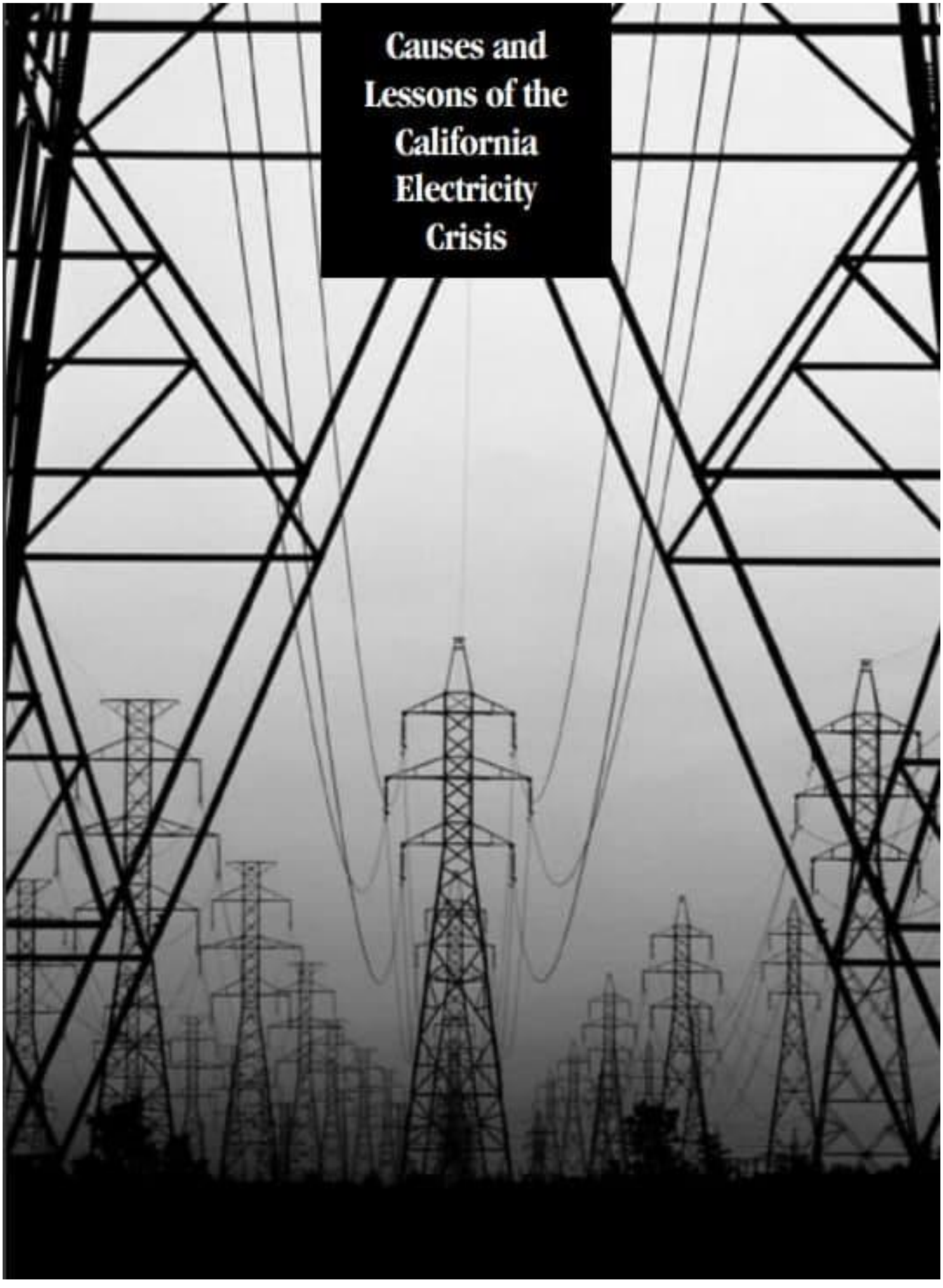
Causes and Lessons of the California Electricity Crisis



Deregulation in California ISO:challenges & lessons

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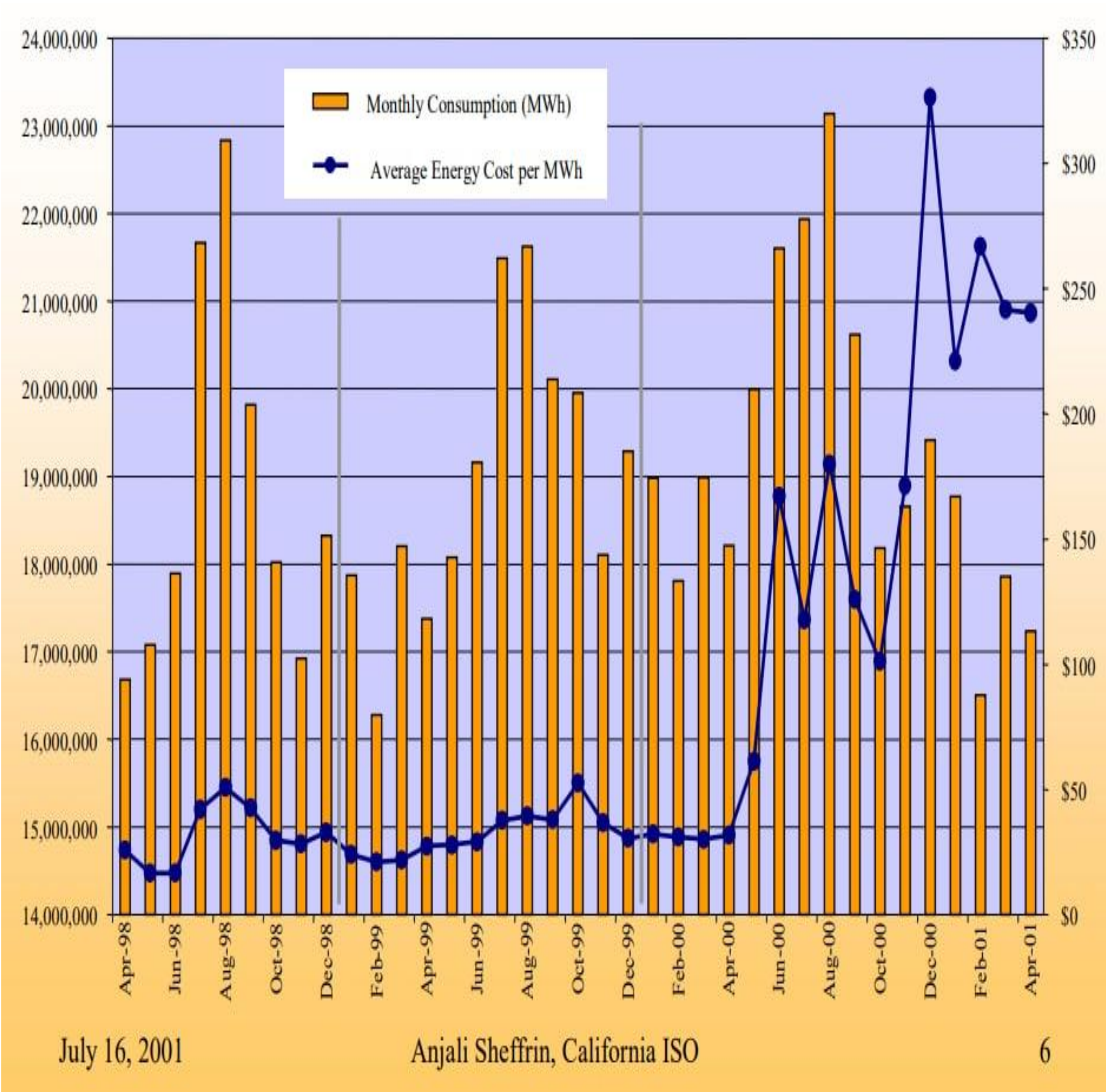
Summary

The 1996 law that restructured California's electricity industry was intended to be the first step toward lower electricity prices for 70 percent of the state's population. Few observers foresaw the situation that would exist in California by the summer of 2001. Just five years after restructuring became law, the state's electricity market was commonly described as begin in crisis. The goals of restructuring—lower prices for residential customers and more competitive prices for industrial customers –-seemed farther away than ever.



ISO

The California Independent System Operator (CAISO) is a non-profit Independent System Operator (ISO) serving California.It oversees the operation of California's bulk electric power system, transmission lines, and electricity market generated and transmitted by its member utilities.

The California Legislature created the CAISO in 1998 as part of the state restructuring of electricity markets. The legislature was responding to Federal Energy Regulatory Commission (FERC) recommendations following the passage of the federal Energy Policy Act of 1992, which removed barriers to competition in the wholesale generation of electricity business. FERC regulates CAISO because interstate transmission lines fall under the jurisdiction of federal commerce laws

As the only independent grid operator in the western U.S., the ISO grants equal access to nearly 26,000 circuit miles of transmission lines and coordinates competing and diverse energy resources into the grid where it is distributed to consumers. It also operates a competitive wholesale power market designed to promote a broad range of resources at lower prices.

Every five minutes, the ISO forecasts electrical demand and dispatches the lowest cost generator to meet demand while ensuring enough transmission capacity for delivery of power.[1]

Strategic framework

OUR PURPOSE

Lead the way to tomorrow's energy network

OUR STRATEGY

- Lead the transition to renewable energy
- Maintain reliability during industry transformation
- Expand regional collaboration to unlock mutual benefits

OUR OPERATING PRINCIPLES

For the benefit of our customers, we:

- Attract, develop and retain a highly skilled workforce
- Operate the grid reliably and efficiently
- Provide fair and open transmission access
- Promote environmental stewardship
- Facilitate effective markets and promote infrastructure development
- Provide timely and accurate information

[1] www.caiso.com

OUR COMMITMENTS

We are committed to being:

- Reliable
- Sustainable
- Efficient
- Resilient
- Responsive

OUR CORE VALUES

- Integrity
- Teamwork
- Excellence
- People focus
- Open Communication[1]

The California Electricity Market

The market for electrical energy in California is characterized by the repeated interaction of several firms and institutions. The two primary institutions are the California Power Exchange (PX) and the California Independent System Operator (ISO). The PX runs a day-ahead and hour-ahead market for energy utilizing a double auction format. (The PX double auction takes bids from both suppliers and consumers and sets a market clearing quantity at the intersection of the resulting supply and demand curves implied by those bids. Since the time of our sample, the PX has changed its \hour-ahead" market (which actually closed three hours ahead of the operation hour) to a \day-of" market, which operates three times daily, each time for different designated hours of the day) Firms can and do submit both demand and supply bids. In the day-ahead market, which is by far the largest market run by the PX, firms may bid into the PX offers to supply or consume power the following day for any or all of the 24 hourly markets. Although they were not originally envisioned as such, the PX markets are effectively financial, rather than physical, markets. As explained below, this is because firms can purchase or sell electricity in real time to change their day-ahead PX positions in what is essentially an energy spot

market run by the ISO.6 In addition to the PX, other institutions, known as ‘’scheduling coordinators," (SCs) can submit the results of completed wholesale energy transactions to the ISO. Each SC, including the PX, is formally required to submit a ‘’balanced" schedule, i.e. one in which supply equals demand. The ISO is responsible for coordinating the usage of the transmission grid and ensuring that the cumulative transactions, or schedules, do not constitute a reliability risk. As the institution responsible for the real-time operation of the electric system, the ISO must also ensure that aggregate supply is continuously matched with aggregate demand. In doing so, the ISO operates an ‘’imbalance energy" market, which is also commonly called the real-time energy market. In this market, additional generation is procured in the event of a supply shortfall, and generators are relieved of their obligation to provide power in the event that there

[1] www.caiso.com

is excess generation being supplied to grid. Like the PX, this market is run through a double auction process, although of slightly different format. Firms that deviate from their formal schedules are required to purchase (or sell) the amount of their shortfall (or surplus) on the imbalance energy market.8 To date, no further penalties are assessed for deviating from an advance schedule. The imbalance energy market therefore serves as the de facto spot market for energy in California.

The ISO also operates markets for the acquisition of reserves and for the relief of constrained transmission interfaces. These reserves are purchased through a series of auctions that determine a uniform price for the capacity of each reserve purchased. Most of this reserve, or stand-by, capacity is also available to provide imbalance energy, and therefore will impact the spot price. A reserve unit would therefore earn a capacity payment for being available and, if called upon in real-time, an energy payment for actually providing energy.

Regulation, the most short-term reserve, is provided by generation that is equipped to respond automatically to voltage fluctuations. Due to the nature of this reserve service, and to metering limitations, generation capacity providing regulation reserves cannot set, or earn, the imbalance energy price. As we describe below, we therefore consider units providing regulation services to be \held-out" of the market.

Market Structure

The California electricity market at first glance appears remarkably unconcentrated. The former dominant firms, Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) divested the bulk of their gas-fired capacity in the first half of 1998. SCE retained only a small proportion of its capacity not already covered under regulatory side agreements. The divestitures before the summer of 1998 left the gas-fired generation assets in California more or less evenly distributed between seven firms. PG&E was the largest generation company during the summer of 1998. The seemingly dominant position of PG&E is offset somewhat by outside regulatory agreements. All of the nuclear generation in California is treated under rate settlements separate from the PX market. Also the incumbent utilities in California were the largest buyers of electricity during this time period. Because of a freeze on the rates of end-users and the effects of the Competition Transition Charge (CTC), the incentives of the incumbent utilities are difficult to interpret. If a utility distribution company (UDC) were concerned that it may not recover all of its stranded costs within the 4-year transition period during which the CTC were in force, then higher energy prices would further jeopardize that utility's chances of recovering those costs. On the other hand, if the UDC were confident that it would recover all of its stranded costs within the 4 year transition period, then that company would be largely indifferent to energy prices on the buy side. The generation side of these firms would clearly benefit from higher prices. The net impact on these firms of higher electricity prices therefore depends upon the firms' prospects for stranded asset recovery as well as the extent to which these firms were net buyers or sellers.

Table 1: California Generation Companies (MW)
1998 Nameplate Capacity

Firm	Fossil	Hydro	Nuclear
PG&E	3700	5728	2160
SCE	1990	1002	2327
SDG&E	1951	0	430
Duke	2650	0	0
AES/Williams	3756	0	0
Houston Industries	3770	0	0
Dynegy	1584	0	0
Thermo Ecotek	256	0	0

Root Causes of the Electricity Crisis

The causes and consequences of the crisis are multiple, complex, and intertwined, but there is wide agreement concerning the broad causal factors of the crisis. Almost unanimously, analysts cite five significant factors:

Limited Demand Response - Rate freeze meant no price signal to load to conserve

Lower Supplies Available and at Higher Cost

* Lack of New Generation for Last 10 Years
* Numerous Outages of Generation and Transmission
* Reduced Hydro Generation and Imports, Increased Gas Prices, High Cost of Emissions

Unrestrained Exercise of Market Power by Suppliers

Any search for simple answers, however, risks misperceiving the intricacies of the systemic failure of California's electricity sector. A satisfactory explanation for the severity of the crisis and its consequences cannot be composed based on any single factor. All of these factors contributed and reinforced one another to create a unique and explosive combination.

A Shortage of Generating Capacity

The tight supply of electricity generating capacity beginning in the summer of 2000 appears to be the primary cause of the California electricity crisis. The evidence indicates that tight supply was a necessary antecedent to the crisis. During the early years of the wholesale market, electricity supply was ample, and the market worked reasonably well. Evidence from other markets also indicates that markets are most competitive when there is ample supply to meet demand, but as the supply of electricity tightens markets become less competitive.[1]

The statistics clearly demonstrate an increasingly tight electricity market.2 Total consumption in California steadily increased by about 1.5 percent per year between 1990 and 2000 .In addition, there was a surge in demand of about 4 percent per year between 1998 and 2000, driven by the then-booming economy. It is important to note, however, that growth in demand during the 1990s was actually lower than the rate of

[1] Bushnell and Saravia, 2002

growth during the 1980s, even when considering the effects of increased population and economic activity .[1]

The growth rates in neighboring states were significantly higher. Nevada's electricity demand grew at a 6.2 percent yearly rate between 1988 and 1998, and Arizona's demand grew 3.7 percent per year. Higher demand in neighboring states is significant because California had historically relied on imports from other states for about 20 percent of its electricity needs. Thus, a major source of supply was being eaten up by growth outside California.

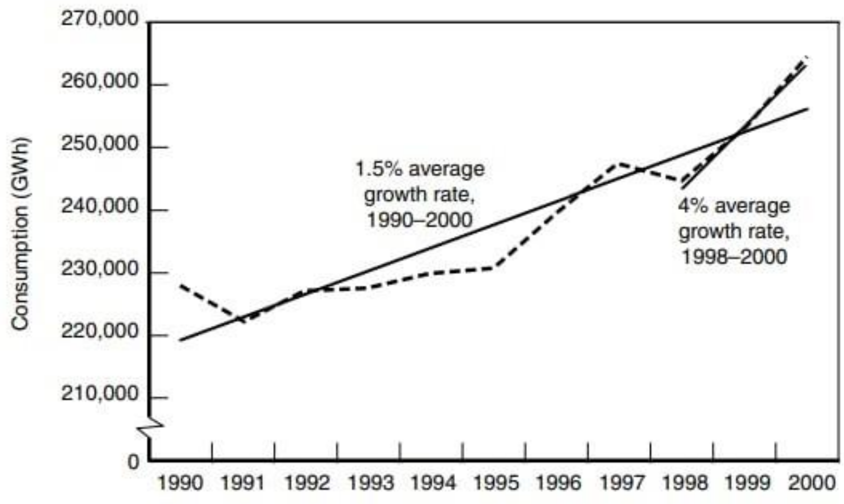


Figure1:Total Electricity Consumption in California, 1990–2000 [2]

Although the shortage in generating capacity is not disputed, the ultimate factors that led to the shortage are more controversial. Finger pointing flourished as commentators blamed deregulation, inaction by the governor, generating firms, and the design of market institutions. Each of these explanations contains an element of truth, but responsibility for the shortage cannot easily be placed on the shoulders of any single actor or institution. The shortage was largely a historical accident, characterized by a unique confluence of factors. A number of unforeseen events combined to lay the foundations for a supply crunch, and regulatory and market failures exacerbated the shortage. Each of these factors is examined in turn.

Unforeseen Events

In a well-functioning electricity system, either regulated or market based, it is important to maintain a balance between available generating capacity and peak electricity demand. Excess capacity is unwanted because it increases the average cost of electricity generation, and insufficient generating capacity leads to the risk of blackouts. This balance, however, can be easily upset in the short term because demand for electricity can change much more quickly than the time it takes to design, gain approval for, and construct new generating plants. Shortages have been rare in the United States because an emphasis on reliability has meant that added capacity was built well in advance of need. Nevertheless, short-term problems have

[1] Brown and Koomey, 2002
[2] California Energy Commission

occurred. In 1948, after a spurt of rapid post-World War II growth and an extended drought, Northern California experienced a series of blackouts before rains refilled reservoirs .[1] In the late 1990s, a confluence of unexpected events combined to produce a similar short-lived imbalance in generating capacity. Market players were caught by surprise by the surge in demand in California and throughout the West in the late 1990s. Generating firms were in the process of planning and building additional capacity

Between 1997 and 2000, they filed applications to build nearly 15,000 MW of generating capacity (see Figure 2). Generator firms, however, appear to have been planning that market demand would outstrip available supply only in 2001 and later. None of these plants were scheduled for completion in 2000, and less than 2,000 MW were scheduled to be available by the summer of 2001. Because of faulty market expectations, these new plants arrived later than needed, leading to interim shortages. The California Energy Commission contests this story, pointing to forecasts dating as far back as 1988 that correctly predicted demand for 2000 and 2001 (California Energy Commission, 2001). The implication is that industry insiders should not have been surprised by the demand for electricity and should have been investing to meet expected demand. The CEC forecasts, however, did not consider how unexpectedly strong demand growth outside California would reduce the availability of imported power.

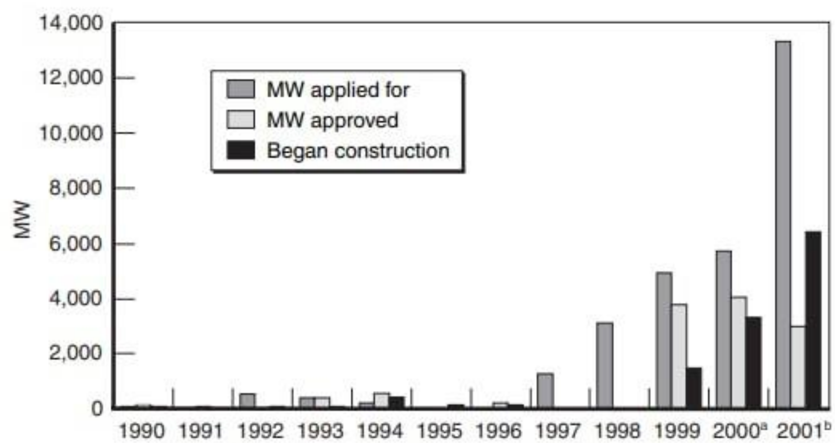


Figure 2:Generation Applications and Approvals, 1990–2001[2]

a) In 2000, 16 plant applications were recorded for 5,740 MW. Of those, eight applications for 1,184 MW were withdrawn. One plant for 99 MW was withdrawn after approval.

b) In 2001, 45 plant applications were recorded for 13,309 MW. Of those, eight applications for 1,509.6 MW were withdrawn. Two plants for 242.4 MW began construction but were later withdrawn (they are not included in the number of MW that began construction)

California and the West were also hit by unfavorable weather conditions. The winters of both 2000 and 2001 were relatively dry in the West, and in particular in the Northwest Consequently, the amount of hydro generation available was severely reduced. Estimates indicate that in the summer of 2000, there were 8,000–12,000 fewer megawatts of hydro power available for import into California, representing up to 20 percent of California's summer demand.[3]

In addition, these conditions were combined with an unusually hot summer in 2000 that drove up electricity demand throughout the western United States As shown in Figure 5, these conditions combined to reduce

[1] Ross, 1974
[2] California Energy Commission, www.energy.ca.gov
[3] California State Auditor

electricity imports to California to their lowest levels in ten years. From the summer of 2000 through the winter of 2001, supply shortfalls were exacerbated by unscheduled outages of generating facilities (see Figure 6). These high levels of outages were to some degree coincidental. They were due in part to poor coordination of standard maintenance.

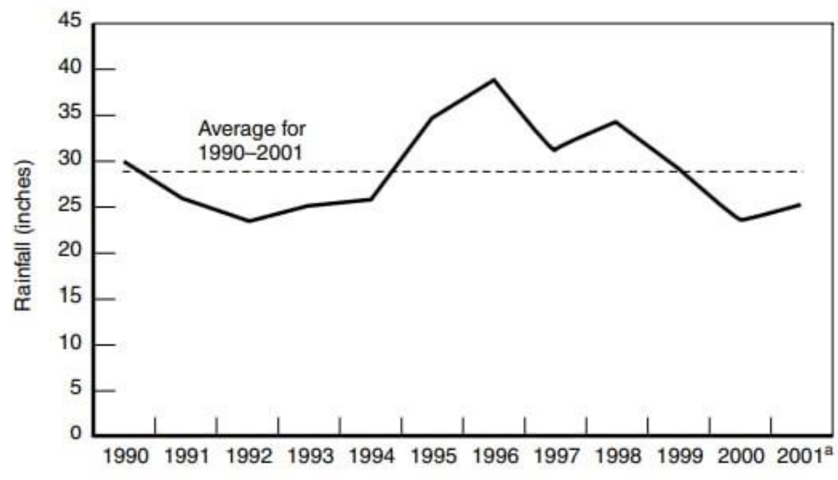


Figure 3:Average Yearly Pacific Northwest Rainfall, 1990–2001.[1]

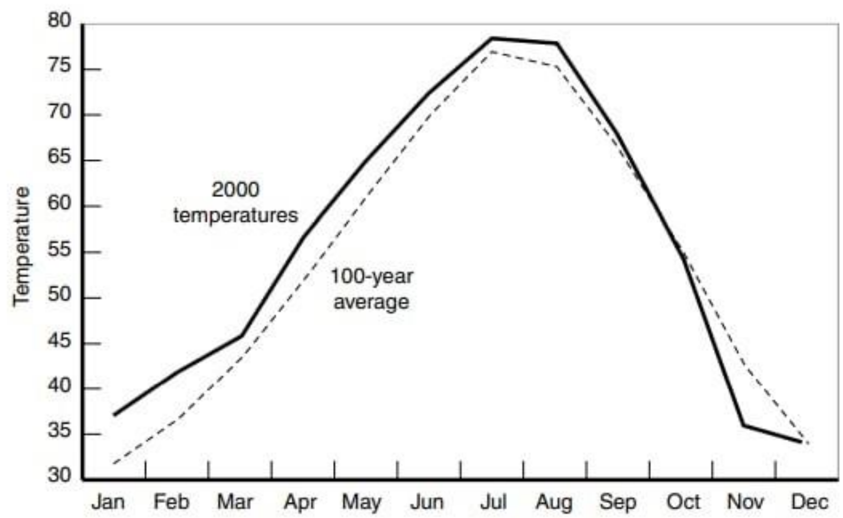


Figure 4:Monthly Temperatures in the Western United States, 100-Year Average and 2000.[2]

[1] Western Regional Climate Center, http://www.wrcc.dri.edu
[2] Western Regional Climate Center, http://www.wrcc.dri.edu

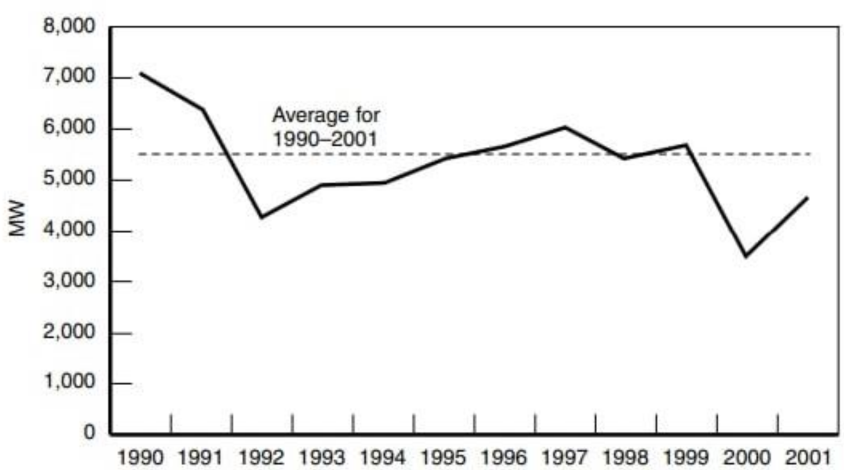


Figure 5:Total Imported Electricity for California, 1990–2001.[1]

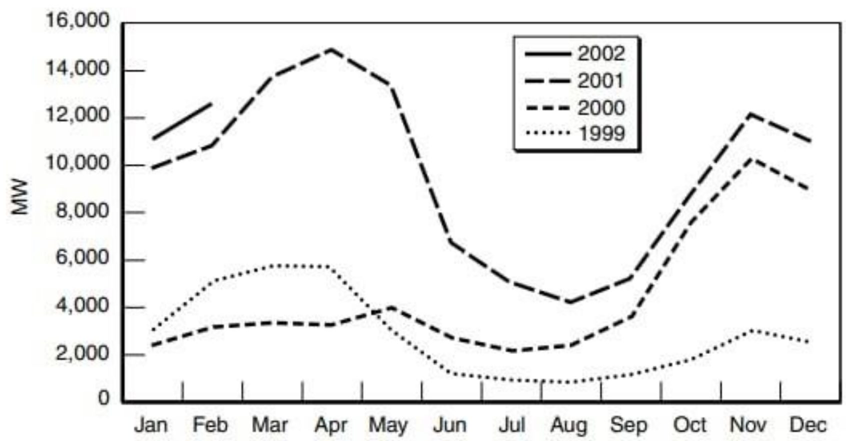


Figure 6:Average Daily Forced or Scheduled Megawatts Off-Line by Month, 1990–2002.[2]

For example, in the fall of 2000, 5,000 MW of power was taken off-line when nuclear plants scheduled maintenance at the same time. Plant operators have also pointed to the age of generation plants and to the fact that they were suffering from deferred maintenance because of heavy use in the early months of 2000. As will be discussed below, others disagree, contending that producers were strategically withholding their plants from the market in an effort to exercise market power and increase the prices they received.

Regulatory Failures

The regulatory environment following the passage of AB 1890 also contributed to the tightening supply situation. During the implementation of the market restructuring, regulatory uncertainty was pervasive as market rules were amended frequently. In addition, Proposition 9 was placed on the ballot in November 1998. It aimed to restrict the payments the utilities could receive for their stranded costs, thereby clouding the future of the California deregulation. It was eventually defeated by more than a 2-to-1 margin but,

[1] California Electricity Commission, Electricity Office, http://www.energy.ca.gov/electricity/electricity_generation.html
[2] California Electricity Commission, Electricity Office, http://www.energy.ca.gov/electricity/electricity_generation.html

nevertheless, it diverted attention away from plant construction at an important juncture. This uncertainty was not unique to California. Throughout the United States, federal and state regulators were moving away from costbased regulation of vertically integrated monopolies. As part of this transition, utilities abandoned their traditional role of constructing capacity. Since the mid-1980s, virtually all capacity additions were constructed by unregulated wholesale generators, but the rules under which these wholesale generators would operate remained incomplete, leading, at least in part, to a more general decline in investment throughout the United States. Several reports have also criticized the environmental review and siting process as too long and too expensive, hindering investment (Bay Area Economic Forum, 2001a; Cambridge Energy Research Associates, 2001a). For example, the average length of the permitting process in California is 14 months compared to only seven in Texas (Bay Area Economic Forum, 2001a; Smith, 2001). The California State Auditor found that for projects proposed since the beginning of 1997, the CEC missed its own one-year deadline in 11 out of 15 cases (California State Auditor, 2001b). Public opposition to projects did contribute to delays but it was not the only impediment to approval. The applicants themselves caused significant delays as they amended applications and submitted documents late. Other government agencies, such as air quality districts, also contributed to the length of the process, forcing the CEC to wait for necessary inputs. The record of the last few years does suggest that regulatory uncertainty and a slow review process delayed the construction of new capacity. The California State Auditor identified over 1,000 MW of capacity that could have been available during the critical months in the late spring and early summer of 2001 if the CEC had completed siting review in a timely manner. Nevertheless, these environmental regulations do not appear to have been a critical impediment to investment. The average length of siting reviews since the passage of AB 1890 has not been appreciably longer than reviews in the 1970s and 1980s. A review took on average one and one-half months longer, and

much of this increase can be accounted for by the fact that more recent projects tended to involve fossil fuels rather than solar and geothermal energy and were submitted by firms with less experience with the siting process. In any case, as is shown by Figure 2, even during the early, more uncertain years of the California electricity market, investors still submitted applications to increase California electricity generating capacity by over 20 percent. Other regulatory decisions not related to environmental review may have had a greater effect in reducing the number of projects undertaken. For reasons discussed in greater detail below, the California Public Utilities Commission issued a number of decisions that restricted the ability of the three main utilities to enter into long-term, bilateral contracts with electricity generators. Firms seeking to construct electricity generators commonly use such contracts to assure banks and potential investors that there is a market for additional electric power and that the proposed plant will be profitable. These restrictions on the utilities removed the main potential purchasers of long-run contracts from the market, increasing the risk of construction, and limiting the amount of financing available. Although these restrictions likely reduced the level of planned investment, the number of forgone projects is not known. At the same time that regulators may have impeded private sector decisionmaking, they were relinquishing their role in the energy planning process. Before deregulation, the California Energy Commission produced comprehensive biannual evaluations of the state of the California electricity sector, but its role in resource planning was significantly diminished with the advent of deregulation. At the same time, conservation efforts diminished. Before deregulation, California had a number of innovative programs that provided utilities with incentives to invest in conservation in lieu of capacity expansion. In the early 1990s, these mandated comprehensive reviews of energy alternatives identified numerous cost-effective investments in energy-saving technologies and conservation programs. Utilities invested as much as $400 million a year to promote these investments and programs. In the move to a competitive environment, these programs lost their constituency and momentum, largely because regulators lost the policy levers with which they provided incentives. AB 1890 did provide for continued support of such investments, but only at a much reduced level—about $220 million per year .[1]

Market Failures

Causes for underinvestment in generating capacity can also be found in the structure and operation of electricity markets.3 Generators may have been reluctant to invest in capacity because the market failed to send strong signals that additional investments were required. The California market relied completely on spot market prices for wholesale power to signal that future investments in capacity would be profitable. In theory, when spot market prices increased or were projected to increase, generators would come forward with new investments. For the first two years after the deregulation, however, a glut of electricity drove the wholesale price to low levels. Until May of 2000, the average wholesale price of a megawatt hovered around $30 and never rose above $50. If generators focused myopically on current prices, they had little incentive to undertake new projects until supplies tightened and the spot market increased. Because of the nature of the electricity markets, however, spot market prices are quite volatile when supplies become scarce .[2]Electricity cannot be stored and there are strict constraints on the amount of electricity that can be generated and delivered at a particular time. In addition, in the short run, consumers have limited options for reducing their electricity consumption. Consequently, when an electricity market nears its maximum capacity, extreme price spikes can occur before generators bring on additional supplies, consumers reduce demand, and the market is brought back into equilibrium. These characteristics of electricity markets can lead to boom and bust cycles in investment. Low prices impede investment until the market 3A highly contentious debate centers on the question of market power whether suppliers withheld capacity from the market in an effort to increase prices and profits. We discuss this issue below. tightens, leading to marked increases in prices. A rush of investments induced by high prices then frequently leads to over capacity and collapsing prices. This cycle has been evident since the crisis abated in the summer of 2001. After wholesale prices plummeted, investments in generating capacity became less attractive, and since the collapse of Enron Corporation, investors have shied away from committing their capital to large electricity-related investments. As a consequence, plans to build several new power plants have been cancelled or postponed, raising the prospect that California may experience new shortages as soon as 2004 .[3] Other markets, such as commercial real estate and microchips, which also involve large, capital-intensive investment with long planning horizons, have experienced such swings in capacity. In sum, much of the blame for the dramatic increases in wholesale electricity prices experienced during the summer of 2000 can be related to inadequate supply. Although merchant generating firms had been applying for permits and had begun construction of additional capacity, these investments were slowed by the low levels of wholesale prices before the summer of 2000, regulatory uncertainty, a sluggish environmental review process, and financing impediments. It is not possible to determine the number of megawatts of additional capacity that could have been made available earlier absent these impediments, but a reasonable lower-bound estimate would be that the 1,415 MW of capacity completed in 2001 for which application had been filed in 1997 and 1998 could have been available sooner. Unforeseen events, in contrast, had clearer and quite significant effects on reducing available supply. Reduced imports, resulting from weather conditions and increased demand in neighboring states, had the largest effect, reducing available capacity by the equivalent of up to 12,000 MW. Poor coordination of plant outages decreased available supply by about another 1,000 MW during the summer of 2000. These supply reductions constituted a significant portion of the approximately 50,000 MW peak summer demand. These events alone turned a situation of adequate supply into a shortage. It is possible

[1] Harvey et al, 2001
[2] Borenstein, 2001
[3] Tucker, 2002

that more favorable weather conditions, a downturn in the state's economy, or better operation of existing capacity could have saved California from its crisis during the summer of 2000. Then the thousands of megawatts of capacity scheduled to come on-line in 2001 and 2002 may have maintained an adequate balance between supply and demand. This shortage, however, fails to explain the entire crisis. In a wellfunctioning, competitive market with fixed capacity, one would expect price spikes when demand reaches system capacity, typically on a hot summer afternoon, but prices should drop during winter months when demand is slack. shows, however, wholesale prices rose to even higher levels in late 2000 just as demand was decreasing. The tight supplies created the conditions for these spikes, but other factors came into play.

Bottlenecks in Related Markets

Scarce electricity generating capacity was not the only shortage leading to unprecedented prices for wholesale electricity. Constraints on related infrastructure and markets, including natural gas pipelines, the market for pollution permits, and the electricity transmission system, also drove prices up. The price of natural gas plays a key role in electricity markets. Because it is relatively clean and inexpensive, it is the fuel of choice for new generation capacity. Virtually all new generation plants burn natural gas, and the proportion of California's in-state production generated with gas plants increased from 23 percent in 1983 to 38 percent in 2000. More important, the costs of gas peaker plants, designed to run only at times of very high demand, often set the market price for electricity because of their relatively high variable costs. From January through October 2000, an unusually cold winter on the East Coast led to a doubling of the price for natural gas at Henry Hub, Louisiana, considered an indicator of the national price of gas. Because the variable cost of electricity is almost completely determined by gas prices, this increase also doubled generation costs. Even if California's electricity sector had remained completely regulated, the prices of electricity would have increased to reflect these increases in input costs. Then in November 2000, the California natural gas market was hit with unprecedented volatility. Under normal circumstances, the price differential between the national and the California markets is quite small, representing the transportation costs from gas fields in the center of the United States to the California border. Yet in November, California prices rose far above the national price, and from November 2000 to June 2001, California natural gas customers were paying two to three times the national price. As with the run-up in electricity prices, the causes of high gas prices are complex—a combination of unexpected events, demand growth, and market manipulation. An explosion in an El Paso gas pipeline on August 19, 2000, temporarily closed that source of supply, cutting off almost 15 percent of California's pipeline capacity for about ten days and reducing flows for over a year. Normally during the summer and early fall, gas is stored underground in California in preparation for winter heating demand, but this pipeline interruption reduced storage. Storage was further limited by unusually high summer demand for natural gas because of heavy use of gas-fired electricity generators to replace imports of electricity. California entered the winter of 2000–2001 with a shortfall of gas storage equal to two weeks of demand, judging by the average of the three previous years.

demand for gas reached all-time highs driven by industrial users including electricity generators.[1]Under these circumstances—reduced supply and increased demand—an increase in gas prices is to be expected even in fully competitive markets, but these circumstances do not fully account for the much higher rates that California paid in comparison to the rates in the rest of the country. Before the summer of 2000, California had excess gas pipeline capacity. If this capacity was available, higher prices in California should

[1] A portion of the increase in industrial use, roughly 30,000 MMcf, is due to the transfer of gas-fired generating assets from the utilities to merchant generators.

have drawn in additional supplies from the Midwest until the premiums paid by California consumers were reduced. The California Public Utilities Commission among others has charged that the El Paso Corporation strategically manipulated its control of the pipeline to drive up prices. FERC has already found that El Paso entered into an unlawful contract with one of its unregulated affiliated companies to control a significant portion of its pipeline capacity. It is further alleged that El Paso took a number of actions to

reduce the amount of gas transported through the pipeline in an effort to constrain supply, increase prices, and boost the profits earned by its affiliate. This affiliate contract expired at the end of May 2001 and, as seen in Figure 3.9, the premiums paid by California evaporated soon thereafter. FERC has yet to promulgate a final ruling on these allegations, but an August 2002 FERC staff report found preliminary indications that manipulation of gas prices at the California border may have occurred. During the summer of 2000, the prices for pollution permits also rose precipitously. Under an innovative pollution control system called RECLAIM (Regional Clean Air Incentives Market), industrial plants in the South Coast Air Quality Management District (SCAQMD) that emit nitrous oxides (NOx) must purchase permits for each ton of emissions. The average price of these permits rose from about \$1–\$2 per pound to \$5 per pound in August of 2000, and some transactions were being consummated at prices exceeding \$30 per pound . This increase was caused by a combination of lower availability and higher demand. SCAQMD lowers the number of permits available every year, and 2000 was the first year in which the total number of permits constrained emissions significantly. At the same time, added generation from high-polluting plants that are not normally run for long periods increased demand for permits. Increases in NOx and natural gas prices had a dramatic effect on the marginal cost of electricity generation. Joskow and Kahn (2001b) estimate that these increased input costs raised the marginal cost of a megawatt of electricity from under \$50 in May 2000 to over \$100 in September 2000. Cambridge Energy Research Associates (CERA) estimate the change in marginal costs between December 1999 and December 2000 and find a much larger increase— from the \$19–\$35 range to the \$83–\$521 range. Limitations of the electrical transmission system also contributed to the crisis. Transmission lines have fixed capacities, at times limiting the ability of energy to be shipped from generating plants to final consumers. One main constraint is Path 15, which connects Northern and Southern California. Congestion on Path 15 can prevent inexpensive power in one part of the state from being shipped to areas being served by more expensive power. This limitation has cost California electricity consumers hundreds of millions of dollars in increased energy costs and has caused rolling blackouts. San Francisco, in particular, has limited connections to the statewide grid because it is situated at the end of a peninsula. Consequently, it is vulnerable to rolling blackouts even when energy is plentiful elsewhere in the state. These related events demonstrate that California's energy crisis extends beyond the market for wholesale power. California is facing a number of intertwined infrastructure issues. The performance of the electricity sector is dependent on, among other things, gas pipeline and storage systems, the electricity transmission system, and environmental goals. Constraints in any of these systems can dramatically and unexpectedly undermine the performance of interdependent systems, impeding the delivery of energy to California consumers.

Wholesale Generator Market Power

Wholesale Generator Market Power The shifts in market fundamentals described above—increased demand and input costs combined with decreased supply—certainly contributed to the increase in wholesale prices, but these factors cannot account for the full magnitude of the price spikes that plagued California. The highest profile and most controversial issue of the crisis has been the allegations of market manipulation and price gouging by generating firms. Early in the crisis, California appealed for relief to the Federal Energy Regulatory Commission, which regulates wholesale prices, and is pursuing \$8.9 billion in refunds from energy marketers through a proceeding. More recently, California moved to nullify the long-term contracts entered into with generators during the height of the crisis, arguing that it signed the contracts under duress because of market manipulation, and during the summer of 2002, it renegotiated several of these contracts with the active encouragement of FERC's chief administrative law judge. The attorney general has filed numerous suits alleging monopolistic activities, and the California Senate has been holding months of special hearings investigating market manipulation. The theory of market power is straightforward. The electricity generation market is dominated by a small number of producers, five national unregulated generation firms and a few public providers such as the Los Angeles Department of Water and Power and the Bonneville Power Authority. In such an oligopolistic market, generators may raise prices above the competitive level (e.g., the industry's cost for the last megawatt of generation produced) by strategically withholding some capacity from the market. When the added revenues from selling electricity at a higher price exceed the lost revenues from not selling all the electricity they could produce, their profits increase. Competition is the main barrier to such exercise of market power. When a generator with unused capacity can profitably undersell the market price, it has incentives to provide more electricity to the market, undercutting other firms' ability to raise prices. The critical role of competition broke down during the California crisis for a number of reasons. Because of the small number of firms involved in California's energy market, it may have been possible for generators to collude, either tacitly or explicitly, to withhold capacity. Even if each generator would have individually benefited by providing additional supplies to the market, they were jointly better off by agreeing not to compete keenly

Moreover, electricity markets are particularly prone to the exercise of market power. New supplies cannot be made available quickly because electricity cannot be easily stored, its transportation is limited by the constraints of the transmission grid, and the construction of new capacity entails long lead times. Consequently, generators do not have to worry that new supplies will flow into the market, undercutting their high bids. In addition, demand for electricity is not easily curtailed in the short run because electricity is essential to modern life and because most decisions that determine electricity usage involve the purchase of long-lived appliances (e.g., air conditioners, refrigerators, and heaters). Because demand decreases very little in response to higher prices, even small decreases in supply lead to significant price increases. The increase in price can be so large that a single firm that owns several plants can profit from shutting down one plant. Even if its competitors do not cooperate with this strategic behavior, the lost profits resulting from scaling back production in the one plant can be more than offset by the large price increase received for selling power from their other plants.[1] These problems caused by insufficient responsiveness to prices were particularly acute in California. Because AB 1890 had frozen retail rates (and AB 265 refroze them for SDG&E customers), consumers were completely shielded from the increases in wholesale prices as the crisis unfolded. They received no signal or incentives to conserve energy and, consequently, power generators were able to bid even higher prices without losing sales. Finally, because of the importance of real-time reliability, electricity markets are much more sensitive to the market share of large producers. The largest merchant generator in California, AES Corporation, controls less than 10 percent of the total demand on a hot summer day. In most markets, a similarly sized firm has little ability to increase the market price. In the electricity market, though, that 10 percent market share can represent the critical margin of power required to keep the lights on and air conditioners working on days with tight supplies. Consequently, relatively small firms can exercise great influence on prices if their withdrawal from the market will lead to blackouts.

Market power has been a pervasive problem in deregulated electricity markets. Numerous analyses have turned up evidence of the exercise of market power in California as well as in other restructured markets

[1] Borenstein, 2001; Joskow, 2001

.[1]In a competitive market, economic theory predicts that firms will sell their goods at a price equal to their short-run marginal costs, the variable cost of producing the last unit produced for the market. Unlike other industries in which firms' costs are not publicly available, these costs are known for electricity generators because of the history of rate regulation and ongoing environmental controls. When comparing actual wholesale market prices to competitive benchmark levels, researchers find observed wholesale prices to be persistently higher. In particular, as demand increases and supplies tighten, generating firms have increasing amounts of market power leading to higher markups over competitive price levels .[2] Although the exercise of market power is common, the California market appears to have been particularly susceptible to manipulation. Firms were able to raise prices above competitive levels even when supplies were comparatively plentiful, and the highest markups occurring during times of tight supply endured for much longer periods. During the worst months of the crisis—November 2000 through May 2001—there is primae facie evidence supporting market manipulation by generators. To raise prices generators would have had to withhold capacity from the market, and plant unavailability in California was significantly higher when compared to the number of plants off-line before the crisis . In addition, detailed analyses of the costs of generation, taking into account the increased costs of inputs and market conditions, find that about a third of the price increases experienced during the summer of 2000 can he attributed to market power .This evidence, however, is not incontrovertible, and generating firms and other analysts have offered up a number of alternative reasons that prices may have spiked. The market clearing price is determined by a host of specific market conditions, many of which are not publicly available or easily observable.[3] Calculations of the competitive market clearing price under competitive conditions are, therefore, crude estimates and cannot by themselves show that market prices were higher than generation costs. High prices may also represent scarcity rents. If the electricity system reaches its capacity with no strategic withholding of supply, supply is essentially fixed. Demanders then will bid up to their maximum willingness to pay to gain access to the fixed supply, potentially driving prices far above production costs.

The evidence concerning plant unavailability is also hotly debated. Generators claim that plants were unavailable because of mechanical failures and not strategic behavior. They claim that their plants were run particularly hard during the 1999–2000 winter, leading to additional failures in the following months. FERC did audit plants to see if they were altering their repair schedules to increases prices .[4]It found no evidence of such efforts to manipulate plant availability, but the study methodology was later criticized in a review by the General Accounting Office.[5] Also, as Figure 6 illustrates, the average amount of capacity off-line has actually increased since the crisis abated in June of 2001. Alternatively, faulty planning by generators may have led to plant unavailability. Certain plants require long lead times to begin operation, and if generators underestimate the demand for the next day, they may be unable to have the plant up and running in time for the market.[6] Finally, certain plants were unavailable because of financial and regulatory chaos. When the utilities lost their creditworthiness in January 2001, they halted payments to QFs that supplied thousands of megawatts. Unable to cover their fuel costs, the QFs were forced to halt production and sued to be freed from their contracts with the utilities. Governor Davis resisted releasing the contracts and allowing the QFs to sell their capacity on the higher-priced spot market because this action would have increased the overall costs of electricity purchased by the Department of Water Resources (DWR). This resistance had the effect of taking 2,000 MW of QF production offline.

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[1] Wolfram, 1999; Borenstein et al., 2001; Bushnell and Saravia, 2002
[2] Borenstein et al., 2001; Bushnell and Saravia, 2002
[3] Harvey and Hogan, 2001
[4] Federal Energy Regulatory Commission
[5] General Accounting Office
[6] Harvey and Hogan, 2001

Although there is ample evidence indicating that market manipulation did occur, the legal case that merchant generators unlawfully engaged in anticompetitive behavior remains unresolved. FERC, under the Federal Power Act, is required to ensure that wholesale generators charge “just and reasonable” prices. During the 1990s, FERC permitted merchant generators to sell their power at competitive rates if they were able to show that the markets in which they operated were reasonably competitive. Although FERC found early in the crisis that wholesale rates were no longer “just and reasonable,” it found insufficient evidence to lay the blame on the exercise of market power by generators, and it has yet to decide the extent of refunds, if any, owed California consumers.

The case is complicated by a number of factors. Many of the actions by generators were probably legal, even if they resulted in higher wholesale prices. Even if generator actions were illegal, courts may not intervene because of legal precedents that defer to the rates set by regulatory bodies. Finally, proving market manipulation after the fact places a heavy evidentiary burden on regulatory and enforcement officials. Because of the intricacies of plant operations, it is virtually impossible for an outsider to determine whether a generating plant did not produce electricity for legitimate reasons, such as mechanical breakdowns, or in an effort to increase wholesale prices. Clearly, the California experience has highlighted that identifying and mitigating market power after the fact is politically contentious, administratively burdensome, and legally complex.

Regulatory Missteps

The magnitude of the crisis and the extent of its repercussions were certainly exacerbated by a number of regulatory missteps. The design of California’s deregulation has received much criticism. Cambridge Energy Research Associates argues that “partial deregulation” based on a “potpourri of competing stakeholder claims” inevitably led to crisis. The Reason Foundation blames the “chaotic implementation” of deregulation .[1]FERC points out that California accounted for the majority of problems arising from newly deregulated markets and has deemed California’s implementation of AB 1890 as “fatally flawed” .[2] Hogan characterized California’s deregulation as “[a] flawed wholesale market and a caricature of a retail electricity market [that arose] . . . as the product of a volatile combination of bad economic theory and worse political economy practice” . Two problems deserve special attention: the implementation of AB 1890 in which a number of decisions led to excess exposure to spot markets and inaction in the face of the impending crisis.

Excessive Exposure to Spot Markets

Although market conditions and market power help explain the extraordinary run-up in electricity prices, they do not in themselves explain the subsequent financial crisis and collapse of the electricity sector. This aspect of the crisis can be explained only by the utilities’ excessive exposure to market risk. The retail rates at which the utilities could sell electricity were frozen, but they were forced to buy that same electricity at fluctuating wholesale rates. In the first years of restructuring, average wholesale rates were well below the level of retail rates. Thus, the rate freeze acted as a rate floor, preventing retail rates from dropping to the low levels of wholesale prices and enabling the utilities to earn additional revenues that they applied toward paying off stranded costs. Despite this early fortunate experience, the utilities were operating with the risk that wholesale rates could increase above these fixed retail levels, leading to losses.

Firms that are exposed to volatile commodity prices typically hedge their risks through forward contracts, long-term contracts, or other financial instruments. For example, it is a common practice for newly

[1] Kiesling, 2001
[2] Federal Energy Regulatory Agency

deregulated utilities that divest some of their generating capacity to sign long-term contracts in which they buy back all or a portion of the power from the new owner.[1] California utilities did not sign such contracts and, consequently, controlled less than 70 percent of their total energy sales through owned capacity or long-term contracts. Moreover, at times of peak demand, the utilities owned or had under contract only about 18,000 MW of capacity, only 40 percent of their peak loads of 45,000 MW. Consequently, the utilities were dependent on the spot market, no matter what price was being charged, for the difference between their own capacity and their customer demands. In addition, as is explained below, the CPUC required that all electricity, even electricity generated by the utilities themselves, be sold through the PX. Thus, during the height of the crisis, the utilities were buying electricity from themselves at prevailing spot market prices. To the extent that the utility holding companies retained a portion of the revenues from these high-priced sales of electricity, the losses incurred by their utility subsidiaries increased, exacerbating the financial crisis.

If California utilities had tied up more supplies through long-term contracts, the volatility would not have had such devastating repercussions. The enormous increases in their energy purchasing costs would have been mitigated, possibly saving them from financial collapse. More important, greater reliance on long-term contracts would have mitigated the exercise of market power, reducing the degree of price volatility. By shrinking the size of the spot market, long-term contracts decrease the benefits of market manipulation because there are fewer megawatts of power that can be sold at high spot market prices.

Neglecting the critical role that long-term contracts play in a wellfunctioning electricity market was a major failure of the implementation of California's experiment in deregulation. At the time of restructuring, many industry insiders fully understood that commodity markets are inherently volatile and risky. Failure to hedge against these risks was the equivalent of refusing to buy earthquake insurance in California, but the implementation of electricity deregulation, through a series of seemingly unrelated actions, did exactly that.

AB 1890 was mute on the issue of long-term contracting, neither requiring nor forbidding it. Initially, the CPUC implemented restructuring by requiring that all electricity, utility-owned generation as well as nonutility-owned, be bid through the PX spot market. The utilities soon requested that they be given permission to hedge their positions. In a number of decisions dating back to 1999, the CPUC did slowly and at times reluctantly grant the utilities the authority to hedge. In July 1999, the CPUC allowed utilities to buy block forward contracts through the PX for up to a third of their minimum load. Then in March 2000 the CPUC expanded the amount of energy that could be purchased through forward contracts, although it retained the right to disallow contract costs.[2] In August of 2000, it again expanded the authority to include bilateral contracts. Despite these moves, the utilities remained inadequately protected from price spikes as the crisis broke.

Part of the explanation for this inaction is that the utilities and regulators were focused on other problems. The early years of deregulation were marked by low prices, and the California Energy Commission, as late as February 2000, was predicting decreasing wholesale prices. Consequently, little attention was being devoted to the risks of price spikes. In the early years of restructuring, regulators were also more concerned about the exercise of market power by the three main utilities rather than the new generators. Because the former vertically integrated utilities controlled the distribution system and vast amounts of generating capacity and had strong customer loyalty, the concern was that they would be able to thwart the development of a fully competitive retail electricity market. The requirement that the utilities divest

[1] Borenstein, 2001
[2] California State Auditor

generating capacity and the restrictions on long-term contracting for power were in large part directed at preventing the utilities from dominating the post-restructuring market.

Efforts to recoup stranded costs also diverted the attention of the utilities and regulators. The utilities wished to recoup these costs as quickly as possible, and regulators wished to end the retail price freeze connected to stranded cost recovery so that consumers could take advantage of what seemed like very low wholesale rates. Requiring that the utilities purchase power through the spot market facilitated this process by simplifying the accounting for these payments.[1]

A second reason for the lack of action was that neither the major utilities nor the California Public Utilities Commission appear to have grasped how their roles had radically changed in a deregulated market. Deregulation called for customer choice and competition to determine electricity rates. Utilities have claimed, nevertheless, that they fully expected regulators to allow them to recover the full costs of their wholesale power purchases—an expectation more fitting a regulated firm than a competitive one .[2] At the same time, the California Public Utilities Commission continued to assert the need to review the prudence of the utilities' long-term contracts, ignoring the role that consumer choice and retail competition could play in disciplining bad investments in long-term contracts.

The failure of retail competition to take hold in California further exposed the utilities to unhedged risk. The initial vision of a deregulated market foresaw a market with vibrant competition between numerous retail energy service providers. Within this vision, requiring that the utilities divest all their thermal generating plants and placing restrictions on their long-term contracts was more logical. The new ESPs would need access to wholesale supplies of electricity to serve their customer load, and they were free to use any hedging strategy they found profitable in their wholesale purchases. The utilities, in turn, controlled sufficient generation to serve the customers that remained with them. Unfortunately, extensive retail competition did not develop.

This anemic record may be attributed to a number of factors. First, consumers, habituated to receiving steady monopoly electricity, tend to take notice of and comprehend new competitive possibilities slowly. When competitive providers broke into the market for long-distance telephone service, for example, it was ten years before 30 percent of longdistance calls were handled by these new entrants, despite the fact that they offered substantially lower prices. The success of residential choice in the United Kingdom may be attributed to the fact that electricity restructuring and choice for larger industrial firms were in place for many years before they were introduced to residential users.

This customer inertia was reinforced by provisions of AB 1890 that were designed to ease the transition to competition. Residential and small commercial customers were given an automatic 10 percent rate decrease and were protected by the rate freeze. These policies dulled incentives to change providers. New entrants found it difficult to undercut the utilities' prices, and competitors could offer few valueadded services to small customers to lure them away from the utilities. The one exception was marketers offering "green power" who attracted environmentally conscious users willing to pay a premium over existing rates. Larger industrial customers, in contrast, benefited more from switching. Because they had not received a 10 percent rate cut from the incumbent utility and because they are heavier users of electricity, new entrants could offer more competitive prices and a host of energy management services

The effect of the rate freeze imposed on utilities is evident in the pattern of customer choice. As seen in figure, beginning in April 2000 as wholesale prices rose precipitously, customers flocked back to the

[1] California State Auditor,Cambridge Energy Research Associates
[2] Edison International Corporation, 2001

utilities. Consumers, who had not entered into long-term agreements with new providers to lock in electricity rates, saw their bills soar, and they abandoned competitive ESPs to take advantage of frozen default rates. Pennsylvania experienced a similar collapse of customer choice when wholesale prices rose above the default rate charged by the incumbent utilities. When wholesale rates dropped to pre-crisis levels, larger customers quickly returned to competitive providers although smaller ones did not react as quickly Regulators were also ambivalent about retail competition. The CPUC implemented a consumer education program as mandated by the restructuring legislation, but otherwise maintained a hands-off approach .[1] In particular, the CPUC did not mandate programs that promoted the switching of customers to new ESPs. In Pennsylvania, in contrast, where residential choice had been initially more successful, utilities were required to move some of their customers to competitors. Also, the CPUC failed to aggressively pursue a set of interconnection rules for metering and billing that enabled newcomers to enter profitably.

Failure of retail competition was a problem in its own right. Many of the benefits of restructuring, such as cheaper rates, innovative payment options, and energy-management services, were to arise out of the competitive struggle to attract retail customers. But the failure of retail competition had the more immediate effect of increasing utilities' risk exposure. If ESPs had attracted more customers, the utilities would have had to serve less load, decreasing their reliance on the spot market. The CPUC placed the utilities in this bind by working at cross-purposes. It required the utilities to purchase through the spot market in part to promote retail competition, but then it failed to follow through on promoting competition, leading the utilities to serve a larger than expected load through spot market purchases.

Finally, efforts to promote long-term contracting were stymied by mistrust and poor relations between the CPUC and utilities. Although the CPUC did act to permit greater utility use of hedging instruments, it remained suspicious of long-term contracts. It continued to reserve the right to disallow long-term contract costs in the future if spot market prices were below the contract price, and it was slow to review the contracts that were signed. The utilities, for their part, were hesitant to hedge, either because of their mistrust of the CPUC disallowance or because they were overly optimistic concerning future wholesale prices. During the summer of 2000, for example, the utilities employed little more than half of the forward contracts they were authorized to purchase . These decisions turned out to be quite expensive for both the utilities and California in general.

Inaction in the Face of the Impending Crisis

The lack of a rapid, decisive, and coherent response by policymakers also contributed to the devastating consequences of the crisis. The problems with the electricity sector became widely evident in June of 2000 as wholesale prices soared above $100 per MW. The utilities were forced to buy expensive wholesale power and sell it for low retail rates, and their debts mounted rapidly, as much as $50 million per day. The dangers of default by the utilities, widespread chaos, and rolling blackouts loomed large.

During the rest of that year, however, California and federal regulators took only limited actions to address the fundamental problems driving the crisis. In December, FERC issued an order with a set of ultimately ineffective market mitigation measures. In the order, FERC made it clear that it believed that California bore the ultimate responsibility to address the crisis. California took a number of actions. During the summer of 2000, the ISO became concerned about increasingly tight supplies and initiated a program to contract for 3,000 MW of additional peaker plants that could be brought on-line for the summer of 2001. [2]With AB 265, the legislature reimposed a rate freeze on SDG&E to shield consumers from a run-up in

[1] California State Auditor
[2] California State Auditor

wholesale prices. It also enacted a number of measures to increase supply through the expedited approval of generating capacity and to decrease demand through conservation efforts.

These programs met with moderate success. The ISO was able to contract for 1,324 MW of capacity, although it still required CEC approval for the plants. Expedited review did lead to about 400 MW of peaker capacity being brought on-line during the summer of 2001, and the various conservation programs led to larger-than-expected reductions in demand during 2001. Nevertheless, these efforts failed to avert the financial and institutional cataclysm that hit the California market in January 2001.

More decisive action was gravely complicated by the division of regulatory authority between the state, which regulated retail rates, and FERC, which regulated wholesale rates. Avoiding the imminent financial collapse of the utilities required raising retail prices, placing controls on wholesale prices, or a combination of the two. The political and economic situation at the height of the crisis was complex and full of uncertainty, leading to pitched debate over the correct course of action. There were several competing diagnoses of the fundamental causes of the crisis. These included, among other things, the exercise of market power, a poorly designed deregulatory structure, higher production costs, and scarcity of electricity. Each of these causes led to different policy solutions. To the extent that the crisis reflected higher production costs, and scarcity, price increases were warranted. In contrast, to the degree that high wholesale prices reflected the exercise of market power, price increases would simply ratify the distortions that arose because of that market power, while not solving the underlying problem.6 Rather, market power called for price caps or other methods of mitigating the exercise of market power.

California politicians and regulators, being closer to California consumers, wished to avoid price increases for their constituents, as evidenced by their support of AB 265. These proclivities were likely reinforced by the extended presidential election in November 2000 as politicians wished to avoid becoming mired in crisis when political advancement in the next administration remained possible. Correctly or incorrectly, they believed that the behavior of the wholesale market was not purely the result of competitive market forces, supporting their decision to maintain retail price controls. They would certainly have reinstituted wholesale price controls if they had had the authority to do so.

FERC, in stark contrast, through its efforts to liberalize electricity markets throughout the United States, was more closely aligned with the power generators with whom it shared pro-restructuring positions. It advocated strongly that the crisis was not due to the exercise of market power. Interventions in the market would, in its view, risk further damaging the market and impeding the investments in new capacity required to alleviate the crisis in the long run. Increased prices would mitigate the exercise of market power by increasing demand responsiveness, but they would not prevent generators from earning monopoly profits Resolving these issues of cause and appropriate policy response would be difficult under any circumstances. Here, the crisis atmosphere, combined with strong ideological differences and mutual mistrust and recrimination between FERC and California, prevented the two from working in concert. Earlier unilateral action by either party—a price increase by California or the imposition of wholesale price caps by FERC—was unlikely because it undermined each party’s political and ideological position.

In retrospect, a well-designed combination of increased prices and short-term price controls on wholesale prices implemented in 2000 could have avoided much of the damage of this crisis. They would have protected the utilities from fiscal collapse by simultaneously increasing their revenues and decreasing their costs. Retail price increases would have addressed the fundamental capacity shortage by signaling the need for conservation, and wholesale price caps may have reduced the exercise of market power. Wholesale price controls would have made retail price increases more politically acceptable and retail price increases would have signaled to generators that California wished to maintain a healthy investment environment. In the end, both California regulators and FERC relented, adopting policies along the lines of this compromise. The CPUC ratified two price increases of historic proportions, one of 10 percent in January and a second larger increase averaging 46 percent in March. At the federal level, the politics surrounding energy regulation changed dramatically during the spring of 2001. President Bush appointed two new members to the Federal Energy Regulatory Commission, and the Democratic Party gained control of the Senate, leading to renewed calls for action. Consequently, FERC switched its antiregulatory stance and imposed effective regional price caps on June 19, 2001. Unfortunately, by the time these policies took effect the damage had been done.

Faulty Market Design

The disastrous performance of the California market has also been linked to the structure of its market institutions. The design of well functioning electricity markets is intricately complex. Design must incorporate elements of regulation, coordination, and competition. Auctions for power must be designed to provide incentives for least-cost dispatch of power, for the expansion of generation and transmission capacity when needed, and for mitigating the potential abuse of market power. The entire system must be coordinated to control for the externalities of network operations and the need to maintain system balance in real time. The details of market design are critical and getting them wrong can lead to perverse actions by market participants. It is common for deregulated markets to require amendment as design issues arise .[1]

Several specific deficiencies with the California example have been identified. The overall design was complex, relying much more on market forces than other examples of deregulation. Joskow has characterized it as “the most complicated set of wholesale electricity market institutions ever created on earth and with which there was no real-world experience” . During the implementation of AB 1890, energy traders, generators, and other interests bargained over rules paying closer attention to their interests than to efficient and effective market design. In the end, the rules were opaque to all but industry insiders.

An example of this complexity was the separation of the PX, which conducted day-ahead auctions for power, from the ISO that runs the transmission grid and purchases power in real time. This bifurcation of responsibility created incentives to move transactions from the day-ahead market to the real-time market where competition is attenuated because of the exigencies of maintaining system balance.[2] These bidding strategies complicated the administration of the grid and raised wholesale prices. Hogan also criticizes the market structure for lacking sufficient pricing zones. Network congestion can cause the market-clearing price to differ from location to location because inexpensive power is unable to flow to areas being served by more expensive generators. California had only a two-zone congestion system that failed to track congestion within each zone. Consequently, price signals for efficient dispatch of generation and for investments in needed additions to transmission capacity were not being properly generated by the market. Revelations of Enron trading strategies have highlighted how faulty market design left the transmission market vulnerable to manipulation. In one strategy, for example, Enron played California’s market against regulated transmission in neighboring states. It would claim to ship energy through California counter to the direction of congestion, thereby collecting payments for congestion relief. It would then sell that power back to the original location through regulated transmission in neighboring states. No net energy was moved or congestion relieved, but Enron profited from the spread between California congestion payments and tariffed transmission charges. These problems are particularly important given that transmission bottlenecks

[1] Hogan, 2001
[2] California State Auditor, Hogan

have been a major source of concern during the crisis, and additional transmission will be required to improve the operation of the California electricity system

These market design issues were probably not fundamental factors in the California crisis, certainly not in comparison to the supply shortage and the exposure to the spot market. As Harvey and Hogan admit, “the conditions were so extreme in California that even a good market design may not have survived the summer of 2000 and its aftermath” .[1] Nevertheless, the future of the California experiment in deregulation will depend on getting the details of market design correct.

Addendum: The Crisis Fades

Unexpectedly, the summer of 2001 saw the crisis begin to abate. Late in the spring, experts were still predicting ever-higher prices and days of rolling blackouts (Vogel, 2001). Instead, no blackouts occurred and wholesale prices tumbled to their precrisis levels. Although the end of the crisis was unexpected, the underlying reasons for this turn of events are not surprising. Several trends that caused the crisis in the first place were reversed.

The supply shortage abated as movements in both supply and demand brought them more into balance. Available capacity increased for a number of reasons. Over 2,000 MW of additional capacity was brought on-line. Of this capacity, 634 MW had been rushed to market through the emergency fast track regulatory approval process established by Governor Davis, but most of it had been in the pipeline before the beginning of the crisis.[2] In addition, the amount of unscheduled outages of generating plants plummeted

These shifts were complemented by lower electricity demand. Even though the summer of 2001 was on average hotter than the summer of 2000, electricity demand decreased noticeably, topping out with an 8.4 percent decrease in June (see Figures 7 and 8). These conservation efforts were not directly a response to increased retail prices given that they preceded the steep increases that took effect in June. A number of targeted demand-reduction programs, however, offered compensation for reduced usage. For example, the 20/20 program offered consumers a 20 percent rebate on their summer 2001 electricity bill if they reduced their usage by 20 percent. These programs combined with heightened public awareness of the crisis and public appeals for conservation played significant roles in reducing consumption. In addition, price increases for natural gas over the winter, which many consumers confused with increased electricity prices, and a slowing economy appear to have contributed toward curbing demand.

Tight conditions in the markets for inputs for electricity also abated. The price of natural gas tumbled to the single-digit range Electricity generating plants were removed from RECLAIM’s NOx trading system and were charged a flat rate for each pound of emissions. These shifts reduced the costs of generation and helped drive wholesale prices down.

[1] Harvey and Hogan
[2] California Energy Commission

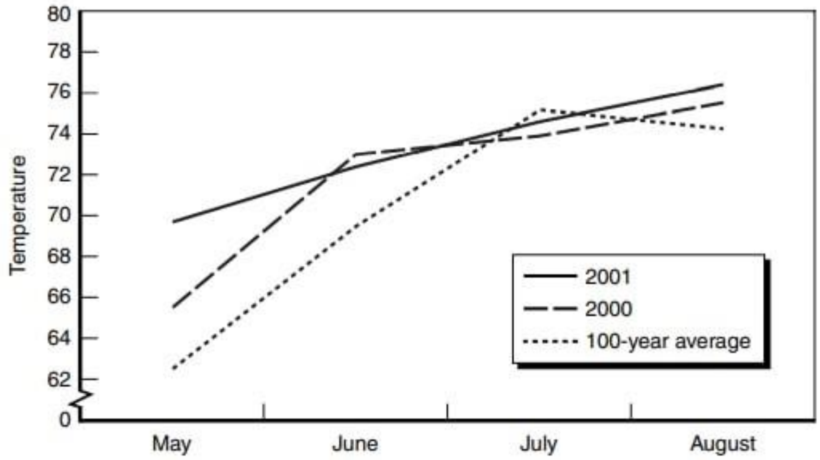

Figure 7:California Summer Temperatures, 2000, 2001, and 100-Year Average.[1]

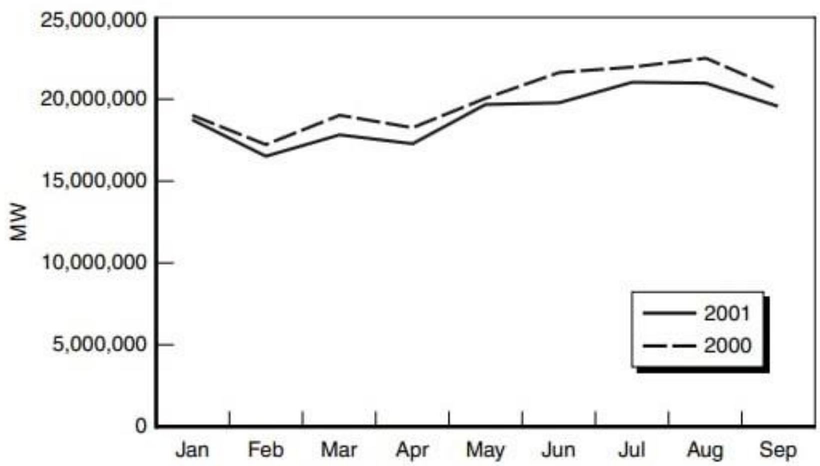

Figure 8:Weather Adjusted Loads, January–September 2000 and 2001.[2]

Actions taken by policymakers also helped. The price increases implemented by the CPUC not only contributed toward curbing demand, they mitigated the financial turmoil enveloping the electricity sector. It also appears that policy actions that reduced generators' incentives to strategically withhold power decreased the exercise of market power during the summer. First, FERC implemented a strict, regionwide cap on wholesale rates in June, limiting the ability of generators to increase market prices. Second, the Department of Water Resources locked up a large portion of California's energy needs in long term contracts, thereby reducing the size of the spot market. The decrease in the number of plant outages seems to indicate that these actions were successful.

Since the summer of 2001, the California energy sector has hobbled forward in a muddled, though stable, state. Spot market prices have moderated considerably, hovering near their precrisis levels. Unfortunately, consumers are not benefiting much from these dramatically lower prices, because most power is procured

[1] Western Regional Climate Center, http://www.wrcc.dri.edu
[2] ISO, DMA Directors Report

through the long-term contracts signed by the state, leaving only marginal amounts to be bought through the spot market. Hot spells during the summer months of 2002 have shown that California is not yet completely out of the woods. Spot market prices have at times bumped up close to FERC's current $91.87 price cap, and the ISO has declared some emergency notices as reserves have dipped low. The system has held up, nevertheless, and no rolling blackouts have been necessary. The grid has been strengthened by continued additions to generating capacity. Since the beginning of 2001, over 10,000 MW of capacity have been brought on-line or are nearing completion. Nevertheless, the long-run adequacy of California generating plant remains a concern. In reaction to plunging wholesale prices, power producers have either cancelled or delayed almost 5,000 MW of planned construction.

Investigations and court suits concerning allegations of market manipulation have dragged on with no sight of an early conclusion. The most prominent revelation has been the Enron memo detailing the trading schemes it employed to manipulate design flaws in the California market. These schemes focused on ancillary markets that are much smaller than the main market for wholesale power, and they were not responsible for the overwhelming problems faced by California. Despite providing no smoking gun for the more fundamental allegations of market manipulation, the memo has given credibility to the charges and has prompted much closer scrutiny to the practices of energy traders.

California, however, cannot allow its electricity management to continue to drift, as significant challenges lie ahead. FERC's market mitigation measures expired at the end of September 2002. It declared its intention to replace the current price cap formula with a straight $250 per MW cap, and California regulators fear that this increased level may reopen the market to manipulation. Also, the state's authorization to purchase power expires at the end of the year, requiring that the three main utilities resume their traditional role of purchasing power for their customers. Most important, California continues to lack a clear direction out from the crisis. The next chapter reviews options for moving forward, and Chapter 5 examines three specific recommendations for improving the performance of the electricity sector.

Market Power Analysis

The Behavior of Price-Taking Firms and Competitive Markets

A firm exercises market power when it reduces its output or raises the minimum price at which it is willing to sell output (its offer price) in order to change the market price. A firm that is unable to exercise market power { a price taker { is willing to sell output so long as the market price is above the firm's marginal cost of producing and selling the output, properly calculated. In the electricity industry, the marginal cost of production will include both the variable costs due to fuel and the other variable operating and maintenance costs, i.e., all costs that actually vary with the quantity of power that the plant produces.

Still, the cost of selling a unit of electricity can be greater than the simple production costs if the firm has an opportunity cost that is greater than its production cost, such as the revenue the firm would get from selling power or reserve capacity in a different location or market. For instance, a power producer in the northwest U.S. can sell power into California or can sell power in its own location or some other location in the Western Systems Coordinating Council (WSCC). Generators also have the option to sell capacity in any of the ISO's ancillary services markets where their capacity can meet the technical requirements to provide that service. If the producer expects that it can earn $21/MWh selling the power in another location, and if transmission were available and no more costly than transmission into California, then it would not be willing to offer power in California for any price less than $21/MWh. This would not indicate that the firm is exercising market power: the firm is not raising its offer price in California in order to raise the California market price. It is simply choosing to sell its power where price is highest. Of course, a high price in an alternative market can reflect market power in that market, resulting in the transmittal of high prices across markets by the response of competitive suppliers.

Because a price-taking firm sells its output at the market price, and that market price is usually strictly above the marginal production cost of almost all the output it produces, price-taking firms can still cover their full costs of production, including their going-forward fixed costs of operation. If the industry marginal cost (i.e. supply) function, which is the aggregation of all firms' supply functions, exhibits distinct steps { as is often thought to be the case in the electricity industry { then a competitive market equilibrium may be reached at which the price exceeds the marginal cost of even the last unit of output produced, but is still less than the marginal cost of producing one more unit of output Similarly, if all units of production are in use, then the intersection of supply and demand can occur at a price above the marginal production cost of any unit. That is, in the absence of market power by any seller in the market, price may still exceed the marginal production costs of all facilities producing output in the market at that time. Price above marginal production cost of all operating plants is not in itself proof of market power abuse. However, offering power at a price above marginal production (or opportunity) cost, or failing to generate power that has a production cost below the market price, is an indication of market power abuse.

Some analysts of the electricity industry have raised the concern that price-taking behavior on the part of every ¯rm is simply too strict of a standard to be used as a benchmark. They argue that it is unrealistic to think that no market power will exist, because market power exists in most markets. We recognize this fact and that even with some market power present in the electricity industry there may be lower retail prices than under the historical vertically integrated regulated utility regime. Nonetheless, we must also point out that there are many markets in which virtually no market power exists: most agricultural and natural resource markets, for instance. These industries are notable for producing virtually homogenous products and selling them over a large geographical area, characteristics that bear an important similarity to the electricity industry. Thus, while the presence of some market power should not be grounds for declaring deregulation of electricity generation a failure, neither should it be accepted as inevitable based on observations from other industries.

The Behavior of a Firm with Market Power

In contrast to price-taking firms, a firm with market power can unilaterally influences the market price by withholding output at the margin or raising the price at which it is willing to sell this marginal output. By taking such actions, the firm risks selling less, but it raises the price it will get for all output that it does sell.

Two factors are critical in determining the extent to which such unilateral exercise of market power is likely to be profitable for the firm: the sensitivity of market demand to price changes and the sensitivity of the supply of other producers to price changes. If the market demand is very price elastic, then reducing output (or raising the offer price on marginal units), will have very little impact on price as consumers will react to even a very small price increase by reducing consumption enough to match the reduced output. If demand is very inelastic, then only a large price increase would cause enough demand reduction, in which case it is more likely to be profitable for a producer to reduce its supply.

Likewise, if the supply of other producers is very elastic, then one firm reducing output (or raising the offer price on marginal units), will have very little impact on price as other suppliers will react to even a very small price increase by increasing their output enough to match the first firm's reduced output. Inelastic supply of other producers, in contrast, implies that it is more likely to be profitable for a producer to reduce its supply.

Economists generally believe that the ability to exercise market power unilaterally is correlated, albeit imperfectly, with a producer's market share. If, for instance, a firm supplies 1% of the total output in a market, then if it were to reduce output in order to raise its profits, it would run into two problems. First, demand would not have to adjust very much to absorb the loss of part of the firm's production so price would not have to rise very much. Second, with 99% of the output produced by other companies, they probably could expand their output by the small amount necessary to replace the firm's reduced production without driving up their own costs appreciably. So, even a slight increase in price would probably bring forth a replacement of the reduced supply, undermining the firm's intent when it reduced its supply. In other words, a firm with a very small market share is more likely to see demand as relatively price elastic, and the supply of other firms as relatively price elastic, over the range of output that it might contemplate removing from the market or offering to sell only at a high price.

In contrast, a firm with a large share of the market is more likely to be able to lower its output, or raise the offer price on part of its output, in a way that is difficult for demand to adjust to because the firm's action constitutes a significant share of the entire market production. Likewise, other companies may find it much more difficult to replace the output reduction of a large firm without themselves running into production constraints that would drive up their own costs.

The connection between market share and market power, however, can be overstated.1 In some situations, a firm with even a relatively small market share might find it profitable to restrict its output or raise its offer price on marginal output. Think about a situation in which demand is not at all price elastic, in the extreme a situation in which buyers don't even know the price at the time they are buying. Then add to that a situation in which other factors, such as a very hot day, have driven up the quantity of electricity that buyers want to consume to the extent that virtually every company is operating at its absolute production limit. That is, the price elasticity of supply from other producers is very low because they are at or near their capacity constraints. In that case, a firm with even a small share of the market might be able profitably to reduce output or raise its offer price.

This situation is particularly relevant to markets in which demand is highly variable { so that there are times when virtually all production capacity is necessary to meet contemporaneous demand { and the output cannot be stored { so that inventories are not available as an alternative supply source if a firm tries to exercise market power. For this reason, electricity markets are more vulnerable to the exercise of market power than are, for instance, gasoline markets. See Borenstein, Bushnell, and Knittel (1998), for a more detailed discussion of the applicability of concentration measures to market power analysis in electricity markets. When a firm does exercise market power, all firms in the market benefit. In fact, other firms may benefit proportionally more than the company that is exercising market power. Thus, even a price-taking firm in a market has a strong incentive to resist any attempts to detect or undermine the exercise of market power. Thus far, we have discussed only situations in which a firm unilaterally exercises market power. Antitrust law is more often concerned with collusive attempts to exercise market power. Unfortunately, many of the attributes that facilitate collusion are present in electricity markets: In most markets, firms play repeatedly, interacting on a daily basis, so there is opportunity to develop subtle communication and collusive strategies. The payoff from cheating on a collusive agreement may be limited due to capacity constraints on production, though for the same reason, the ability to punish defectors may be limited. Finally, the industry has fairly standardized production facilities, so homogeneous costs may make it easier for firms to reach tacit or explicit collusive behavior. All that said, we have not explored the question of tacit or explicit collusion among firms in the California market. Rather, in this paper we focus on market outcomes.

The Consequences of Market Power

An important fact to consider when discussing market power in the California electricity market is that, during the 1998-2001 transition period, end-use consumers are insulated from energy price fluctuations by the Competition Transition Charge (CTC). The CTC is a mechanism that was implemented along with the restructuring of the industry in order to allow the incumbent utilities to recover their stranded generation costs. The vast majority of end-use consumers currently face fixed rate schedules that were also imposed along with the CTC. Even \direct access" consumers, who buy energy from some source other than their incumbent utility, are insulated from wholesale energy price fluctuations in the short-run by the CTC. This is because the stranded cost component paid by all consumers is calculated in a way that moves inversely to the energy price. The higher the energy price, the lower the CTC payment for that hour. Thus, the CTC greatly lessens the elasticity of final consumer demand with respect to the price of energy. When the CTC is considered, the exercise of market power by suppliers results, in the short run, in a transfer of wealth from the incumbent utilities, rather than end-use consumers, to other suppliers.2 However, because of the way the CTC has been designed, higher energy prices are likely to delay its expiration, and thereby delay a significant drop in the rates of end-users. It now appears that this is certainly the case for SDG&E customers and very likely to be the case for customers of PG&E and SCE. In that case, by delaying the end of the CTC, the effect of market power exercised today in the California market is to transfer wealth from end users to non-utility generators. It is also worth noting that the incumbent utilities still sell a significant share of the energy produced in California, so the transfer occurs only on the power they buy from other generators. Even if we ignore the issue of transfers between utilities, consumers, and producers, market power can still yield negative consequences. In a market with a diverse set of firms, the exercise of market power by some firms will decrease the productive efficiency of the industry. While each firm will want to produce whatever quantity it decides to sell in the most efficient way possible, a firm exercising market power will restrict its output so that its marginal cost is below price (and equal to its marginal revenue), while other firms that are price-taking will produce units of output for which its marginal cost is virtually equal to price. Thus, there will be inefficient production on a market-wide basis as more expensive, competitive, production has been substituted for less expensive production owned by firms with market power. This is precisely what Wolak and Patrick (1996) describe as occurring in the U.K. market, where higher cost combined-cycle gas turbine generators owned by new entrants provide baseload power that could be supplied by coal-fired plants which are being withheld by the two large generators exercising market power.

In addition, several recent analyses have demonstrated that the exercise of market power in an electricity network can greatly increase the level of congestion on that network.This increased congestion creates negative impacts on both the efficiency and the reliability of the system. Market power can also lead firms to utilize their hydro-electric resources in ways that decrease overall economic efficiency.Lastly, it is important to remember that current electricity prices influence long-term decision-making in a way that can seriously impact the economy. While it has been pointed out that high prices should spur new investment and entry in electricity production, these investments may not be efficient if motivated by high prices caused by market power, which indicates a need not for new capacity, but for the efficient use of existing capacity. Conversely artificially high prices can lead some firms not to invest in productive enterprises that require the use of electricity. The deregulation of the electricity industry was largely motivated by the hope that a competitive market would lead to more prudent investment decisions than those produced under regulation. For this hope to be realized, market prices must reflect the underlying economic conditions of the industry.

Distinguishing Competition from Market Power

The previous subsections have explained how prices are determined in competitive markets and in markets in which some firms exercise market power. In both cases, prices can end up being higher than the marginal costs of all generating units producing power at a point in time. In analyzing the electricity market in California, it is critical to be able to distinguish between competitive market pricing and pricing that results from the exercise of market power. Two indicators clearly distinguish these possible market results and each leads to a distinct estimation technique.

1. In a competitive market, a firm is unable to take any action, including output decisions or offer prices, that will significantly affect the price in a market
2. In a competitive market, a firm is always willing to sell a unit of output so long as its cost of selling that unit is less than the price it receives for that unit. Its offer price will always be its marginal cost, which will be the greater of its marginal production cost or its opportunity cost of selling the power elsewhere.

While these two indicators can be stated clearly, it is more difficult to apply them using the available data. The first indicator suggests a method of estimation that involves studying the specific actions of the various firms in the markets. In particular, one can examine, the bidding and output decisions of each unit or firm in the market to detect successful attempts to manipulate prices. This is the general approach used by Wolak and Patrick (1996), Wolfram (1998), Wolak (1999), and Bushnell and Wolak (1999). The second indicator yields implications that can be tested by studying market-wide, rather than unit-specific behavior. As such, these tests are less vulnerable to the arguments of coincidence, bad luck, or ignorance that can be applied to the actions of a specific generator. In general, we test whether market prices are consistent with the hypothesis that the market as a whole is acting in a competitive manner. This approach is less informative about the specific manifestations of market power, but is effective for estimating its scope and severity. This is the approach used in Wolfram (1999), and the one that we adopt in this paper. A potential drawback of this approach is that it captures all inefficiencies in the market, some of which may not be due to market power. If, for instance, the ISO systematically held low-cost generators out of production simply due to a faulty dispatch algorithm, that would impact the estimate of market power. The California market clearly still has a number of design flaws that contribute to inefficient dispatch and market pricing. For the great majority of these, however, the flaw would be fairly benign if firms acted as pure price takers, rather than exploiting these design flaws to affect the market price. Still, the estimates must be taken with the caveat that they include failures to achieve competitive market prices for reasons other than market power, including bad judgment and confusion on the part of some generators or market-making institutions.

Lessons for future restructuring efforts

California's problems have occurred at a time when many other states are restructuring, or are debating the merits of restructuring, their electricity markets. The experience of California suggests several lessons for those states about both the supply and demand sides of electricity markets. In particular, if markets rather than regulation are to determine the price of power, prices must be allowed to respond when unanticipated disturbances occur—such as last year's very hot summer in the West. The supply and demand sides of the market together must be sufficiently robust to dampen such swings.

Supply-Side Lessons

The lessons for the supply side of the market are twofold. First, restructuring is more likely to succeed when more of the power in a market is free to respond to price signals. As California attempted to restructure, regulatory constraints limited the flow of power to the state's wholesale market from municipal utilities in California, from utilities in other states, and from federal power agencies. Second, utilities should be free to manage the risks of adverse price movements in that competitive environment by entering into long-term contracts. One lesson not to take from the California experience relates to the size of the reserve margin: building enough generating capacity to meet the demand for electricity under any scenario may not be cost-effective. If restructuring is to allow supply to be more responsive to prices by moving power within the market, it must also address regulatory barriers to the construction and operation of transmission systems. A restructured market that works well will probably feature an immediate increase in the demand for transmission services, as communities increasingly acquire power from new sources in new locations not envisioned by the original designers of the transmission grid.40 The regionwide costs of supplying electricity can drop if low-cost generators from some states in the region are able to provide more power than before. Moreover, the responsiveness of regionwide supply can improve if additional suppliers from part of the region are able to put more power into the grid to offset disruptions in supply locally or unexpected surges in demand elsewhere in the region. To realize those gains, however, consumers must be willing to accept a trade-off: the lower prices that result from access to out-of-state power supplies will sometimes rise when their state sends supplies to other parts of the region.

Any increase in the distance that power is transmitted will result in some additional transmission losses (about 9 percent of the electricity that leaves power plants is lost to heat transfer, which results from resistance in the power lines).

Making sure that transmission capacity does not limit the responsiveness of supply may require changing how transmission services are regulated and priced (to create appropriate incentives for new construction) and how new lines are approved. For example, some analysts have called for charging different, market-sensitive rates for transmission in different parts of the overall system—a practice known as node pricing—to provide greater incentives for construction to remove bottlenecks. The FERC believes that creating regional transmission organizations to operate large sections of the grid could help, too.[1]Restructuring is also more likely to be successful if utilities are allowed to use standard risk-management tools. Letting utilities both enter into long-term contracts with suppliers at fixed prices and hedge through the futures market would help protect them from the financial difficulties that have plagued California’s power distributors. It would also enable the utilities to offer greater price certainty to their customers (in place of a freeze on retail rates). That price certainty is important not just because it protects against high prices but because it creates a better climate for producers, distributors, and consumers. Having a large reserve of generating capacity could ease the transition from a regulated to a competitive market structure. Indeed, if California had implemented its plan in the early 1990s, when the state’s utilities still possessed more capacity than they needed, the market could have better handled the stresses that arose in the summer of 2000. That improved response could in turn have masked some of the faults of the restructuring plan. Creating such a reserve as a matter of policy, however, is an expensive way to ensure price stability. One of the reasons that the state moved to a competitive market structure was to help reduce electricity prices by lowering the costs of the utilities’ reserve capacity. In a competitive market, producers’ investment in reserve capacity should be consistent with the amount of price stability (or, equivalently, supply security) that consumers are willing to pay for in the form of long-term supply contracts.

[1] See Federal Energy Regulatory Commission

Demand-Side Lessons

California's freeze on retail rates inhibited the response of electricity users to the state's supply problems. Thus, it proved to be a major factor in the ensuing crisis. A simple lesson of that experience is that consumers need to face the real cost of electricity. Exposing consumers to price changes will induce them to increase their use of power when prices fall and curtail it when prices rise. When prices do not change along with costs, and when the amount of power demanded cannot respond to prices in that way, a greater adjustment must be made on the supply side of the market. Price signals should encourage consumers not only to buy more or less power now but also to invest in the ability to adjust their future power use. Some of the same demand responsiveness that results from having consumers pay market prices may also be achieved if utilities either compensate customers for reducing their use or allow customers to resell power to others (in which case, a third party is paying them to reduce their use). An important distinction exists between long- and short-term capabilities for lowering power use. In California, consumers have already responded over the years to high electricity prices by, among other things, adding thermal insulation to buildings, purchasing efficient appliances, and switching to natural gas. Those are longterm investments. Indeed, the state ranks among the lowest nationally in per capita use of electricity by households. However, electricity consumers—particularly households—have acquired few devices that would let them reduce electricity use on short notice, such as real-time meters (which would tell them when prices were changing), backup power supplies, or dual-fuel capabilities. One reason is that consumers do not usually face real-time prices (in particular, the full cost of generating electricity during peak-use times). Another reason is that although electricity prices in California have been high overall, they have historically been stable. Some analysts believe that the supply adjustments and resulting price increases in California would have been much smaller if various techniques to manage demand had been in wide use before restructuring.[1] For example, several approaches can make real-time pricing easier, such as technologies that monitor electricity use and prices, and contracting arrangements with electricity suppliers that permit the customer (or a designated agent) to interrupt service when the price rises. In many cases, large industrial customers already have the capacity to monitor and adjust their demand in the face of rising prices and, in fact, do so. Successful restructuring may necessitate that residential and commercial customers acquire many of the same demand-management capabilities that industrial consumers have.

Conclusion

The tidal wave that struck California's electricity sector from the summer of 2000 through the spring of 2001 was due to a specific combination of factors that befell California. Some common simplifying myths concerning the origins of the crisis do not stand up to scrutiny. It was not due to explosive demand growth in California. Demand was growing more slowly than it had in the 1980s and much more slowly than in neighboring states. Also, it was not caused by rampant "NIMBYism" preventing construction of new generating plants. The regulatory review process slowed plant construction, but new plants were being sited, funded, and built. Among the remaining factors, no single one fully explains the crisis. The fault cannot be pinned entirely on the shortage in generating capacity. Other states, such as New York, have experienced shortages without catastrophic consequences, and even in California, the worst of the crisis occurred during the winter of 2000–2001, when demand was low. Similarly, market manipulation by generators does not tell the whole story. There is strong evidence of the exercise of market power, but even if wholesale markets had been perfectly competitive, wholesale prices would have increased because of increases in input prices. In addition, blaming market players does not explain why they did not flex their

[1] See Stephen J. Rassenti, Vernon L. Smith, and Bart J. Wilson, Demand-Side Bidding Will Control Market Power, and Decrease the Level and Volatility of Prices

market power to the same degree before May 2000 and after June 2001. The flaws in the restructuring of the electricity sector cannot account for everything. The market, after all, worked reasonably well for the first two years of its operations, and many of the features that have been criticized, such as the retail price freeze, are common to other restructured markets that have performed better.

Although the division of regulatory authority between California and FERC led to catastrophic policy paralysis in response to the crisis, it cannot be blamed for the run-up in wholesale rates that instigated the crisis. Finally, inadequacies in the design of market institutions created greater opportunities for manipulation and impeded coordinated responses to emergency conditions, but such problems were not unique to California. The design of electricity markets is complex, and all efforts at restructuring have encountered unforeseen difficulties, requiring midcourse corrections. Given the uniqueness of California's experience and the large number of factors at play, it is not possible to fully disentangle the unique contribution of each factor and the interactions between them that led to blackouts, major financial crisis, and the systemic breakdown of market institutions. Some important conclusions can be offered nevertheless.

First, California's electricity sector was rocked by a number of factors unrelated to restructuring: the rise in national natural gas prices, higher costs for pollution permits, and a drought in the Northwest that reduced available imports of electricity. Even if the electricity sector had remained regulated, prices would have increased, and some blackouts would possibly have occurred between May 2000 and June 2001.

Second, market and regulatory conditions aligned, making a particularly ripe environment for the exercise of market power. The shortages in generating capacity played a critical role, increasing the bargaining strength of merchant generators and signaling the enormous profits that could be gained through supply shortages. At the same time, the excessive reliance on the spot market, constraints on transmission capacity, features of the market structure, and the division of regulatory authority all increased the opportunities and incentives for strategic manipulation of the markets.

Third, the exercise of market power fed back to exacerbate underlying problems. It increased the severity of shortages and appeared to interact with the natural gas market, driving up prices to unprecedented levels.

Fourth, increasing wholesale prices combined with the perilous risk exposure of the utilities to create a full-blown financial fiasco.

Finally, the division in regulatory authority and market structure impeded policymakers from developing a rapid, coordinated, and effective response before major damage was inflicted on the electricity sector, the California economy, and all Californians.

An important lesson from the crisis is that electricity systems are complex, interdependent systems. Decisions concerning generation, transmission, distribution, the delivery of energy sources such as gas, and consumption must be coordinated in real time at all times under tight constraints of reliability. The state of competition, market rules, and regulatory oversight interact in multiple and complex ways to coordinate actors, control market power, elicit investments, and send signals to consumers. Changes in certain elements of the system can have profound effects on other elements. Consequently, policymakers must be cautious in dealing with reforms in a piecemeal fashion.

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