were required to transfer management of the assets to CAISO. CAISO takes the schedules submitted by the PX and other scheduling coordinators [67] and, assuming the transmission lines can support the proposed the plans, orders dispatch according to the submitted schedules. If transmission is inadequate, the scheduling coordinators must modify their schedules and, if appropriate, pay congestion fees set by CAISO.

CAISO runs both day ahead and hour ahead auctions to purchase ancillary services, which are subsequently billed to the scheduling coordinators. These are the services needed to run an electricity system, including commitments from generators for power that can be supplied at the last moment to balance actual supply and demand (the "real time" market). CAISO also contracts for commitments from plants to withhold power at the last minute if real-time supply would otherwise exceed demand, and reserve capacity that can be made available with different lead-times to back up unanticipated demand increases or supply disruptions. CAISO acquires ancillary services according to the standards established by NERC and the WSCC. If insufficient reserves are provided in the auctions, it attempts to purchase them in "out-of-market" transactions. When reserves fall to unacceptable levels, and no out-of-market purchases are available, CAISO will order utilities to shed load.

An important attribute of the ancillary service market is that while the auctions are run on a statewide basis, the generators that provide ancillary services must reside in specific geographical areas due to transmission load restrictions. Under some transmission conditions only isolated plants are qualified to provide the services. The restructuring plan anticipated that these facilities would have "reliability-must-run" contracts, as discussed in the previous section, to keep prices reasonable for CAISO under constrained transmission conditions.

Public Interest Charges

An examination of the space allocation in *Yellow Book*, the CPUC's Restructuring Ruling and AB 1890 is instructive. All three documents deal extensively with the consequences of the changes for "public interest activities" – more extensively than they do, for example, with the potential for monopoly abuses under the new structure. The documents reveal the extent to which electricity regulation in California served a broad spectrum of initiatives. These were funded out of retail bills. Differential retail rates cover the subsidies (e.g., rates are higher than average for commercial users and lower than average for retail customers). The expenditure programs are paid for by surcharges on retail. It was expected that none of these programs would have been continued by competitive sellers of electricity. Base-line rates, low income assistance, agricultural subsidies, demand-side management, research oriented towards renewable energy use, investment in plants that use renewable resources or other alternative energy supplies, rural subsidies, electric vehicle programs – "public purpose programs" use up a 20 page chapter in the CPUC document, second only to the "Market Structure" chapter which discusses the goals of restructuring and the CPUC's jurisdiction over its components; and longer by 25 percent than the chapters on market power or stranded costs. Parsing an assembly bill is an exercise in futility,

[67] Approximately 40 scheduling coordinators operated in California. This included organizations like energy supply firms (e.g., Enron), the California Dept of Water Resources, and the Bonneville Power Administration. Scheduling Coordinators were required to submit balanced bids to the CAISO, that is, schedules where the proposed supply of energy equaled purchase commitments. Scheduling Coordinators also needed to satisfy certain financial conditions to participate in the California market.

but AB 1890 also underscores how important the maintenance of the redistributive programs were to political acceptance of the plan.

The restructuring legislation treats the public purpose programs in two main ways. First, consumers are protected with rate freezes, and retail consumers are further protected with a ten percent rate reduction. Second, a non-bypassable surcharge is attached to all retail bills to pay for a system benefit fund.

The system benefit fund established the following activities

- Energy Efficiency - $870 Million for four years (managed by CPUC)
- Renewables - $525 Million for four years (managed by CEC)
- R&D - $250 Million for four years (managed by CEC)
- Low Income Support - $100 Million per year (managed by CPUC)

These programs are discussed further in Chapter 4.

2.5 How the California Plan Diverges from Federal Deregulation Trends

AB 1890 states that the California plan is a response to federal actions:

> Section 1. (a) The Legislature finds and declares that the restructuring of the California electricity industry has been driven by changes in federal law intended to increase competition in the provision of electricity.

As the previous sections discuss, federal policies had moved the industry in the direction envisaged in the bill, particularly with respect to policies to ensure that non-utility generators would not be discriminated against for sales of energy. The provisions of the California restructuring plan that provided for divestiture, stranded cost recovery, unbundling wholesale, transmission and distribution for remaining utility generation, and the establishment of the CAISO are consonant with federal policies. Indeed, aside from the divestiture, these actions are arguably required under current FERC orders. In addition, wholesale spot markets are a long-standing component of the electricity system in the United States. Power pools usually run spot markets. [68]

The California plan has two components that stand out from the federal regulations and from historical experience in the industry. First, the CAISO relies on decentralized decisions by many actors to a far greater extent than other power pool operators do. Generators enter bids for energy, but in addition must decide whether to hold back capacity from the energy markets to bid in the ancillary markets, and if so, which markets – regulation, spinning, and so on. CAISO is required to acquire ancillary services based on scheduled supply and estimated demand, but has no influence over the amount of energy scheduled in advance. The unbundling of ancillary services, not just from energy sales and transmission but from each other, is unique.

Second, the markets – for all the discussion of competition and choice – severely limit the contractual opportunities of its major players. CAISO was directed to purchase all ancillary services from its own markets (or, in a pinch, from out of market trades) and could not purchase energy on the PX markets to then use for balancing power or reserves. The utilities, between requirements and CPUC incentives, satisfied their entire energy requirements from short-term markets.

This restriction is stunning for the utility world. Like other long-lived infrastructure, contracts in the utility business usually run for years. Utility investments are usually immovable and have few alternative

[68] The WSCC has run a spot market since the early 1980s.

uses. The case is the same as that made by qualifying facility proponents 20 years ago in support of the ISO4 contracts, but much more compelling for traditional utility investments. A nuclear reactor, for example, is of minor or perhaps negative value if used for something other than generating electricity and selling it into the grid where it is located. Similar arguments hold for distribution and transmission systems. Exiting the business is a costly, unattractive option: the investment may largely be lost. Even in competitive markets (that is, when there are multiple buyers of the output), owners of large, fixed investments want long-term contracts to share risks of future price variation. While spot markets are important to deal with unexpected supply and demand conditions, these types of businesses never consign their "base" load to short term markets. The California plan, where utilities bought and sold all power on short-term markets is unprecedented and, by all accounts, unfortunate.

CHAPTER 3: THE CALIFORNIA "CRISIS": PERFORMANCE IN THE RESTRUCTURED ELECTRICITY MARKET

3.0 Overview

In the past two years (2000-2002), the poor performance of electricity markets in California has given way to financial disaster and state intervention. Expenditures for electricity in the ISO region totaled $578 million in April 2000, $3.6 billion in June 2000, and over six billion dollars in December 2000.[69] In the summer of 2000, the California utilities intentionally interrupted their residential customers for the first time in their history. [70]

Because the retail rates of PG&E and SCE were frozen during this time, their revenues remained flat in the face of the increased costs, and both companies were functionally bankrupt by 2001. One consequence was that they were no longer qualified to participate in the California ISO market. The California Department of Water Resources (CDWR) commenced purchasing power on behalf of the utilities' customers, and remains today the largest scheduling coordinator in the California electricity markets. From the December 2000 high of $317/MWh, electricity costs have declined by at least two-thirds, although they remain at least 50 percent higher than their average in 1998 or 1999. [71]

The breakdown of the electricity industry in California in 2000 was caused by two sets of factors. First, the markets were poorly designed, so that they were vulnerable to price spikes and exercises of monopoly power under tight supply conditions. During 2000 supplies did indeed become tight. Several other factors exacerbated these conditions. Prices of inputs to electricity production (natural gas and pollution permits) rose in 2000. As is discussed below, the input price increases were arguably in part a consequence of the basic problems in the industry. Second, the division of responsibility between the federal and state governments inhibited mid-term corrections.

This chapter presents an overview of the market and resource problems that led to the meltdown of the California markets in 2000.[72] We first consider a counterfactual: how the California market would operate if no firms exercised monopoly power. Even without any market manipulation, the structure of the auctions in California, the frozen retail rates and the reliance on spot markets would have led to price volatility and periodic wholesale price spikes. We then discuss how the problems are greatly exacerbated when some market participants have market power. This discussion provides a background to understand why the relatively modest resource constraints in 2000 caused apparently dramatic changes in the industry.

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[69] California ISO, Department of Market Analysis, Second Annual Report of Market Issues and Performance, April 1999-December 2000, Nov. 2001.

[70] Michael Kahn and Loretta Lynch, California's Electricity Options and Challenges: Report to Governor Gray Davis, August 2000, p. 21. (Cited below as Kahn-Lynch Report.)

[71] Now that the state is purchasing power through a variety of contracts, prices are not transparent in the California markets. CAISO estimates costs for the second half of 2001 under the assumption that the cost of energy under CERS bilateral contract power equals the price for the WSCC wholesale transactions (hub prices). The contracts are reported to be much more expensive than the hub price, so the CAISO estimates are probably too low. CAISO reports an estimated average cost of energy and A/S services for October, November and December 2001 at about $45.00. Average cost in 1998 and 1999 was $33.00, and the 2000 average was $114.00. The last month for which CAISO provides actual, rather than estimated, data is July 2001, when average cost was $75/MWh. *CAISO Dept. Market Analysis, Third Annual Report*, p. 10.

[72] Extensive literature analyzes the California market during this period, and the discussion here draws from these accounts. See Severin Borenstein, "The Trouble with Electricity Markets," *Journal of Economic Perspectives*, Winter 2002; Borenstein, Severin & Bushnell, James - "An Empirical Analysis of the Potential Market Power in California's Electricity Industry", *Journal of Industrial Economics, Vol. 47, No. 3, September 1999.* Borenstein, Severin, Bushnell, James & Wolak, Frank - "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market", *POWER Working Paper # 064, August 2000; Bushnell*, James & Wolak, Frank - "Regulation and the Leverage of Market Power in the California Electricity Market", *POWER Working Paper # 070, September 1999; Paul* Joskow, Paul & Kahn, Edward - "A Quantitative Analysis of pricing Behavior In California's Wholesale Electricity Market During Summer 2000", *NBER Working Paper # 8157, March 2001;* Joskow, "California's Electricity Crisis," *NBER Working Paper 8442*, August 2001 and James Sweeney, *The California Electricity Crisis*, Hoover, 2002. In addition, the CAISO has issued a series of excellent reports on the crisis; these are cited below.

Monthly System Cost Table: 2000 and 2001											
	ISO Load (GWh)	Est PX Energy Costs (MM$)*	Bilateral Energy Costs (MM$)*	RT Energy Costs (MM$)**	AS Costs	Total Energy Costs (MM$)	Costs of AS+ Energy (MM$)	Avg Energy Cost ($/MWh)	A/S Cost ($/MWh Load)	A/S Costs as % of Energy Costs	Total Costs ($/MWh Load)
Jan-00	18,984	$495	$103	$3	$12	$601	$612	$32	$1	2.0%	$32
Feb-00	17,807	$419	$103	$20	$10	$542	$552	$30	$1	1.9%	$31
Mar-00	18,989	$432	$90	$39	$11	$561	$572	$30	$1	2.0%	$30
Apr-00	18,212	$429	$101	$31	$17	$561	$578	$31	$1	3.1%	$32
May-00	19,997	$828	$225	$108	$63	$1,161	$1,224	$58	$3	5.4%	$61
Jun-00	21,605	$2,303	$529	$339	$436	$3,171	$3,607	$147	$20	13.8%	$167
Jul-00	21,935	$1,896	$346	$216	$125	$2,458	$2,583	$112	$6	5.1%	$118
Aug-00	23,141	$2,786	$585	$515	$282	$3,886	$4,168	$168	$12	7.3%	$180
Sep-00	20,620	$1,819	$389	$236	$152	$2,445	$2,597	$119	$7	6.2%	$126
Oct-00	18,184	$1,400	$356	$27	$56	$1,388	$1,434	$100	$3	3.3%	$104
Nov-00	18,656	$2,292	$402	$195	$114	$2,889	$3,004	$155	$6	4.0%	$161
Dec-00	19,412	$3,742	$820	$1,149	$440	$5,711	$6,151	$294	$23	7.7%	$317
Total 2000	237,543	$18,842	$4,048	$2,877	$1,720	$25,373	$27,083				
Avg 2000	19,795	$1,570	$337	$240	$143	$2,114	$2,257	$107	$7	6.8%	$114
Total 1999	227,533	$5,866	$982	$180	$404	$7,028	$7,432				
Avg 1999	18,961	$489	$82	$15	$34	$586	$619	$31	$2	5.7%	$33
1998 (9 mo)	169,239	$4,148	$556	$209	$638	$4,913	$5,551				
Avg 1998	18,804	$461	$62	$23	$71	$546	$617	$29	$4	13.0%	$33

* Estimated PX Energy Costs include UDC owned supply sold in the PX, valued at PX prices.
Estimated Bilateral Energy Cost based on the difference between hour ahead schedules and PX quantities, valued at PX prices.
** Beginning November 2000, ISO Real Time Energy Costs include OOM Costs.
*** AS costs include self-provided quantities.

Summary of 2001 Estimated Energy Costs											
	ISO Load (GWh)	Forward Energy (GWh)*	Est Forward Energy Costs (MM$)**	RT Energy Costs	AS Costs	Total Energy Costs (MM$)	Total Costs of Energy and A/S (MM$)	Avg Cost of Energy ($/MWh)	A/S Cost ($/MWh Load)	A/S % of Energy Costs	Avg Cost of Energy & A/S ($/MWh Load)
Jan-01	18770	16950	$2,710	$756	$247	$3,466	$3,713	$185	$13.15	7.1%	$198
Feb-01	16503	14876	$2,657	$917	$198	$3,574	$3,772	$217	$12.00	5.5%	$229
Mar-01	17857	16744	$2,736	$881	$181	$3,616	$3,797	$203	$10.14	5.0%	$213
Apr-01	17237	16267	$2,537	$755	$178	$3,292	$3,471	$191	$10.34	5.4%	$201
May-01	19651	18351	$2,771	$601	$176	$3,372	$3,548	$172	$8.97	5.2%	$181
Jun-01	19777	19468	$1,598	$111	$187	$1,709	$1,896	$86	$9.48	11.0%	$96
Jul-01	20976	20599	$1,458	$54	$71	$1,513	$1,583	$72	$3.37	4.7%	$75
Aug-01	21048	21571	$1,329	$34	$50	$1,363	$1,414	$65	$2.38	3.7%	$67
Sep-01	19562	19562	$958	$19	$19	$977	$996	$50	$0.97	1.9%	$51
Oct-01	19105	19395	$854	$10	$15	$864	$878	$45	$0.77	1.7%	$46
Nov-01	17707	18028	$774	$10	$12	$784	$796	$44	$0.68	1.5%	$45
Dec-01	18830	18673	$811	$14	$12	$826	$838	$44	$0.65	1.5%	$44
Total 2001	227024	220484	$21,194	$4,162	$1,346	$25,356	$26,702				
Ave 2001	18919	18374	$1,766	$347	$112	$2,113	$2,225	$114	$5.93	5.3%	$118

* Sum of hour-ahead scheduled quantities
** Includes UDC (estimated cost of production), CDWR costs after 8/2001 projections only; bilaterals estimated at hub prices
*** Includes OOM, dispatched real-time paid MCP, and dispatched real-time paid as-bid
**** Including ISO purchase and self-provided A/S priced at corresponding A/S market price for each hour, less Replacement Reserve refund

Table 3.1 - Monthly System Cost Table, 2000 and 2001

Source: California ISO

3.1 Performance in the California Electricity Markets

The California market involved over a dozen different auctions, some sequential and some simultaneous.[73] The California private utility distribution companies (UDCs) purchased energy in the day ahead and hour ahead PX markets. Generators could also participate in the ancillary markets that CAISO operated, also on a day ahead and hour ahead basis. Dispatch decisions were made by CAISO, subject to the schedules submitted by market participants, and CAISO also conducted the ex-post reckoning for energy options exercised on the ancillary markets. Table 3.1 presents summaries of expenditures in the different markets.

The prices in the all of the markets are closely related. On average, we would expect the prices for the day ahead and hour ahead markets for each product to be similar, as otherwise there would be opportunities to arbitrage between them. Many generating units have a choice of entering bids in the energy markets or the ancillary markets (or can commit shares of their capacity to each), so prices among all the markets are tied. In this section we first consider the issue of price volatility in electricity (energy) spot markets where there is no market power. We then turn to the potential and incentives for firms to exercise market power. Last, we turn to special considerations with the ancillary markets, where some of the market manipulation issues are particularly acute.

Wholesale Price Volatility in Efficient Spot Markets

In California (and most other places) retail rates are fixed in advance of taking delivery on the electricity. Thus while demand for electricity varies with weather and the activities (commercial, residential, and so on) undertaken at different times, it does not respond to actual spot prices for electricity.[74] In principle, producers could set any price they wanted for electricity, constrained only by another producer offering a lower price or by government intervention.

We consider first an efficient spot market, where multiple bidders drive the price of electricity down to the competitive market price. Spot prices are higher during peak loads than off-peak, because of the high operating cost of most peak units. Efficient market prices will be even higher in peak periods when production approaches capacity. In these cases, the prices will include a surcharge associated with the capacity constraint, which pays the fixed costs of the plant and provides price signals about the value of new construction. Congestion on transmission lines will likewise cause efficient prices to rise.

Demand for electricity varies over the course of the day and year, and most of the time it is fairly predictable. Figures 3.1 and 3.2 show demand and day-ahead PX prices on three "normal" days in 1999. Demand early in the morning on the spring day (May 15, 6:00 a.m.) is half that of an afternoon in the fall (September 15, 4:00 p.m.). The spot price for the September afternoon is nearly three times that of the May morning.[75]

Unanticipated demand or supply conditions can greatly magnify volatility. Figure 3.3, which graphs the bids into the day ahead PX market for May 15, 1999 at 6:00 a.m. and 4:00 p.m. (the day's lowest and peak demand hours) illustrates both the standard concept of high prices when capacity is reached and also the problems associated with short-term variations. Note that both the on-peak and off-peak bid curves increase very rapidly in the region of the actual trading prices, although in the latter case demand should not approach system capacity. Nevertheless, the bid curves illustrate the high costs of increasing production in the short-run, whatever the absolute level of production. Most generating plants need time to increase their load. Dispatchers schedule them for expected output, and changing the plan (for example,

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[73] This chapter concentrates on how the market worked in 2000, before the Power Exchange ceased operations.

[74] The discussion here is simplified and stylized, but the unresponsiveness of demand to real-time supply conditions is a general feature of the industry in California. Under cost-based regulation, retail prices were based on expected average costs, so that increased costs would eventually show up in retail bills and possibly inspire some demand response. In addition, time-of-day prices, reflect the higher cost of production during peak loads and are intended to promote a demand response (i.e., energy conservation). Few customers in California have time-of-day prices at this time.

[75] California has an unusual amount of flow-of-river hydroelectric power in the late spring, which depresses off-peak prices in the spring.

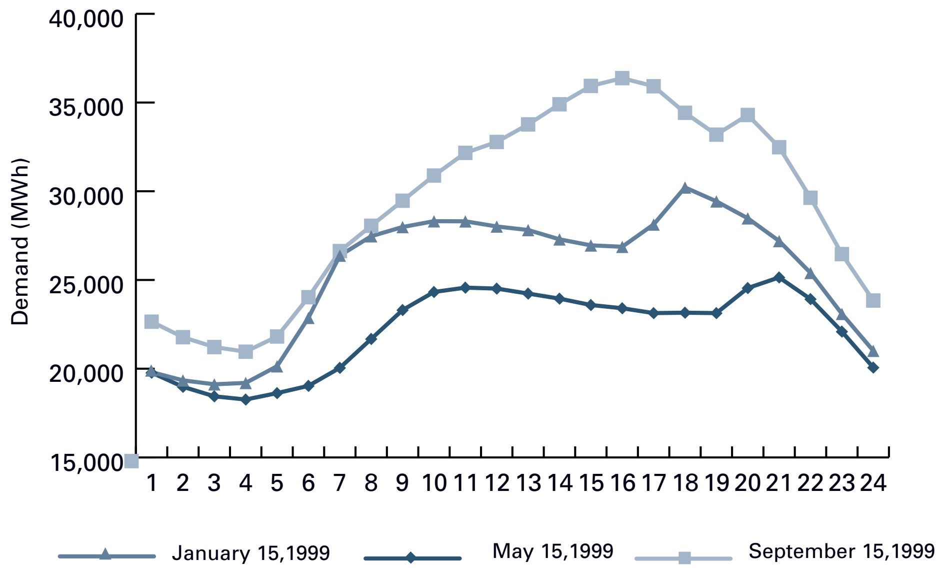

Figure 3.1 – Day Ahead Demand Forecast (PX Data)

Source: CPUC

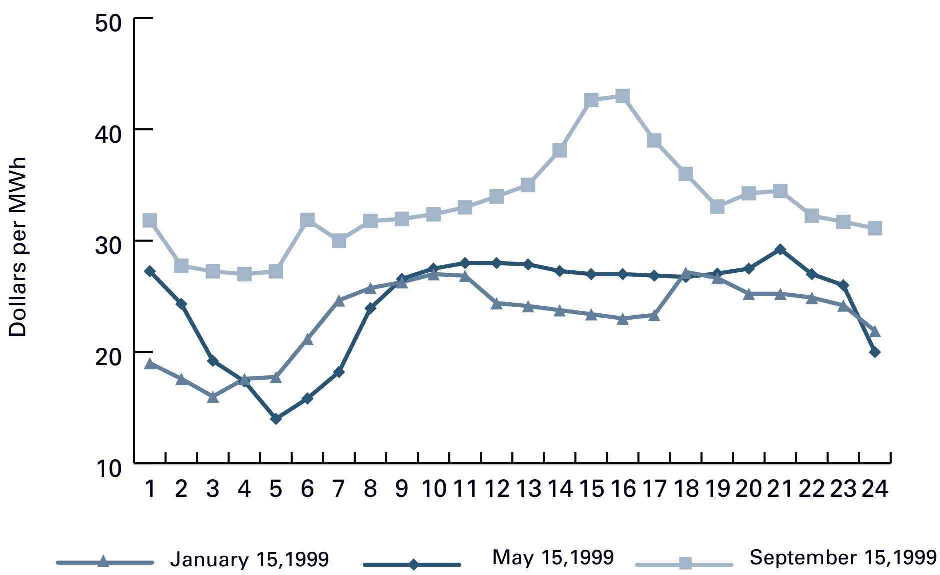

Figure 3.2 – Hourly Price for Three Days in 1999

Source: California PX price data, available at the UC Energy Institute Electricity Market Data web-site, www.ucei.berkeley.edu/ucei/datamine/datamine.htm

if one of the plants elsewhere in the system has an unscheduled outage) can be costly. This characteristic of electricity markets contributes to the volatility of spot markets in times other than the system peak.

The Market is Vulnerable to Manipulation

In the context of a competitive market, price volatility carries risk for market participants. Of course, in such markets participants would typically cover some of their risks through forward contracting. But the prices are not inefficient per se. High spot market prices would indicate supply constraints and provide a signal to add capacity.

Alternatively, in a market with few suppliers, the volatility is problematic. The situation is illustrated in Figure 3.3. To take a concrete example, suppose firm X has 2000 MWt of electricity to bid into the market at 9:00 p.m., and X has one of the less expensive units on line. The argument requires that demand is close to capacity: all of the available inexpensive units are bid into the market, and remaining alternatives are the expensive units that make the far right side of the bid curves. If X bids in all its power at cost ($25) it will sell all of it at a price of $50, for revenues of $50,000. Alternatively, if X withholds

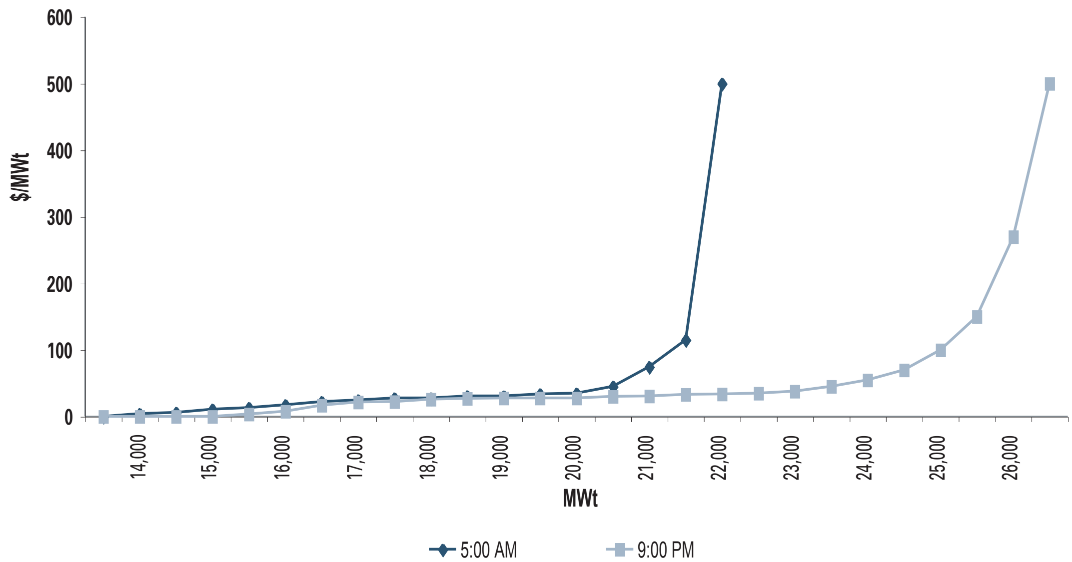

Figure 3.3 – Supply Bids May 15, 1999: Day Ahead

Source: California PX price data, available at the UC Energy Institute Electricity Market Data web-site, www.ucei.berkeley.edu/ucei/datamine/datamine.htm

half his power and only bids in 1000 MWt, the market clearing price rises to $250, and his revenues to $250,000. At peak times, when demand is close to capacity, withholding a relatively small amount of power from the market can be exceptionally lucrative.

Our argument depends on a firm having sufficient presence ("power") in the market that its own supply constraining activity has a major impact on price. By conventional measures, the market in California is not concentrated: the merchant generators collectively control only 30 percent of the capacity in the state. The conventional viewpoint is why the possibility of market power was largely dismissed in the hearings and planning for restructuring in California. But that turned out to be wrong. The most important opportunities to exercise market power came in the ancillary markets, when transmission conditions effectively divided up the state into sub-units, so that the local plants constituted the relevant market and concentration was far higher than the state average. In general, opportunities to exercise market power depended on both the quantity and distribution of alternatives.

When there are market power opportunities, the lack of demand responsiveness and of forward contracts becomes critical. For demand responsiveness, the logic is straightforward. High prices are

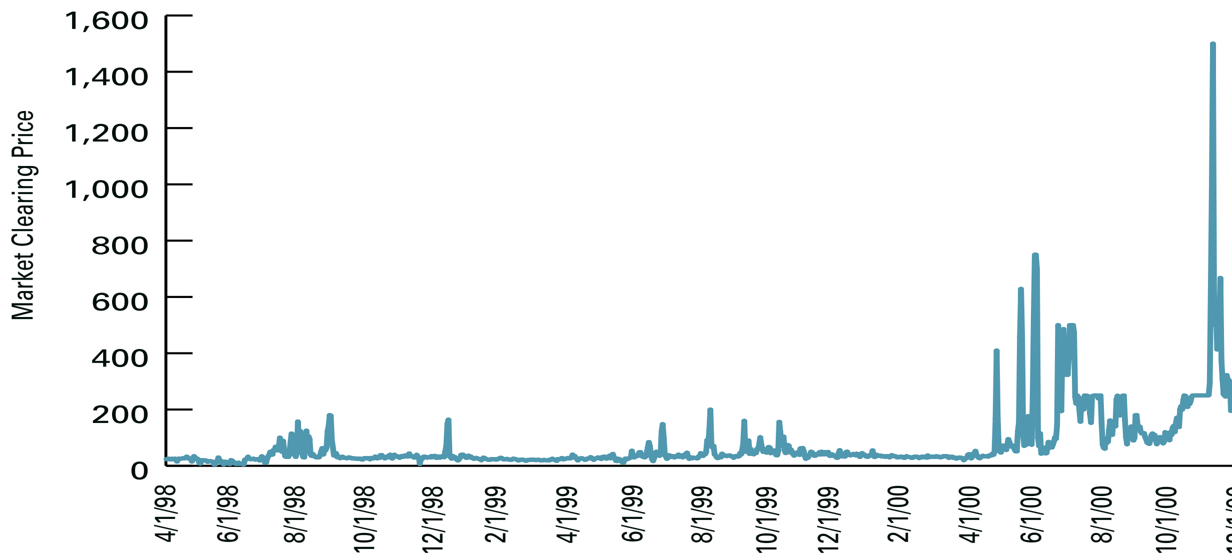

Figure 3.4 – 6:00 PM Price in the Unconstrained Day-Ahead PX Market

Source: California PX price data, available at the UC Energy Institute Electricity Market Data web-site, www.ucei.berkeley.edu/ucei/datamine/datamine.htm

caused by high bids at the margin of the supply (or bid) curve. Faced with those prices, consumers would reduce their consumption, driving prices down. If the prices are particularly high, they will decline by a very large amount because the bid curves are very steep when capacity is tight. An ounce of conservation *at the right time* is worth a ton of antitrust litigation.[76]

The impact of forward contracting can also be significant. In our example, the firm was able to realize large profits while sacrificing sales because of the high price that he realized on remaining units. But, suppose some of his power is sold in long-term contracts at a fixed price. While he may be able to affect the same increase in spot market prices by withholding power, he will have fewer units still for sale on the spot market to be sold at the high price. Withholding the power may not be attractive to begin with.

There is strong evidence that electricity generators obtained high prices by strategically withholding power from the markets in California starting in 1998 in times when demand was very high. Similar events occurred in other parts of the country as well, however, these initial incidents were relatively isolated. They are consistent with the much larger distortions in 2000 when supply conditions altered.

Figure 3.4 shows the daily 6:00 p.m. market clearing price on the day-ahead unconstrained PX market.[77] Price volatility is apparent throughout the period, although the most striking feature of the figure is the enormous run-up in prices in the summer of 2000.

Ancillary Services

The ancillary markets have posed difficult problems in the California market. Many of these markets are, some of the time, very thin due to local congestion. They consequently present some generators

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[76] A superb elucidation of the concept as well as demonstration that real time pricing need not lead to volatile monthly electric bills is given in Borenstein, Severin - "The Trouble With Electricity Markets," *Journal of Economic Perspectives*, Winter 2002

[77] This is the market-clearing price from the first auction that the PX runs, prior to adjustments and charges for transmission congestion.

with significant opportunities to increase profits through bidding practices that are detrimental to the reliability and efficiency of the system.

CAISO buys balancing power and different types of reserve power in day ahead and hour ahead markets. Ancillary services also include plants that can supply additional energy on very short notice ("regulation reserve"), those that take longer ("spinning reserve") and plants that may need substantial notice to become available ("non-spinning reserve"). Reserve requirements are set by NERC and WSCC, and vary with the difference between scheduled energy and projected demand. The owner of a generator is paid a fixed fee for providing an energy option to CAISO. If the energy is taken, the owner receives another payment based on the market clearing price. If insufficient reserve capacity if offered in the auctions, CAISO will go "out of market" to acquire balancing and reserve capacity at any cost. If it does not succeed in purchasing sufficient reserves, it will direct the utilities to shed load according to NERC and WSCC regulations.

The ancillary markets are a novel feature of the California restructuring plan, and, not surprisingly, have not operated smoothly. We discuss here three specific examples of problems that have arisen in these markets. The first case shows the complexity of using unbundled auctions for ancillary services. The second two illustrate the sort of market manipulation problems that have occurred in these markets.

The so-called "BEEP stack" has been one source of trouble. (BEEP refers to Balancing Energy and Ex-Post Pricing.) Bidders submit bids for different reserve capacity types at different prices, and the CAISO (formerly) "stacked" the bids in the planned order of acceptance. The basic problem with this procedure is that bids differ on multiple relevant dimensions of price, quality, and location. The one-dimensional stack cannot give an optimal acceptance criteria. CAISO's algorithm for scheduling reserves have undergone a number of modifications in the past three years.

A problem that surfaced in 2000 concerned hydroelectric facilities. These facilities provide excellent reserve capacity because of the speed with which they can increase and decrease production. But, some of these plants are energy constrained due to fixed amount of water available for the summer/fall season: production early in the season forecloses the opportunity to produce later in the year. Hence, the best way to use some of them may be mostly for reserve and emergency contingencies, rather than routine dispatch or even regulation reserve. In the fall of 2000, insufficient power was bid into the PX markets and reserve capacity was frequently dispatched. Generators became unwilling to bid their energy-constrained spinning reserve capacity into the ancillary market. Then, not only did CAISO have insufficient energy and regulation reserve, but had to pay high prices for the spinning reserve requirements as well. Of course, a fix exists – identify such plants in the auction as for use only in a real emergency – and CAISO has implemented the change. During each year of operation, at least so far, a fairly large number of issues of this type have arisen.

In addition to fixing these kinds of problems, as CAISO has obtained experience with scheduling reserves it, and WSCC, have modified the various constraints on quantities of reserves of different types that ISO requires and the constraints on the physical location of reserves (e.g., raising the share of spinning reserves that can be satisfied through imports). The measures have increased competition in the markets much of the time, and have lowered prices. Ancillary service costs as a share of Energy costs fell from 13 percent in 1998 to 5.7 percent in 1999 and between two and three percent during the first four months of 2000.[78]

A second more serious problem with the ancillary markets is that they frustrate attempts to control prices on the energy markets. For example, during most of 2000, caps constrained prices in the real time energy market. Late in the year, the price cap of $250 fell below operating costs of at least some of the middle-load gas generators, and the price in the PX markets systematically exceeded that of the BEEP market. Buyers were unwilling to buy on the PX market, preferring the price-capped CAISO market.

[78] ISO-DMA *Second Annual Report*, p. 5.

Sellers, however, were unwilling to bid in energy at $250. Instead energy was underscheduled, and CAISO was forced to acquire extra ancillary products and exercise reserve options, at very high prices.

Unfortunately, the markets present many opportunities for exercising market power, in part because the ancillary markets may be very small, depending on congestion. The must-run contracts, discussed in the previous chapter, cover only a fraction of the potential congested cases. CAISO has documented evidence of purposeful congestion in the dispatch plans of some generators so as to create an exploitable local market. The unit could then withhold from the energy markets, bid into an ancillary market, collect the fixed fee, and be assured of energy sales as well.

As CAISO has identified strategies and closed loopholes, the generators have found more obscure, but still lucrative strategies. CAISO's position is that it must acquire adequate reserve capacity at all times. During late 2000 and early 2001, little energy was bid into the markets, and ancillary power became a "name a price" market with transactions rising to the thousands of dollars per MWt. CAISO has not ceased proposing modifications to the structure of the markets.[79] All these changes require FERC's approval, which has had less than infinite tolerance of experimentation.[80] FERC's reluctance to continue modifying the market is in part unrealistic. Given the novelty of the markets, adjustments are appropriate. But in part, their position that these Band-Aids will not resolve fundamentally flawed markets is correct. The frequency with which the ancillary markets are manipulated follows from their vulnerability. As with the energy markets, too many services are traded on the spot prices, and the volatile prices provide strong incentive to pursue disruptive measures and reduce supply. We consider market power issues further in Market Power section below.

Currently, CAISO staff is preparing a proposal for a comprehensive overhaul of their markets. A new plan is due at FERC this spring that broadly addresses the structure of the California markets.

3.2 The Run-up in Prices in 2000

There is little disagreement that the run-up in prices in the summer of 2000 was caused by three phenomena: increases in electricity production costs, tight electricity supplies and the exercise of market power by producers. In addition, some observers claim that the three phenomena are really just one because market manipulation was at the root of the tight supplies and the production cost increases. These arguments are reviewed below.

Demand Growth and Capacity Constraints

Market prices are dictated by supply and demand. If demand grows and supply is fixed, price will increase. In the electricity business, as the bid curves and discussion in the previous section demonstrate, relatively small increases in demand may cause surprisingly large price increases. Some critics of California allege that the electricity crisis was due to a failure by the state to increase capacity and keep up with demand growth in the state. This criticism is technically wrong. But, as is explained below, the sentiment has some merit.

As is discussed in the previous chapter, electricity demand growth in California over the past 20 years has been fairly modest. Capacity expanded in California at about the average rate for the WSCC area. While little was built in California in the way of large central generating stations, the state's QF program was outstanding from a capacity expansion perspective. Jolanka Fisher and Timothy Duane calculate the ratio of capacity in the state to consumption between 1977 and 1998, and find that California not only has by far the highest increase, but it the only state in the region where the ratio increased at all: capacity-to-consumption (MWt/GWh) in California went up by ten percent over the 20 years. For WSCC as a whole, it dropped ten percent, led by a

[79] See, e.g., California ISO, *Operations Economic Report*, 2001, or the CAISO-DMA *Annual Reports*.

[80] A detailed discussion of the ancillary markets is contained in Paul Joskow, "California's Electricity Crisis," NBER Working Paper 8442, August 2001.

decrease of over 30 percent in Arizona, New Mexico and Nevada.[81] California added five percent to installed nameplate capacity between 1998 and 1999; essentially nothing in 2000, and nearly four percent in 2001. The state's summer peak declined by 3.6 percent from 1999 to 2000. In contrast, WSCC summer peak increased by 1.4 percent that year. In sum: demand in other WSCC states has increased more rapidly than their capacity additions. California has been relatively frugal on both sides, but particularly in its demand growth, so that, counter to WSCC trends, capacity expanded in California more rapidly than demand.

Nevertheless, an argument on the side of the state's critics is easy to make. Notwithstanding the state's consumption patterns, it is a net importer of electricity. California is the largest net importer in the WSCC region, both in absolute terms and as a fraction of consumption. Imports as a share of generation were 23 percent in 1991, and remained around 17-19 percent for the next decade. In 1999, imports were 18 percent of generation. This is not a picture of self-sufficiency. Meanwhile, the other states in the region grew rapidly, and started competing with California for the use of the electricity resources within their states. The prospect of "their" power being bid up by prices in California has, for some of the states, unpleasant associations.

In any event, in the late 1990s, California depended on imported electricity. In 2000, the imports were cut by about 40 percent, or seven percent of the State's total consumption. Substituting within-state resources increased prices as older, dirtier plants were employed. The substitution plausibly spilled over to the cost of complementary resources in fixed supply, and contributed to the price increases for pollution permits and gas supplies, discussed below.

In both 2000 and early 2001, generating plants were unavailable in California in large numbers. While this clearly had a major impact on prices, it is less obvious whether the outages were "market fundamentals" or whether they were market manipulation. One view holds that the outages in winter 2001 were due to deferred maintenance and to the environmental constraints. In late 2000 some of the plants that did not run at full capacity had in fact used up their NOx emissions quotas for the year, and were precluded from further production. Some cynics observed that a lack of permits had not proved to be an obstacle to production in previous years. The conspiracy view holds that the outages were deliberately scheduled in order to drive up prices, so that this source of price increase is due to market opportunities, rather than a dynamic "fundamental" relating to inadequate long-term investments.

Even if the market manipulation argument has some validity, it is important to note that it does so only if capacity is relatively tight at the start. The value of withholding a small amount of capacity, and sacrificing sales, in order to drive up price, is a rational strategy if the company doesn't have to withhold very much, and the price increase is large. Those conditions are likely to hold for electricity when supply is tight. If there is excess capacity or less than perfectly inelastic demand, the putative manipulator would have to withhold too much supply in order to obtain the desired price increase. Thus the two arguments go together.

Production Costs Increased

Production costs increased in 2000 relative to 1999. Unlike a shift in demand or supply, production cost increases should have a proportionate impact on price: when fuel prices double, for example, the price of electricity should go up at most by the share that fuel contributes to production costs.[82]

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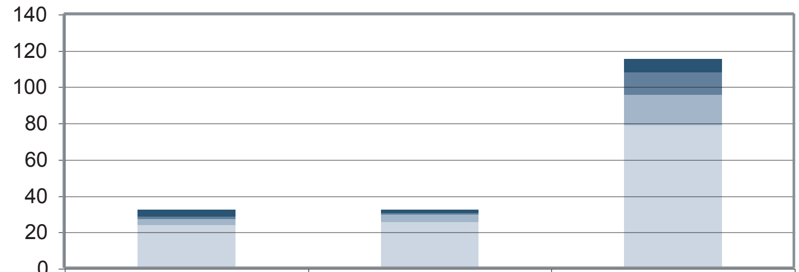
[81] Fisher and Duane, *op. cit.*

[82] A shortage might drive production to more expensive plants, but there were no claims in California in 2000 of gas shortages if a firm were willing to pay the higher price. Joskow estimates that an increase in the cost of gas from $2.50 to $6.00/Mcf increases production costs at gas units by about a factor of two for fairly efficient units, and by a around 130 percent for the most expensive plants. Joskow, "The California Crisis," *op. cit.*



	1998	1999	2000
AS	4	2	7
ISO Real Time	1	1	12
Bilateral Energy	3	4	17
PX Energy	25	26	79

Figure 3.5 – Electricity Costs by Market Component, $/MWh

Source: California PX price data, available at the UC Energy Institute Electricity Market Data web-site, www.ucei.berkeley.edu/ucei/datamine/datamine.htm

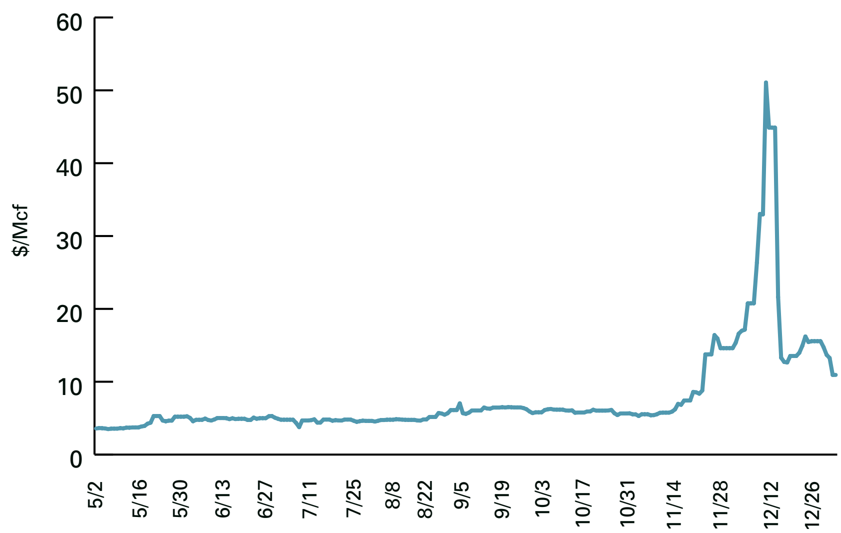


Figure 3.6 – Burner-tip Price of Natural Gas in California, May-December 2000

Source: California PX price data, available at the UC Energy Institute Electricity Market Data web-site, www.ucei.berkeley.edu/ucei/datamine/datamine.htm

Gas prices increased dramatically in California during 2000 (see Figure 3.6), and there were a series of competing claims about whose market flaws were to blame. By 2000, the gas industry was vulnerable to price increases. Little pipeline expansion (none in California), together with increased reliance on natural gas-based electricity production left the industry operating close to capacity which, as with electricity, left the spot market open to price volatility.[83] Whether the high prices resulted merely from

[83] Gas markets have extensive future trading components, which reduces the risk of financial ruin from short term perturbations. The cost that generators paid on average for gas during the period of high spot prices was much less than the spikes.

unfortunate accidents in the industry or whether the suppliers deliberately manipulated a promising set of market conditions is currently a matter of litigation.[84]

The price of tradable NOx permits rose from two or three dollars per pound to seven dollars in June 2000, and then to between 35 and 45 dollars from August 2000 through March 2001.[85] While these tradable permits are only relevant to electricity production in the LA Air Basin, the Basin includes over half of the gas thermal generation in the state. The permits have a large impact on the price of operating some the dirtier plants in the Basin. These can produce up to six pounds of NOx per megawatt-hour of electricity, yielding a cost increase at the high end of 6 x 50, or $300 per MWt.[86] And, in principle, that plant could be setting the market price in California.

Unlike electricity retail prices, NOx prices are demand sensitive. The NOx program called for reducing the available number of permits each year, in order to improve air quality over time. Permit scarcity in 2000 was expected to produce price increases, even before the electricity crisis. But when the older gas plants were brought into service in 2000 to make up for shortfalls in imports, pressure increased dramatically on the permit prices. The factors worked together to push up electricity costs in California.

A second factor may have been at work in late 2000. Wholesale electricity prices are subject to FERC regulation. While FERC had approved the market-based rates, it could, at any time, find the prices unreasonable and intervene in the market. In late 2000 FERC approved a "market mitigation" policy that included what became known as a "soft price cap." Important features of the cap include: (1) bids in the auction would be paid the market clearing price only if that price were less than $150/MWt; (2) if the market clearing price was greater than $150, the market was bifurcated: anyone who bid less than $150 received $150 and other accepted bids were paid the bid price; (3) all transactions in excess of $150 were subject to ex post review by FERC, who established a standard for acceptable bids based on unit-specific characteristics and input prices. This is where the NOx permit prices enter: the FERC formula allowed "reasonable" prices to increase with the price of the NOx permits. Thus, if companies could make these permits look more expensive (by selling permits to out of state affiliates and repurchasing them at a higher rate), the constraints that FERC placed on energy transaction prices would relax. Allegations of such dealing are under investigation.[87] For our purposes, whether it happened or not is less relevant than the fact that the markets provided an incentive for this kind of behavior. The opportunity illustrates the extraordinary difficulty in controlling prices in a decentralized industry.

Market Power

There is strong evidence that electricity generators obtained high prices by strategically withholding power from the markets and strategically allocating their bids among the different markets in California. Actions in the ancillary markets, discussed above, clearly show that market power exists and is exploited at some times in the system. How important is the problem?

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[84] See Prepared testimony of Dr. John Morris, Ph. D. United States of America before Federal Energy Regulatory Commission. PUC of California v. El Paso Natural Gas, EL Paso Merchant Gas L.P. and El Paso Merchant Energy Company, May 7, 2001; and Prepared Testimony of Joseph P. Kalt, Ph D. United States of America before Federal Energy Regulatory Commission. PUC of California v. El Paso Natural Gas, EL Paso Merchant Gas L.P. and El Paso Merchant Energy Company, May 7 2001.

[85] Prices quoted are for the Cantor-Fitzgerald Weekly Index, and reflect weighted averages of trades for different permits with different expiration dates.

[86] Future markets existed for NOx permits during this time. Because the dirtier plants in LA are operated rarely, their owners probably did not have permits at the time of the crisis, and had to pay the index prices quoted here in order to operate the units.

[87] The California State Senate established a Special Committee to Investigate Market Manipulation in California Electricity Markets. They are looking into a wide range of alleged illegal behavior.

Measuring the consequences of market power is complicated because it is not accurate to merely compare the costs of production to the market prices. As is discussed above, an observed price may reflect one of (at least) three factors that would cause it to differ from production costs yet still be efficient. First, transmission lines might be congested. The price of power actually sold in the congested area should (from an efficiency point of view) contain a surcharge that would provide an incentive to de-congest the region. Second, capital charges (capacity) are efficiently allocated among purchasers not as a straight surcharge but rather taking into account differences in use of the facility. Efficient peak load pricing yields high prices when capacity is constrained. Third, energy constrained plants, which include hydroelectric capacity and plants with limited pollution rights, should be dispatched and priced in a way that responds to current and anticipated system demand and supply.

A number of studies have taken these and other considerations into account in their estimates of market power and prices.[88] The studies conclude that the exercise of market power in 1998 and 1999 resulted in a surcharge of at least 15 percent on electricity prices.[89] Using a similar structure, but imposing the 2000 and 2001 opportunities, including import conditions, and the increase in production costs leads to fairly startling conclusions. The most comprehensive studies have been conducted by the CAISO's Department of Market Analysis, which finds markups of 30 percent or more. The estimate is a lower bound, and is likely to be a very conservative measure as it excludes hours when scarcity might support an alternative peak-load pricing explanation and ignores the possible endogeneity of the pollution permit prices. One study credits over half the price paid for electricity in 2000 to exercise of market power. If the prices of inputs and actions taken to compensate for unit outages in California are credited to market power, its cost contribution becomes much larger.

3.4 Reforming the Market Institutions

There is a broad consensus among energy analysts and economists about how to fix the market institutions in California. Proposals call first, for retail restructuring and retail prices that are sensitive to the spot price of electricity. This change is probably the most effective way to make the system robust to supply disruptions. As Severin Borenstein shows, real-time prices can be instituted in a way that maintains both cross subsidies and limits total monthly bills (that is, the average per KWt charge).[90]

It is not surprising that reforms involving rate increases do not command the same enthusiasm from state regulators. But a possible benefit of the state intervention in power purchases is that rates have increased to cover its costs. The real-time options could not be plausibly instituted within the average rate framework in the state.

While retail rates remain (formally) within the regulatory jurisdiction of state governments, the recent court decision in *New York v. FERC* suggests that the jurisdiction may nevertheless have little scope. Real-time pricing then assumes additional importance for consumer protection.

Second, all of the market participants, but particularly the UDCs and CAISO, should be allowed to engage in forward contracting. The restrictions on trading, that made prices entirely reliant on the volatile spot markets both created and exacerbated the market problems. A richer array of contracts allows for risk management, which is valuable on its own. Furthermore, forward contracting greatly

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[88] In contrast, evidence of collusive behavior among these participants, of great interest from the legal perspective, has not been established using statistical techniques. See Puller, Steven L. - "Pricing and Firm Conduct In California's Deregulated Electricity Market", *POWER Working Paper # 080, January 2001.*

[89] In contrast, evidence of collusive behavior among these participants, of great interest from the legal perspective, has not been established using statistical techniques. See Puller, Steven L. - "Pricing and Firm Conduct In California's Deregulated Electricity Market", *POWER Working Paper # 080, January 2001.*

[90] Borenstein, Journal of Economic Perspectives, op. cit.

facilitates the real-time pricing option because the retail price would be much less volatile, and much more predictable, than were wholesale prices during the California crisis.

A third important remedy involves modifying the ancillary markets so that generators do not have incentives to manipulate prices in both the spot and ancillary markets. The CAISO has made a number of changes in the structure of the ancillary markets and is scheduled to propose major changes to FERC this spring.[91] The troubled history of these markets, however, and their basic illiquidity, indicate that at this point these markets are not competitive. Some form of regulatory control over prices is appropriate for the present.

The fourth proposal that provides minimal regulatory control for the ancillary markets is the employment of price caps. Properly set, the caps should be a safety net against exercise of market power. Their use recognizes that price regulation is a continuing feature of electricity markets. Price caps were not effective in California until June 2001. FERC's "soft caps," deployed in early 2001, resulted in compensatory bidding behavior that created underscheduling in the energy markets and more problems for reserve scheduling and the CAISO markets. In addition, as is discussed above, these caps may have contributed to price increases in the input markets. The history of caps in the electricity industry suggests that they can be successful, but require active oversight.

The caps are necessarily federal – by the logic of the market structure as well as by law. Federal actions introduced interstate commerce in electricity. The commerce – rather than the interstate connections, which have existed for decades – created interstate markets, and limit the ability of states to influence the activities of companies in the industry. This applies to investments as well as prices, as the FERC BRPU decision suggests.

By June 2001, prices had moderated in California. The supply constraints that pushed the system into a vulnerable position had moderated. Some new capacity came on line inside the state, imports again became available, and a cool summer contributed to loosening capacity. Retail prices finally increased with incentives for conservation (not in real time) whose effectiveness caused some surprise. The state took over as a scheduling coordinator for the UDCs and immediately abandoned the spot markets in favor of long term contracts. Thus, the state has in fact backed off from some of the more problematic features of the restructuring plan, but the better outlook for electricity may be a temporary result of favorable demand conditions. PG&E remains in bankruptcy court, investment in infrastructure has stalled, and the state has yet to institute reforms that maintain the advantages of restructuring. The next chapter considers some of the options available to the state.

[91] CAISO, Third Annual Report, op. cit.

CHAPTER 4: CONCLUSIONS

4.0 Overview

Proposals that have been advanced to fix the California electricity industry take one (or both) of two approaches. One is to reform the market institutions so that they are relatively robust to the kinds of resource restrictions observed in California in 2000. The second is to expand the resource base. [92] We consider here the proposals in the light of the discussion in the previous chapters about the evolution of federal and state policies for electricity. The recent history of electricity in California underscores the importance of aligning policies with governance bodies that have both the authority and incentive to deal with problems that are likely to surface in the industry.

The extent to which the state and federal regulators have been working at cross purposes is apparent in their reaction to the energy crisis in 2000, when their split authority allowed each to delay actions and instead blame the other, worsening the financial position of the state. In retrospect, it is clear that the initial deregulatory plans of the two governments similarly duck problems through assumptions about responsibilities of the other plan. The first part of this chapter discusses these issues. We then turn to our principal recommendations.

4.1 Split Governance in the California Electricity Markets

The recent interactions of the federal and state electricity regulators have been more than unfortunate. The first part of this section considers the impact of the California restructuring plan on federal deregulatory goals. We then turn to more recent history.

Reforms at Cross Purposes

As the previous chapter makes clear, both the federal and state agencies planned restructuring based on a fundamentally flawed view of the potential for market power in electricity markets. Both governments assumed that independent generators would be too small to exercise market power, but that as long as the utility distribution companies maintained dominant positions in retail, they would need to be constrained from exercising market power in wholesale markets.

In the absence of the state actions, the federal assumption that independent power producers lacked market power was largely accurate. Conditions could cause IPPs to have short-term market power, as was demonstrated with price spikes in the Midwest in the mid-1990s. But these events were sufficiently rare that they were unlikely to cause financial collapse in California, even given the supply constraints and warm weather of 2000. Counteracting the ability of IPPs to exercise market power in other jurisdictions were the investor owned utilities. The market power of the IOUs muted potential exercise of market power by IPPs, and allowed FERC to maintain its "market price" standard rather than taking a pro-active role in setting wholesale rates.

The choices in California's restructuring plan follow the federal lead in presuming that the IPPs would not have significant market power. The state plan emphasized constraining potential exercise of market power by the IOUs. Two key actions were taken to limit IOU market power: the large-scale divestiture and the buy/sell spot market trading requirement. Together, the requirements responded to concerns that the IOUs would be able to manipulate bilateral contracts to their advantage (which may

[92] Various state officials have also expended great effort on establishing illegal acts by merchant generators and energy traders. This activity has two (potentially) important consequences: first, they may be able to recover some of the very large sums of money spent by the state of California during the crisis (although the firms in question seem to have fewer resources daily). Second, proof of illegal behavior could spur the federal government into taking some of the actions that state regulators have proposed to improve markets in California. Some of these issues are developed below.

in fact have been correct) and that both energy and ancillary markets would have sufficient liquidity to be competitive, which was not correct.

As is discussed above, prior to restructuring in California, there was really no experience with using spot markets to supply unbundled ancillary services. But it became apparent fairly soon after restructuring that the ancillary markets were not sufficiently liquid in a significant number of cases. Given the illiquidity of the ancillary markets, FERC's basis for allowing market prices to set rates – sufficient competition – was breached.

Agencies at Cross Purposes

The actions of electricity regulators in 2000 and 2001 clash abruptly with their rhetoric of four years earlier. In the place of cooperative federalism, regulators aggressively undermined each other's efforts to fix the market. As wholesale prices mounted in 2000, "cooperative federalism" between the state and federal electricity regulators gave way to hostility. The state maintained that the markets were inherently non-competitive and that they needed price controls to counteract monopolistic abuses. The initial federal response was equally dogmatic, with the claim that high prices would provide appropriate incentives to add the generation capacity needed in California. As the financial position of the utilities became increasingly shaky, federal rhetoric shifted to demands for retail price increases and loosening the contractual restrictions on the utilities. State rhetoric merely intensified with claims that the federal government had shirked its responsibilities under the Federal Power Act to insure that wholesale prices were just and reasonable.

The demise of the CalPX is illustrative of state-federal relations. By fall, 2000, wholesale prices were averaging three times the retail rates that PG&E and SCE were allowed to charge their retail customers. The CPUC argued that wholesale prices were clearly not just and reasonable and FERC had to disallow them and order the generators to return the difference. In its November 1 Order, FERC agreed that the spot market rates in California had been (on occasion) "unjust and unreasonable." FERC found that the cause of the problem was California's market rules, which "provided electricity wholesale sellers the opportunity to exercise market power during periods of tight supply." [93] However, FERC continued that there was insufficient evidence to find unjust and unreasonable pricing by any individual seller, so no refunds were ordered.

FERC diagnosed the central problem with the California market to be over-reliance on short-run spot markets. In several orders during the fall of 2000, the agency attempted to restructure the markets to reduce the importance of the spot markets. The critical order is the agency's December 15 Order, which eliminated the CalPX buy/sell requirement for the utilities. The provision, intended to take effect immediately, allowed the utilities to engage in forward contracting. However, FERC had exclusive jurisdiction only over utilities' sales of wholesale power. FERC therefore ordered that the utilities could not sell power in the CalPX unless it was surplus power, that is, not needed for their retail loads. As the U.S. Ninth Circuit Court of Appeals described in a case filed by CalPX; [94]

> Because the IOUs participate in both the California retail as well as interstate wholesale markets, however, they fall within the jurisdiction of both the CPUC as well as FERC. FERC noted that its proposal to eliminate the mandatory buy/sell requirement had received overwhelming support from almost all interested parties except the CPUC. In fact, the CPUC specifically declared that FERC's "elimination of its 'buy' requirement does not eliminate the California Commission's 'buy' requirement," and emphasized that its buy requirement would remain in place until the CPUC itself removed it…

[93] Decision, U.S. Court of Appeals for the Ninth Circuit, *In re: California Power Exchange Corporation* No. 01-70031, citing 93 FERC § 61,121 at 61,350.

[94] *In re: California Power Exchange Corporation*, op. cit.

> Faced with the CPUC's refusal to abandon its reliance on the spot market – indeed, in the face of the CPUC's explicit declaration that it would continue to require, whether directly or indirectly, that the IOUs continue to procure the bulk of their power needs through the CalPX spot markets – FERC was forced to take "the unusual step" of terminating the CalPX's wholesale tariff and rate schedules, including its CTS forwards market rate schedule, effective April 30, 2001.

Neither of the regulators blinked in the face of the impending financial doom of both the utilities and the CalPX. (The U.S. Court of Appeals also declined to intervene.) When the utilities' credit ratings achieved junk status, they were no longer allowed to trade in the California spot markets. The ISO filed a requested amendment with FERC to change its tariff so that the utilities could continue to purchase electricity, and FERC refused the request. Rather than acceding to FERC's demand to lift restrictions on the utilities' forward trading options, California chose to enter the market itself. Ironically, the state then acquiesced to the federal demands. It immediately eschewed the spot markets in favor of long-term bilateral contracts with the state's merchant generators, and has raised retail rates to consumers.[95] For its part, FERC finally imposed an effective price cap in June 2001. Together with loosening resource constraints in summer 2001, energy supplies have been adequate in the state, and wholesale spot prices moderated so much that the CDWR's long-term contracts appear to saddle the state with poorly-executed long-term commitments.[96]

4.2 Lessons Learned and Recommendations for Future Resource Planning

The principal lessons learned from California's experience with restructuring are:

- The lack of clear assignment of responsibility for planning and managing resource portfolios resulted in a failure to respond to early warning signals of supply/demand imbalance and reduced the ability to or proactive responses to manage risks associated with that imbalance;
- No entity had clear responsibility for market interaction action if system issues developed;
- Limited consideration was given to activities that markets do not do well, such as maintaining adequate generation reserve and gas storage capacities; and
- Mechanisms for consideration and inclusion of rapid demand side response strategies were inadequate.

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[95] James Sweeney provides a comprehensive evaluation and discussion of the electricity contracts negotiated by CDWR. *The California Electricity Crisis*, 2002, *op. cit.*

[96] The State's participation in markets creates a number of potential and actual conflicts of interest. The state's entry in the market did not reduce jurisdictional tensions. CDWR initially arranged ancillary services outside the CAISO, and refused to acknowledge (or, more precisely, refused to pay for) CAISO's grid-stabilizing activities on behalf of PG&E and SCE's customers. The CAISO 2001 Operations Economic Report discussed the issue in diplomatic terms:

An unexpected result of CDWR's assumption of the role of guarantor is that CDWR has declined to pay third-party suppliers for energy procured on behalf of PG&E and SCE … [but] has elected instead to focus on inter SC transactions outside of the ISO markets …

On November 7, 2001, the FERC directed the ISO to invoice CDWR for all ISO transactions it entered into on behalf of SCE and PG&E. The ISO promptly invoiced CDWR. As of the date of this report [December 21, 2001], CDWR has met these payment schedules.

CAISO 2001 Operations Economic Report, op. cit., p. 5.

The shift in regulatory jurisdiction from the state to regional and federal levels create challenges for state policy. Nevertheless, it leaves the state with a range of tools to address state priorities in energy use:

- Retail rates remain regulated by the state and should be the focus of efforts to promote conservation.
- State influence on generation mix can derive from pollution tax policies or from state subsidy programs.
- State participation in the regional markets and regional infrastructure (transmission; water use) is increasingly important in the restructured environment.

Finally, it is clear that the introduction of markets does not remove state benefits from energy planning. Indeed, the reverse is the case: state energy use projections and plans, while considerably more difficult, are integral to accomplishing public goals.

CHAPTER 5: RECENT ACTIONS 2003

5.0 Overview

A great number of analyses have been made, and will continue to be made, about the California energy crisis of 2000-2002. Criminal investigations continue and so far three Enron energy traders have been indicted. El Paso Natural Gas has settled some claims out of court. No consensus exists on what went wrong and why, partly because of the complexity of the situation. While the crisis has been alleviated, policy makers seem to agree that a comprehensive energy strategy needs to be developed.

A number of actions have been taken during and after the California energy crisis. Some have been discussed in more detail previously. This review is to emphasize that, taken together, they comprise the elements of a long-term strategic plan.

5.1 New Power Plants Construction

In response to the shrinking capacity reserves in spring 2000, Governor Davis signed various executive orders to expedite the approval process for emergency "peaker" plants. These were typically simple-cycle power plants that could be constructed in a relatively small area, did not require water supplies for cooling, and could readily be connected to the existing transmission and natural gas system. The goal to meet the electricity needs during peak demand periods was to add 1,000 megawatts (MW) of new power plants by September 30, 2001.

In addition to the regular 12-month siting process for all power plant types with a capacity over 50 MW, the California Energy Commission (CEC) was directed to introduce a 21-day emergency permit process and a four-month peaking power permit process for peaking power plants that could be brought on-line by September 30, 2001, and by August 2002, respectively.

The CEC also introduced a six-month expedited permit process for all kinds of power plants that will not cause significant adverse impacts to public health, the transmission system, and the environment, and will comply with all local, state and federal laws, ordinances, regulations and standards. The normal 12-month schedule is necessary for projects that may take time to resolve issues such as zoning changes, or adverse impacts to biological resources, water resources, air quality, the transmission system, nearby neighborhoods, public health and safety, etc.

Peaking power plant projects under the 21-day expedited review process were exempt from certain requirements of the California Environmental Quality Act. In addition, power plant developers were allowed to file applications without air quality offsets in-hand. These offsets are often gained by retrofitting an existing manufacturing or generation facility elsewhere. However, the peaking power projects were required to show no public health or safety impacts, mitigated environmental impacts, and little or no public controversy.

The four-month siting process for peaking power plant projects included a "Mitigated Negative Declaration" type environmental review and a 30-day public review of the proposed decision. The operating permit expires after three years, but there is the possibility of reapplication.

By September 30, 2001 there were six peaking power projects totaling 449.5 MW on-line that have been reviewed under the 21-day emergency permit process. As of October 22, 2002 there were five other peaking power projects with a total capacity of 637 MW approved and on line.

Despite the added peaking power plants there was a 24% reduction in average NOx emissions from power plants in California between the summer of 2000 and the summer of 2001.[97] The most important reasons for the emission decrease were the completed pollution control retrofits on 17 existing power plants with about 5,000 MW, the energy conservation success, and the installation of about 2,000 MW new, clean baseload power plants during 2001, which reduced the dependence on peaking units.

Counting both peaking and baseload power plants, there were 2,004 and 2,358.4 MW of new power brought on-line during 2001 and 2002, respectively. As of October 9, 2002 there were 23 power plant projects totaling 9,369 MW approved, under review, or announced by the California Energy Commission.[98] Most of these plants will be combined cycle plants fueled by natural gas. The timeframe in which these new power capacity additions are expected to be on-line is depicted in Figure 5.1.

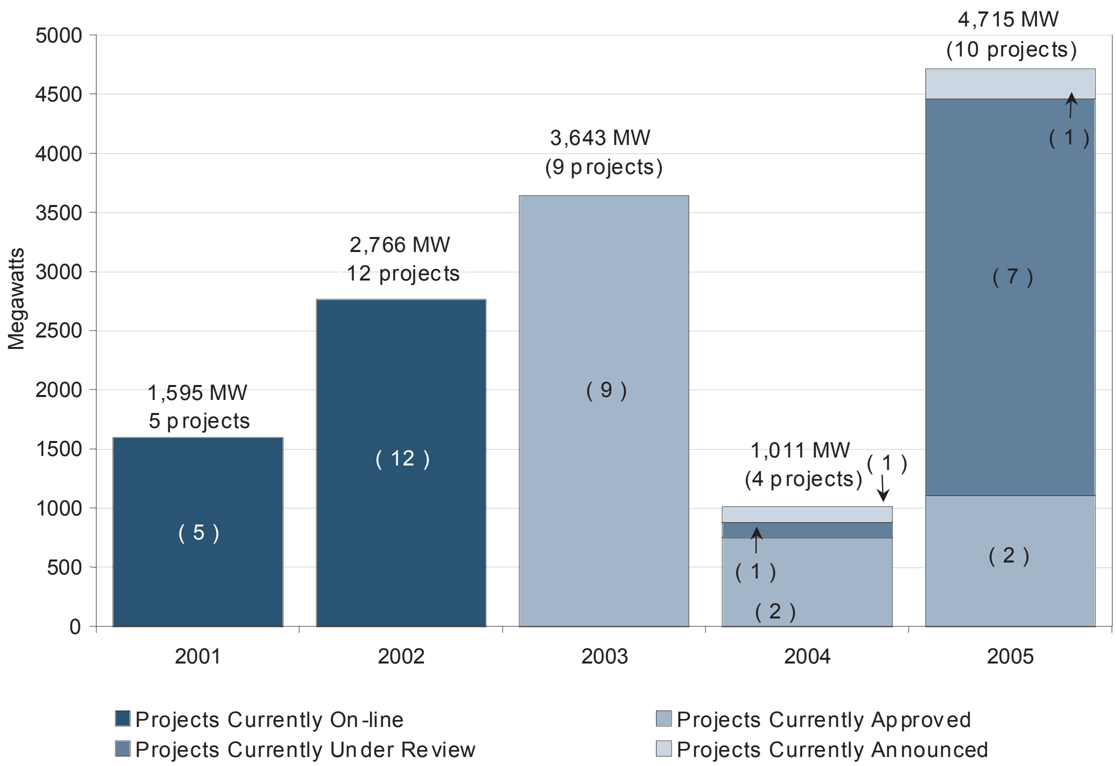

Figure 5.1. Estimated Generation Capacity Added from Energy Commission-Approved Power Plants (by July 31 each year)[99]

With these new capacity additions and demand response improvements, the California Energy Commission predicts that supply will be well above demand in the near future (see Figure 5.2).

5.2 Power Purchases by the State of California

From January 2001 onwards, the financial problems of the investor-owned electric utilities (IOUs) prevented them from purchasing sufficient power on the wholesale market to meet the demand of their default customers. The state of California stepped in as a power purchaser through the California

[97] California Environmental Protection Agency, Air Resources Board, "Informational update on California's electricity situation," September 20, 2001. <http://www.arb.ca.gov/energy/pwrupdte.ppt>

[98] California Energy Commission, Intranet, November 12, 2002.

[99] California Energy Commission, Intranet, November 12, 2002.

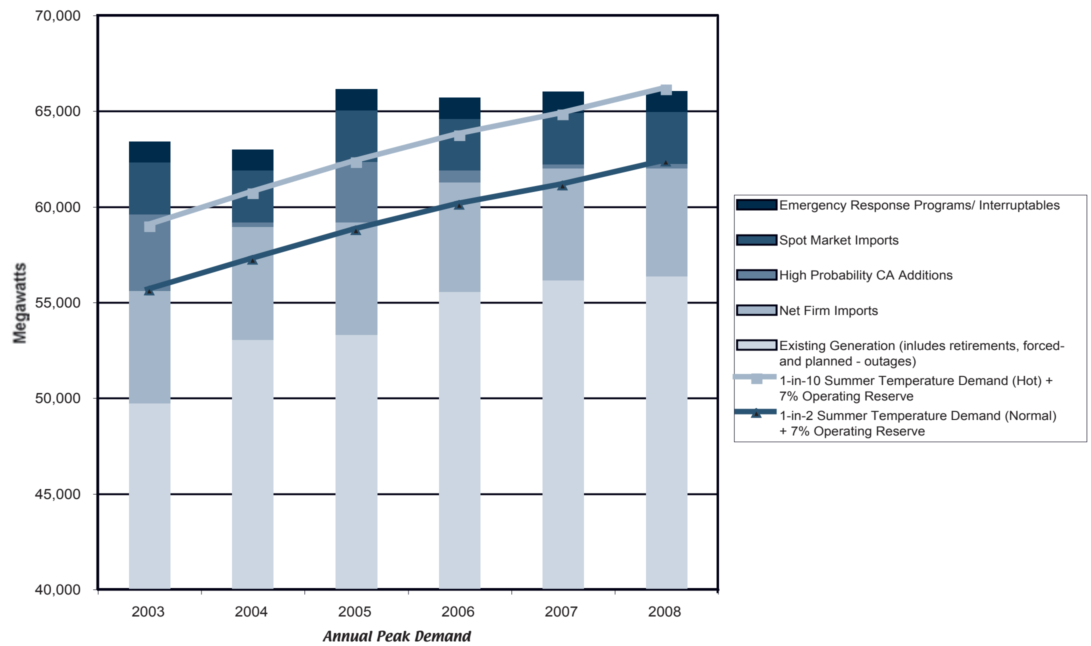

Figure 5.2. California Statewide Electricity Supply/Demand Balance[100]

Department of Water Resources (DWR). The DWR began purchasing about one third of the totalelectricity needs in the IOUs' service areas on behalf of the utilities. This allowed California to keep the lights on.

From this point forward, the IOUs delivered to their customers only electricity that was either self-generated or purchased through preexisting contracts. The DWR, in contrast to the IOUs, was not forced to buy the utilities' net short position only on the volatile wholesale market. It could negotiate bilateral short-, medium-, and long-term power purchase contracts with various generators. Consequently, the state of California became the dominant buyer of electric power in California.

In addition to purchasing the energy for the IOUs' customers that could not be paid by the utilities, the state of California decided to increase its future role in California's electricity market. The DWR entered long-term power purchase contracts with various generators for the next 20 years. Unfortunately, these contracts were negotiated at a time of very high wholesale prices for electricity and may, therefore, lock the state - and ultimately the customers of the IOUs - into contractual commitments to pay unreasonably high prices for electric power over the next two decades. For this reason, some of the long-term contracts will be renegotiated by the state.

From January 17, 2001 until August 31, 2002, the state of California spent $14.1 billion for electricity on behalf of the IOUs.[101] The power purchases have initially been financed using a short-term bridge loan and then rolled over to a higher-interest medium-term loan. It is expected that this loan will soon be repaid using the revenues of the issuance of $12.5 billion of state revenue bonds. The revenue bonds would become financial obligations for retail electricity consumers of the IOUs, on behalf of whom the state purchased the electricity and incurred those costs. It is also expected that the California Public Utilities Commission (CPUC) will guarantee future retail electricity rates sufficiently high to allow the

[100] California Energy Commission, Intranet, November 12, 2002.

[101] California Department of Water Resources <http://wwwcers.water.ca.gov/pdfFiles/Monthly%20Cost%20Summary%202001-2002.pdf>.

payment of the principal and interest of the revenue bonds.[102] Without such a guarantee, the repayment of the revenue bonds would be uncertain and the revenue bonds could not be issued as investment-grade instruments. The whole financial construction is, therefore, a deferment of the high wholesale electricity costs during 2000 and 2001 into the future. Customers of the IOUs were spared from sharp retail price hikes in 2000 and 2001 at the cost of elevated retail rates in the near future. Besides veiling clear price signals for used electricity to consumers, and in this way discouraging energy conservation, the financing mechanism also caused inter-temporal inequities since it defers the incurred costs of current ratepayers to future ratepayers.

In order to prevent the customers of the IOUs from switching to other electricity suppliers and circumventing payment of the state revenue bonds, the California Legislature abolished direct access, which was the ability to purchase electricity from suppliers other than the local IOU. The repeal of direct access means that one of the central elements of deregulation, namely retail competition, will be lost for many years. They did not restrict direct access for business and commercial customers.

The suspension of direct access guarantees a stable customer base for IOUs in the future, which will be the ultimate financing source not only for the repayment of the revenue bonds, but also for past and future power purchases by the state of California. Therefore, the Legislature decided that retail access would be suspended as long as the DWR supplies power, which will be for the next 20 years. The CPUC amended this suspension of retail access to exclude large industries.

5.3 California Power Authority

In response to the diminishing reserve levels during spring and summer of 2001, California established a new state energy agency, the California Consumer Power and Conservation Financing Authority, or more commonly called the California Power Authority (CPA). The initial purpose of the CPA was to restore stability in the energy market in the peak of the crisis by acquiring additional power and by financing conservation programs. The CPA was authorized to issue $5 billion in revenue bonds for this purpose.

Apart from the initial goal to overcome the supply-demand imbalance of 2001 and to stabilize the electricity prices through long-term power contacts, the CPA has two main long-term responsibilities. First, it strives to ensure sufficient reserve margins. Second, it does this by encouraging energy efficiency, energy conservation, demand-responsiveness, and the use of renewable energy resources.

The role of the CPA among other California state energy authorities is depicted in Figure 5.3. Whereas the CEC, the CPUC, and the Independent System Operator (ISO) are regulating agencies, the CPA is a financing authority that can acquire energy to avoid shortages. The CPA's responsibility is to finance energy projects that would not have been undertaken by others and that will help to maintain adequate capacity reserves by investing in energy efficiency, energy conservation, demand-response, and renewable energy projects.

The CPA's main long-term responsibility is to ensure sufficient electricity reserves. In deregulated electricity markets, reserves serve two discrete functions. First, they are needed to ensure the reliable operation of the system in real-time. Second, they assure market stability by reducing market volatility and, with this, the opportunity for the exercise of market power.

The CPA developed an Energy Resource Investment Plan, which proposes to set a target reserve level at 22%.[103] This target level is based on an installed capacity basis and translates into an approximately

[102] California Public Utility Commission, Decision 02-02-051 February 21, 2002.

[103] California Consumer Power and Conservation Financing Authority, "Rulemaking: Establishment of Target Reserve Level for the California Power Authority Investment Plan," Draft Decision for Public Review and Comment, Docket 2002-07-01, September 16, 2002.

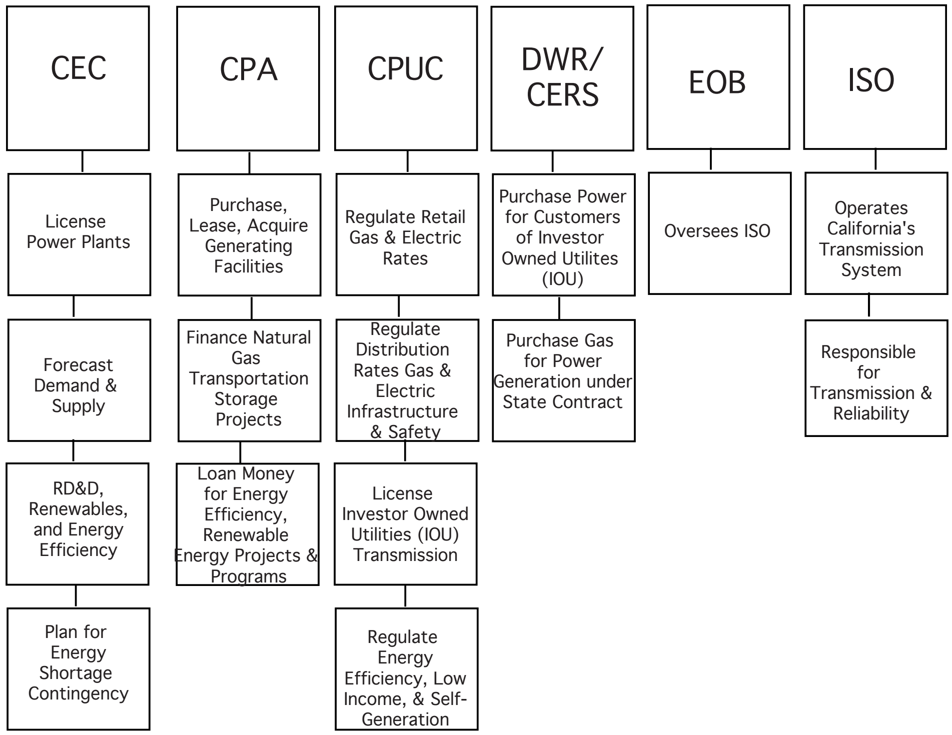

Figure 5.3. Energy Agencies in California[104]

12% reserve level based on unforced capacity, which is the installed capacity reduced by its historic forced outage rate.

The CPA proposes that the 22% reserve target should be met by a variety of measures. An appropriate portfolio of short, medium and long-term instruments, created from reserves of many types, is the best strategy to get needed reserves and associated reliability at the most reasonable cost. While it typically takes about two to three years to bring traditional base load resources on line, and about one to two years for traditional peaking resources, demand programs tend to be less capital intensive and can be brought on line in six to 18 months. The CPA recommends that 25-50% of the reserve level come from demand programs. On the supply side, the CPA proposes to install 8,000 MW of new, clean resources to meet the growing demand for electric power over the next five years.[105]

5.4 Renewable Portfolio Standard

On September 12, 2002, Governor Davis signed several energy-related environmental bills into law including Senate Bills (SB) 1078 and 1038. SB 1078 establishes the California Renewable Portfolio Standard (RPS) and SB 1038 renews and extends the CEC's Emerging Buydown Program fund for an additional ten years. Both bills are linked together; SB 1038 ensures the financial support for the new renewable generation required by SB 1078.

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[104] California Consumer Power and Conservation Financing Authority, "Clean Growth: Clean Energy For California's Economic Future," February 15, 2002.

[105] California Consumer Power and Conservation Financing Authority, "Clean Growth: Clean Energy For California's Economic Future," February 15, 2002.

The California RPS requires every retail seller of electricity to increase its total procurement of eligible renewable energy resources by at least 1% per year so that 20% of its retail sales are procured from eligible renewable energy resources, which must occur by 2017. The 20% renewable mandate will be the highest in the nation and it will nearly double California's existing base of eligible renewable energy resources covered under SB 1078.

Eligible renewable resources include biomass, solar thermal, photovoltaic, wind, geothermal, small hydropower of 30 megawatts or less, digester gas and landfill gas, and a limited number of municipal solid waste incinerators.

The CPUC is required to establish rules on how to select the "least-cost and best fit" renewable resources to fulfill the RPS obligations. The CPUC is also required to allow retail sellers to recover the costs of the RPS requirements through rates.

5.5 Distributed Generation

As of June 2002, more than 2,000 megawatts of distributed generation (DG) facilities were installed in California.[106] At the same time there were another 3,000 megawatts of DG used as emergency backup generators.[107] The installed DG systems are mainly internal combustion engines, photovoltaic cells, and wind turbines.

Four California state agencies are involved in DG issues. The CEC is working on the development of standardized interconnection rules on a statewide basis, known as "Rule 21." The CPUC is developing a variety of state policies surrounding DG, such as developing definitions for DG, determining ownership and control of DG, defining the role of utilities in DG, policies addressing the impacts of DG on the environment and on electric reliability of the grid, the rate design, and cost allocation issues.[108] The California Air Resources Board is responsible for the development of emission standards for all DG units. The CPA is a financier of DG installations. The CPA recently solicited proposals from DG vendors to provide DG technologies for publicly owned buildings throughout the state. The DG technologies selected were microturbines, fuel cells, and solar photovoltaics.

The most important issues surrounding DG currently under discussion and development are interconnection rules, costs and fees, direct access, and exit fees.

Interconnection Rules

California is one of the first states with a statewide standard practice for the interconnection of DG devices to the electricity grid. The new Rule 21, approved by the CPUC on December 21, 2000,[109] replaces the former differing interconnection rules of the California IOUs and specifies standard interconnection, operating, and metering requirements for DG generators on a statewide basis. Interconnected DG devices may allow for the flow of electricity in two directions and may be eligible for net energy metering, a metering method where the electric meter spins either in a positive or reverse direction depending on the direction of the electricity flow.

Parallel to the development of Rule 21 in California, the Institute of Electrical and Electronics Engineers (IEEE) is in the process of developing a nationwide interconnection standard IEEE P1547. This

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[106] California Energy Commission, "Distributed Generation Strategic Plan," June 2002.

[107] California Energy Commission, "Distributed Generation Strategic Plan," June 2002.

[108] California Public Utilities Commission, Rulemaking 99-10-025, October 21, 1999.

[109] California Public Utilities Commission, Decision 00-12-037, December 21, 2000.

standard will provide requirements for the performance, operation, testing, safety, and maintenance of interconnected DG resources with electric power systems.

Costs and Fees

The CPUC identified five general cost categories associated with interconnected DG units:[110]

- Generation facility costs
- Interconnection facility costs
- Distribution system modification costs
- Interconnection study costs
- Interconnection application review fees

Interconnection facility costs are costs for metering and for the installation of protective systems needed for a safe interconnection. Customers who install DG devices are responsible for all five cost categories. However, generators eligible for net energy metering are exempt from paying for costs associated with distribution system modification, interconnection studies and application review fees. The limit for net metering is 1 MW of generation

Another cost factor associated with interconnected DG systems are the standby charges. Standby charges are utility rates that a customer pays to receive power from the grid when its own DG is unavailable. Only residential and small commercial customers who installed wind or solar facilities and are eligible for net energy metering are exempt from standby charges.

Direct Access

The suspension of direct access, implemented by the CPUC effective September 20, 2001, has a big impact on the DG market. The suspension of direct access removes an important benefit for DG users, namely the possibility to sell excess power to other retail customers. Of course, owners of DG devices may sell their excess power in the wholesale market, but this is currently complicated and economically unattractive.

5.6 Transmission

Before deregulation, regulated monopolies provided bundled electric generation, transmission, and distribution services to customers within their service area. The vertically integrated utilities were at these times responsible for managing the distribution and transmission system, which was predominately used for locally restricted power transactions.

The introduction of competitive wholesale power markets in the 1990s changed the role of transmission in the electric power industry significantly. Trade in bulk power has increased substantially and the U.S. transmission grid system is being used more and more for long distance power transactions. Today, more than half of all electricity generated is traded in regional wholesale markets before being delivered to the end-users.[111] The Western Governors' Association estimated the cost of necessary transmission expansion in the Western Systems Coordinating Council area for a period up to 2010 between $2.1 billion and $12 billion, depending on the added generation mix.[112] Because of the incomplete restructuring of the electric industry and the regulatory uncertainty associated with recovery of investment in the transmission assets, there has been a lack of investment

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[110] California Public Utilities Commission, Decision 02-03-057, March 21, 2002.

[111] National Governors Association, "Interstate Strategies for Transmission Planning and Expansion," 2002.

[112] Western Governors' Association," Conceptual Plans for Electricity Transmission in the West," August 2001.

in the transmission system in the last years. The new competitive wholesale market requires, therefore, a redesign and new management of the current transmission system.

Because of the increasing amount of long-distance power transactions, control over the planning and the operation of the transmission grid should move from the former monopoly utilities to regional institutions. This led to the Federal Regulatory Energy Commission (FERC) Order 2000[113] of December 19, 2000 calling for the formation of Regional Transmission Organizations (RTOs).

According to this order, an RTO is a regional electric transmission system operator that is independent of power market participants and controls the transmission facilities so that they are used to provide reliable, efficient, and nondiscriminatory transmission service. An RTO may be for-profit or non-profit; be an ISO, transco, hybrid, or other structure; and is not required to own the transmission facilities.

The main functions of an RTO will be tariff administration, congestion management, parallel path flow management, provision of ancillary services, calculation of available transmission capacity, market monitoring, transmission planning and expansion, and interregional coordination. In addition to the expected improvements in the efficiency of the grid management, RTOs are also supposed to improve grid reliability and remove remaining opportunities for transmission providers to unduly discriminate in favor of affiliated power market participants.

The FERC encouraged all utilities that own electric transmission facilities to participate in an open collaborative and voluntary process to design RTOs that should be tailored to specific needs of each region.

In October 2000, a group of Pacific Northwest companies developed a plan to form a Western U.S. RTO. Under this plan, owners of transmission facilities in the western states would transfer operational control of their transmission system to a newly formed independent system operator, RTO West. Despite some opposition to this proposal, mainly due to concerns about the long time needed to establish such a regional organization and the resulting uncertainty and delay in transmission investment urgently needed, FERC approved the proposal.[114]

On July 12, 2001, FERC proposed the formation of four RTOs across the U.S.: West RTO, Midwest RTO, Southeast RTO, and Northeast RTO. The RTO West would control all transmission within eight western states (Washington, Oregon, Idaho, Montana, Nevada, Arizona, Utah, and the parts of California not controlled by the California Independent System Operator (CAISO)). An issue that is not yet resolved is whether the proposed RTO West should combine with CAISO into one RTO or let them work in parallel. In any case, it may take several years before all these issues are resolved. California and other Western states have resisted efforts by FERC to force them into a specific structure with specific market rules.

5.7 Demand Reduction Programs

During the energy crisis, Governor Davis introduced a variety of energy efficiency and peak demand reduction measures. These included the "20/20 plan," retail rate increases, rebate programs, publicawareness campaigns, real time metering, and updated energy efficiency standards. In addition, two new energy efficiency bills, Assembly Bill (AB) 29X and Senate Bill (SB) 5X, were signed into law.

The "20/20 plan" encouraged residential customers of the Californian IOUs to reduce their monthly consumption of electric power by 20% from their consumption in 2000 by providing a 20% rate

[113] Federal Regulatory Energy Commission, Order No. 2000, Docket No. RM99-2-000, December 20, 1999.

[114] Federal Regulatory Energy Commission, Docket Nos. RT01-35-000 and RT01-15-000, April 26, 2001.

reduction for those consumers who met this goal. The "20/20 plan" was first introduced between June and September of 2001 and was repeated in 2002 between July and October, with the slight modification that the 20% rate reduction was then already offered if a 15% usage reduction was achieved. The incentive was twofold: first, the reduction in the electricity bill based on lower consumption, and second, the additional 20% rate reduction.

In addition to this electricity reduction incentive, the CPUC introduced a new, tiered rate tariff plan in June 2001(Table 5.1, Figure 5.4). The rate increase was disproportionally high for high electricity users and encouraged by this energy conservation. In order to finance the power purchases of the DWR, the CPUC approved another 1.46 cent per kWh rate increase that became effective October 1, 2001.

Tiers	% of Baseline	PG&E Cents /kWh	SCE Cents/ kWh	SDG&E Cents/kWh (Summer)	SDG&E Cents/kWh (Winter)
Tier 1	0 - 100%	12.6	13.0	13.4	13.4
Tier 2	100 to 130%	14.3	15.2	15.9	15.1
Tier 3	130 to 200%	19.3	19.7	16.8	16.0
Tier 4	200 to 300%	23.6	23.7	17.7	16.9
Tier 5	300%	25.8	25.9	19.3	18.7

Table 5.1. Residential Electricity Rates for PG&E, Edison and SDG&E Customers (5% of Tier 5 means that 5% of customers had electricity consumption over 300% above the baseline and were charged 26 cents/kWh instead of the previous 13 cents/kWh.)

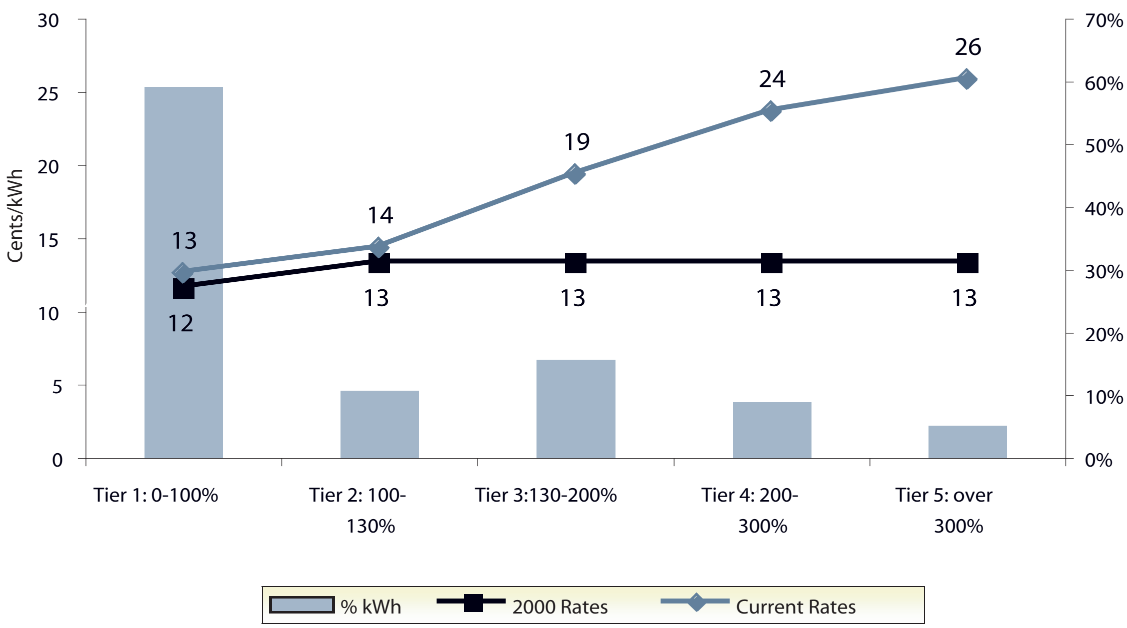

Figure 5.4. Residential Retail Rates for PG&E Customers effective June 1, 2001

Further measures to encourage energy conservation were administered by the California utilities in the form of rebates and incentive programs for energy efficient lighting and appliances, heating, ventilation and air conditioning systems, motors, home retrofits and renovations, and new construction.

In order to make the people of California aware of the value of energy conservation, the state of California launched the "Flex Your Power" media campaign. This campaign reached 95% of all adults in California an average 25 times. Information about how to reduce energy consumption was spread over television, radio, and print media in English, Spanish, Mandarin, Cantonese, Vietnamese, and Korean. The result was that 56% of Californians said that electricity is the most important issue facing California, according to a survey released by the Public Policy Institute of California in July 2001.[115]

While all IOUs' customers with electricity consumption over 500 kW already had "Time of Use" (TOU) rates, 23,000 new real time meters were installed for all customers above 200 kW. Those customers were also required to switch to TOU rates. This was one part of AB 29X, which was signed into law on April 11, 2001.

In July 2001 new statewide building efficiency standards for new construction became effective. The new standards require among other measures more efficient air conditioning and heating ducts, and windows with reduced heat transfer. The new standards are the toughest building standards in the U.S.

The achieved energy conservation results due to these measures were impressive. The peak demand during the summer 2001 was between 8 and 14% lower than in the summer of 2000, when adjusted for weather and economic growth.[116] Also the monthly electricity use between June and September 2001 was between 5 and 12% lower than in 2000.[117]

The reduction was mainly achieved through turning off lights and changes in laundry, dishwasher, and air conditioning usage (Figure 5.5).

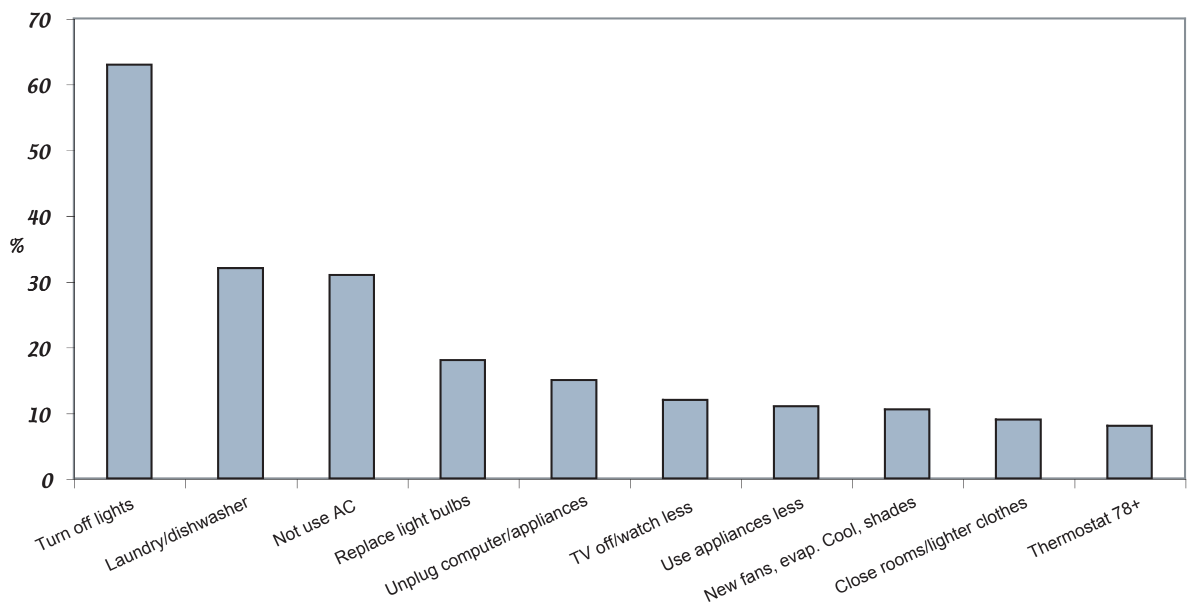

Figure 5.5. Household Conservation Actions

All of these actions taken together provide a vision of the future electrical system of California. This vision can be stated as follows; "provide electricity that is affordable, clean, distributed to energy efficient customers."

[115] Public Policy Institute of California, "PPIC Statewide Survey: Californians and Their Government," July 2001.

[116] California Energy Commission <http://www.energy.ca.gov/electricity/peak_demand/2001_peak_demand.html>

[117] California Energy Commission <http://www.energy.ca.gov/electricity/peak_demand/2001_peak_demand.html>

This vision requires the balancing of a number of factors:

Prior to the passage of AB 1890 planning for the electric system was performed by the utilities under direction of the CPUC. They were required to submit a 20-year resource plan on a biannual basis. Since then the planning process has become fragmented and all the actions described above were instituted without any broader plan in mind, but instead as a response to an existing crisis.

As the planning process became more public, other criteria were introduced by a variety of activist groups. This was the Biannual Resource Planning Update (BRPU), California's name for integrated resource planning. The methodology of integrated resource planning attempted to allocate future investment in three areas, traditional power generation, renewables, and energy efficiency. With the FERC decision to overturn the results of the BRPU process all planning ceased. The conventional wisdom was that the market would perform this function. No integrated plan has been produced since then.

At the time of the last BRPU, utilities and interested stakeholders were the principal participants. Utilities carried the greatest burden since they owned generation, transmission and distribution (T&D). Since then the situation involves a larger number of organizations so that these functions are not all in the same organizational structure. It has not been decided what organizational responsibilities California entities will have in the future. An attempt to return to a more regulated structure is contained in SB 888. The bill has however not been passed as of July 2003. While organizational responsibility is still uncertain, the Legislature has passed a series of actions (as described above) that will influence the future of the electrical system. Interestingly these actions have included precisely those elements that lead the state to attempt an integrated resource plan or BRPU in the first place.

These actions constitute the basis of an integrated resource plan that expresses the desire of the Legislature to increase investments in renewables, transmission, demand management and distributed generation. Yet no plan exists for pulling these various options into a least cost resource plan. The planning process has been made more difficult because there are many organizations involved. They range from the Independent System Operator, to the California Energy Commission, and from the California Public Utilities Commission, and the utilities.

There is presently a series of actions taking place that are part of an overall strategy even though they may not be guided by an overall plan:

AB 970	Identification of T&D restraints and solutions
SB 1038	Provide transmission plan for renewables
SB 1078	Establish the RPS program

There is also an energy action plan underway that may have elements of an integrated plan.

The importance of an integrated plan cannot be over-emphasized. Since actions are required by a number of organizations and there is a need to prevent decisions contrary to an overall plan. A plan for the future would not usurp any future action by the Legislature, but would provide a backdrop for evaluating actions taken by involved organizations. Without some integrated plan it will be difficult to direct investments to where they will be most effective.

APPENDIX A: AUTHORS

Linda Cohen

Linda Cohen is Professor for the Department of Economics at UC Irvine. She received an A.B. from UC Berkeley in Mathematics and in 1979, a Ph.D. from the California Institute of Technology in Social Sciences. Her fields of study are political economy, government regulation, government policy for science and technology, and positive political theory and law.

Dr. Cohen has held positions at the Brookings Institution, the Kennedy School of Government, Harvard University, and the Rand Corporation. She was the 1998 Olin Visiting Professor in Law and Economics, USC Law School and is a member of the Irvine Research Unit in Mathematical Behavioral Sciences at the University of California, Irvine.

Stephen C. Peck

Stephen Peck joined EPRI in 1976 serving in a variety of positions and overseeing work related initially to utility planning and then to the environment. He served finally as Vice President of Environment from 1995 to 2000. From 1995 to 2000, the EPRI Environment Group led the remainder of the Institute, by far, in measures of utility customer satisfaction and was a high morale place to work. Peck is now President of Fléche, [118] a consulting firm.

Since leaving EPRI, among other activities, he has formed a multifaceted virtual company to provide to electricity companies threat assessment and risk management services related to terrorism across a broad range of activities that influence them – from fuel extraction, transportation, inventorying, production, transmission, distribution, load management and particular vulnerabilities related to large scale HVAC systems.

Stephen Peck was educated in England and the United States as an engineer (MA) and economist (M.Sc.). He holds an MBA and Ph.D. degree from the University of Chicago's Graduate School of Business, where he studied under Professor Arnold Zellner, the well-known Bayesian econometrician. He served as an Assistant Professor in the Economics Department at UC Berkeley, where he taught price theory, macroeconomics, industrial organization, antitrust and regulation, monetary economics and econometrics.

Paroma Sanyal

Paroma Sanyal is a specialist in areas of R&D and electricity deregulation. She has a Ph.D. from the University of California, Irvine. Areas of concentration include R&D and patenting, the relationship between technology and environment and electricity deregulation in California. She has worked in the Development Research Group of the World Bank, as an intern. While there, she has conducted intensive empirical research on social and gender issues. Currently she is involved in a project on electricity deregulation for the California Science and Technology Commission.

[118] A fléche is a running attack in fencing and there were no other fictitious business names remotely like it in the San Jose new business registry.

Carl J. Weinberg

Carl Weinberg is the principal of Weinberg Associates, which he founded in 1993 after 19 years with the Pacific Gas and Electric Company where he effectively managed and grew an internationally respected energy research and development program. Weinberg Associates was formed with the primary objective of accelerating the introduction of renewable and distributed power systems.

He is a recognized and respected spokesperson with a comprehensive view encompassing and integrating technical, regulatory, policy and environmental perspectives. Most recent activities involve policy issues and their technical considerations in the restructuring of the utility industry, with particular emphasis on the concept of sustainability in a competitive framework, and the introduction of distributed resources. He serves on the boards and working level committees of numerous energy efficiency and renewable energy organizations in the public and private sector.

Prior to joining PG&E in 1974, he spent 21 years in the United States Air Force. He received a B.S. and M.S. degree in Civil Engineering from UC Berkeley and a M.S. in Physics from Vanderbilt University. He is a registered Civil Engineer and a member of the California Civil Engineering Honor Society XE, the Engineering Honor Society, the Research Honor Society ΣX, Cal Club, and the University of California Order of the Golden Bear.

APPENDIX B: LARGE SCIENCE PROJECTS COMMITTEE

This Project has been conducted under the guidance and review of the 2002 Large Science Project Committee of the California Council on Science and Technology. Members include:

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Chris Caren is the former Corporate VP of Science and Engineering at Lockheed Corporation, where his career spanned over 30 years. Dr. Caren is a fellow of the American Association for the Advancement of Science, the American Institute of Aeronautics and Astronautics, the American Astronautical Society, the Institute for the Advancement of Engineering and the Society of Automotive Engineering. He is also a member of the National Academy of Engineering. He is a founder and member of the Board of Directors of Litex Inc. a company involved in automotive emission reduction systems. He is chairman of Hawkeye Enterprises a company involved in the upgrade of subquality natural gas. He is also a member of the Board of Directors of Superconductor Technologies Inc.

Richard Balzhiser

Richard E. Balzhiser retired as President and Chief Executive Officer of the Electric Power Research Institute (EPRI) in Palo Alto, California in August 1996. He remains active in a President Emeritus role at EPRI in addition to serving on the boards of Reliant Energy, Aerospace, Electrosource, and Nexant. He also serves on advisory boards for the National Renewables Energy Laboratory (NREL), the National Research Council, California's Public Interest Energy Research Program (PIER), and was a member of the two recent PCAST studies requested by the White House.

Dr. Balzhiser joined EPRI in 1973 at the time of its founding as Director of the Fossil Fuel and Advanced Systems Division. He became Vice President of Research and Development in 1979 and Executive Vice President in 1987 before assuming the Presidency in 1988. Prior to joining EPRI, he served in the White House Office of Science and Technology in 1971-73 as Assistant Director for Energy, Environment and National Resources. Previously, Dr. Balzhiser was Chairman of the Department of Chemical Engineering at the University of Michigan, Ann Arbor. He was Professor of Chemical Engineering from 1960-70 except for 1967-68 when he served as a White House Fellow in the Office of the Secretary of Defense. He was twice elected to serve on the Ann Arbor City Council.

Dr. Balzhiser received his B.S. and Ph.D. degrees in Chemical Engineering and his M.S. in Nuclear Engineering from the University of Michigan and was an Academic All American on Michigan's 1953 football team.

Linda Cohen

Linda Cohen is Professor for the Department of Economics at UC Irvine. She received an A.B. from UC Berkeley in Mathematics and in 1979, a Ph.D. from the California Institute of Technology in Social Sciences. Her fields of study are political economy, government regulation, government policy for science and technology, and positive political theory and law.

Dr. Cohen has held positions at the Brookings Institution, the Kennedy School of Government, Harvard University, and the Rand Corporation. She was the 1998 Olin Visiting Professor in Law and Economics, USC Law School and is a member of the Irvine Research Unit in Mathematical Behavioral Sciences at the University of California, Irvine.

Lawrence Coleman

Lawrence B. Coleman is the Vice Provost for Research for the University of California and Professor of Physics at the University of California, Davis. He served as Chair of the University-wide Academic Senate in the 1999-2000 academic year following a year as vice chair of the UC Senate. Arriving at Davis in 1976, he was promoted to Associate Professor in 1982. While at the UC Davis he has held the positions of Chair, Davis Division of the Academic Senate, 1995 - 1997; Director, The Internship and Career Center, 1988 - 1994; Acting Vice Provost - Academic Programs and Dean - Undergraduate Studies, 1991-1992; and Acting Associate Vice Chancellor - Academic Programs, 1990-1991.

Coleman's previous affiliations include: Postdoctoral Research Investigator, Department of Physics, University of Pennsylvania, 1975-1976 and Research Fellow, Department of Physics, University of Pennsylvania, 1970-1975.

Lawrence Coleman received a Ph.D. from the University of Pennsylvania in 1975 in experimental condensed matter physics. He received a B.A. in physics from The Johns Hopkins University in 1970.

Susan Hackwood

Susan Hackwood is currently Executive Director of the California Council on Science and Technology and Professor of Electrical Engineering at the University of California, Riverside.

Dr. Hackwood received a Ph.D. in solid state ionics in 1979 from DeMontfort University, UK. Before joining academia, she was Department Head of Device Robotics Technology Research at AT&T Bell Labs. In 1984 she joined the University of California, Santa Barbara as Professor of Electrical and Computer Engineering and was founder and Director of the National Science Foundation Engineering Research Center for Robotic Systems in Microelectronics.

In 1990, Dr. Hackwood became the founding Dean of the Bourns College of Engineering at the University of California, Riverside. Dr. Hackwood's current research interests include science and technology policy, distributed asynchronous signal processing and cellular robot systems. She has published over 140 technical publications and holds 7 patents.

John McTague

John P. McTague is the Vice President-Laboratory Management at the University of California, Office of the President. Dr. McTague was founding co-chair of the Department of Energy National Laboratory Operations Board and a member of the Secretary of Energy Advisory Board from its inception in 1990 through 2000. From 1994 to 1999, he was also Chairman of the Fermilab Board of Overseers. In January 1999, he retired from Ford Motor Company, where he served more than 12 years, first as Vice President of Research and then as Vice President of Technical Affairs.

Prior to joining Ford in 1986, Dr. McTague served as Deputy Director and Acting Director of the White House Office of Science and Technology Policy, and was Acting Science Advisor to President Reagan. During the Bush administration he was a member of the President's Council of Advisors on Science and Technology and U.S. Chair of the U.S.-Japan High Level Advisory Panel on Science and Technology.

A physical chemist, Dr. McTague received his undergraduate degree with honors in chemistry from Georgetown University in 1960 and his Ph.D. from Brown University in 1965. Brown also bestowed on him an honorary Sc.D. in 1997. He began his professional career at the North American Rockwell Science Center. From 1970 to 1982, he was a professor of chemistry and member of the Institute of Geophysics and Planetary Physics at the University of California, Los Angeles.

C. Kumar N. Patel

C. Kumar N. Patel is professor of physics and astronomy, chemistry, and electrical engineering at UCLA. From March 1993 to December 1999, he was the Vice Chancellor of Research at UCLA. Until joining UCLA in March 1993, he was Executive Director, Research, Materials Science, Engineering and Academic Affairs Division at AT&T Bell Laboratories, Murray Hill, New Jersey.

He is the Past President of the American Physical Society (1995) and Sigma Xi, The Scientific Research Society (1993-1995). He co-chaired (with N. Bloembergen) the American Physical Society Study of the Science and Technology of Directed Energy Weapons. From 1979 to 1988, he served as a member of the Board of Trustees of the Aerospace Corporation. In January 1986, he was elected to the Board of Directors of the Newport Corporation. He was the Chairman of the Board of Directors of Accuwave Corporation, from 1994 to 1998, and was a member of the Board of Directors of the California Micro Devices Corp from 1990 to 1996.

Dr. Patel received his B.E. in Telecommunications from the College of Engineering in Poona, India in 1958. He received M.S. and Ph.D. in Electrical Engineering from Stanford University in 1959 and 1961, respectively. In 1988, he was awarded an honorary Doctor of Science degree from the New Jersey Institute of Technology. He is also a recipient of the National Medal of Science, 1996.

C. Bruce Tarter

Bruce Tarter is Associate Director at Large for Lawrence Livermore National Laboratory. Tarter was the eighth director of the Lawrence Livermore National Laboratory. His career began in 1967 as a member of the Theoretical Physics Division, and he has served in various technical leadership assignments at the Laboratory in weapons physics, geosciences research, and space programs including strategic defense projects. Tarter has served on numerous research and institutional management committees within and outside the Laboratory, has been a lecturer and graduate student advisor at the Department of Applied Sciences of the University of California, Davis/Livermore, and is an Adjunct Professor, Department of Applied Science, University of California, Davis. Memberships include the American Physical Society, American Astronomical Society, International Astronomical Union, and the American Association for the Advancement of Science. He received the Roosevelts Gold Medal Award for Science and is a Fellow of the American Physical Society.

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