The California Situation:

What Went Wrong?

The basic problem underlying the California crisis has been an imbalance between the steadily growing demand for power and the limited increases in generation and transmission capacity during the 1990s.

by Stephen M. Gehl and Karl E. Stahlkopf

The recent California power crisis is only the most visible part of a larger and growing energy problem in the United States, resulting from more than a decade of inadequate investment in power generation, transmission, distribution, and customer demand-response programs. The solutions put forth thus far have not addressed the fundamental technology issues nor the risks to the economy imposed by chronic underinvestment in electricity infrastructure. Already, the direct economic losses to the nation of power interruptions and inadequate power quality conservatively exceed $100 billion per year.

What is the problem?

The basic problem underlying the California crisis has been an imbalance between the steadily growing demand for power and the limited increases in generation and transmission capacity during the 1990s. An inadequate market design, in which price signals were not available to

continued on page 22

continued from page 21

moderate demand, exacerbated this supply/demand imbalance. Beginning in 2000, a combination of market forces and external events—including a hot summer, low water levels for hydroelectric power generation, high gas prices, above-normal number of plant outages, and rapid economic growth in areas like Silicon Valley—precipitated the California energy crisis, which threatened the entire Western region. The total cost for power in California rose from $7 billion in 1999 to $28 billion in 2000 and was projected by the California Independent System Operator (CAISO) to exceed $50 billion this year.

Rolling blackouts in California can have both direct and indirect impacts on the state's economy. In terms of direct costs, estimates in the San Francisco Bay Area run as high as $1 million per minute of lost economic output for large high-tech firms and $1 million per hour for smaller firms. Indirect costs include the cumulative impact of rolling blackouts, such as the failure of small businesses, the movement of jobs and production out of the state and region, and intangibles such as the effect of power outages on public health and safety.

Customers received no market signals to guide buying behavior and had no opportunity to take advantage of new pricing and service opportunities, such as time-of-use rates and contracts to sell "negawatts" (reduced demand from unused load) back to suppliers.

In the early part of the summer of 2001, California was facing the dire prediction of hundreds of hours of outages and rolling blackouts. The problem was narrowly averted by larger than expected customer response to calls for conservation, an extremely cool summer in the west, and some rather heroic efforts on the part of CAISO. The economic downturn may also have contributed to a smaller than forecast electricity demand. Unprecedented responses by the citizens of California cut peak demand for electricity by as much as 14 percent. In the meantime, a few new power plants came on line, adding nearly 1500MW of capacity. An additional 2500MW of capacity was scheduled to be available by the end of September.

Nevertheless, the basic infrastructure problem has not gone away. Reserve margins throughout the U.S. have shrunk from around 25 percent a decade ago to less then 10 percent today. Investment in upgrading our aging power delivery system has stalled because of policy instability and lack of incentives. This is most evident in the transmission area. In California, for example, only 145 miles of transmission lines are planned over the next decade, an increase of only 0.5 percent from today's system capacity.

The Market Imperative

Failure to maintain an adequate electricity infrastructure and supply has been made more critical by reductions in demand-response programs during the restructuring of electricity markets. Under the previous market paradigm, vertically integrated utilities performed long-range planning under the scrutiny of regulators, who allowed a preset authorized rate of return on prudent infrastructure investments. The guiding principle was the "obligation to serve," which encompassed the whole electricity value chain from generator to customer meter. Under this regime, there was little incentive to promote enabling technologies, such as smart meters needed for demand-response programs.

A fundamental weakness of the transition in California is that customers were never fully engaged in the new, more competitive paradigm. In particular, customers received no market signals to guide their buying behavior and did not have the opportunity to take advantage of new pricing and service opportunities, such as time-of-use rates and contracts to sell "negawatts" (reduced demand from unused load) back to suppliers. Further restructuring of markets will require the application of several different types of technologies on both the supply and demand sides to enable full customer participation in the marketplace.

Under the new market regime, utilities in many states have been restructured into separate functional units where market competition, rather than regulation, is expected to provide the necessary incentives for investments in supply and delivery systems. The problem in California, however, is that wholesale and retail markets have been decoupled and given separate guiding principles—market-based for one, and rule-based for the other. The inherent conflict has hindered incentives for investment, exacerbated by a pre-existing supply deficit. Distribution utilities are still left with the "obligation to serve," but because of decoupling, no longer have control over the means to serve.

The unique attributes of electricity make the design of well functioning markets a significant technical challenge that has generally been overlooked by policymakers. The California experience illustrates three of the most serious market flaws. First, wholesale power was made too dependent on the spot market. Utilities had been required or strongly encouraged by regulatory policy to sell their fossil generation facilities, yet discouraged from locking in stable wholesale electricity prices through long-term contracts. Second, the wholesale market organization was fragmented by a poorly structured separation of the Independent System Operator (ISO) from the Power Exchange (PX). This separation allowed generators to bid only a portion of their capacity ahead of time into the PX, then reap exceptionally high prices when the ISO was forced to buy power in real time to balance supply and demand. Third, retail prices were frozen, which meant that there was no way for rising wholesale prices to be moderated by reduced demand.

Partly due to frozen retail rates and lack of incentives for utilities to pursue innovative pricing programs, the market experienced a condition known as the "last man bidding" problem. In this condition, suppliers are rewarded for holding their bids off the market until the last minute, when buyers are desperate and will pay almost anything to get the power needed to meet demand.

The result of these market flaws was skyrocketing wholesale prices that essentially bankrupted the state's utilities, which had to continue providing power to their customers at enormous losses. Eventually the state itself had to begin buying power for its citizens, but at a cost so high that California's own creditworthiness was eventually downgraded.

Electricity is unique among energy commodities because of the difficulty of storing it in bulk. Instant-response storage units such as batteries, for example, have very limited capacity, while pumped hydro storage is large but involves a long response time. In general, supply/demand equivalence must be instantaneous, with production exactly matching consumption moment by moment. This requires very complex and long-lead-time infrastructure planning. As a result, the interrelationship between market and infrastructure is undergoing a greater transformation than those that have affected most other industries undergoing deregulation.

Before the industry can make a complete transition toward a viable new market structure, a coordinated planning mechanism and market-based incentives are needed to ensure adequate investment in generation, transmission, and load management.

In addition to declining investment, a variety of other issues contributed:

- A lopsided fuel mix exacerbated the imbalance between electricity demand and supply in California. The generation mix in the state is heavily weighted toward hydro and natural gas generation. (Hydro accounts for about 25 percent and natural gas for about 50 percent of total installed capacity.) Such an imbalance underscores the importance of supply portfolio risk management and a public policy that recognizes the strong interdependency between electricity and gas markets.
- The California situation was also made worse by problems spreading across interconnected energy markets. In particular, the unbalanced fuel mix linked California's electricity market closely to the natural gas markets. About half of California's annual production of electricity is generated by gas. Therefore, a significant increase in natural gas prices during the course of the year 2000 caused a commensurate increase in electricity prices.

Electricity is unique among energy commodities because of the difficulty of storing it in bulk. In general, supply/demand equivalence must be instantaneous, with production exactly matching consumption moment by moment.

Market-Based Demand-Response Programs

The California situation reinforces the idea that when faced with a capacity shortage, the best near-term option is to provide customers with an incentive to reduce demand during times of constrained or costly electricity supplies. This reaction to the time-value of electricity can be accomplished through a variety of programs that make customer demand responsive to price changes. Such programs have the potential for reducing demand rapidly, at low cost, and without adverse environmental impacts. Customers willing to pay for the high cost of power may continue to use it at their "normal" levels, while those willing to lower demand or shift it to lower-cost periods benefit from lower bills. An Electric Power Research Institute (EPRI) study shows that a 2.5 percent reduction in electricity demand statewide could

continued on page 24

continued from page 23

reduce wholesale spot prices in California by as much as 24 percent and help preserve electric power reliability.

Demand-response programs that explicitly incorporate time-dependent economic signals to customers include:

- *Real-time pricing (RTP)*, in which the customer is usually given some advance warning (generally one day ahead) of the hourly prices for a future time (typically a 24-hour period)
- *Coincident peak pricing*, in which the hourly prices for the projected high-cost hours for a year are averaged and the average price applied to those hours (probably 100-300 hours). Prices for projected low-cost hours are similarly averaged. The customer then pays the low-cost-hour price unless the energy provider notifies the customer that certain hours (say, the following day) will be high-cost hours.
- *Time-of-use (TOU) rates*, which differentiate prices by sets of hours in a day, between weekdays and weekends, and between seasons. These rates are pre-set, compared to the constantly fluctuating prices of RTP.
- *Demand bidding programs*, in which the customer bids in "negawatts" of reduced demand in order to receive varying amounts of financial incentives.

Risk management tools are needed because the market for electricity is characterized by significant price volatility.

These pricing approaches encourage the customer to invest in technologies or operating practices that will modify electric demand to relieve generation as well as transmission and distribution (T&D) constraints. However, *a key barrier is the need for advanced meters*. Such meters are often called electronic (interval) meters and need to be distinguished from conventional, spinning disk meters. Such meters are available now, but their cost needs to be reduced through mass production encouraged by user market incentives and/or regulation.

Demand-response programs also include market-driven load management technologies, such as automated energy control systems (of which the smart thermostat is one example), two-way communication between the customer and the energy supplier, and distributed generation technologies such as cogeneration systems and microturbines. In addition, progress in semiconductors and computer systems has brought forth a variety of new digital infrastructure technologies to allow customers to choose the level of service. This new crop of technologies takes advantage of communications system backbones, such as cellular, paging, and Internet technologies. These options can be made two-way and closed-loop to verify that customers are receiving the level of service they expect.

Managing risks using portfolio management techniques

Although the current crisis was due to a fundamental imbalance in market demand and supply exacerbated by escalating fuel prices, a well designed market with sound risk management options should be able to function and to stimulate solutions in spite of these problems. With limited availability of financial instruments for risk management, such as forward markets and transmission rights, a problem was converted into a crisis in California.

Risk management tools are needed because the market for electricity is characterized by significant price volatility. There is no obvious way to eliminate this price volatility, since much of it arises from difficulties in storing electricity and from the present low level of cash interest and participation in forward markets for electricity. This problem has been observed not only in the United States, but also in the English, Australian, New Zealand, and Alberta power markets. The best way to deal with price volatility is for both buyers and suppliers to have a diverse portfolio of short-, medium-, and long-term contracts.

If power suppliers sell all of their output through fixed-price long-term contracts, they ensure a level of cash flow, but also risk selling their product at a lower price than might prevail in the spot markets of the future. On the other hand, if they don't commit a portion of their supply to long-term contracts, their cash flow for the future becomes very uncertain. Thus, based on their assessment of future price volatility and their own risk tolerance level, they need to decide what portion of their resource portfolio to sell long- and medium-term, and what portion to sell on the spot market.

Buyers face similar challenges. Entering into a long-term contract insures them against future price volatility but is achieved by paying an insurance premium in the form of a higher price

level. The situation is analogous to buying a home mortgage at a fixed rate versus an adjustable mortgage. Long-term purchases are not devoid of risk, however, because customers may be prevented from benefiting from any reductions in the future price of power.

Thus, both buyers and sellers need to hold a portfolio of contracts. The optimal portfolio needs constant updating and dynamic balancing, as new market information becomes available. In addition, changes in management may bring about changes in a firm's risk tolerance levels, and portfolio balancing may be necessary.

Coordinating wholesale and retail markets

When electricity markets are restructured, it is important to restructure both the wholesale and retail markets in a coordinated manner. In the Midwest, during 1998 and 1999, price spikes took place on the wholesale market that resulted in the price of electricity exceeding $10,000 per megawatt hour for short periods of time. These spikes could have been mitigated by as much as one-half to two-thirds if the retail markets had not been disconnected from wholesale markets. Retail markets were disconnected because their prices were capped, not based on the fluctuating price of power on the wholesale market.

To prevent these types of situations from occurring, retail prices should be based on wholesale prices, rather than being frozen. This does not mean that all customers would have to pay hourly prices for electricity. Most customers are risk averse and would prefer to pay a fixed price. However, this fixed retail price would not be based on a historical value that reflects the cost of service. Instead, it would need to be based on a number of factors such as the shape and volatility of the customer's load, wholesale price volatility, and the correlation between customer loads and wholesale prices. In other words, customers would pay an "insurance premium" to keep their rates fixed.

A coordinated planning process is needed to design power markets and their interface with the underlying infrastructure. The planning process must ensure appropriate balance in reliability and market efficiency as the market evolves. In addition, this process should recognize the interdependency of different markets—including the natural gas and electric power markets. The federal and state governments should take the primary responsibility to develop such a process. Ultimately, an independent institution/agency is needed to perform periodic assessments of the performance of the infrastructure, markets, and their interface. An important consideration is how to balance the objectives of a strong planning function (to reduce congestion and volatility) against the risks of direct RTO (Regional Transmission Organization) involvement in energy markets.

A coordinated planning process is needed to design power markets and their interface with the underlying infrastructure.

What have we learned?

Winston Churchill famously observed that "the future, though imminent, is obscure."

The same is true of California's energy future, but the crisis has provided an important opportunity to fix underlying problems in today's electricity markets and introduce new technologies that will help make these markets function more smoothly regardless of short-term anomalies and further evolution in the regulatory arena. Deregulation's endgame will require fully enabled customer choice and an infrastructure able to support 21st century electrical requirements. ■

Stephen M. Gehl and Karl E. Stahlkopf are scientists at the Electric Power Research Institute, Palo Alto, California.