The California Electricity Crisis

Lessons for Other States

Prepared by
Eric Hirst

Prepared for
Edison Electric Institute

July 2001

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Prepared by
Eric Hirst
Consulting in Electric-Industry Restructuring
106 Capital Circle
Oak Ridge, Tennessee 37830
865-482-5470
www.ehirst.com

Prepared for
Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004
202-508-5000
www.eei.org

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1. INTRODUCTION

California was supposed to show the rest of the nation a brighter electricity future. That future, as outlined by the California Public Utilities Commission (PUC) in 1994, envisioned an electricity industry featuring competitive markets. Such markets were intended to produce lower costs and more choices for consumers, while ensuring profits for efficient energy suppliers and encouraging the retirement of old, inefficient power plants.

Although the first two years of restructuring (beginning in April 1998) seemed to bear out these promises, the last year has been a disaster for California's electricity consumers, taxpayers, and electric utilities. Part of the fallout from California's electricity crisis is considerable concern—even opposition—in other states to restructuring the electricity industry.

Although a few states have decided, based on the California experience, not to restructure, I believe that is the wrong outcome. Instead, the primary lessons other states should learn from California are that competitive markets can work; competition is not to blame for California's problems; and basic economic principles of supply, demand, and prices affect market outcomes.

These debates are about *restructuring*, not *deregulating*, the U.S. electricity industry. Specifically, state and federal governments are unbundling the traditional vertically integrated utilities to separate the competitive functions from the monopoly functions.

Generation, marketing, and retail-customer service (shown as ovals in Fig. 1) are competitive functions that would not be subject to traditional government regulation. System operation, transmission, and distribution, because they are monopoly functions (shown as rectangles in Fig. 1), would remain

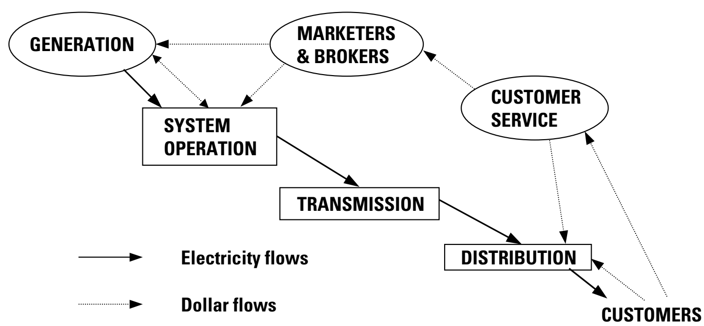

Figure 1. Schematic diagram showing structure of a competitive electricity industry.

regulated. The Federal Energy Regulatory Commission (FERC) would regulate system operation and transmission because these functions involve interstate and wholesale electricity operations and markets. State PUCs would continue to regulate distribution companies, as they have in the past. In addition, regulators would monitor the competitive functions to prevent fraud and exercise of market power.

The decision to restructure the U.S. electricity industry, at both national and state levels, is part of a two-decade process. That process involves a broad movement away from government regulation to competition for several industries, including banking, telecommunications, airlines, trucking, and natural gas. In general, competition should lower costs, better align prices and costs, improve producer efficiency, and encourage the introduction of new consumer services and pricing plans.

Section 2 briefly reviews the history of electricity regulation and restructuring in California and the problems that occurred beginning in May 2000. Section 3, the heart of this paper, offers guidance to other states on the key ingredients of a competitive electricity industry (Exhibit 1).

Exhibit 1. Key Ingredients of a Competitive Electricity Industry

- Maintain a favorable investment and regulatory climate for new generation to ensure that enough generation capacity is online and planned to meet growing loads.
- Ensure that enough infrastructure (transmission capacity and natural gas pipeline capacity) is in place and planned to meet growing loads, maintain reliability, connect new generators to the grid, support large regional markets, and provide fuel to power plants.
- Encourage retail customers to participate in dynamic-pricing and voluntary-load-reduction programs (i.e., couple retail and wholesale markets).
- Create honest retail competition: avoid standard-offer rates with artificial discounts, create conditions that encourage many companies to offer retail services without favoring individual competitors.
- Encourage electricity suppliers to manage and diversify their supply and price risks.
- Create efficient and integrated wholesale markets for energy, ancillary services, and transmission congestion.
- Monitor and minimize horizontal market power (generation) and vertical market power (combined ownership and operation of generation and transmission).

2. WHAT HAPPENED IN CALIFORNIA AND WHY

In the early 1990s, California's economy was in a deep recession and its electricity prices were among the highest in the nation. Prices were high in part because California is a fuel-poor state that imports 20 percent of its electricity from neighboring states and Canada. More importantly, the California utilities had built several nuclear plants in the 1980s that turned out to be much more expensive and took much longer to complete than anticipated. And, the California PUC had required the state's utilities to sign long-term power-purchase agreements with small generators at prices that turned out to be much too high.

In reaction to the high cost of these investments and contracts, California's PUC and Energy Commission set up elaborate resource-planning processes to ensure that future generating capacity additions and demand-side programs were truly least cost for the state's electricity consumers. Unfortunately, these regulatory processes were very time consuming, complicated, and ineffective.

Faced with this dismal situation, the PUC, in early 1994, issued a blueprint for a different electricity industry, one that was to be dominated by competitive-market forces rather than by extensive regulatory oversight. In late 1995, the PUC issued its policy decision on restructuring, most of which was codified into state law, approved unanimously by the California State Legislature, and signed into law in September 1996.

To facilitate wholesale competition, California created two nonprofit entities, the California Power Exchange and the California Independent System Operator (ISO). The Power Exchange established day- and hour-ahead markets for energy, in effect providing a forum for the entities shown in Fig. 1 to buy and sell electricity short term. The ISO manages the transmission grid owned by the investor-owned utilities, and operates day- and hour-ahead markets for reliability (ancillary) services[1] and a real-time (intrahour) market

[1] Ancillary services refer to a set of functions required to maintain reliability and support commerce. Most of these services are provided by the same generators that produce energy, hence the need for coordination across these markets. These ancillary-service-providing generators follow minute-to-minute variations in system load (called the regulation service) and are available to respond to major generation or transmission outages within a few minutes (called contingency reserves).

for energy. The Power Exchange and ISO began operation in April 1998, at which time all electricity consumers served by the California investor-owned utilities were free to choose new electricity suppliers. Under the new law, all residential customers received a 10 percent rate reduction and a freeze on retail rates for up to four years.

In response to this state law and PUC recommendations and rules, the three investor-owned utilities sold much of their fossil fuel-based power plants. Unlike the divestitures of generating capacity that later occurred in other states, the California utilities were not permitted to sign multiyear contracts to buy some or all of the output from the plants they had just sold. Thus, the California utilities, largely because of PUC prohibitions, were required to buy virtually all of the power they needed to meet retail demands in the day-ahead and hour-ahead markets run by the Power Exchange and the real-time market run by the ISO. This lack of any risk management (portfolio diversification) greatly magnified the problems that occurred when wholesale prices skyrocketed in Summer 2000.

For the first two years, the wholesale system worked reasonably well. In particular, wholesale electricity prices were moderate and varied in accord with normal market conditions. However, wholesale prices increased dramatically in May 2000 and have remained very high since then (Fig. 2). These high prices are a consequence of:

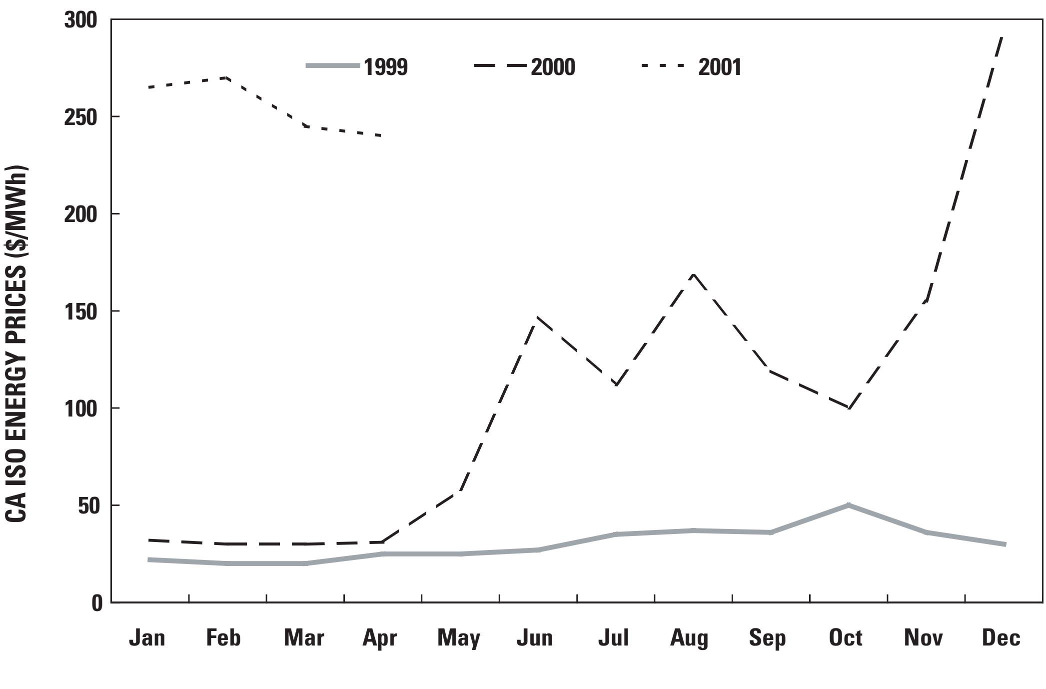

Figure 2. Monthly wholesale electricity prices in California for 1999, 2000, and 2001.

- Much higher natural gas prices (about four times higher in late 2000 than in 1999),
- Limited allowances for nitrogen oxides in southern California (which led to dramatic increases in the costs of these allowances),
- A very dry year (which meant that the hydroelectric dams in California and the Pacific Northwest were able to provide little power to California),
- Especially hot weather in the summer and cold weather in the winter (which increased demand for electricity),
- Growth in electricity demand in the rest of the West (which meant that electricity producers in those states had less power to export to California), and
- Poor design of wholesale markets.

The primary problem that underlies the symptoms listed in the preceding paragraph is the large imbalance between electricity demand (which has been growing steadily) and supply (which has not been growing); see Fig. 3. While California's electricity demand grew by about 3,000 MW between 1996 and 2000, generating capacity increased by only 500 MW. No major power plants were built in the state during the 1990s because utilities and other private companies were unwilling to make such large investments when the regulatory and financial climates were so uncertain. According to the California Energy

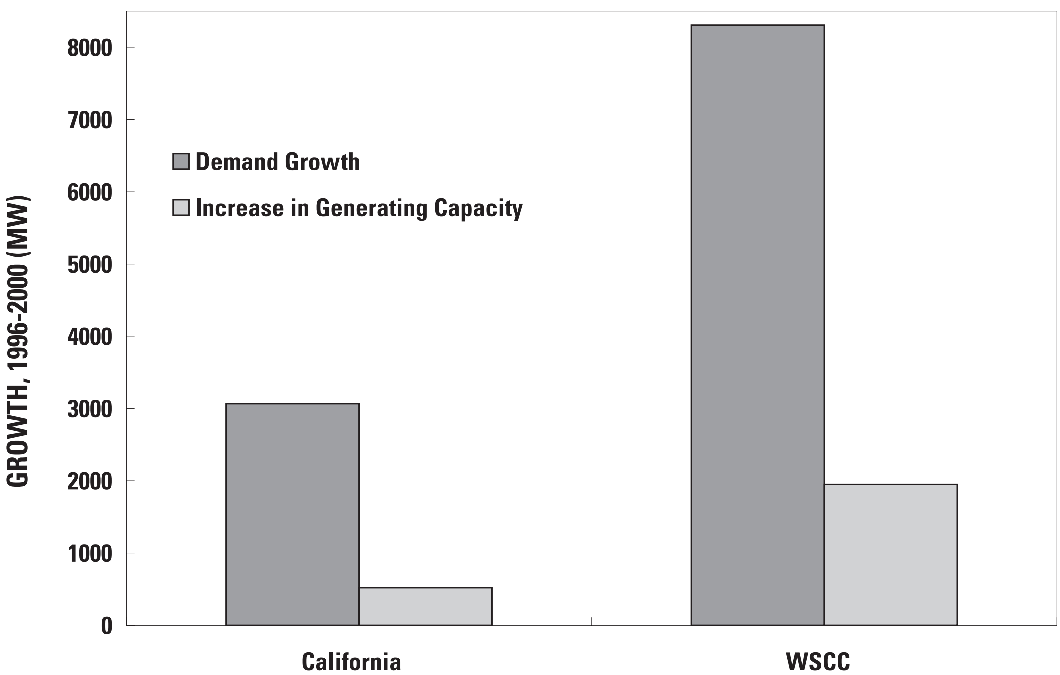

Figure 3. Growth in electrical demand and supply from 1996 to 2000 in California and the West.

Commission, “no power plant applications were filed with the Energy Commission between 1994 and 1997 because there was so much uncertainty during the restructuring of the electricity industry.”

California’s strict and complicated siting reviews may also have deterred investment in new generating facilities. Because of the large gap between demand and supply, the effects of all the other problems in California became much more pronounced. Indeed, California’s problems may worsen for a year or two before they get better.

Historically, California has been a net importer of electricity, relying on out-of-state generators for 20 percent of its electricity needs. Unfortunately, at the same time instate generation was lagging California’s load growth, the same thing was happening in the rest of the West (Fig. 3). This growth in demand throughout the West made it difficult for out-of-state generators to provide electricity for California’s booming economy.

Lack of sufficient transmission capacity, both within California and between California and other parts of the West, made the problem still worse. For example, congestion on California’s Path 15 (a set of north-south transmission lines in the middle of the state) cost electricity consumers up to $220 million between September 1999 and December 2000. As shown in Fig. 4, the amount of transmission capacity, normalized by summer peak demand, fell throughout the 1990s. (The up and down movement in the figure is caused by

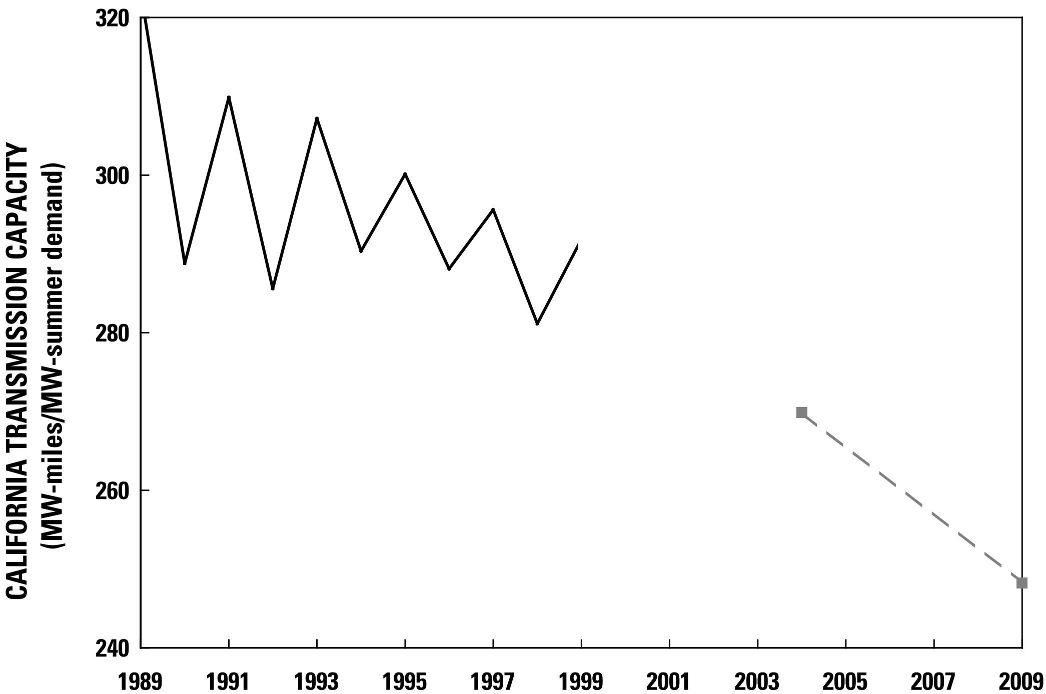

Figure 4. California transmission capacity normalized by summer peak demand from 1989 through 1999 plus projections for 2004 and 2009.

year-to-year changes in summer temperatures and, therefore, in peak demand.) To make matters worse, the utility forecasts of future transmission additions, as of 2000, showed continued declines in transmission adequacy through the end of this decade.

At the retail level, almost no residential consumers switched suppliers because competitive retail providers were unable to profitably offer services at prices lower than those mandated under the 10 percent price reduction.

Since problems first arose in Summer 2000, the California situation has worsened considerably. What began as a supply crunch soon became a financial disaster for the utilities. The utilities were buying electricity at wholesale prices up to $300/MWh from the Power Exchange and ISO, but were required by the PUC, under the terms of the retail-rate freeze, to sell that power to retail customers at only $60/MWh.

For many months, California's Governor and PUC refused to raise retail rates. They insisted that others were at fault (in particular, the out-of-state owners of instate power plants and FERC) and that refunds for alleged market-power abuses would obviate the need for price increases. As a result, the state's political leaders did not take short-term actions (price increases) that would have helped in the long term. The state's refusal to face the uncomfortable truth that California consumers were going to have to pay more for electricity—either now or later, either through taxes or through direct price increases—increased utility losses to about $18 billion as of April 2001. At that time, Pacific Gas & Electric, one of the nation's largest utilities, declared bankruptcy. Southern California Edison, the other large California utility, was close to bankruptcy at that time. In addition, "protecting" consumers from price increases ensured that retail loads would not be reduced because of higher wholesale power costs, the natural response of a working competitive market.[2]

Many generation owners, both the large out-of-state companies and the instate small power producers, withheld supplies from the California markets. They did so because they were worried about the financial status of the California utilities. The utilities, facing bankruptcy and with no cash reserves, had stopped paying their bills. This reduction in supplies made available to California worsened the supply-demand imbalance and led to several electricity emergencies, including rotating blackouts in January and May 2001. Thus, the capacity shortfall became a financial crisis, which then led to major reliability problems.

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[2] A group of "professors, former public officials, and consultants" concerned about the state's unwillingness to raise retail rates issued a *Manifesto on the California Electricity Crisis* in January 2001. They urged, among other things, an increase in retail rates as an essential element of the solution to California's electricity problems.

As the financial situation of the California utilities deteriorated, the state began to buy power through its Department of Water Resources to offset the increasing reluctance of power suppliers to sell to the financially strapped utilities. Later, the Department began signing long-term contracts for power. Between January and May 2001, the Department spent $7.6 billion on power purchases. (Standard & Poor's downgraded the rating on California bonds from AA to A+ because of the state's rapidly increasing power bill.) The state is also negotiating for the purchase of the utilities' transmission systems, and is contemplating construction, ownership, and operation of its own power plants. Thus, as time went on, the state moved further and further away from competitive electricity markets, and more and more toward massive state-government involvement in the electricity industry.

The state legislature passed new laws to expedite approval of new power plants, invest in renewable energy sources, expand the state's ambitious energy-efficiency programs, implement real-time pricing to reduce and modify customer demand, and authorize the Department of Water Resources to buy power on behalf of California consumers (both short-term purchases through the ISO and long-term bilateral contracts). Finally, the legislature established a Consumer Power and Conservation Financing Authority to market up to $3 billion in bonds to build and operate new power projects in California.

In March 2001, the ISO filed a report with FERC claiming over $6 billion in excess energy charges between May 2000 and February 2001. More than 30 percent of wholesale energy costs, according to the ISO, can be attributed to market power. The ISO calculated that the costs of energy and ancillary services exceeded $11 billion in just two months, December 2000 and January 2001, almost double the comparable costs for all of 1999. The ISO proposed that FERC adopt several mechanisms to limit market power, including ISO coordination of generator maintenance outages, outage reporting, an obligation that all unsold capacity be made available to the ISO in its real-time energy market, and unit-specific energy bid caps. In June 2001, the ISO filed emergency motions with FERC, asking the Commission to revoke the authority of several power suppliers to charge market-based rates. (The existence and extent of market-power abuses in California is a hotly contested issue. Some parties believe it to be a major cause of the state's electricity problems, while others believe it is only a minor factor.)

FERC issued several orders that dealt with the California wholesale markets. The December 2000 order lowered the price cap in the ISO's markets from $250/MWh to a "soft" cap of $150/MWh in an effort to mitigate market power. FERC eliminated the state's requirement that utilities buy all their power through the California Power Exchange. Eliminating this requirement, combined with the utilities' inability to pay their power bills, drove the Power Exchange to declare bankruptcy as buyers and sellers took their business elsewhere. Thus, California currently has no formal day- and hour-ahead energy markets.

The April 2001 order eliminated the soft price cap and substituted a generator-specific bid cap (based on daily natural gas prices and the unit's characteristics) to apply whenever reserve margins drop below 7.5 percent in California. FERC also authorized the ISO to coordinate generator maintenance outages and monitor generator forced outages, required generators to offer any available power they have to the ISO in real time, and required retail providers to bid price-responsive demand into the ISO markets. FERC also initiated an investigation of wholesale prices throughout the West.

The June 2001 order extended the price-mitigation system to all hours and to 10 other states in the West. The single market clearing price is based on the marginal cost of the most expensive gas-based generator running during reserve-deficiency hours, with adders for operations and maintenance costs and credit uncertainty. Prices at other times are set to 85 percent of the highest ISO price during the last reserve deficiency.

3. LESSONS FOR OTHER STATES

The key lesson *not* to learn from California is that competition can't work. On the contrary, restructuring the electricity industry can provide substantial benefits to electricity consumers and to society at large. In particular, letting private investors decide whether and when to build new power plants and retire, repower, or continue to operate existing units can, in the long run, lower the costs of electricity to consumers relative to the costs that would occur if regulators make those decisions. Similarly, letting competitive retail-service providers and consumers decide on suitable combinations of electricity prices and risk management can expand choices and lower costs to consumers relative to what would occur if regulators set retail rates for large classes of customers (all of whom are assumed to have identical preferences).

Today's wholesale power markets permit buyers and sellers to secure the best deals across large geographic areas. Such broad regional markets lower consumer prices and ensure that electricity is produced with the lowest-cost generating units, subject to transmission constraints. These changes are reflected by the increasing role played by power marketers in wholesale markets (Fig. 5).

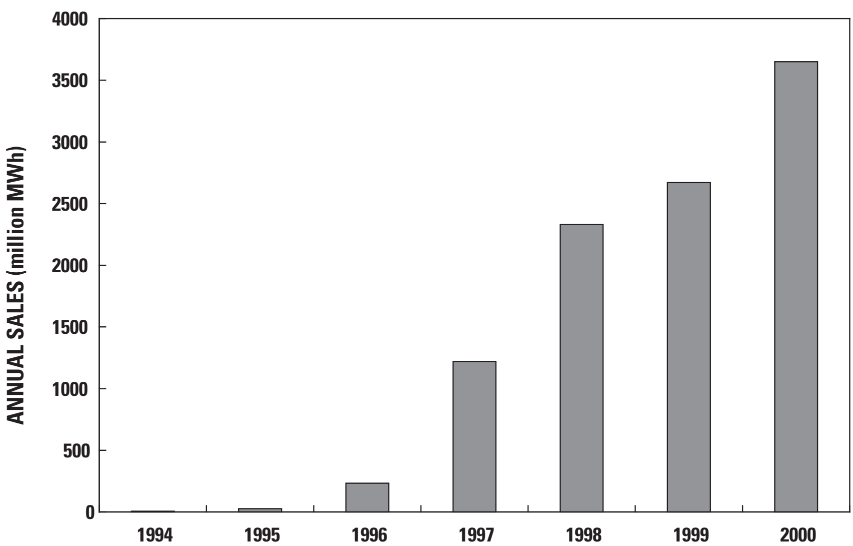

Figure 5. Power-marketer electricity sales.

Beyond these general, philosophical conclusions, what does the California experience teach us about creating and sustaining a competitive electricity industry? The following discussion offers suggestions on the underlying generation and transmission infrastructure; retail competition, including retail-customer participation in wholesale markets; risk management; coordinated markets for energy, ancillary services, and transmission congestion; and market power (Exhibit 1).

GENERATION ADEQUACY

Probably the most important factor in creating and sustaining workably competitive electricity markets is sufficient supply. Supply involves both generation and its supporting transmission and natural gas pipeline infrastructure. Consider generation first. The key to encouraging construction of the appropriate types and amounts of new generating capacity is electricity pricing that fully reflects the costs of energy production. Such pricing will signal investors on the types and quantities of power plants to build to meet their investment criteria.

In competitive electricity markets, investors—not government regulators—decide what kinds of power plants to build, where to locate these facilities, and when to construct them. Because individual investors make these decisions, they—not consumers—bear the financial risks of building the wrong kinds of plants, in the wrong places, and at the wrong times. On the other hand, if their estimates of market needs are correct, their investments will yield substantial returns, and consumers will get the energy services they want and need.

In the former world of the highly regulated, vertically integrated utility industry, regulators, acting through the utilities, made these decisions on new construction. Because regulators made these decisions, retail customers bore most of the financial risks of these investments. Retail rate increases caused by the high cost and long delays associated with the construction of several nuclear units in the 1970s and 1980s were a key motivator for making wholesale electricity markets competitive.

State legislators and regulators should pay close attention to the balance between generating capacity and customer demand. Ample supplies at the time of market opening will minimize the costs of identifying and correcting the inevitable flaws in initial market design.

For the long term, state legislators and regulators will want to be sure that the economic and regulatory environment does not discourage investors from building new power plants in that region. A key consideration here is assurance that siting issues are addressed in a way that respects environmental quality without needlessly delaying decisions on approval of new power plants. Government needs to provide a stable and simple set of rules under which power plants will be reviewed, approved, and then constructed, operated, and paid for.

Efforts to “protect” consumers by imposing price or bid caps will backfire if they discourage construction of needed generation. If caps are imposed, they should be set high enough to ensure that (1) generators are not forced to shut down because they are unable to recover all their operating costs and (2) investors are not discouraged from building new power plants in the region. In addition, caps should be short-term in nature.

The economic and regulatory environment in Texas is apparently much more hospitable to new generation investment than in California. (Electricity demand in Texas is slightly higher than in California.) Between 1997 and 2000, more than 7,000 MW of new generation was completed in Texas (Fig. 6). Investors plan to build another 15,000 MW in 2001 and 2002.

Nationwide, the picture also looks positive. Announced plans for new generation total 220,000 MW over the next four years, more than the 210,000 MW the federal Energy Information Administration anticipates is needed for this entire decade. Although some of the announced projects will not be completed, enough new capacity will likely be constructed to substantially increase generating reserve margins.

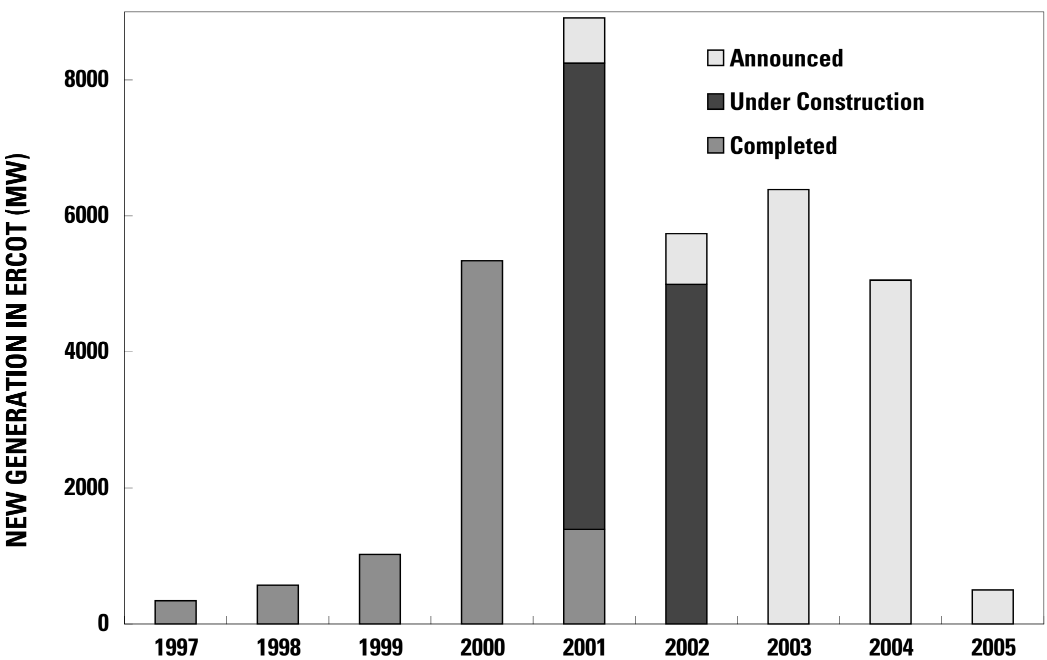

Figure 6. Additions of new generating capacity in the ERCOT portion of Texas.

Although California (and, perhaps, a few other states) may face a capacity crunch for a year or two, the long-term outlook is for ample generating capacity, driven by competitive electricity markets, not by traditional regulation. Even in California, new construction is expected to add about 11,000 MW of generating capacity between 2001 and 2003, increasing instate capacity by almost one fourth.

One possible way to ensure that sufficient generating capacity is available is to impose an installed-capacity requirement. This standard would require all retail providers to acquire, either through contracts or physical assets, sufficient capacity to meet peak demand plus a certain reserve margin. Such an installed-capacity requirement might be a useful transitional mechanism to prevent capacity shortages and wholesale price spikes. On the other hand, many people oppose such requirements because they interfere with the workings of competitive markets, in which investors, not central planners, decide how much generation to build and when.

INFRASTRUCTURE ADEQUACY

Sufficient infrastructure, especially transmission lines and natural gas pipelines, is essential to well-functioning electricity markets.

Traditionally, utilities built transmission lines to deliver electricity from their generators to their customers and to maintain minimum levels of reliability, in accordance with the *Planning Standards* of the North American Electric Reliability Council. In today's competitive wholesale markets, transmission serves other important purposes. It:

- provides flexibility so that loads can be served under a variety of generation, demand, and transmission conditions;
- reduces the amount of installed generation capacity needed for reliability by connecting different electrical systems;
- permits economic exchange of energy among systems;
- connects new generators to the grid; and
- limits the ability of generators to artificially raise prices by expanding the geographical scope of competition.

Although generation and transmission are usually complements, they are sometimes substitutes. That is, properly located generation (e.g., close to load centers) can substitute for some transmission. Similarly, additional transmission facilities can provide access to generation resources located far away, substituting for local generation.

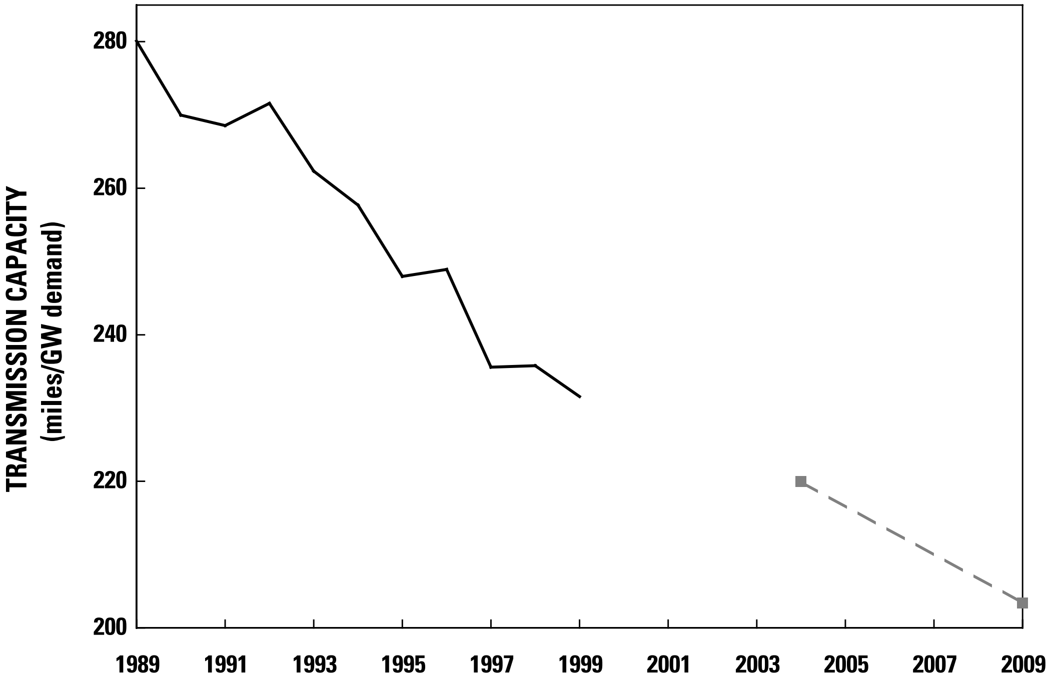

Figure 7. U.S. transmission capacity normalized by summer peak demand from 1989 through 1999 and projections for 2004 and 2009.

In spite of the importance of transmission to a healthy electrical system, transmission construction has consistently lagged load growth during the past two decades (Fig. 7). Even worse, utility plans show a continued decline in transmission adequacy over the coming decade.[3]

Two factors account for much of the lag in transmission investment. First, local opposition and complicated regulatory-approval processes make it difficult to site and build transmission lines. Although transmission increasingly serves regional needs, decisions on whether and where to build new facilities are made at the local and state level, often with little regard for broader economic considerations. It may be appropriate to consider shifting oversight of new construction from states to the federal government. Just as FERC has long-standing authority to site natural gas pipelines, perhaps it should also oversee and approve siting of new transmission facilities.

Second, utilities, in response to FERC directives, are transferring their ownership of transmission facilities to regional transmission organizations (RTOs). These new entities are uncertain about the financial returns on their investments. It is not clear whether FERC will allow an adequate return on investment and whether it will approve transmission-

[3] The California ISO has approved 122 transmission projects in California, representing an investment of over $1 billion. It remains to be seen, however, how many of these projects are completed and when.

pricing systems that provide financial incentives for efficient operation and expansion of transmission systems. In addition, RTOs and utilities are unsure whether FERC will approve rates of return on new transmission investment that reflect the financial risks associated with competitive wholesale electricity markets. Such uncertainties inhibit investment in transmission facilities needed for robust electricity markets.

More than 90 percent of the new power plants announced during the past few years will be fueled with natural gas. Indeed, the Energy Information Administration notes that "projected increases in natural gas use are led by electricity generators." To deliver that fuel to power plants requires the construction of more pipelines. Pipeline mileage needs to be increased substantially.

COUPLING WHOLESALE AND RETAIL MARKETS

Wholesale markets today (not just in California) resemble the sound of one hand clapping; they are incomplete and inefficient because retail customers are not able to respond to changes in wholesale electricity prices.

Electricity costs vary substantially from hour to hour, often by a factor of ten within a single day. Because most retail customers buy electricity as they always have—under time-invariant prices that are set months or years ahead of actual use—consumers are fully insulated from the volatility of wholesale markets. This insulation prevents customers from taking actions that would reduce the frequency and magnitude of price spikes, improve efficiency, and lower costs for all electricity consumers.

Retail electricity prices reflect two components that should be priced separately: (1) the electricity commodity (the kilowatt-hours we use to power our modern society) and (2) the insurance premium that protects customers from price variations and permits them to use unlimited amounts of electricity at any time. This insurance premium eliminates all the risks consumers might otherwise face in wholesale markets.[4]

Regardless of whether a state chooses to open retail electricity markets to competition, regulators should offer customers the *opportunity* to see electricity prices that vary from hour to hour, reflecting wholesale-market price variations. Regulators, as a starting point, might require the installation of interval meters for all large customers (e.g., with demands greater than 20 kW). (Interval meters read and record electricity-use data at the hourly or subhourly level.) At a minimum, such meters would let retail suppliers know exactly what it costs them to serve different customers.

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[4] The risk-management service that time-invariant prices provide is analogous to the portfolio management services a mutual fund manager provides to investors in the stock market. Just as the portfolio manager is paid for its services, so too should the retail electricity provider that guarantees a fixed price.

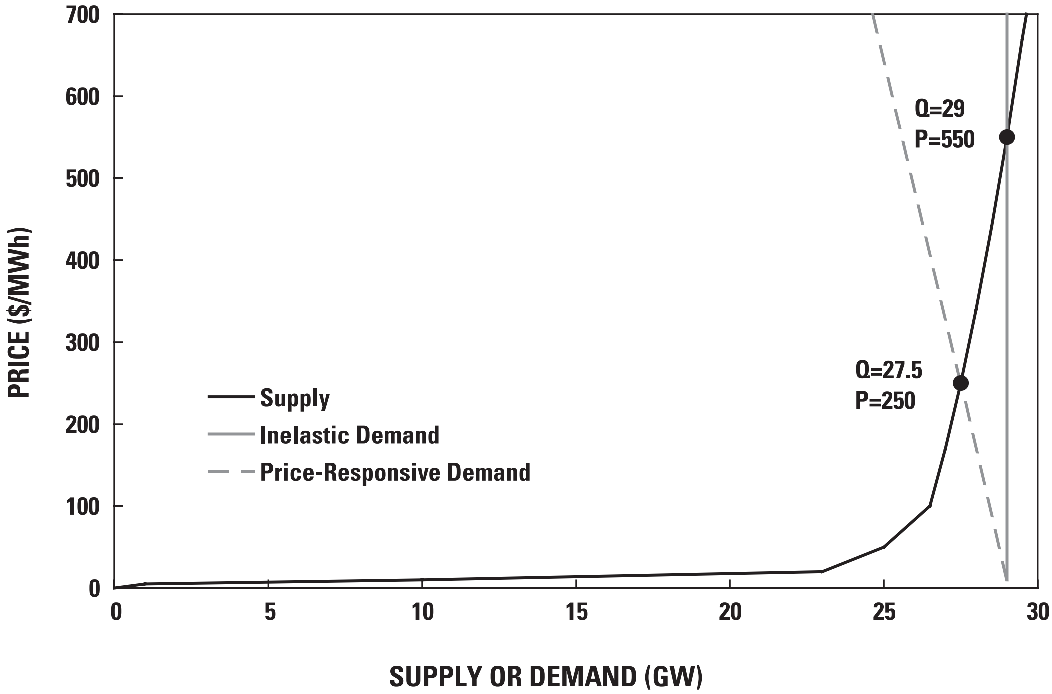

Figure 8. Hypothetical wholesale supply and demand curves. The vertical line represents demand that is insensitive to price; the dashed line represents demand that varies with price. For this case, consumer response to price reduces demand (Q) by 5 percent and cuts price (P) by 55 percent.

Permitting customers to face the underlying variability in electricity-production costs can improve economic efficiency, increase reliability, and reduce the environmental impacts of electricity production. Economic efficiency requires a range of customer choices. Offering customers a variety of pricing options is an essential component of efficient markets and a key to improving customer well-being. Customers who choose to face the volatility of electricity prices can lower their electricity bills in two ways. First, they provide their own insurance. Second, they can modify electricity usage in response to changing prices, increasing usage during low-price periods and cutting usage during high-price periods.

Retail customers who modify their usage in response to price volatility help lower the size of price spikes.[5] This demand-induced reduction in prices is a powerful way to discipline the ability some generators might otherwise have to artificially raise prices when demand is high and supplies tight. And, these price-spike reductions benefit *all* retail customers, not just those who modify their consumption in response to changing prices; see Fig. 8.

[5] One analysis of the California electricity market estimated cost savings between 5 and 16 percent for summer 2000 from price-responsive demand.

Customers who face real-time prices and respond to those prices provide valuable reliability services to the local control area. Specifically, load reductions at times of high prices (generally caused by tight supplies) provide the same reliability benefits that additional generating capacity would.

Finally, strategically timed demand reductions decrease the need to build new generation and transmission facilities. When demand responds to price, system load factors improve, increasing the utilization of existing generation and reducing the need to build new facilities. Deferring such construction may improve environmental quality. Cutting demand at times of high prices may also encourage the retirement of old and inefficient generating units.

Ultimately, retail electricity markets, either competitive or regulated, will likely feature two kinds of demand-response programs. First, some customers (especially large commercial and industrial customers) will choose to face electricity prices that vary from hour to hour. Typically, these prices will be established day-ahead in the markets run by RTOs, such as those now operating in New York and the mid-Atlantic region. Second, some customers will select fixed prices, as they have in the past, but voluntarily cut demand during periods of very high prices; the customer and the electricity supplier will share the savings associated with such load reductions.

RETAIL COMPETITION

States differ in their decisions on whether (and, if so, to what extent) to open retail electricity service to competitive suppliers. While some states prefer to begin wholesale and retail competition together, others prefer to start with wholesale competition and defer retail competition for a later date. In either case, regulators need to ensure that retail prices reflect wholesale electricity costs, as discussed above.

In some states with retail competition, the desire to guarantee an immediate rate reduction for customers has led regulators to mandate standard-offer services that are priced too low. Prices that do not accurately reflect wholesale energy costs rob customers of any incentive they otherwise would have to face market prices, and they prevent competitive retail suppliers from entering the market. In addition, they require the providers of these services (typically the incumbent distribution utility) to absorb market risks associated with price and load uncertainty and volatility, perhaps without adequate compensation. Ultimately, there is no free lunch! Customers will pay for these costs later if they don't pay for them in current rates. The bankruptcy of Pacific Gas & Electric, driven primarily by the refusal of the California PUC to raise rates, exemplifies the problems that can occur when regulators focus narrowly on short-term issues (no rate increases for customers) and ignore the long-term consequences of their actions.

True retail competition can exist only when competitive retail providers:

- obtain resources as they see fit (i.e., build their portfolio with whatever combination of physical and financial assets, short- and long-term, they prefer),
- are exposed fully to wholesale markets (i.e., pay the real-time spot price for electricity when their loads exceed the amount of generation they purchased in forward markets),
- set retail prices based on competitive factors, and
- are allowed to leave the business if their judgments on the other factors are incorrect.[6]

Because of current regulatory requirements for standard-offer service, the primary retail provider is usually the incumbent utility. Because of the standard-offer requirements, the PUC continues to heavily regulate the utility and its power-procurement practices, controlling retail prices, which, in turn, stifles retail competition.

RISK MANAGEMENT

As suggested above, a key ingredient of successful competition is an appropriate balance between physical (generating units) and financial (contracts) assets and between short- and long-term arrangements. In particular, retail providers need not own generating units to be prudent risk managers. Instead, they can hold contracts that give them the rights to the outputs of individual generators or portfolios of generators.

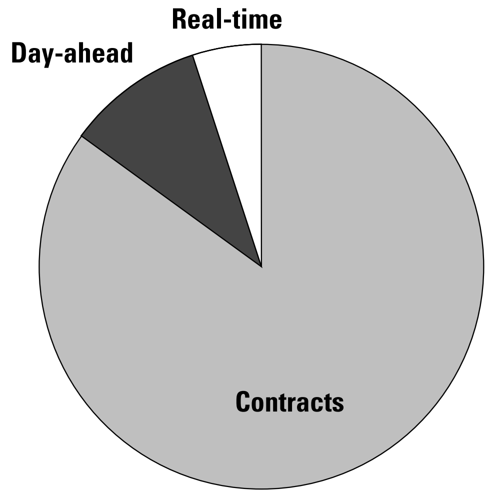

Figure 9. Possible resource portfolio of long-term contracts and participation in day-ahead and real-time markets.

The key here is to permit individual market participants, both retail providers and retail customers, not government regulators, to decide on the appropriate risk-management strategy. Fig. 9 shows roughly how market participants might choose among long-term contracts, day-ahead purchases, and real-time purchases. In this hypothetical example, the supplier acquires most of its energy through long-term contracts. It buys about 10 percent of its needs in day-ahead markets in response to tomorrow's weather forecast and other factors that might affect expected

[6] Although retail-service providers can be permitted to go out of business because other firms will step in to fill the gap, the same is not true for transmission and distribution providers. These latter firms provide monopoly services for which there are no substitutes.

load. Finally, it buys (or sells) any differences between its actual load and its generation in the real-time market.

The initial design of the California markets *prohibited* the three major utilities (which, ultimately, were responsible for most of the retail load) from purchasing any generation through long-term contracts. This prohibition forced the utilities to obtain their supplies from volatile spot markets. Subsequently, FERC prohibited retail providers from using the California ISO's real-time market for more than 5 percent of their load. Instead of having regulators set artificial limits, suppliers and their customers should be free to choose whatever kinds of risk management make sense to them, just as we do in other markets.[7]

MARKET DESIGN

Bulk-power electric systems are complicated and highly interdependent. The complications occur because

- electricity production and consumption must occur at essentially the same time, and
- what happens in one part of the transmission grid can affect what happens in other parts of the grid.

As a consequence of these two factors, real-time (minute-to-minute) operations and the associated markets and prices are essential ingredients of a competitive wholesale electricity industry. In addition, these intrahour markets are the foundations of all forward markets and contracts, including hour- and day-ahead markets, monthly futures, and bilateral contracts.

Fig. 10 shows just how dynamic and volatile these intrahour markets can be. During this 12-hour period, prices ranged from a low of –$30/MWh (which means suppliers were willing at that time to pay consumers to use their output) to a high of almost $100/MWh, with an average price of $30/MWh. This large variation in prices reflected rapidly changing conditions in available generation, load, and transmission congestion.

Transmission systems are tightly coupled networks, in which events at one point (e.g., the injection or withdrawal of power) can have effects in many other parts of the grid. Therefore, the markets for energy, ancillary services, and transmission congestion need to be integrated with each other and with real-time operations. That is, the markets for all three sets of products and services should be cleared (balanced) simultaneously to maximize economic efficiency.

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[7] Governments impose no requirements on individuals concerning the mix of stocks, bonds, and other investments they hold. Similarly, they set no limits on the kinds of stocks (large vs small cap, growth vs value) people can hold, nor on the quality and duration of bonds they can hold.

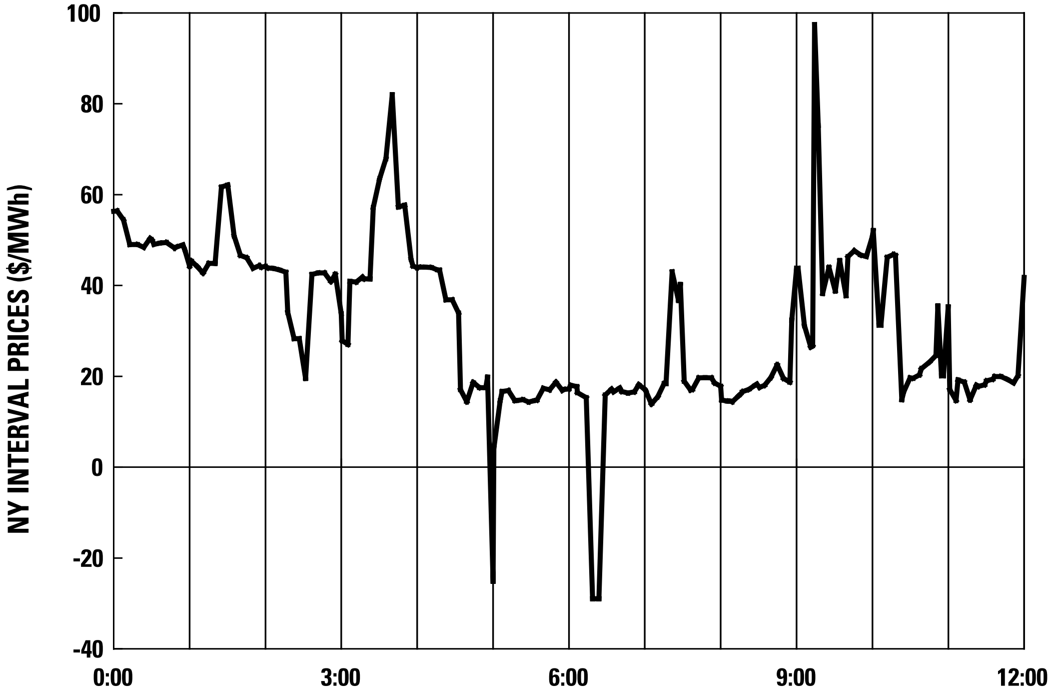

Figure 10. Intrahour prices for the New York West zone for a 12-hour period in September 2000.

The California design artificially separated these markets, requiring suppliers to buy and sell these services at different times, some through the ISO (real-time energy, ancillary services, and congestion) and some through the Power Exchange (day- and hour-ahead energy) in very decentralized and complicated ways. The California design required individual suppliers to match their supplies with offsetting loads, although this requirement for *balanced* schedules is not needed for reliability. These restrictions on sensible market behavior likely raised costs to suppliers and, therefore, to consumers also. The market designs in New England, New York, and the mid-Atlantic region, on the other hand, do not create artificial constraints on these markets and their participants.

In the short term, market rules should promote economic efficiency, which means that customer loads are served and reliability is maintained at the lowest possible cost. In the long term, these markets should produce prices that stimulate appropriate levels of investments in new generation and transmission capacity. In addition, the market rules should be clear and easy to understand, both to encourage broad participation in these markets and to ensure fairness. Such a process will reduce the need for government oversight because it will be to a large extent self-policing. Stated differently, if markets are well designed it will be difficult for individual participants to manipulate results in their favor.

Clearly, restructuring wholesale operations and markets is complicated. Creating and sustaining competitive markets requires substantial experience and expertise in electrical engineering, economics, and market design and operation. Therefore, state policy makers and FERC need to be sure that the operating and market rules conform with the physics of electrical systems and the economic principles of market design.

MARKET POWER

Market power is defined as the ability of a supplier to profitably raise prices above competitive levels and maintain those prices for a significant time. Two types of market power can exist in electricity markets. *Horizontal* market power occurs when a firm profitably drives up prices through its control of generating capacity, either by withholding capacity from the market or by raising the price it bids into markets. *Vertical* market power occurs when a firm that manages both generation and transmission uses its dominance in one area (transmission) to raise prices and increase profits for the overall enterprise.

FERC dealt with vertical market power in its Orders 888 (April 1996) and 2000 (December 1999). Order 888 requires electric utilities to unbundle their generation and transmission services into two separate sets of activities. Order 2000 continues the process of unbundling by directing utilities to join RTOs, which must be independent of market interests.

FERC deals with horizontal market power through its authority to ensure that wholesale rates are “just and reasonable.” However, it can be difficult to determine what is just and reasonable in competitive markets. FERC will rely, in part, on the market-monitoring units in each RTO as they are formed and become operational. These groups collect and analyze data on the behavior of individual market participants and on the markets themselves. They investigate claims of market-power abuse, such as the withholding of available generating capacity from markets in an effort to raise prices or strategically bidding generation at prices higher than marginal costs. These market-monitoring units then report their findings to FERC. Ultimately, FERC has the authority to order refunds when it finds such instances of abuse, as it has done with some suppliers to the California markets.

To prevent problems from occurring with horizontal market power, states should eliminate any barriers that might unfairly block construction of new generating units. States should participate in FERC proceedings on RTO formation to ensure that the RTO is truly independent of market interests, is large enough to fully encompass regional electricity markets, and has in place suitable market-monitoring and -mitigation measures.

4. CONCLUSIONS

Ultimately, competitive markets for electricity in the United States will lower costs and prices, better align consumer prices with producer costs, improve producer efficiency in both investment and operation, maintain or improve reliability, and yield greater innovation in customer services and pricing options.

But, this transition from one industry structure to another is turning out to be long and complicated. It is complicated because electricity is so important to our modern, high-tech society; electricity is our most flexible fuel, providing light, heat, motive power, and the energy to operate all our electronic equipment. Also, electricity truly is a real-time product for which production and consumption must occur at the same time.

Although the problems that have occurred in California since Summer 2000 are substantial and worrisome, regulators and legislators in other states should focus on the long-term benefits of competitive electricity markets and accept the possible short-term problems that may occur. They also need to recognize that wholesale markets are *regional* in scope and extend far beyond the boundaries of any single state. Even for a state as large as California, what happens to the electrical system inside the state affects the entire West and vice versa. Finally, competition in retail and wholesale markets must be coordinated; in particular, it is not possible to have competitive wholesale markets unless at least some retail load faces time varying prices.

If states restructure properly to create competitive markets for wholesale energy and retail services, we should all benefit. Consumers will enjoy lower prices, they will have many more choices of energy services and price-risk tradeoffs, reliability will be improved because most reliability services will be obtained through markets instead of by engineering edict, and the financial risks associated with building and operating power plants will be assigned properly to investors rather than consumers.