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California's Electricity Market

A Post-Crisis Progress Report

By Carl Pechman

SUMMARY

In the 1990s, California led the nation in deregulating its electric utility industry. California's approach limited the role of the state's utilities and relied on new economic entities to provide service to customers. The result was a disaster. The state experienced an energy crisis during 2000 and 2001 characterized by extraordinarily high prices and blackouts.

After navigating the crisis, the state turned its attention to modifying the structure of regulation and the industry. The goal of this reregulation process has been to assure that the power system has adequate resources to provide reasonably priced power to the state's electricity customers while reducing greenhouse gases through reliance on conservation and renewable resources.

This issue of *California Economic Policy* provides a progress report on the state's post-crisis efforts to achieve these policy goals. The process of reforming the state's electricity markets is a work in progress. The state is once again taking a leading national role in balancing issues of customer needs and environmental goals through a combination of market and regulatory instruments. It is attempting to do this through a portfolio of supply and demand options that are designed to meet aggressive conservation, renewable energy, and greenhouse gas reduction goals. However, a number of issues remain unresolved. In particular, the state has yet to fully determine the role that markets will play in meeting environmental goals and consumers' electricity requirements.

Success is not guaranteed. The state needs to institute transparent and participatory procedures that monitor progress, report problems, and make adjustments in policies to meet its responsibility to protect both customers and the environment.

California Economic Policy *is a quarterly series analyzing and discussing policy issues affecting the California economy.*

Introduction

In May 2000, California entered a sustained period of extraordinarily high and volatile electricity prices and power system instability. California's electricity crisis lasted until June 2001 and imposed huge costs on the state's residents and businesses. Although the crisis was due to many factors, it is now clear that the way California had deregulated its power industry—with a heavy reliance on short-term markets—made it vulnerable to market manipulation. Since then, the state has become increasingly concerned about the need to meet its growing population's demand for electricity, given the failure of market-based approaches to provide new generation capacity. Policymakers have revised the state's regulatory agenda, adding longer-term strategies to encourage investments in capacity. In this post-crisis era, the state has become an active participant in resource planning, emphasizing the adoption of renewable energy sources and conservation.

California's electricity crisis has been called a perfect storm. Multiple contributing factors included a drought that reduced the level of hydroelectric power available to serve customers in the western United States, unexpected outages at nuclear power plants, high natural gas prices, and strong demand for power.

This issue of *California Economic Policy* provides a progress report on the state's post-crisis efforts and the steps taken to resolve problems associated with deregulation and the acquisition of adequate capacity, a process known as "resource adequacy" in the electricity industry. The state has labeled its new strategy a hybrid market approach, designed to "capture the best features of a vigorous, competitive wholesale energy market and renewed, positive regulation" (California Energy Commission, 2003, p. 1). In principle, a hybrid strategy would bring regulatory and market tools together in a way that maintains a safe, reliable, and affordable electricity system. Because the state's focus so far has been on regulatory tools, however, its commitment to employ market tools has not yet resulted in a fully developed program.

We first describe the steps California has taken in its post-crisis restructuring of the state's electricity industry, then we discuss the implementation of the new resource adequacy policies. Finally, we examine the potential role of markets in enabling the state to meet its energy goals.

Restructuring in the Wake of the Electricity Crisis

California's electricity crisis has been called a perfect storm. Multiple contributing factors included a drought that reduced the level of hydroelectric power available to serve customers in the western United States, unexpected outages at nuclear power plants, high natural gas prices, and strong demand for power (Weare, 2003; LECG, Inc., 2003). Some observers, such as William Hogan of Harvard, have argued that market fundamentals explain the high prices Californians faced during the crisis. Others have provided evidence that prices in California were manipulated through the exercise of market power (Joskow and Kahn, 2001, 2002; Sheffrin, 2002; Borenstein, Bushnell, and Wolak, 2002). The actual extent of market manipulation and its exact effect on price will probably never be known.[1]

Nevertheless, the crisis did demonstrate the importance of three metrics of market performance: price, reliability, and the financial health of market participants. As seen in Figure 1, prices were both high and extremely volatile during the crisis period. By its conclusion, the total cost of power purchases for the state's three investor-owned utilities—Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E)—had nearly quadrupled, from $7.4 billion in 1999 to $27 billion in 2000 and $26.7 billion in 2001 (California Energy Commission, 2002, p. 11).

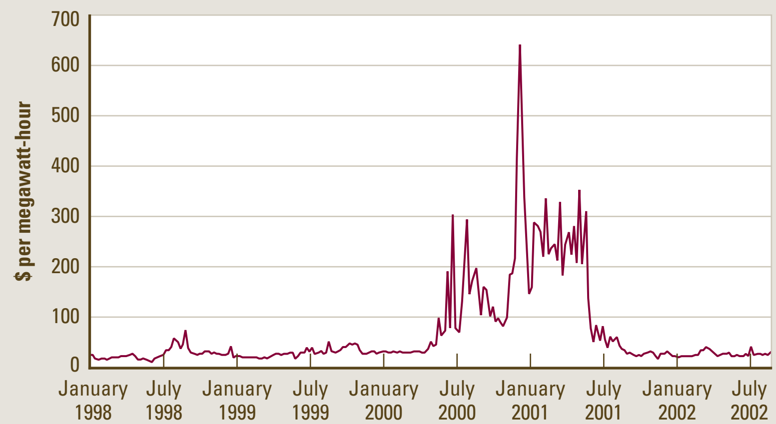
Reliability of supplies was also a significant factor. During the summer of 2000, there were shortages of available capacity needed to maintain the reliability of the power system. By January 2001, these shortages had become so severe that it was necessary to institute rolling blackouts to avoid larger and less controllable cascading blackouts. The depth of the crisis can also be measured by the number of power emergencies, defined by inadequate capacity, and shown in Figure 2. Before the crisis, in 1999, the power system experienced five power emergencies. In 2000, the number had increased to 92, and in 2001 to 173. In 2002, after western state price controls had been put in place, the system experienced only three emergencies (California Independent System Operator, 2003).

The spikes in market prices left the state's utilities in financial crisis. Both PG&E (which filed for bankruptcy protection) and SCE were left without the creditworthiness to continue acquiring power.[2] By the end of February 2001, PG&E had accumulated \$8.9 billion of wholesale power costs not covered by rates; the comparable figure for SCE was \$3.6 billion.[3] A number of the state's new competitive providers that had entered the market during deregulation also faced financial difficulties, among them Enron (bankrupt), Calpine Corporation (bankrupt), U.S. Generating Company (power generation operations liquidated in bankruptcy), Mirant Corporation (emerged from bankruptcy), and NRG Energy, Inc. (emerged from bankruptcy). Dynergy, Inc., the AES Corporation, Reliant Energy, Inc., and the Williams Companies all had severe financial difficulties as well.

The crisis abated after the Federal Energy Regulatory Commission (FERC)—the federal agency that regulates wholesale electricity markets—instituted a western state (including California and the states in the Southwest and Pacific Northwest) price cap in June 2001. By that time as well, many of the market fundamentals, such as natural gas prices, had moved back to their pre-crisis levels. In addition, the state had entered into long-term contracts to purchase power, adding some market stability.

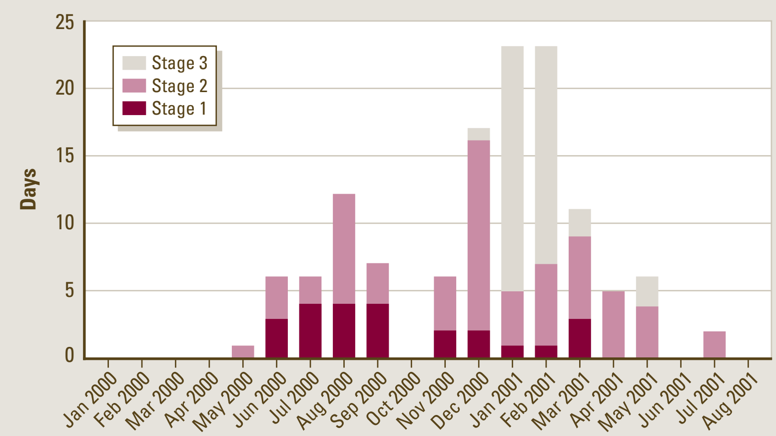
Once the immediate crisis ended, the state moved from short-run tactics to keep the lights on to longer-term strategies that would encourage resource acquisition. Among these were steps

Figure 1. Weekly Average On-Peak Prices in West Coast Spot Markets, 1998–2002



Source: Author's calculations using data from *Energy Reports*.

Figure 2. Staged Power Emergencies in California, 2000–2001



Source: Nichols (2001).

to recreate a regulatory structure, which in turn meant

- reestablishing utility obligations to provide adequate service;
- specifying policy directions on resource choice;
- developing a new process for utility resource procurement, including the preapproval of utility plans for acquiring power; and
- creating a reinvigorated role for planning.

We discuss the status of each of these reforms. It is worth noting that the new regulatory model is a work in progress. The two lead regulatory agencies—the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC)—have engaged stakeholders (representatives of residential, commercial, and industrial customers as well as environmental groups) to review regulatory activities on an ongoing basis. These consultations will no doubt lead to further adjustments. As a result, this overview is necessarily a snapshot of the current state of affairs in mid-2006.

Reestablishing Utility Obligations

An important component of post-crisis recovery was legislation encapsulated in Assembly Bill (AB) 57. During the electricity crisis, when SCE's and PG&E's financial problems had made it impossible for them to buy electricity on the market, the state stepped in. The California Department of Water and Resources (DWR) spent approximately $10.7 billion to purchase power to meet California's daily power needs and entered into 52 long-term purchase power contracts with a nominal value of $42.9 billion (California State Auditor, 2003). These contracts committed the state to purchase a significant amount of California's projected needs over the following decade (Figure 3). They also gave the state some breathing room to get the utilities back in the business of planning and procuring power for their customers. AB 57 was designed to continue that effort and to get the state out of the business of buying power for them.

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To some extent, AB 57 returned utility obligations to their pre-deregulation status. Before deregulation, utilities maintained system reliability by investing, maintaining, and coordinating adequate resources to provide service to all customers within their franchise boundaries. A major objective of deregulation had been to allow customers to choose their provider of electricity, on the theory that competition would force down prices. Advocates of choice argued that the traditional utility role of guaranteeing service conflicted with the provision of choice. Therefore, a deregulated market that provided choice required a fundamental change in the way utilities did business.

The vision of the utility in a deregulated environment was that of a "pipes and wires" company responsible for the delivery, but not the provision, of power. A parallel can be drawn to the deregulated market for telephone services, in which the pipes and wires company is equivalent to the local telephone companies, and the new competitive energy companies (also known as "energy service providers") are like long-distance carriers that transact with customers over the local telephone companies' infrastructure. Customers who did not choose to go with the new competitors would continue to receive, by default, energy services through the local utility.

The utilities were required to divest a substantial portion of their generation capacity, to allay concerns that they would self-deal and make it difficult for new retail providers to compete. The utilities' role of providing reliable service by operating the electricity system was transferred to two new institutions, the California Power Exchange (PX) and the California Independent System Operator (CAISO), which ran spot electricity markets (the PX for "day-ahead" purchases and the CAISO for "real-time" purchases).[4]

The utilities were obligated to purchase electricity through these spot markets. Again, the purpose was to protect fledgling retail power providers from the utilities' market dominance.[5] The unintended consequence, however, was to keep the utilities from entering into long-term contracts that provide a hedge against market price increases. Between 50 and 60 percent of customers' energy needs were acquired in unhedged spot markets at the market-clearing price.[6] When California's spot market became volatile, this high level of exposure produced the unprecedented electricity cost increases and resulting utility revenue shortfalls.

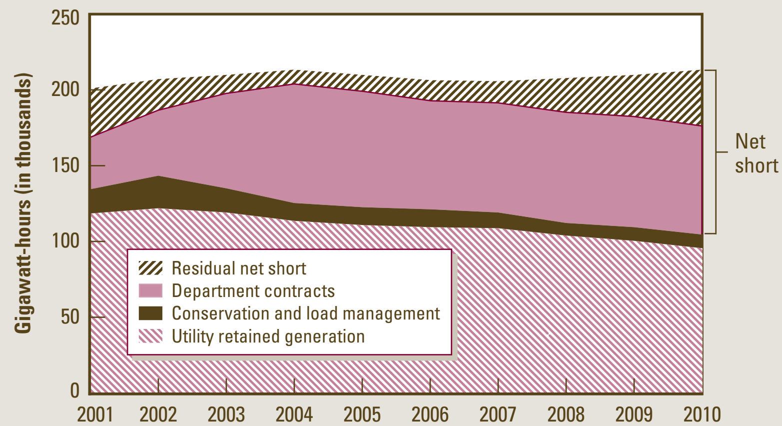
The new, post-crisis CPUC regulations require that the utilities limit the amount of power they purchase in the spot market and acquire minimum amounts through forward procurement. In 2002, the commission set a 5 percent limit on spot purchases (California Public Utilities Commission, 2002a). In 2004, it required that utilities forward-contract 90 percent of their expected resource requirements for that summer (May through September) (California Public Utilities Commission, 2004b). As of May 2006, utilities and other power providers (also known as "load-serving entities")[7] were required to demonstrate that they had acquired 100 percent of their forecast peak needs, plus a cushion of 15 to 17 percent. These "resource adequacy requirements" are now the state's key tool for encouraging the acquisition of capacity.

The time horizon and scope of the utility procurement plans have also expanded rapidly since the end of the crisis, beginning with one-year procurement plans and quickly expanding to five- and now ten-year planning horizons. These plans are subject to confidential review by the CPUC and representatives of interested parties and stakeholder groups.

Policy Directives on Resource Choice

The CPUC reviews and preapproves procurement plans using the state's new loading order priorities, which reflect the post-crisis emphasis on conservation and on renewable power sources such as solar, wind, and geothermal. Senate Bill (SB) 1078, passed in 2002, established a renewable portfolio standard and set a goal of renewable generation for 20 percent of the state's requirements by 2020. It also established a structure for accounting and acquisition of renewables. The legislation anticipated that renewable energy would generate "diversity, reliability, public health and environmental benefits" (SB 1078, Article 16, 399.11 (a)). It implicitly acknowledged that these benefits—most of which are not reflected in market prices—would lead to higher costs of energy procurement.

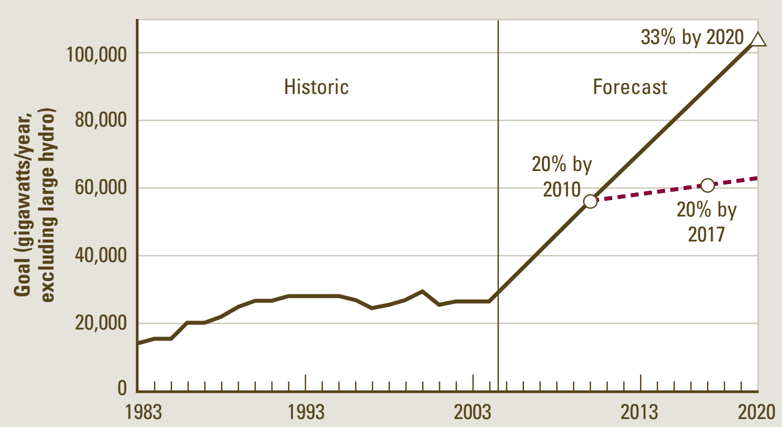
Figure 3. Forecasted Annual Net-Short Energy Position for California, 2001–2010



Source: California State Auditor (2001).

The CPUC and CEC, working together with shared authority, have issued two Energy Action Plans since this legislation. The first, in 2003, established the loading order that prioritized the acquisition of resources to reflect the state's new preferences for capacity acquisition (California Energy Commission, 2003). It also accelerated SB 1078's renewable portfolio standards goal, moving the 20 percent goal up to 2010. SB 107, signed into law in September 2006, formally adopts this accelerated goal. Governor Schwarzenegger has proposed an even more ambitious goal of 33 percent of renewable electricity sales by 2020 (Schwarzenegger, 2005b). The second Energy Action Plan identified the steps necessary to implement the governor's goal. As Figure 4 shows, a significant growth in renewable capacity will be needed to meet either of these higher goals.

Figure 4. California’s Renewable Energy Historic Production and Future Goals, 1983–2020



Source: California Energy Commission (2005b).

Conservation through improved efficiency was already an important part of the state’s energy policy before deregulation, and California was one of the most energy-efficient states in the country.

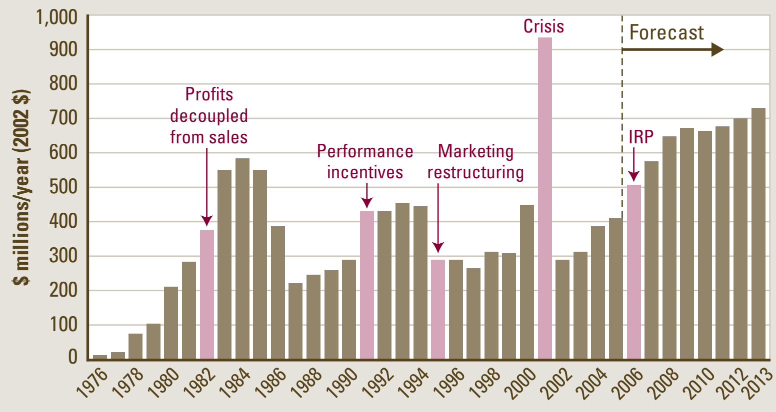
The loading order prioritizes the acquisition of different types of energy resources. The first priority is to rely on energy conservation to minimize increases in electricity and natural gas demand. The second priority is to fill new generation needs with a combination of renewable energy resources and distributed generation. Distributed generation is small-scale generation, typically on a customer’s property—such as solar roof panels—which reduces the amount of power bought from the utility. The third preferred resource is clean fossil-fuel-based generation, such as natural gas. The loading order requires that this third priority be used only if conservation, renewable sources, and distributed power are insufficient to meet forecast needs.

Conservation through improved efficiency was already an important part of the state’s energy policy before deregulation, and California was one of the most energy-efficient states in the country. As shown in Figure 5, investments in conservation are expected to grow in importance. The CPUC has adopted a goal that 55 to 59 percent of the state’s incremental electricity needs between 2004 and 2013 be met through increased energy efficiency, and it has increased resource funding for utility implementation of consumer conservation programs (California Public Utilities Commission, 2004a, p. 20).

The first priority of the loading order—to optimize energy conservation and resource efficiency—also recognizes the importance of another type of demand-side measure known as “demand response.” During periods of shortages, when prices are high, customers who are aware of these prices and able to reduce electricity-consuming activities will do so, thereby reducing demand. Demand response can mitigate the exercise of market power by generators and improve the reliability of the power system. Demand response requires a system to communicate prices from the power system to the customer and to record the customers’ electricity use in a way that matches the time of consumption with the market price.[8] Advanced electronic meters have both communication and data-recording capabilities to support this type of pricing program. The California Public Utilities Commission (2003a) has adopted ambitious demand response goals: By 2007, the system should be able to exercise a 5 percent reduction in demand (or “load”) whenever it is needed.

Since the preparation of the second Energy Action Plan, Governor Schwarzenegger has also established new goals for greenhouse gas (GHG) emissions, announcing in an executive order (Schwarzenegger, 2005a) that his goal is “by 2010, [to] reduce GHG emissions to 2000 levels; by 2020, reduce GHG emissions to 1990 levels; by 2050, reduce GHG emissions to 80 percent below 1990 levels.” The goal of achieving 1990 GHG emission levels by 2020 was subsequently incorporated into law when the state legislature passed, and the governor signed, AB 32 in September 2006. AB 32 also authorizes the state Air Resources Board to adopt market-based mechanisms to achieve the specified emission requirements. SB 1368, signed into law at the same time, requires that the CPUC and the Air Resources Board establish GHG emission performance standards for all base-load generation. This strategy increases the importance of both renewables and conservation efforts. A recent study led by Hanemann and Farrell (2006) evaluated the economic effect of the governor's greenhouse gas initiatives. Their study concluded that the 2020 goals can be met at moderate costs and recommended policies to promote innovation as a way of meeting the 2050 goals more efficiently.

Figure 5. California's Investment in Energy Efficiency, 1976–2013



Source: California Public Utilities Commission (2004a).
Note: IRP = integrated resource plan.

Reforming the Utility Procurement Process

In addition to restoring responsibility to the utilities for maintaining system reliability, AB 57 placed new responsibilities on the CPUC. The commission is now required to review and approve utility energy procurement plans, establish policies and cost-recovery mechanisms for energy procurement, ensure that the utilities maintain an adequate reserve requirement, and implement a long-term resource planning process. The first Energy Action Plan calls this new proactive role in utility planning and procurement "positive regulation."[9]

This relationship is particularly important with respect to the acquisition of capacity, given the significant investments and commitments that utilities must make. In the new system, the CPUC preapproves these decisions, rather than making after-the-fact judgments on whether the investments were prudent. (Such "prudence reviews," which evaluate the reasonableness of utility decisions, are the traditional way to determine whether rate increases are warranted in regulated utilities.) This change in timing reduces the utility's risk that some of the expenditures incurred will be disallowed, in which case the utility is unable to recover its costs from its ratepayers.

Under this new regulatory regime, the CPUC does not give up its review of how well the utility implemented the procurement plan (for example, it might decide that building a power plant is prudent but will still be able to disallow recovery of imprudent cost overruns through rates). But preapproval of procurement and investment plans reduces disincentives, and may even increase incentives, for utilities to take the appropriate risks in building their energy portfolios. For instance, in a preapproval system, utilities will not be penalized if spot prices end up being lower than contract prices, as long as the information available in the planning stage supported the use of forward contracts. Preapproval can thereby help utilities to balance various short- and long-term risks.

Reinvigorating the Role of Planning

Planning, abandoned during deregulation, is back. There are now multiple planning processes being coordinated among the utilities, CAISO, CEC, CPUC, and the Western Electric Coordinating Council, with input from interested parties. The orientation of planning has also been expanded. Historically, planning was narrowly focused on minimizing the cost of meeting customers' expected needs, without specifying which energy sources should be used. Consistent with the state's new policy goals, planning now focuses on the development of a broader portfolio

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of resources, to encourage the development of generation powered by renewable resources and load reductions through conservation and demand response. In effect, the goal is now to create a portfolio of resource options, not just to pick a single winning option—as natural gas-fired generation has been for much of the last decade. This new approach also recognizes that some important goals are not reflected in market prices, such as the environmental and public health benefits of renewable resources and demand-side efforts.

Although California has met its renewable energy targets so far, significant increases in renewable output will be required if the state is to continue meeting targets over the years ahead.

Implementing the Resource Adequacy Requirement

California's new regulatory system has set some ambitious goals for the electricity sector: Utilities and other power providers must meet strict standards of forward contracting to ensure reliability for their customers, and they must create a supply portfolio that relies more heavily on renewable resources, conservation, and demand management. With the new preapproval process for power acquisition, regulators in turn are playing a more proactive but also potentially riskier role. With preapproval, the regulatory process can lose critical oversight activities by giving up the ability to second-guess utility decisions and to lower rates in the event that those actions were found to be imprudent.

Some early indicators suggest that the new system is paying off in terms of capacity acquisition. As of mid-2005, the state's utilities had signed about 80 contracts for power deliveries beginning in 2004 or later.[10] In addition, the utilities are once again developing and purchasing generating units.[11] However, some important questions remain concerning the implementation of these new resource adequacy requirements. First, what are some of the key considerations in the state's renewable energy policy? Second, what challenges are posed by the new policy to encourage greater demand responsiveness? And, finally, what criteria can the state use to gauge whether resource adequacy goals are being met?

The Renewable Portfolio Standard

When the legislature created the renewable portfolio standard for California in SB 1078, it envisioned an annual competitive procurement process for new renewable energy sources. The energy generated by renewable sources will be used to meet customers' needs in place of energy from conventional sources (such as natural gas and coal-fired facilities). The CPUC adopted a "least-cost best-fit" process, a central element of which is the "market price referent"—an estimate of the price of conventional generation displaced by renewables (California Public Utilities Commission, 2004d). The market price referent is used to rank renewable projects, and it acts as a benchmark price to determine the level of public funds required to cover the above-market costs of procuring renewable energy.[12]

Offers from generators of renewable energy are first ranked based on the costs of generation only. In a second ranking, bids are reordered based on a more comprehensive set of costs, including that of integration (the cost of including the renewable resource in system operation). For example, with wind turbines, the system must compensate for changes in wind conditions by changing the operating levels of other generating units. This also includes transmission costs, if new transmission lines are required to use renewable resources situated in remote locations.

California's renewables policy explicitly recognizes the potential need for subsidies. The subsidy level, known as the supplemental energy payment, is set as the difference between the market price referent and the offer price and is funded through a public goods charge on customers' bills. Once the supplemental energy payment funds are depleted in any given procurement cycle, the utilities are considered to have fulfilled their renewable portfolio standard obligation, even if the level of renewables falls short of the established targets.

Although California has met its renewable energy targets so far, significant increases in renewable output will be required if the state is to continue meeting targets over the years ahead (Figure 4). Going forward, an important question is how much the renewable portfolio standard will cost. Contracts for renewables entered into by SCE and PG&E in 2005 were all priced below the 2005 market price referent of approximately $60 per megawatt-hour (MWh), and hence required no subsidies (Freedman, 2005). However, without significant technological change, the cost of renewables can be expected to increase because the cheapest sources are being used first.

The Center for Resource Solutions (2005) prepared an analysis for achieving a 33 percent renewable energy target—in line with Governor Schwarzenegger's goal—that provides insight into the relative cost of different types of renewable generation and the expected mix of a renewable resource portfolio for the state (see the table).

Renewable Cost and Portfolio Assumptions

Resource	Resource Cost ($/MWh)	Renewable Resource Portfolio (%)
Wind	66	50
Geothermal	86	30
Biomass	78	10
Solar[a]	120	10

Source: Center for Resource Solutions (2005).
[a] The estimated cost of solar is based on concentrating solar technology. The cost of photovoltaic cells was reported as $200/MWh.

The report's findings demonstrated that two key variables—the price of natural gas and the cost of developing renewables—will determine the ultimate cost of renewables for California's ratepayers. Gas is critical for determining the cost of renewables. As a general rule, natural gas is the fuel supplying the marginal units in California; it therefore determines the market price referent used to determine subsidies.

Promoting Efficient Consumption

As noted above, the new regulatory policy also sets ambitious goals for improved demand response—i.e., reductions in demand. One factor that exacerbated the electricity crisis was the inefficiency of the retail pricing system. In an efficient market, the marginal value of customers' consumption would be equal to the spot-market price. Customers would respond to high market prices by reducing their demand. During the crisis, the pricing system in place was incapable of sending the relevant price signal to customers. Utilities were buying wholesale power at prices in the hundreds of dollars per MWh, while most retail customers were paying prices based on the pre-crisis generation cost of $67.45 (California Public Utilities Commission, 1997). Consumption decisions were inefficient, and the difference between the wholesale and retail prices for energy resulted in the utility insolvency and bankruptcy that customers will be paying off through higher rates for years to come.

In an efficient market, the marginal value of customers' consumption would be equal to the spot-market price. Customers would respond to high market prices by reducing their demand. During the crisis, the pricing system in place was incapable of sending the relevant price signal to customers.

Demand response did contribute to ending the crisis, but it was based on public relations strategies rather than on price signals. Proper price signals would have increased the amount of demand response.

California's power providers have fallen behind the CPUC's targets for demand response—the ability to exercise a 5 percent load reduction by 2007. Governor Schwarzenegger has recognized that the state has not met its goals, and he has argued for an increase in the priority of demand-response programs.

In a 2005 report, the CPUC identified a number of reasons for the slow development of demand response (California Public Utilities Commission, 2005b), and the CPUC and CEC are now pursuing remedies. In particular, the report identified problems of measurement and evaluation. Given the lack of a track record for demand response, there is uncertainty about how to treat demand-response resources for planning and for meeting resource

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adequacy standards. The state has begun to improve analytical methods for evaluating demand response.

Another impediment to more rapid development is the lack of availability of an appropriate price signal, a concern even if advanced meters are installed. From a practical standpoint, this price signal mechanism must convey system conditions to customers early enough for them to respond. Typically, this is considered to be equivalent to the day-ahead price that the California Power Exchange had produced until it went bankrupt in 2001. The CAISO market redesign described below will create a day-ahead price signal that can be used in demand-response programs.

While the CPUC is resolving some of the regulatory issues surrounding demand response, the state's utilities are increasing their solicitations to customers willing to participate in demand-response programs. The significant deployment of advanced meters, combined with the increased availability of price signals from the CAISO, should enhance the ability to meet the state's goals.

However, in rolling out the advanced metering programs, both the utilities and the CPUC should remain vigilant to ensure that customers benefit from those investments. A recent study by PG&E highlights the issues at stake (McNicoll and Berman, 2006). The utility estimates the cost of implementing advanced metering at $2.265 billion, whereas the benefits were only slightly higher, at $2.362 billion, for an overall benefit-to-cost ratio of only 1.04. Approximately half of the benefit comes from automating the meter-reading process and displacing or eliminating the jobs of meter readers. With such a small expected benefit from such a large expenditure, caution and careful monitoring of costs in the rollout is warranted.

Criteria for Determining Resource Adequacy

The resource adequacy requirement in place since May 2006 obliges utilities and other power providers to demonstrate that they have acquired 100 percent of their forecast peak needs, plus a cushion (called the installed reserve or planning reserve margin) of 15 to 17 percent. When the CPUC set this planning reserve margin, it acknowledged the tradeoff between costs and levels of reserve. It was concerned that requiring a higher cushion might be inconsistent with the goal of increasing the share of conservation and renewable resources in the energy portfolio (California Public Utilities Commission, 2004b). In this sense, California's level of required reserves is somewhat ad hoc. Unlike many other power systems, California has not based its reserve margin on a calculation of the amount of generation required to meet preset reliability criteria. The state should continue to reexamine the planning reserve targets, in particular as the broad range of resources required by the loading order is incorporated into the capacity mix.

More generally, the state needs to monitor progress toward meeting its resource adequacy goals using the three metrics discussed above: price, reliability, and the financial health of market participants. The amount of capacity that counts toward meeting resource adequacy goals needs to be tracked in a transparent and public manner. One way to do this is to make publicly available a load and capacity table, showing expected trends in demand and new generation resources. Uncertainties associated with the resources in the table should be explicitly identified. Such a table can also be used for sensitivity analysis—assessing how well the state is meeting its resource adequacy goals using different assumptions of the probability of success of different additions. The state should also provide, or require the utilities to provide, forecasts of future electricity prices. Utilities should also demonstrate how their pursuit of state policy goals will affect the expected price. Finally, the state should monitor the financial condition not only of the utilities but of various other power suppliers in the market. If suppliers cannot remain creditworthy under the state's resource adequacy policies, then the state will need to rethink the provision of resources to customers.

The Role of the Market

After California's disastrous experiment with competition, a central question for the state is: What role will markets play in its electricity future? In the state's new hybrid market model, the aim is to combine competitive markets and regulation (California Energy Commission, 2003, p. 1). To date, many of the questions about the market component of this mix have yet to be answered, such as when (or whether) retail competition will resume, and which types and quantities of energy resources will be provided in the market. Four markets could help the state achieve its long-term policy goals. One is the spot wholesale market for electric energy. Declared "dysfunctional" by FERC during the crisis, it is now on the mend. The others are the capacity market, a greenhouse gas allowance market, and the market for renewable energy credits.

The Spot Electricity Market

CAISO continues to operate the wholesale spot market for electricity in California. Although reducing the number of spot-market transactions is one goal of the new resource adequacy requirements, the spot wholesale price produced by CAISO is still a critical element. It helps to rationalize the adoption of renewable resources, because the market price referent reflects an expectation of CAISO prices. Similarly, forward prices used in long-term contracting represent the market's risk-adjusted expectation of CAISO prices.

CAISO is in the process of restructuring the spot electricity market, in part to incorporate the functions previously assigned to the PX. This includes reintroduction of a formal market for day-ahead scheduling, which will improve price signals for demand-response programs. CAISO is also adopting software to improve monitoring of the physical system to improve the incorporation of renewable resources, advanced metering, and demand response. The restructured market should be fully operational by 2007.

Capacity Markets

Although demand-side tools are an important part of the state's new resource strategy, developing new capacity is also an essential goal. A particular type of market mechanism—a capacity market—is one tool for providing incentives to developers of new capacity. Because these markets are relatively new, there is more information about their design than about their performance. Four capacity market design proposals are germane to this discussion: New York's Demand Curve, the New England Independent System Operator's (NEISO) Locational Installed Capacity (LICAP) proposal, the Pennsylvania–New Jersey–Maryland ISO's Reliability Pricing Model (RPM), and the New England Forward Capacity Market (FCM), which supplanted the NEISO LICAP proposal. Of the four, only the New York system is operational, but there has yet to be any new power generation built based on it. New England's FCM has now been approved by the FERC. The RPM is still under review at the FERC, with action expected by the end of 2006.

Although demand-side tools are an important part of the state's new resource strategy, developing new capacity is also an essential goal.

The Rationale for a Capacity Market

In electricity markets, there is a concern that when the market price is limited by price regulation, energy revenues alone are insufficient to support the addition of new generation (Joskow, 2005; Hogan, 2005; Federal Energy Regulatory Commission, 2006). This shortfall occurs because payments based on competitive energy prices do not provide sufficient revenues to pay for both the fuel costs of a new power plant and the capital cost of the plant. This has been labeled the "missing-money" problem[13] and has traditionally been solved by a combination of utility ownership of generating capacity, long-term contracts, and customer rates based on average rather than marginal costs.

Other options are available for dealing with the missing money. Hogan (2005) argues that in an energy-only market (i.e., a system in which all energy is acquired on the spot market) without price caps, prices could rise sufficiently during shortage periods so that there would be no missing money in the long run. Unfortunately, it is exactly during those periods that power generators are also most able to exercise market power. Bushnell (2005) points out that there is a reluctance to adopt the energy-only market because of fears of increased market power and price risk. An alternative is to provide generators with a side payment. In power markets, this side payment is called a capacity payment and is provided for in a capacity market.

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Design Lessons

New York's Demand Curve, established in 2003, was designed to replace that state's initial capacity market design, which suffered from a high degree of volatility.[14] The concept behind this system is an application of classic peak load pricing theory. When the system has just the right amount of capacity to meet reserve margin requirements, the power company would be paid the cost of new entry, in addition to the marginal value of the energy it produced, and there would be no missing money. (The cost of new entry is typically measured as the capital costs of building a "peaker"—a generating plant with low capital but high operating costs).[15] Any additional capacity would have diminishing value and reduce the price below the cost of the new entry. Similarly, shortages of capacity drive up the value of additional capacity. This relationship is reflected in Figure 6. During periods of extreme shortage, the price of capacity is capped at two times the annualized cost of the peaker. At the target level of capacity (118% of peak load), the price on the demand curve is equal to the annualized cost of a peaker, and from there the price declines linearly to zero at the maximum level of capacity at which power generators will be paid (132% of peak load). In the example in Figure 6, the market clearing price ($58 per kilowatt (kW)-year) is below the annualized cost of a peaker ($68 per kW-year), because the amount of capacity exceeds the target level of capacity.

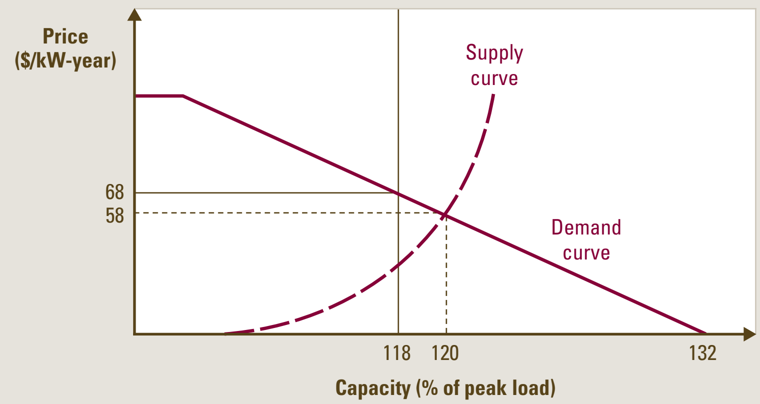
The New England LICAP and Pennsylvania–New Jersey–Maryland RPM approaches are also variants of the demand-curve model. The development of each of these curves requires an administrative determination of how fast the price should decline, at what point the price should be zero, what price should be considered the cap, whether the demand curve should be represented by a straight line, and, if not, where any kinks in the curve should be located. Power generators provide offers to sell capacity at different prices, and the ISO ranks those offers against the demand curve to determine the amount and price of capacity that it procures.

The New York demand curve and the New England LICAP are both designed to procure capacity for short-term commitments of less than a year. The underlying theory behind these approaches is that the short-term price signal will encourage long-term investment. However, given the practical constraints on building new capacity, only power plants that are already built can participate in these short-term supply auctions. Therefore, the mechanism design does not enable market discipline to be exerted by potential new entrants. Meehan et al. (2003) suggested a solution to this problem—allowing generation that has not been built to compete directly with existing generators.

The Pennsylvania–New Jersey–Maryland RPM and the New England Forward Capacity Market are both designed to enable new generation to compete with existing generation. A forward-looking capacity product facilitates competitive entry by creating a lag between the time of the auction and the commitment period. The idea is to allow enough time to develop new generation. New England adopted a three-year lag between the auction date and the start of the commitment period, and the Pennsylvania–New Jersey–Maryland system uses a four-year lag.

The two systems operate in a different manner, however. The RPM is essentially a multiyear demand curve, where the amount of capacity procured is determined by the shape of the demand curve and the offers by suppliers.[16] In contrast, the FCM establishes a fixed capacity requirement, and a multiround descending clock auction is held to determine the transaction price of capacity. The starting price is set at a level sufficient to elicit more than the required amount of capacity. When the ISO receives offers for more than it requires, it lowers the price incrementally until it has the amount of capacity that it desires.

Figure 6. The New York Demand Curve



Source: Federal Energy Regulatory Commission (2003).
Note: Prices are illustrative.

Incentives to Perform

Capacity market proposals differ significantly in the incentives and obligations for generators to perform when needed. In New York, when a generator receives a capacity payment, it must offer to sell its energy to the New York ISO when available, but there are no specific requirements regarding availability during times of system stress. Similarly, in the proposed Pennsylvania–New Jersey–Maryland system, there is no direct penalty if the generator's power is not available during peak system requirements. Yet the generator's source of value to system reliability is precisely its availability during such periods of system stress. Price incentives (or penalties) directly matched to delivery performance are therefore an important tool in these markets. Failure to include such tools misaligns the generators' incentives with the system's needs.

New England's FCM proposal builds on the LICAP proposal by calling for the loss of capacity payments if power is not available during a shortage event. The shortage events capture hours when capacity resources are determined to be most needed due to conditions on the power system. On days when the system identifies shortage events, a generator that is not available can have its payment reduced by up to 10 percent of its annual capacity payment. This type of mechanism provides an incentive for generators to be available.

An alternative approach, proposed by Bidwell (2005), is the Reliability Option (RO). The RO is a call option with both physical and financial characteristics. The RO has financial characteristics in that it is a call option triggered by a strike price. This strike price is indexed on a visible and easily attainable fuel price index and is announced by the ISO at the beginning of each day. The RO has physical characteristics in that it is associated with a specific plant that will be penalized if it is either not generating or not available as a reserve when the spot price exceeds the strike price. An additional cost per kW-hour is imposed for nonavailability at a time of system stress when reserves are deficient. Generators must perform when called on or bear the financial consequences—paying for the power to replace the failed generation at real-time market prices, plus a penalty. The RO thereby makes generation withholding an uneconomic activity.

Capacity market proposals differ significantly in the incentives and obligations for generators to perform when needed.

Capacity Market Considerations in California

CPUC staff have prepared an evaluation of capacity markets and assessed how development of such a market in California could contribute to the state's resource adequacy objectives (California Public Utilities Commission, 2005a). This paper acknowledges that capacity markets are a way to resolve the missing-money problem while facilitating retail choice, and it highlights a number of ways that capacity markets could "complement and aid in the effectiveness of the Commission's Resource Adequacy program." The Bilateral Trading Group (2006) has called for the development of bilateral markets as opposed to central capacity markets, such as those being developed in the east.[17] Bilateral markets are private markets that involve trades among individual market participants. It is important to note that this group has called for "standardized, tradable capacity products and price transparency." The CPUC should investigate the advantages and disadvantages of bilateral versus central markets in achieving the state's resource adequacy needs.

The appropriate design of a capacity market for California depends on the role that the state expects the market to perform. If the market is a residual one—designed only to procure supply above and beyond what utilities are required to provide as part of their procurement plans—then it will tend to be a short-term market. If, instead, the state is interested in using the market as a vehicle for supporting new investment, then the market needs to be a longer-term one. In either case, the state should carefully consider the importance of power availability during periods of system stress to assure that consumers are receiving the reliability benefits that they are paying for.

Unlike electricity, which cannot be stored, renewable energy credits are bankable—allowing buyers to stock credits and use them later.

Greenhouse Gas Markets

AB 32 establishes a target for greenhouse gas emissions and allows the state Air Resources Board to use market mechanisms to help achieve those reductions. Trading the right to pollute is a relatively recent environmental policy instrument. Traditional air quality regulation involved command and control measures. Power plants had mandated pollution control equipment and emission rates. The advantage of market mechanisms is that they allow firms to reduce the cost of achieving emission reduction targets. Markets have been used to minimize the cost of achieving both sulfur and nitrogen emissions. Now there is a great deal of interest in using markets to reduce GHG emissions.

A number of important issues face California in the development of a GHG market. The first step, recognized by AB 32, is to create an inventory of emissions. Existing generators will be allocated GHG credits that they will be able to sell if it reduces GHG emissions. The state will need to determine how it will count carbon emission reductions or carbon sequestration outside California toward the achievement of its emission reduction targets. An additional issue is how a market created within California will be integrated into the global GHG market as it develops.

Renewable Energy Credits

The second Energy Action Plan called for the implementation of a renewable energy credit (REC) trading system. RECs are a mechanism that could facilitate the adoption of renewable energy in California. They represent the value of environmental benefits associated with the generation of renewable resources—i.e., the incremental cost of renewables relative to traditional energy sources. A market in RECs would serve two purposes. First, it would reduce utilities' costs of meeting their renewable portfolio standards, because they could support the production of renewables without actually having to take ownership or delivery of the energy (California Public Utilities Commission, 2006b). Second, it would provide a source of revenue for renewable electricity generators. Because many renewable energy sources are location-specific and have variable output levels, such a market could provide valuable flexibility to California in implementing its renewable portfolio goals.

Unlike electricity, which cannot be stored, renewable energy credits are bankable—allowing buyers to stock credits and use them later (Hamrin and Wingate, 2003). Setting up an REC market requires a tracking system. In 2002, the Western Governor's Association adopted a resolution supporting the creation of an independent regional renewables tracking system, the Western Renewable Energy Generation Information System (WREGIS). This system is being designed to facilitate the tracking and development of REC markets (California Energy Commission, 2003). The CEC is now leading the development of the WREGIS in cooperation with the association and with input from stakeholders.[18]

The CPUC (2006c) has initiated a proceeding to explore the use of unbundled or tradable RECs for compliance with the renewable portfolio standards. The focal point of the proceeding is a CPUC staff report on RECs (California Public Utilities Commission, 2006b), which seeks to build on the experience of other states including Nevada, New Mexico, and Texas that have already developed systems for using RECs. It raises a number of important concerns about the implementation of RECs, such as the contract length, their effect on the supplemental energy payments to renewable generators, and the prospect of double-counting.

Although markets in renewable energy credits, greenhouse gas emission credits, and capacity are distinct instruments, there is an important interaction among them. RECs would provide generators with additional revenues. GHG markets can increase either revenues or costs depending on whether a power plant is able to reduce its GHG emissions below the level allowed by its inventory of credits or whether it needs to purchase credits to allow it to emit GHGs. These revenues would likely affect the prices at which capacity is offered. It is therefore important for the CPUC to address whether coordination between these three markets could make them more efficient.

Conclusions

California has learned some harsh lessons about the costs of inefficient market design. An efficient market requires price transparency, a diverse energy portfolio, the ability to encourage demand response with price signals, and clear obligations for acquiring power resources. The state has responded to those lessons by creating a hybrid market structure that seeks to benefit from the best that a combination of competition and regulation have to offer. To date, the principal focus has been to assure that there are adequate resources to meet electricity customers' needs, while achieving ambitious environmental objectives. California's utilities are once again procuring power, owning power plants, and planning for future needs. In addition, the redesign of the spot wholesale market operated by CAISO should create new efficiency-enhancing market mechanisms (such as real-time pricing) when it is operational in 2007.

The state has established ambitious conservation and renewable resource objectives through the adoption of a loading order that prioritizes these resources over traditional power sources. In addition, state law now requires a reduction in GHG levels and the imposition of GHG performance standards on generation. Because the cost and success of pursuing these goals are uncertain, however, tracking and evaluating progress are essential.

State policy also recognizes the importance of demand responsiveness as a tool for managing reliability and the cost of the power system during times of shortage. Getting the correct demand response is difficult, and the state has lagged in meeting its objectives. As California goes forward in this area, there will be a need to assess impediments continually and to overcome them. Moreover, devotion to demand responsiveness should not be pursued at any cost. The state must be vigilant in its monitoring of costs and adjust its goals as it receives new information.

Although markets in renewable energy credits, greenhouse gas emission credits, and capacity are distinct instruments, there is an important interaction among them.

Since the energy crisis, the state has relied more heavily on developing regulations and implementing the loading order than on pursuing the benefits of competition. This is certainly understandable, given the costs of the early foray into competition during the crisis. However, failure to use competitive markets can reduce efficiency and increase costs, costs that will ultimately be borne by consumers. Properly designed, a capacity market can mitigate market power in short-term markets, ensure adequacy, and provide a benchmark for evaluating utility procurement practices. Improperly designed capacity markets will increase customer rates without providing customer benefits.

In the state's first foray into deregulation, there was a single simple solution to how customers' needs would be met—the market. The market unfortunately did not provide, at least not at a reasonable cost.

Market tools can also facilitate the reduction of GHG emissions and the development of renewable resources, through the use of emissions and renewable energy credits. As California considers the creation of these new markets, it should explore whether the design of GHGs and RECs should be integrated with the design of capacity markets. For example, if REC and capacity auctions are held at the same time, developers might have better information about their expected revenues. This could reduce the developers' risk and allow them to reduce their offer price.

In the state's first foray into deregulation, there was a single simple solution to how customers' needs would be met—the market. The market unfortunately did not provide, at least not at a reasonable cost. Now the state is pursuing a portfolio of programs to meet customers' needs. Like any portfolio, some parts will perform better than others. The state should be vigilant in its monitoring and analysis of the portfolio it is nurturing. Programs and goals that add undue costs to customers should be reconsidered.

The state's efforts to restructure the electricity sector are quite complicated. At this point, there is no transparent, user-friendly way to convey to interested policymakers and citizens the successes and failures of this new market. Planning and regulation of utilities often proceed with more certainty than is warranted. Articulating uncertainties is not a path to popularity, but it is important to prudent regulation and utility activity. The CPUC and CEC should explicitly invite comments and prepare a detailed report that provides information and identifies uncertainties to the public and policymakers on the progress that utilities and other market participants are making to achieve policy goals. ❖

Notes

[1] Most of the principal sellers during the crisis have settled claims without an admission of guilt or the development of a judicial record to determine guilt. The amounts of these settlements were Williams Energy Marketing & Trading ($1.788 billion), Reliant Energy, Inc. ($524 million), Duke Energy ($201 million), Dynergy, Inc. ($281 million), Mirant Corporation ($495 million) (Federal Energy Regulatory Commission, 2005).

[2] These financial difficulties were the result of a number of factors, including market volatility (which was not restricted to California), over-leveraging of merchant energy companies, and the nature of the merchant business model (Moody's Investors Service, 2002).

[3] Pacific Gas & Electric (2003), p. 8; Southern California Edison (2002), p. 2.

[4] The definition of a "spot market" for electricity was a major source of controversy in refund proceedings before the FERC. Within this report, the term means short-term markets, including organized day-ahead and real-time markets, as well as bilateral trades (trades between any two market participants). The PX was a casualty of the energy crisis and declared bankruptcy in 2001. Its functions have largely been absorbed by the CAISO.

[5] The utilities were obligated by AB 1890 to purchase power through the PX and CAISO during a transition period. When the crisis got under way, the transition period had ended for SDG&E but not for PG&E or SCE.

[6] This was a much greater reliance on the spot market than occurred in New England and the mid-Atlantic states during this period, where unhedged spot-market transactions ranged between 10 and 20 percent (Jurewitz, 2001).

[7] Load-serving entities are power providers that have an obligation to serve customer load requirements. This group includes regulated utilities, competitive energy service providers, and "community load aggregators," such as the Los Angeles Department of Water and Power, which provides electricity to the City of Los Angeles.

[8] Borenstein, Jaske, and Rosenfeld (2002) differentiate between static and dynamic approaches to increasing demand-side participation in the market. Static approaches have time-varying prices that are preset with a known schedule. Time-of-use rates fit into this category. Dynamic rates allow prices to change on short notice. Dynamic rates are more costly to implement because of the metering and communication requirements, but they provide more information to the customer about system conditions. The authors argue that the value of dynamic pricing is greatest when system operators are able to anticipate the customers' price response. This suggests that California's electricity system managers need to gain an improved understanding of the potential of this tool to reap the greatest benefits.

[9] The concept of positive regulation is not a well developed topic in the literature on regulation and regulatory economics. Pechman (1993) articulated a theory of positive regulation that included the pre-declaration of prudence as a major element.

[10] These contracts vary in length with about 9,000 megawatts (MW) for the one- to three-year contracts, about 1,500 MW for the three- to five-year contracts, and about 2,000 MW for the five-plus-year contracts.

[11] Southern California Edison signed a power purchase agreement with an affiliate company for the 1,054 MW Mountain View Project. San Diego Gas & Electric acquired two projects, including the 550 MW Palomar Project, and PG&E acquired the rights to construct the partially completed 530 MW Contra Costa 8 project (California Energy Commission, 2005b, p. 52).

[12] The CPUC has also initiated cost-effectiveness tests to evaluate portfolios of conservation investments. The evaluation of conservation is performed using a measure of "avoided costs"—a somewhat different measure than the market price referent used to evaluate renewables. Cost-effectiveness tests include nonprice components such as environmental benefits (known as "environmental adders") (California Energy Commission, 2005a).

[13] The theoretical basis for the revenue shortfall is based on Boiteux (1949), Steiner (1957), and Turvey (1968). If the only revenue source for generators is the energy price, then the marginal generator (which sets the energy price for the particular hour) will just break even by producing in that hour. Consequently, the "peakers" (the generators with the most expensive energy costs) will never see a positive difference between the price they receive and their costs. Therefore, the peakers cannot recover their capital costs unless energy prices rise far above their operating costs or there is a side payment. The capital costs of the peaker, which are the lowest (reflecting the fact that its operating costs are the highest), are the missing money.

[14] See Federal Energy Regulatory Commission (2003). The New York ISO's initial capacity market, known as the Installed Capacity market (ICAP), was launched in May 2000 and was based on deficiency payments paid by utilities under New York Power Pool rules. The New York Power Pool would impose penalties in the form of deficiency payments when a utility did not meet the required level of reserves. Utilities could avoid these penalties by paying others to produce generating capacity. The result was a market with a great deal of price volatility and boom-bust cycles. In periods where there was adequate available generation capacity, the price was driven down, close to zero. When there was a shortage, the price would reach the deficiency value, which serves as a market price cap. The New York Power Pool was formed after the 1965 Great Northeast blackout to coordinate the reliability of the state's electric grid. It has been replaced by the New York Independent System Operator.

[15] The cost of new entry takes into account expected energy revenues that the generator will receive.

[16] The RPM is also a more computationally complex form of the demand curve, in that it evaluates market power concerns and power plant operating characteristics (such as load following and quick-start capabilities) to determine the winning offers.

[17] Members of the Bilateral Trading Group include California Large Energy Consumers Association; California Manufacturers and Technology Association; City and County of San Francisco; Coral Power, L.L.C.; Division of Ratepayer Advocates; Energy Users Forum; J. Aron & Company; Strategic Energy, L.L.C.; and The Utility Reform Network.

[18] See: http://www.energy.ca.gov/portfolio/wregis/.

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About the Author

Carl Pechman is president of Power Economics, Inc. Before founding the company, he was Supervisor of Energy and Environmental Economics at the New York Public Service Commission. Dr. Pechman has been an active participant in market design and has served as an expert witness in litigation investigating California market manipulation and remedies.

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