6

POLICY OPTIONS

What Next?

Now that the crisis has passed, blight is threatened, and public attention has subsided, California and all the western states still face important policy issues relating to both the electricity system and the financial implications of the two crises. Some of the decisions may be driven at the federal level through the FERC. Others involve state regulatory or other policy decisions. However, most involve opportunities—or requirements—for cooperation at the state, regional, and federal levels. In the remainder of this chapter, these policy issues are discussed in terms of a series of prescriptive recommendations.

IMPROVE REGIONAL INTEGRATION

Integrated physically through an extensive grid of electricity-transmission capacity, the electricity systems of the eleven western states are highly dependent on one another. The electricity crisis made it clear that long-run supply and demand trends and short-run variations in those trends in any part of the region can have important ramifications throughout the entire region. Regulatory policies in one state can influence electricity markets throughout the region. Information about new capacity development in one state can influence decisions about whether new capacity development will be profitable in other states. Yet the regulatory policies, information flows, and market management rules of the eleven western states have not been well integrated. Thus, there are opportunities for mutual gain among the states through actions that increase regional integration of decision making and information flows.

Publicly Available Supply/Demand Information

Many decisions made by either public sector or private sector entities depend largely on good information about regional electricity supply, demand, and prices, in addition to state-specific information. For example, decisions to invest in generation capacity made by either public sector or private sector entities depend on beliefs about future supply and demand balances and/or future wholesale electricity prices. If potential investors—in either the public sector or private sector—believe there will be surplus generating capacity for many years, they tend to avoid making new capacity investments, recognizing that it is unlikely that they will recover the costs of the investment, much less earn a profit. If they believe there will be shortages over the relevant future, potential investors are likely to choose to invest in new capacity. Thus, good information about historical and current conditions and reasonable projections of future conditions throughout the region can help to avoid boom and bust cycles in the electricity markets. Monitoring to detect exercise of market power can be more effective if based on information from throughout the interconnected region rather than information from simply one state. Evaluation of the relative impacts of energy conservation programs, retail price changes, and reductions in economic activity would be improved by high-quality state-specific and regional data, and such evaluations would be helpful in improving policy interventions in response to possible future electricity challenges or crises.

The nature and extent of publicly available electricity information vary radically among the various states. California, the largest state, provides a rich array of information through the CAISO and the California Energy Commission; much of these data is readily available on the Internet. The California Energy Commission periodically publishes projections of electricity supply and demand. The Northwest Regional Planning Council develops periodic estimates of electricity demand and supply for the northwestern states. However, some of the states provide relatively little information through readily available sources.

The Energy Information Administration, an agency of the U.S. Department of Energy, regularly publishes state-by-state electricity data on a comparable basis. However, these data are too limited to guide private sector and public sector decision making. The Western Governors' Association and the FERC have both published studies that examine the entire region, as have several researchers.[1] Yet these sources do not provide sufficient information for continued decision making.

Cooperative efforts among the states to coordinate either information development or information communication could provide mutual gains. Whether such cooperative efforts would best be organized through direct cooperation among state agencies, the Western Governors' Association, a regional transmission organization, the Western Systems Coordinating Council (WSCC), research institutes, or some federal agency is not clear. What does seem clear, however, is that better publicly available region-wide data could improve private sector and public sector decision making and provide the general public better opportunities to evaluate the policy decisions being made and communicated by public officials.

Regional Transmission Organization

In December 1999, the FERC issued Order 2000, calling for the formation of regional transmission organizations (RTOs) spanning large geographic regions and responsible for providing reliable, nondiscriminatory, and efficient transmission service for regional competitive wholesale electricity markets. In Order 2000, the FERC expressed its belief that the creation of such RTOs could reduce any remaining transmission-related impediments to competitive wholesale electric markets—in particular, any remaining engineering and economic inefficiencies in the operation and expansion of transmission grids and any opportunities for transmission owners to discriminate to favor their own (or affiliated companies') wholesale market purchases and sales.

In April 2001, the FERC accepted the proposal for the creation of RTO West, an RTO that would control all transmission within the eight western states (Washington, Oregon, Idaho, Montana, Nevada, Arizona, Utah, and parts of California not controlled by the CAISO). The FERC noted, "RTO West can serve as an anchor for the ultimate

[1] For example, Jolanka V. Fisher and Timothy P. Duane have published such a study.

formation of a West-wide RTO."[2] The new RTO West will serve as the independent system operator for its entire area and "will operate more than 90 percent of the high voltage transmission facilities from the U.S.-Canadian border to southern Nevada."[3]

An important issue for California is whether to combine the functions of the CAISO and RTO West into one RTO that could more efficiently control transmission services over almost all, if not all, of the interconnected western region of the United States. Such an integration could remove any problems of transmission coordination between California and the rest of the West. However, in principle, any remaining problems could be eliminated without creating a single organization but rather through sufficient coordination between the two existing organizations. In practice, however, as long as operational rules of the two entities remain different from one another, such coordination is likely to be imperfect. If California wholesale electricity purchases and sales return primarily to spot market transactions while bilateral contracts continue to characterize most of the transactions in the other areas, the structural differences in wholesale electricity markets may make integration of the two entities more difficult. In addition, the integration would take the power to appoint the members of the governing board out of the hands of the California governor and may therefore reduce the degree of political control over the transmission system.

Whether the CAISO should remain as its own RTO and simply cooperate with RTO West or the two entities should become one is not clear. However, the California governor and legislature need to address this issue in the near future.

IMPROVE CALIFORNIA ELECTRICITY MARKETS

Redesign Wholesale Markets for Electricity

In examining causes of the energy crisis in California, this book has focused most attention on issues of regional energy supply and demand, California price regulation of the retail and wholesale markets, risk management, and long-term problems stemming from decisions made by California's political leaders. Issues of California

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[2]FERC press release April 25, 2001, re Docket Nos. RT01-35-000 and RT01-15-000.

[3]Ibid.

market design have been important but not central to understanding the fundamental causes of the crisis. No matter how perfectly the wholesale market had been designed in California, the fatal flaws in the regulation of the investor-owned utilities coupled with the perfect storm leading to supply/demand imbalances would have created a challenge, and the failure of the political leaders to address the problem meaningfully would have led to the crisis.

However, the wholesale markets in California remain severely flawed. They are unnecessarily complex and uncoordinated. Although the degree to which market power has been exercised, generating capacity has been strategically withheld, or market rules have been manipulated for financial gain, may not be fully resolved, it is clear that the currently flawed markets continue to create risks that costs will be increased and prices will be elevated above the appropriate levels. There is a great need to modify these markets to reduce the chance that another garden-variety storm will produce perfect-storm symptoms.

Restructuring Principles

Many authors have addressed means of restructuring the market. A clear and cogent statement of some of the principles is incorporated in Hogan's statement to Congress, from which the following passage is taken:

> *The experience is now sufficient for FERC to go beyond its previous deferential approach to markets created by stakeholders without regard to a set of detailed standard design principles. The good experience is concentrated in New York and in PJM, which serves the Mid-Atlantic region. These two markets now function under independent system operators (ISO) who employ a standardized spot market design for system coordination. . . . The common elements of this standard design include a bid-based, security-constrained, economic dispatch with locational prices, bilateral schedules, financial transmission rights, license-plate access charges and a broad scope for market-driven investment. Efficient pricing consistent with the ISO coordination functions then permits maximum commercial freedom without undermining reliability. The market monitoring and market power mitigation rules follow from the design. . . .*

These principles would include:

1. *The ISO must operate, and provide open access to, short-run markets to maintain short-run reliability and to provide a foundation for a workable market.*
2. *An ISO should be allowed to operate integrated short-run forward markets for energy and transmission.*
3. *An ISO should use locational marginal pricing to price and settle all purchases and sales of energy in its forward and real-time markets and to define comparable congestion (transmission usage) charges for bilateral transactions between locations.*
4. *An ISO should offer tradable point-to-point financial transmission rights that allow market participants to hedge the locational differences in energy prices.*
5. *An ISO should simultaneously optimize its ancillary service markets and energy markets.*
6. *The ISO should collaborate in rapidly expanding the capability to include demand side response for energy and ancillary services.*[4]

The CAISO's Wholesale Market Redesign Efforts

The CAISO has recently taken policy leadership by developing proposals for fundamental improvements in the wholesale market design through its "Market Design 2002" project. A team within the CAISO has been assigned the responsibility of developing a program of market changes that would address the most fundamental of the wholesale market problems. On January 8, 2002, the CAISO issued a preliminary draft of its proposed market changes.[5] Although the draft is still explicitly a "work in progress," it proposes substantial changes to repair some of the most troublesome aspects of the current wholesale markets in California and represents an excellent step

[4]"Statement of Professor William W. Hogan before the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs, United States House of Representatives" (August 2, 2001).

[5]California Independent System Operator, "Market Design 2002 Project: Preliminary Draft Comprehensive Design Proposal" (January 8, 2002). http://www.caiso.com/docs/09003a6080/13/58/09003a6080135879.PDF.

toward adopting restructuring principles consistent with those outlined above.

Central elements proposed by the CAISO include the following:[6]

- *Available Capacity (ACAP) Obligation on Load-Serving Entities*
- *Day-Ahead Congestion Management*
- *Firm Transmission Rights (FTRs)*
- *Forward Spot Energy Market*
- *Residual Day-Ahead Unit Commitment*
- *Real-Time Economic Dispatch Using Full Network Model*
- *Real-Time Bid Mitigation for Local Reliability Needs*
- *Damage Control Price Cap on CAISO Markets*

Most of these proposed elements represent much-needed and appropriate reforms to the well-identified market flaws. Under the *day-ahead congestion management* proposal, the CAISO would start using a "fully accurate model of the CAISO grid for the purpose of adjusting generation and load schedules to mitigate transmission overloads and ensure local reliability, instead of today's simplified three-zone model." This change will allow the CAISO to move toward nodal pricing and control, which recognize that economic conditions at various nodes of the grid may vary significantly from one another even within a given geographic zone.

Firm transmission rights are financial instruments that would allow market participants the right to ensure their electricity would be transmitted at a particular time between particular generator locations and load locations. These would allow participants to hedge risks of possible high congestion charges.

The proposal for a *forward spot energy market* would replace the now-defunct PX with an organized short-term futures market for electricity. However, rather than a market run totally separate from the CAISO, the new forward spot energy market could and should be integrated into the CAISO operations (although the

[6]Each of the following elements is a direct quote from "Market Design 2002 Project: Preliminary Draft Comprehensive Design Proposal." Quotations in the paragraphs that follow are from this document as well.

CAISO believes the market could be operated by another entity). As the CAISO team has recognized, under the proposed congestion management changes, there will be spot market transactions among electricity market participants; creation of a formal forward spot market would improve the efficiency of these trades.

The proposal for *residual day-ahead unit commitment* would allow the CAISO to assess whether the day-ahead schedules include enough resources to meet the next day's demands. If needed, the CAISO could make commitments to pay electricity-generating resources that have long start-up times for both the times they are generating and the costs they incur for start-up and for remaining in operation even when the electricity may not be needed.

Under the proposal for *real-time economic dispatch using full network model*, "every 10 minutes during each operating hour the CAISO would run a 'security-constrained economic dispatch' program to determine which resources to dispatch at what operating levels to meet real-time needs." Such an approach would allow the CAISO to use cost-minimizing, modern optimization models, taking into account the relevant constraints facing the system ("transmission constraints, local reliability needs, and generator operating constraints, as well as system imbalance energy needs"). This proposal would be consistent with the move toward nodal real-time pricing in the wholesale market. In addition, it would eliminate the requirement for scheduling coordinators to submit balanced loads. The overall optimization program would perform the balancing function and thus individually balanced loads would not be important.

Finally, the proposal for *real-time bid mitigation for local-reliability needs* would allow the CAISO to mitigate locational market power that could be exercised by generators that are the only units operating at a constrained location on the grid.

Although the detailed implementations of these plans undoubtedly have not yet been completed and, once completed, will be subject to much debate, these proposed changes together represent a very strong and useful movement toward improving the design of California wholesale markets.

Two of the proposals, however, may not be appropriate in their current form, or at least require significantly more design. The proposal for an *available capacity (ACAP) obligation on load-serving entities* would place on the utilities (and other load-serving entities) the responsibility "to procure adequate capacity to meet their expected peak monthly loads plus reserve requirements," which would move the California wholesale markets sharply away from spot markets and is likely to lead utilities to enter into a mix of long-, medium-, and short-term contracts to purchase electricity. This allocation of responsibility would be a very positive step, as would the shift away from spot markets. However, it is not yet clear whether the CAISO-proposed mechanisms for accomplishing this end would be workable. Under this proposal, each load-serving entity would be required to have contractually available electricity generation capacity equal to "a fixed margin above the next month's forecast peak load (for example, in the area of (1.15)× forecast monthly peak load)," which could be met "by a combination of own generation, firm energy contracts, . . . capacity contracts, and physical demand management."

Before the beginning of each month, each load-serving entity would be required to demonstrate to the CAISO that it has procured adequate capacity for the following month. Those entities that had shortfalls would be assessed a substantial penalty.

Whether such a plan will improve the market operations is unclear. It would increase the demand for electricity contractual commitments and, at least in the short run, would increase the wholesale price of electricity. The CAISO would be required to evaluate the demand forecasts of each utility and substitute its own forecasts for the utility forecasts if they differ from one another. The proposed incentive structure is likely to lead to more unused generating capacity in times of short supply than would be desirable. The plan might encourage somewhat more capacity development than would otherwise be the case and might reduce the degree of price volatility. In short, though this plan has many desirable characteristics, more design and analysis is still required.

Finally, the proposal for a *damage control price cap on CAISO markets* has been designed to "limit the adverse cost impacts of an unusually severe price spike." However, this proposal cannot be evaluated until the level of that price cap, the conditions under which it is applied, and the structure of prices under the cap are specified. Whether price caps, bid caps, or no controls at all are more appropriate to deal with severe price spikes has not been settled.

The CAISO has clearly communicated its intention to use the preliminary draft as a starting point in the redesign process, not as the ending point. As such, the CAISO is now taking a very appropriate and much-needed leadership position in working to improve the California wholesale electricity markets.

Ensure Competition in Wholesale Markets

The California experience suggests that particular attention must be paid to ensuring that there is true competition and only a minimum chance for the exercise of market power. Because there are so many constraints on the electricity system—based on the nonstorable nature of electricity, the locational structure of electricity generation and use, and limitations associated with transmission capacity—enforcement of antitrust laws and other procompetitive laws is important. However, in doing so, the empirical rules that have been developed for other industries may be difficult to apply directly.[7]

Public visibility of actions taken by the various participants in the system—generators, local distribution companies, traders, and governmental agencies—is also crucial for appropriate policy making and enforcement of market rules. Thus, reliable, publicly available data would allow analysts and members of the public to see more clearly the actual workings of the system. Appropriate data include both the regional supply and demand data described above plus more detailed data (possibly made available only after several months) about actions by individual market participants.

Finally, given the possibility of complex bidding structures, it is important that the system be designed to reduce the possibility that firms with relatively small market share can exercise market power. Some of the market redesign issues discussed above can be important for this goal.

Promote Retail Competition by Restoring Direct Access

As discussed above, retail competition for serving small residential customers may be problematic. However, retail competition for serving large industrial loads is feasible and would have several important benefits. If industrial customers can negotiate contracts with electricity generators, absent requirement for CPUC intervention, those contracts can provide appropriate risk-sharing mechanisms

[7]For example, given the almost vertical demand functions and the supply functions (when capacity is low), empirical rules based on conventional measures of market concentration are likely to understate the opportunities for exercise of market power.

that are mutually beneficial to the generator and the user of the electricity. For example, such contracts could implement a real-time pricing system, with real-time prices varying along with some objective measure of spot wholesale prices. The real-time pricing system could be implemented as a two-part system, so that marginal prices can vary along with wholesale prices while the average payment for the electricity varies only by a much smaller amount.

Direct access could allow those companies that need a much higher degree of supply reliability and are willing to pay for it to be able to acquire such reliable electricity supplies. Direct access could also promote the development and installation of micro turbines or fuel cells that are located very close to the point of electricity use.[8]

Finally, direct access for large industrial customers could be the starting point where we begin to experiment with the possibility of more complete retail competition.

As discussed above, however, current law precludes direct access for all customers. The California Legislature recognizes that direct access would conflict with the intention of the State to pay for the sunk costs it has incurred through increased future electricity prices.

There are viable alternatives for recovering the sunk costs that do not require elimination of direct access. For example, the State could impose a tax on electricity sales, either for sales in service areas of the investor-owned utilities or throughout the state. Alternatively, the CPUC could adopt an exit charge, under which any industrial customer choosing to bypass utilities would be obligated to pay into a fund designed to cover the State's sunk costs.

An even better alternative would be to recognize the nature of the problem—the State of California agreed to a large number of unwise financial obligations, which were the responsibility of the governor and the legislature as representatives of the California citizens. The State could keep these mistakes as financial obligations through the State Treasury. The State of California would still pay the financial burden of the errors made by the governor and the legislature, but the payment, over many years, would remain strictly a financial

[8]It is possible, however, that the *lack* of direct access could encourage distributed generation located on the facilities of the customer wishing to purchase electricity, if that customer were precluded from the opportunity of directly negotiating an appropriate contract for electricity generated off of its premises.

problem rather than the cause of restrictions on the freedom of California's economy to operate effectively.

Thus, it is both desirable and possible to restore direct access at least for large electricity customers. The failure to do so is a step backwards, toward direct governmental controls rather than market operations.

Improve Pricing in Retail Markets

Markets for electricity, like markets for other commodities, can allow people the freedom to choose the goods and services they wish to consume while at the same time ensuring that the quantities they purchase are economically efficient. Markets can encourage consumers to buy goods and services whenever those products are more valuable to the consumer than their cost and can discourage purchases whenever the value to the consumer is less than the cost. However, markets can function in such an efficient and free manner only if prices correspond to costs, in particular to marginal costs.

One of the fundamental problems during the challenge period and the electricity crisis was that retail electricity prices were not allowed to follow marginal costs even approximately. Retail prices were artificially constrained to well below marginal costs of electricity production and distribution during the entire challenge and crisis periods. When retail prices are kept well below cost, consumers are not naturally encouraged by market forces to reduce their use of electricity. The resultant overuse of electricity provides motivations for governmental organizations to impose restrictions on personal freedom to choose how much electricity to use. Now retail prices charged by the investor-owned utilities remain well above marginal costs and promise to remain at elevated levels for decades to come. When retail prices are kept well above cost, consumers find ways of using less electricity than would be optimal from their own perspectives and incur excessively large costs for reducing their use of that electricity. Thus, both underpricing of electricity during the challenge period and crisis and overpricing of retail electricity afterwards cause economic inefficiencies.

The functioning of retail electricity markets could be significantly improved if retail prices were allowed to track costs of providing that electricity to customers. Tracking of costs could be improved in two dimensions. First, during times of particularly high wholesale prices, average retail prices should be elevated to correspond to the high average wholesale prices and during times of low wholesale prices, average retail prices should decline: the retail price level should on average correspond to costs. Second, during the course of the day, as wholesale prices fluctuate between high levels during peak times and low levels at off-peak times, retail prices should follow this daily variation in wholesale costs.

The problems of failing to allow the retail prices to increase during times of exceptionally high wholesale prices have been extensively discussed in previous chapters of this book. The discussion need not be repeated here. However, the problem of failing to allow retail price variations during the course of the day to correspond to cost variations has not been adequately discussed and will be the subject of what follows.

Allow Real-Time Retail Pricing

Wholesale electricity prices vary sharply over the course of a day, week, or month, with high prices during times of high demand and low prices during times of low demand. Figure 6.1 illustrates this price variation using data on wholesale prices and transactions volume on the California PX during July 1999, a normal period. The volume, shown by red lines, has a scale from 0 to 40,000 MW. Wholesale price, shown by blue lines, has a scale from $0 to $160/MWh.

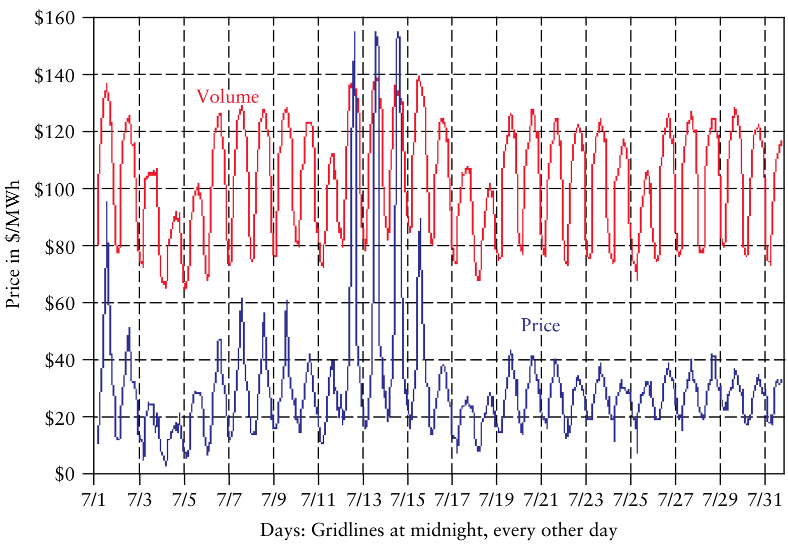

FIGURE 6.1: PX Price and Volume during the Course of a Month: July 1999

SOURCE: California Energy Commission

Figure 6.1 shows that during the course of the month, wholesale price varied from a low of $2/MWh to a high of $155/MWh, roughly an eighty-fold variation. During the days with least variation, the high price was roughly twice the lowest price and during days of medium price variation, the high price could be six times as high as the lowest price.

Figure 6.1 also shows that prices were high during periods of high volume, when demand reductions would be appropriate, and prices were low during periods of low volume, when there is no particular need for demand reductions. If consumers could be motivated to shift the timing of their electricity use away from the peak times toward off-peak times, wholesale price increases during peak periods could be substantially alleviated, inducing only small increases in the off-peak prices.

Even in the face of these large normal variations in wholesale prices, and thus in costs of acquiring electricity, regulated retail prices for all but the largest customers remained constant. For example, for PG&E, the retail price of electricity during this time was $125/MWh, including $60/MWh for delivery services and $65/MWh for electricity. Thus, for most times during that interval the retail price of electricity itself exceeded the marginal cost of electricity, but for some times the price was much lower than marginal cost.

Efficiency in the use of electricity could be significantly improved if customers faced retail prices that varied on a real-time basis, corresponding to marginal cost variations. Such a time-varying system is generally referred to as "real-time pricing." In principle, real-time pricing would promote economic efficiency since it could be designed to ensure that retail prices closely tracked marginal costs of electricity on an hour-by-hour basis or more frequently.

In practice, however, installing meters, designing and operating the communications systems, and managing the billing system would be costly, even though the meters are currently being installed for the largest customers. For the largest customers and those most able to change their electricity purchases in response to time-varying prices, the costs of metering will be smaller than the economic gains from real-time pricing and, on net, real-time pricing would lead to net economic benefits. For the smallest customers and those least able to adjust electricity purchases in response to changing prices, the costs of metering would exceed the economic gains from real-time pricing, which, on net, would not be attractive. Thus, although real-time pricing is an attractive option for many electricity users, it is not economically attractive for all.

Real-time pricing is likely to grow as a contractual structure for the larger users if retail competition, particularly direct access, is restored. Under such a competitive system, electricity users who would, on net, benefit from real-time pricing would be free to choose such a pricing arrangement, and those who would not benefit would be free to keep prices that remain constant within a given day. In addition, for those under CPUC tariffs, real-time pricing should be made broadly available.

Under a pure system of real-time pricing, the price of all electricity purchased by large customers would vary on an hourly basis with the wholesale market price. Such a system is referred to as a "one-part real-time pricing" system. The difficulty of a one-part real-time pricing system is that the total expenditure for electricity by large electricity users could vary radically from week to week or month to month. If an electricity user wishes to avoid large fluctuations in electricity purchase costs, one-part real-time pricing may be unattractive.

An alternative, especially for large industrial customers, is a "two-part real-time pricing system," under which a contractually determined base-load quantity of electricity purchased by the large user is made available at some more stable price. For increases or decreases in the quantity of electricity used around that level, the price for incremental increases or decreases in use of electricity would be set equal to the real-time price. Under such a two-part system, the large customer bears less risk of price variations but still faces incentives to reduce demand during high-price times, since the marginal retail price of electricity would move with the wholesale price. Two-part real-time pricing would allow a balance between the stability of average expenditures and the variability of marginal prices responding to changing conditions.

The disadvantage of a two-part real-time pricing system, however, is that if the base-load quantity is set at a price lower than expected for the future, each user will fight to have a large base-load quantity. The allocation of the baseline in that case becomes a difficult political process.

Even this problem can be solved if the price of the base load is set equal to or slightly above the expected price of the electricity in the future. In that case, the customer can freely choose the base-load quantity for the future and sign a binding contract to that effect.[9] However, the problem cannot readily be solved if the base load is made available at a subsidized price, as was the case during the electricity crisis. Thus, although real-time pricing would have been useful during the challenge period and the crisis, those times would have been the most difficult to introduce such a system. Thus, it perhaps should not have been a surprise that, although the California Legislature voted for $35 million to install real-time meters, a real-time pricing system has not yet been approved and implemented within the state.

IMPROVE RISK MANAGEMENT

Risk management for the electricity system involves identification and appropriate reduction of both the physical and the financial risks and involves improving the response of the system to adverse events. Physical risks are discussed first. A subsequent section addresses financial risk protection.

Reduce Infrastructure-Related Risks

Improve Fuel Supply Infrastructure

In California, the infrastructure to transport natural gas both into the state and within the state has been a bottleneck causing natural gas prices to soar; this infrastructure should be expanded. With these pipelines at or near capacity, whenever there is a significant increase in the use of natural gas to run generating plants, we can expect sharp increases in natural gas price, with a consequent increase in wholesale costs of electricity.

High prices for infrastructure services provide market signals that greater amounts of that infrastructure would be economically efficient and profitable for investors. The price for natural gas transportation services within California can be measured by the difference between the delivered natural gas price and the price at the California border, a difference that rose to $50/mcf. Although this price persisted for only a short time, transportation services prices exceeding $5/mcf persisted for months, which strongly suggested the need for additional pipeline capacity.

[9]Pricing of mobile telephone service is organized that way. The buyer decides how may “free” minutes to have available each month and pays a fixed cost for the fixed availability of these free minutes. Additional minutes, purchased as spot transactions, are at a much higher rate.

Now that the crisis is over and the very inefficient gas-fired generating plants are not being used, natural gas pipeline capacity currently appears sufficient. However, the new gas-fired electricity-generating plants soon coming on-line will again increase the use of natural gas and will thus require an increase in natural gas pipeline capacity. In order to minimize the risk of similar natural gas price spikes, California's natural gas pipeline system needs expansion. The California Public Utilities Commission needs to support, and even encourage, future proposals for pipeline expansion.

Improve Transmission Infrastructure

The infrastructure for electricity transmission is currently too limited at a few important bottlenecks on the grid. Significant increases in the electricity price in Northern California, relative to the Southern California price, were associated with the inability to move adequate quantities of electricity from Southern California to Northern California when needed, along Path 15. An expansion of the transmission capacity between Northern and Southern California would be a significant infrastructure improvement, but a very costly investment.

In October 2001, Secretary of Energy Spencer Abraham announced that a power transmission line would be built to relieve congestion along Path 15. Estimated to cost about $300 million, the line will be built by a consortium of private companies and public agencies.

In addition, the crisis made it painfully clear that the western United States is electrically virtually isolated from the rest of the country. The West had very high spot wholesale electricity prices, whereas prices to the east of the Rockies remained much lower. The construction of new tie lines connecting the western part of the United States with the rest of the nation would allow a sharing in either direction as needed and would reduce the likelihood of regional electricity shortages. On the other hand, transmission facilities are expensive. Costs of such investments would likely dwarf the $300 million expected for the Path 15 upgrades. In addition, investment in new gas-fired electricity generators is relatively cheap. Whether investment in such new transmission capacity would be economical, relative to the alternative of new generation capacity, remains to be seen, but an assessment of that option is needed.

Make Energy Infrastructure More Secure from Terrorism The infrastructure serving California's electricity system, including natural gas pipelines and electricity transmission systems, is vulnerable to terrorist attacks. Successful attacks have the potential of creating another electricity crisis, although probably of shorter duration than the 2000–2001 events.

The natural gas pipelines that serve California cover long distances, in many places above ground. The above-ground sections could be vulnerable to terrorist attack, although the below-ground sections are likely to be difficult to attack. Successful attacks could reduce California's ability to generate electricity using natural gas, the energy source for 50 percent of California's electricity generation. Pipelines coming into California each have the capacity to supply on average less than 10 percent of California's electricity generation. Unless the system is near full capacity, only successful attacks on multiple pipelines can create such a crisis. Moreover, a decrease in natural gas availability would cause the least efficient gas-fired generating units to be taken off-line, not the most efficient. Thus, although California is vulnerable through the natural gas pipeline system, the potential for damage is smaller than that for the electricity transmission system.

Electricity transmission lines remain very vulnerable to terrorist attacks, although successful attacks on most lines themselves could be repaired relatively quickly. In addition, local transmission grids are designed to operate effectively if one transmission line is out of operation. However, there are several transmission lines essential to system operation. Given the large fraction of electricity moved along Path 15, between Northern and Southern California, and the large fraction moved on the two interties from the Pacific Northwest, successful terrorist attacks at these parts of the grid could precipitate a short-term physical shortage of electricity.

Even more damaging than attacks on transmission lines would be attacks on substations, which cannot be repaired quickly because the large transformers and the switching equipment typically cannot be made available quickly.

How one can best protect this vulnerable infrastructure is not clear; however, the solution should involve some combination of protection, redundancy of infrastructure, and equipment stockpiles allowing rapid facility repair. Each of these strategies adds costs to the electricity system.

Improve System Response to Adverse Events

One approach to improving risk management involves reducing the likelihood that adverse events, such as supply shortages, will occur. That approach, discussed in the previous section, may lead to a focus on reducing the infrastructure-related risks. There is another, complementary approach: reducing the harm that results from adverse events, should they occur.

Typically, harm can be reduced by making the system more flexible and more responsive to changing economic conditions. The responsiveness then allows, even encourages, individual consumers and producers to adjust in ways that reduce the harm they face and, in so doing, reduce the harm to the entire system. Generically, such approaches involve increasing the electricity demand responsiveness and electricity supply responsiveness to changing conditions.

Increase Electricity Demand Responsiveness

As has been discussed in previous chapters, one of the fundamental causes of price volatility in the wholesale electricity markets was the lack of responsiveness of electricity demand to wholesale prices. Figures 3.14 and 3.15 illustrated that if the demand for electricity were more responsive to wholesale price changes, the wholesale price changes caused by variability in supply and demand would be greatly reduced. Thus, price-spike-related economic damages would be reduced if electricity demand were more responsive to wholesale price increases.

A significant factor ending the electricity crisis has been the reduction in use of electricity. Some of the underlying demand reductions are transient and some are permanent. The permanent reductions in demand, although beneficial, will not provide the "shock absorbers" needed to increase the demand responsiveness of the system. Market participants and governmental agencies will take into account these permanent demand reductions as they evaluate or forecast future electricity demand. Such expectations of future electricity demand strongly influence new generation capacity.[10] Therefore, permanent

[10]The influence may be direct in that firms estimate the future generating capacity needed to satisfy future demand. Or it may be indirect in that firms evaluate the supply/demand balance and assess the likely future market prices of electricity. Through either route, expectations of future demand influence capacity investment decisions.

demand reductions will ultimately lead to equivalent reductions in electricity-generation capacity, just compensating for the demand reductions. Therefore, once all adjustments are completed, permanent reductions in electricity demand will not enhance the ability of the state to respond to future price volatility.[11]

Policies that lead to greater demand reductions that occur quickly in response to wholesale price increases could significantly reduce future wholesale price spikes. Implementing such policies in California would be good, although implementing them throughout the West would be much better.

One strategy would be to make retail prices quantitatively more responsive and more quickly responsive to wholesale prices, counting on consumers to reduce electricity purchases in their own interest when retail electricity prices increase. This strategy could involve many different approaches.

At the most basic level, this strategy would require electricity regulators to abolish fixed-price retail price controls. California's dogged maintenance of retail price controls in the face of skyrocketing wholesale prices was the single most harmful California policy failure. If Governor Davis and/or the CPUC had allowed retail rates to increase appropriately during the challenge period, demand would have dropped enough to allow California to avoid the crisis.[12]

Even without such retail price controls, most utilities, municipal or investor owned, charge retail rates to approximate the cost of delivery services plus the average cost of acquiring electricity. Moreover, most utilities acquire the vast majority of their electricity

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[11] One should remember that California has a long tradition of successful policies designed to reduce electricity demand. In 1999, California per capita residential electricity use was 37 percent below the national average. This history of relatively low electricity intensity did not save California from the crisis.

[12] One might reasonably conclude that, after observing the great harm caused by California's maintenance of retail price controls into the crisis, no state would ever make such a fundamental mistake in the future. But price controls have been a resort of political leaders in the United States before and they are likely to be again. And Governor Davis seemed to understand fully the great damages his policy was causing. Moreover, because the economic factors underlying California's restructuring are common across many electricity systems, the reasons underlying California's initial imposition of price controls may be relevant elsewhere. However, even if retail price controls are imposed during times of relatively stable wholesale prices, California's plight should make it clear that such controls must be eliminated during times of sharply rising wholesale prices.

through long-term fixed-price contracts or their own generation (incurring costs not closely related to the wholesale price). Thus, the average acquisition cost of electricity increases by far less than does the spot wholesale price.[13] Therefore, under average cost pricing, retail prices increase by only a small fraction of the increase in spot wholesale prices. The magnitude of the resultant retail price increase is much smaller than the magnitude of the spot wholesale price increase.

In addition, regulated retail electricity prices generally respond only slowly to wholesale price increases. Typically, regulators calculate average cost in a backward-looking manner, based on many months of historical experience. Regulator agencies seldom, if ever, calculate the average of current acquisition costs. Therefore, calculated average costs respond only slowly to changes in spot wholesale prices. As a result, the retail price increase is often delayed for many months, and the speed of its increase is much slower than that of the spot wholesale price increase.

Regulatory agencies could take steps to make the speed and magnitude of retail price increases correspond more closely to the speed and magnitude of changes in the spot wholesale market by quickly adding surcharges onto the standard retail rates in times of rapid wholesale price increases. These surcharges can be larger than the increase in average acquisition cost and yet may be smaller than the increase in the spot wholesale price. Such surcharges would increase the net revenues of the utility during wholesale price spikes. Regulators could require the utility to accumulate these excess revenues in a special account that could be drawn on during times of sharp reductions in spot wholesale prices.[14] In this way, state agencies could still regulate utilities so that prices *averaged over time* corresponded to average costs while varying retail prices by more than the variation in average acquisition cost.

In addition, retail pricing could include two-part tariffs, either with or without real-time pricing, allowing the marginal retail

[13]As an example, if a utility acquires 90 percent of its electricity on long-term fixed-price contracts and 10 percent on the spot market, then a \$100/MWh increase in the spot wholesale price would lead to a \$10/MWh increase in the average wholesale price.

[14]This statement assumes that regulators allow retail prices to fall by more than the decrease in average acquisition cost during times of sharp drops in spot wholesale prices.

prices—that is, the prices for increases or decreases in the quantity of electricity purchased—to increase or decrease by as much as wholesale spot prices while keeping the average retail price equal to average acquisition costs. Such a system—if one could transcend the problem of customers fighting to increase their low-priced base quantity—would enhance the efficiency of retail markets and greatly increase the responsiveness of demand to wholesale market conditions.

A further step would be for utilities to institute real-time pricing broadly, as discussed in a previous section. Real-time pricing, with variations in marginal prices corresponding to wholesale price variations, would give the fastest, most complete incentives for demand to respond to wholesale price movements.

The farther utilities move along this sequence, the more responsive retail demand will be to wholesale prices. The more responsive retail demand is to wholesale prices, the less volatile the wholesale price will be. However, the farther utilities move along this sequence, the more volatile the retail prices will be and the greater the political impetus to reestablish retail price controls will be.

Retail price variations are not the only means of increasing energy demand responsiveness. Utilities could introduce a system of demand-side bidding, in which large users of electricity could agree to reduce their use of electricity while being compensated financially for those reductions. Utilities could establish a formal auction to allow such demand-side bidding to proceed efficiently, which the CAISO's "Market Design 2002" project envisions.

In addition, utilities could increase the currently existing programs of direct control by the utilities of some loads—for example, air-conditioning loads. Many uses could be set under computer control and utilities could exercise that control in times of tight electricity markets. The equipment for that communication and control is available now. The utility and the customer would enter a contractual relationship that allows the utility to cycle the appliances, or to reduce the use of those appliances during hours of the day in which prices of electricity are particularly high. The utilities would need to negotiate ahead of time the contractual agreements to allow such widespread load-shedding in times of need. Under such a system, the customer would not pay large increases in electricity price but would still be motivated to reduce demand when needed.

Increase Supply Responsiveness

The most fundamental long-term solutions to the California electricity crisis were initiated four years ago with the boom in construction of new electricity-generating facilities. Including the plants that were completed this summer, 11,000 MW of new generating capacity is under construction. Of this total, about 6,000 MW can be expected to come on-line within the next year or is already generating electricity. Another 11,000 MW of new generating capacity is under review by the California Energy Commission.

A fundamental requirement for avoiding perfect-storm problems is adequate electricity-generating capacity. However, “adequate” must be defined in a regional context, not simply a California-specific context, since the regional markets are so tightly interconnected. Thus, there need to be incentives for new generation capacity throughout the region, including in California, where the issue is how not to discourage development of generation capacity. In the other states, the issue is how to encourage the appropriate amount of new construction.

Since the restructuring legislation of 1996, which included a significant deregulation of electricity generation, there has been a boom in construction of new generating plants in California. Nevertheless, it is important not to get in the way of this process. Threats to take over these plants by eminent domain or a return to the old regulated system, as well as a long-term system of wholesale electricity price control, could each dampen enthusiasm for new construction. These threats create large uncertainties for those considering investing in new electricity-generating facilities. Similarly, actions by the State Power Authority to use State funds to compete with private sector investment would be contrary to the goal of allowing the private sector to develop new generation capacity. State-created investment uncertainty is neither in the long-run interests of the citizens of California nor in the interests of investors in the electricity system.

Given the long lead-time from decisions to invest in new generating units until the time the new generation is on-line, increasing supply responsiveness must account for the responsiveness of investment decisions to forecasts of future market needs. However, future supply and demand conditions in electricity markets are not perfectly predictable. Hydroelectric generating capacity is very dependent on the amount of rainfall. Increased costs of natural gas can make some generating facilities uneconomical and thereby reduce supply. Construction of new generating facilities can be delayed for a host of different reasons. Prediction of the growth in electricity demand is at best an imperfect art. Air-conditioning loads are very dependent on weather, so consumption of electricity can vary greatly on a daily basis. And for states like California, which count on other states to supply a significant amount of electricity demand, supply and demand conditions in those other states may also be unpredictable. For that reason, improvements in the quality of prospective market information, including the breadth and quality of current and historical regional electricity market data, could be important contributors to the goal of increasing electricity supply responsiveness.

In addition, financial incentives could encourage utilities or generators to ensure that there will be reserve capacity in the system, which would increase the short-run supply responsiveness and thus help reduce the damages associated with adverse supply and demand conditions. One approach would be the creation of capacity markets. However, capacity markets are very difficult to develop and manage and thus may not be a viable means of increasing capacity to increase the short-run supply responsiveness. Another approach might be the implementation of something like the "available capacity obligation on load-serving entities" currently being proposed by the CAISO.

Distribute Financial Risks Appropriately

California's electricity crisis made it clear that the financial risks associated with rapid increases of wholesale prices were felt very unevenly by the various utilities in the West. Those that had secured all or almost all of their electricity needs through long-term fixed-price contracts faced little or no financial risk. On the other hand, those, such as California's investor-owned utilities, that were required to purchase more than one half of their electricity on the volatile spot markets faced tremendous financial risks. In addition, those utilities that could respond by increasing retail electricity prices were able to avoid risks by passing them on to their customers, whereas those utilities whose retail rates remained fixed bore all risks of wholesale price increases themselves.

Each utility and its customers will typically wish to reduce the risk of price spikes associated with short supplies of electricity. One method of any single utility reducing its risk and those of its customers would be to enter long-term contracts to purchase electricity at fixed prices. If a utility covered all of its electricity needs this way, variations in spot wholesale prices would have no necessary financial consequences. If the utility's retail rates were based on its average acquisition price of electricity, then its customers would also not be subject to financial consequences of wholesale price increases. In this way, the utility and its customers could avoid all risk of wholesale price variations.

However, long-term fixed-price contracts may reduce the risk facing the utility holding the contracts while increasing the risk to utilities (and their customers) buying electricity at spot market prices. In some sense, long-term contracts do not reduce the overall market risk but simply transfer that risk to other market participants. This occurs because utilities typically sell electricity to their customers at prices based on the average acquisition price of that electricity. If, when wholesale prices increase, the average acquisition price does not change, utilities typically keep retail electricity prices constant. Constant retail prices imply that the electricity users have no incentives to reduce their demands as wholesale prices increase. Therefore, long-term contracts tend to substantially reduce the electricity demand responsiveness and imply that larger wholesale price increases are needed to balance supply and demand after a given reduction in electricity supply or increase in demand.

The role of contracts in distributing the financial risk, rather than reducing the overall risk, can be illustrated by a group of five identical utilities each purchasing 10,000 MW of electricity. Under one assumption, none use any long-term contracts, compared to another assumption that each covers 80 percent of its initial purchases using long-term contracts. Assume that in either case, some event reduces the electricity supply by 5,000 MW. Then, each firm, being identical to every other firm, would ultimately reduce its consumption by 1,000 MW.

Assume now that every $2/MWh rise in the retail price of electricity reduced the demand for electricity for a given firm by 100 MW. Therefore, the retail price of electricity would need to increase by $20/MWh in order to motivate the 1,000 MW demand reductions for each firm. This required retail price increase would be $20/MWh, no matter whether no utilities or all utilities used long-term contracts.

If no firms had any long-term contracts and all priced retail electricity at the average wholesale cost, then in response to the 5,000 MW reduction of supply, the wholesale price would increase by \$20/MWh, which would apply to all 9,000 MW that each utility was still purchasing. Thus the cost increase for the 9,000 MW ultimately purchased would be \$180,000 per hour of purchases (9,000 MW × \$20/MWh).

If each firm had long-term contracts covering 80 percent of its initial electricity needs and all priced retail electricity at the average wholesale cost, then in response to the 5,000 MW reduction of supply, the wholesale price would now increase by \$180/MWh, not \$20/MWh. The \$180/MWh increase in price would apply to the 1,000 MW the utility would continue to purchase on the spot market; there would be no price increase for the other 8,000 MW under long-term contract. A \$180/MWh increase in price applied to one-ninth of the purchases would increase the average wholesale price and the average retail price by \$20/MWh. Thus the cost increase for the 1,000 MW ultimately purchased on the spot market would be \$180,000 per hour of purchases (1,000 MW × \$180/MWh), identical to the increase that would occur if no firms had long-term contracts. A similar equality would hold for increases in electricity supply leading to reductions in wholesale electricity price.

Thus, although each individual utility could use long-term contracts to protect itself from the risks of wholesale price increases stemming from supply reductions, it could do so only if the other utilities continued to purchase on the spot markets. If all utilities tried to protect themselves using long-term contracts, none ultimately would be any more protected than when all electricity was being purchased on the spot markets. Long-term contracts simply protect those utilities that have entered long-term purchase contracts and transfer the risks to the other utilities.

Equal distribution of the financial risk among utilities, therefore, requires that each utility be given an equal opportunity to protect itself with long-term contracts.[15] If most utilities are so

[15]A numerical example illustrates different firms having different contractual protection. Assume three utilities had long-term contracts for 80 percent of initial electricity needs and two had no contracts. In response to the 5,000 MW reduction of supply, wholesale price would increase by \$42.86/MWh. The \$42.86/MWh price increase would apply to 1,000 MW of 9,000 MW for utilities with contracts, increase average price by \$4.76/MWh, and reduce demand by 238 MW for each of these three utilities, for a total reduction of 714 MW. The \$42.86/MWh increase in price applied to all purchases of the other two utilities would increase average price by \$42.86/MWh and reduce demand by 2,143 MW for customers of these two utilities, for a total reduction of 4,286 MW.

protected but some are required to purchase the majority of their electricity on spot markets, those purchasing on spot markets will bear a disproportionate share of the risk. A similar phenomenon would occur if utilities were not allowed to increase retail prices when wholesale prices increased, as was the case in California.

To keep the example simple, assume that public utility commissions, to protect consumers, allowed only 10 percent of the wholesale price increase to be passed on to retail customers and that utilities purchased all electricity on the spot market, as in the first case. Then, in response to the 5,000 MW supply reduction, wholesale prices would increase by \$200/MWh, not \$20/MWh. Since 10 percent of this \$200/MWh increase in wholesale price would be passed through to consumers, consumers would face an increase in retail price of \$20/MWh, just enough to motivate the requisite demand reduction. Consumers, although protected by the Public Utility Commission, would face exactly as much of a price increase as they would with no such protection. However, now the utility would lose \$180/MWh for each of the 9,000 MWh it purchased, for total losses of \$1,620,000 per hour of purchases.[16]

The examples illustrate the fundamental point. Every restriction that keeps wholesale price increases from translating to retail prices will result in greater increases in the wholesale prices, since each such restriction reduces the electricity demand responsiveness. If some utilities are allowed to enter long-term contracts while others are denied that opportunity, the latter group will face increased financial risk just compensating for the reduced financial risk of the former group. If wholesale price increases are only partially passed through to retail price increases, wholesale prices will go up even more to motivate the requisite demand responses, therefore harming the utilities without in fact protecting the customers.

This fundamental nature of the markets implies that if some utilities throughout the region are allowed, even encouraged, to cover most of their electricity acquisitions through long-term fixed-price contracts, then all utilities must be allowed to do so. If wholesale prices increase, these utilities must be allowed to increase the retail prices correspondingly. Any restrictions on the

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[16] If consumers were ultimately required to pay some share of these losses through long-term bonds, the efforts to protect consumers would make them strictly worse off, since they would save no money during the crisis but would be burdened by high prices afterward, as in the California case.

ability of a utility to enter long-term contracts or to pass wholesale cost increases to retail prices will lead to an uneven distribution of risk among those utilities.

However, the simple examples do not give the complete story, since utilities differ in the financial agreements they have with their customers. Therefore, a wide array of contractual structures should be open to the participants in the system, so they can each choose appropriate contracts depending on their particular circumstances. Electric utilities that have fixed obligations to serve customers are likely to want electricity supply contracts whose time horizon is consistent with the long-time scale of the obligation to serve. Risk-sharing arrangements between the utilities and their large customers or between generators and large customers should be allowed or encouraged. Risk-sharing arrangements may include obligations to provide a fixed amount of electricity at a predetermined price with additional quantities of electricity or reductions in the use of electricity priced in real time. With such contracts in place, the utilities could make long-term contracts to acquire the electricity in sufficient quantities to cover such retail contracts and could thus be free to set up risk-sharing arrangements that are consistent with the preferences of their customers.

MANAGE CALIFORNIA'S FINANCIAL OBLIGATIONS

California has acquired massive financial obligations primarily because of the State's mismanagement of the electricity crisis. The total dollar value of these obligations is still not clear. The FERC has yet to rule on the size of the refunds to which California will be entitled from generators that charged more for electricity than allowable under FERC price mitigation rules. Moreover, the size of the bond offerings and their terms are still outstanding issues. Whatever the ultimate magnitude of the obligations, the State still needs to resolve two issues: how it should treat financial obligations to electricity generators under the long-term contracts and in what ways it should pay for these obligations. These will be the final two issues of this chapter.

Long-Term Electricity Contracts

Now that it has become widely apparent that the State's long-term electricity purchase contracts are at prices well above the current and expected future electricity prices, there is a strong pressure among governmental officials to "renegotiate" the contracts. There seems to be a broad recognition in the State Administration and Legislature that these contracts are not now and never were in California's interest. Yet how the State should proceed is not obvious, since many options involve a trade-off between the credibility of the State as a contractual partner and the depth of the electricity blight.

Renegotiation of many contracts can be valuable for both contractual parties when economic conditions change; however, legitimate renegotiation implies the identification of contractual changes that are preferable for both parties. It typically does not imply changes that are preferable from one party's perspective and disadvantageous from the perspective of the other party. Nor does it mean unilateral reneging on commitments. Yet these distinctions are not apparent from California's policy pronouncements, where renegotiation seems to have lost the concept of mutual gain or mutual agreement.

Attempts by California to achieve unilateral gains can have long-term adverse consequences for California. The continuing ability of the State of California to negotiate contracts on reasonable terms with a wide variety of contractual partners depends largely on its *not* developing a pattern of attempting to avoid its contractual obligations. Thus, California must recognize that even though the long-term contracts are very costly to the State, unilateral attempts to avoid this obligation would be harmful to California's credibility. Thus, it is important that any renegotiations of the contracts be truly bilateral agreements, rather than unilateral attempts by the State to force the generators to provide it with lower prices.

Similarly, the State should not try to overthrow the terms of the contracts by legislation. In particular, one legislative proposal, no longer active, would give repayment of state electricity bonds, if issued, higher priority for payment than the electricity contracts, conflicting directly with terms included in the long-term electricity price contracts negotiated by the State of California. Passage of this bill would be just such a unilateral change in the essential contract terms. Not only would such a change reduce California's credibility as a contractual partner, but it is also likely to be subject to years of litigation. Given the litigation threats, such a legislative solution would not accomplish its end of ensuring that the bonds would be marketable as investment-grade instruments.

Paying for Long-Term Financial Obligations

Currently, Governor Davis has made it clear that he intends the elevated costs of long-term electricity purchase contracts and debt service costs of the long-term bonds (once issued) will be obligations of future retail purchasers of electricity in California. These obligations would keep electricity prices elevated for decades above the marginal costs of electricity acquisition. Such long-term electricity price elevations will lead to long-term distortions within electricity markets unless this method of payment is changed. Two possible changes would reduce the distortions.

The first alternative would be for Californians to pay for these contractual obligations in their role as taxpayers rather than as electricity purchasers, which would not reduce the direct costs to California for these contracts but would reduce the long-term electricity market distortions and thus the depth of the blight. Such a change would allow the State to return direct access as an option for large electricity users.

Fairness issues associated with such a plan can be seen through several different perspectives. The obligations were incurred for purchases of electricity on behalf of the customers of the large investor-owned utilities. From one perspective, it thus seems unfair that all taxpayers should pay the costs. However, the California governor and members of the legislature made the fundamental mistakes. These were officials elected by all of California. Thus, from a second perspective it seems unfair that only a portion of the taxpayers should incur the costs of their mistakes. In addition, the mistakes were made in the years 2000 and 2001. Thus from another perspective, it seems unfair that new firms or consumers entering California after the crisis should be responsible for the mistakes made before they moved to California. In addition, some people and firms will move to or from service areas of the investor-owned utilities. One perspective suggests that it would be unfair for these to avoid the costs or pay the costs of the past decisions, simply because they chose to or are required to relocate within California. It is highly likely and extremely unfortunate that such fairness debates will be central to any policy debates about whether to convert the contractual obligations from an electricity ratepayer obligation to a taxpayer obligation.

Alternatively, a nonbypassable fixed charge, sufficient to pay for the financial obligations of the long-term contracts plus the debt service on the bonds, could be assessed to electricity users. Utility customers who continue to purchase their electricity from investor-owned utilities would simply pay the elevated price. However, those who no longer chose to purchase their electricity from the investor-owned utility would be required to pay an exit fee calculated to cover their share of the financial obligations. Firms and consumers who were not customers of the investor-owned utilities in 2001 would be entitled to a price reduction, the opposite of the exit fee.

In principle, this approach would allow the State to allocate the financial obligations of the long-term contracts and the long-term bonds to those customers who purchased from the investor-owned utilities in the year 2001. In practice, however, such a plan would not be simple. It could create a set of incentives for firms and customers to take actions to avoid the fee; for example, by reducing their scale of operations within the service area of an investor-owned utility but not actually leaving. Hence, though in principle such an approach would be viable, in practice the difficulties may be too great.

Between the two options, considering the difficulties of implementation and the remaining distortions, conversion of the obligations from ratepayer obligations to taxpayer obligations is likely to be the better course of action. However, it is likely that the fairness concerns will dominate the debate and the current California governor and legislature will take no action. If that is the result, California's electricity system could remain in blight for decades to come.