IssuesLetter

Least-Cost Paths to Reliability: Ten Questions for Policy Makers

In the summer of 1998, utilities[1] in several regions of the United States faced escalating reliability problems that resulted in high price spikes, the threat of rolling blackouts and appeals for voluntary curtailment. Resolving reliability problems in a crisis atmosphere undermines customer confidence and is almost always unnecessarily expensive.

In the present movement towards competitive electricity markets, it is important to remember that electric system reliability is, in many respects, a classic public good. By the laws of physics, the essential attributes of adequacy, voltage and frequency are available to all interconnected users simultaneously. Like the textbook examples of lighthouses or national defense, most aspects of electric reliability are provided to everyone or no one, and everyone is required to pay. Public rules, imposed by governments, utilities, reliability councils and/or power pools, will determine the cost of reliability measures and the means of paying for them. In this environment, least-cost thinking can provide substantial benefits to the public and to our economy.

As summer approaches again, a number of states are facing reliability concerns, and regulatory commissions are asking utilities what steps they plan to take to ensure an adequate and reliable supply of electricity. Typically, regulators and utilities think of investment in additional transmission or generation to achieve and maintain reliability. Often overlooked are the reliability benefits that can be captured from the very sizeable energy resources held by *customers* -- demand management and customer-owned generation, customer response to reliability-based market prices and simple improvements in the structure of the wholesale market.

Demand and non-conventional, supply-side resources can provide low-cost reliability solutions to utilities with reliability concerns. These resources include significant existing and new customer-owned generation, as well as load management and efficiency resources. But these resources can be efficiently tapped only if utilities and utility commissions take the necessary steps to establish the right regulatory and market conditions.

We know from long experience with interruptible contracts that many customers will accept lower levels of reliability if it means a lower cost for their electricity. Modern metering and communications technologies have created new opportunities in the demand management arena .To capture these resources, it is essential to create market structures that will reveal the cost of reliability and put accurate prices in front of customers. This Issuesletter identifies ten questions that every utility commission and governor's office concerned with reliability ought to be asking their utilities.

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[1] We use the word utility to mean the distribution utility which is either a stand-alone entity, as occurs in some states that have restructured their electric industry, or a function within the fully regulated vertically integrated utility, as occurs in the states that have not restructured.

1. How much do the proposed reliability improvements cost?

What do health care and electricity reliability have in common? When an emergency occurs, cost takes a backseat to immediate remedial action. When it comes to electric reliability, the cost of remedial actions can be identified beforehand, and doing this can expose a wide range of less conventional power supplies to achieve the same reliability result.

Consider the following simple calculation. The most common utility action to meet peak demand today is to build (or buy) a power plant. A conventional combustion turbine (CT) costs about $400 per kW. The annual carrying cost, including depreciation, property taxes and return is about $80 per kW per year. If the CT is used for 800 hours per year (about 10 percent of the hours), the CT costs 10¢ per kWh. If it is used 80 hours per year (20 hours per week for four weeks), the capital cost is $1.00 per kWh. And, of course, the peaker that is never used, or is used only on the annual peak day, would have astronomical costs on a per kWh basis. Many options could provide equivalent reliability benefits at much lower cost.

The regulatory task is to get these "reliability costs" in front of customers and suppliers in ways that allow lower-cost options to surface and be used. Each of the reliability options discussed in this Issuesletter relies on knowing the price that would be paid for reliability from conventional resources.

2. Do wholesale prices reflect the high cost of energy during peak hours in a tight capacity market?

The question regulators should ask their utilities is how do prices in the region reflect long-term reliability costs? Before competitive markets were established, long-term reliability was met by setting reserve requirements -- the amount of installed capacity above system peak loads. Many utilities in states and regions where retail competition has not yet been introduced continue to use this approach. The capital cost of that added capacity is included in rate base and allocated over many hours, masking the real cost of the reserve margin in customers' bills.

The critical questions for regulators now are: How are these costs are treated in competitive markets? Will customers be exposed to these costs, or will they be hidden? Thus far the approaches vary widely. In the US, reserve margins are based on engineering concepts (e.g. a design standard for a 10-hour outage once every ten years). However, in other countries an economic standard and resulting market prices, rather than regulators or engineers, determine how much generating capacity is available to meet reliability needs.

In the UK, half-hourly spot prices reflect the value of "reliability," and this value is added to the price of power in that period. There is no engineering-based reserve margin. The calculation of the "reliability adder" is straightforward, although the first step is somewhat conceptual. Economists have estimated that reliability is worth about $3.00 per kWh to consumers and society (similar estimates have been made in the US).This is generally referred to as the value of lost load (VoLL) or, alternatively, the "value of energy not served."

Next, for every half-hour of the following day, the UK pool estimates the cost of reliability in that half-hour by multiplying the $3.00 per kWh value by the probability that there will be a shortage of power in that half-hour based on the expected demand and the availability bids received from generators. In most hours, the probability is nearly zero because the available supply greatly exceeds demand, so the reliability adder is also very close to zero. In a very tight half-hour, the probability may approach 100 percent, in which case the reliability/security adder is $3.00 per kWh (1.0 X $3.00 = $3.00). Of course, as the price approaches $3.00 per kWh, supplies that were not available become available, and customers who see real-time prices decide that some of their electricity use can wait. In ten years of operation, this system has balanced supply and demand successfully. In short, market prices are used to deliver adequate generating capacity.

Markets in this country generally do not use the UK approach. Both installed and operating reserve requirements are more commonly set on an engineering basis, although to some extent market mechanisms are being used to compensate owners for the costs of capacity. For example, NEPOOL sets an "Installed Capability" reserve requirement and has created a market-based system that operates monthly for those with surplus capability to sell to those who are capability short. This approach will have the effect of recovering the cost of installed reserves over more hours (i.e. monthly) than the UK's half-hourly, market-based approach, so peak period prices will be much lower than those in the UK.

The questions regulators should ask their utilities are: Do wholesale power prices in the region reflect or hide reliability costs ? Are market approaches being considered?

3. How many customers see real-time prices?

Assume, through market mechanisms or otherwise, a reasonable estimate of real-time costs, including the cost of meeting peak loads, is available. The next question is: Do customers see these prices? In theory, all customers should see real-time prices which would enable them to make their own value decisions at all times, especially during very expensive peak periods. But residential and small commercial customers do not have the sophisticated metering needed to price on a real-time basis. For most customers, high costs in a few hours each year appear as a small increase in average monthly prices. Large customers have the needed meters, but most are not on real-time prices, preferring instead the comfort of predictable prices. Thus, we find we have labored hard to create a competitive, market-based system, but few, if any, customers actually see the resulting prices in a way that would trigger an expected market response.

Fortunately, there are other options that achieve similar results. Real-time, buy back rates for customers with installed generation as described in question four is one option. New approaches to interruptible load as described in questions five and six has been shown to work in a number of states. Demand bidding as described in seven is another way to show customers real-time prices even though they are not "on" real-time prices.

4. Do you have peak purchase rates for customer-generated power?

In many service territories, there exists a large amount of stand-by generation owned by commercial customers at facilities such as hospitals, schools and large commercial buildings and by industrial customers at industrial sites. Although these generators were installed primarily for emergency power, many of them could operate more frequently. Utilities could organize these customers into an available power source by establishing purchase power rates together with an effective communications network. This type of approach also encourages customers to consider installing one of the newer "distributed" types of generation, such as fuel cells or microturbines.

5. How extensively have interruptible rates been marketed? How many customers have interruptible rates available, and how much are they effectively paid for interruptions?

For too many years in too many places "interruptible contracts" have been an excuse for targeted rate reductions to a few large industrial customers. Often, customers have been paid (through lower rates) but have not been called to interrupt for years. In some cases, when they finally are called, unprepared customers either fail to interrupt or simply opt for a firm power back-up rate which is also priced well below the real cost of providing reliable service at peak periods. In these cases, utilities and their customers are paying for reliability enhancements that the system is not receiving. If called upon load reductions are not delivered, reliability benefits are not achieved, reserve margins will have to be higher and the costs of reliability will be greater. One possibility? Utilities and regulators could adopt interruptible rate tariffs that compensate customers for actual, not just potential, interruptions.

Many utilities have interruptible rates available to some industrial customers, but experience shows that there are additional customers who would participate in interruptible rates if the prices paid for interruption reflected their value to the system, and if the benefits of those rates were seriously marketed. Similar kinds of interruptible rates could be established for residential and commercial customers by offering controlled loads for air conditioning, heating, lighting and other specific end uses.

6. Have load-shedding cooperatives been organized?

Encouraging commercial businesses to form load-shedding cooperative arrangements can produce large and highly reliable demand reductions. The agreement to shed is made between the utility and the coop. This allows coop members to have a variety of arrangements among themselves as to which business backs down load, when and in what amounts, as well as how profits will be shared. Commercial businesses in several major metropolitan areas cities, including Orange County, CA, Chicago and Boston, have had such coops operating for many years.

7. Does your spot market include a bidding system for demand-side reductions?

Spot market prices are generally determined a day in advance by utilities or in some regions by an independent system operator, power exchange or similar entity. Demand for each half hour (or other measured period) is projected and a dispatch, or "merit" order for all available power plants, is devised to meet that demand using either marginal costs or bid prices to rank order the plants, and using the cheapest plants first. The cost of the last unit needed to meet demand in that time period sets the spot market price for all energy sold in that period.

A central shortcoming to most of these dispatch systems is that the demand projections used to set the market clearing price are based on load estimates, not on bids, and therefore do not reflect any demand response to the supply-side bids. The result is higher prices for all consumers. Fixing this problem requires a process that allows demand-side reductions to be bid into the dispatch schedule with bids for demand reduction at specific prices. The bids for demand reduction could be received simultaneously with supply bids, or in a second round auction held to see what load chooses to back down given spot prices. (The "multi-settlements", or second round bidding, approach is currently being proposed by the New England ISO and has been endorsed by regulators in that region.) It is important to realize that the benefits of lower clearing prices will accrue broadly across the system, whether or not demand-reducing bids are compensated directly in the market or are simply the result of better pricing information. Either approach can work and either could produce lower prices, lower demand and improve reliability.

8. What are you doing to facilitate a competitive wholesale market and remove barriers to competitive wholesale suppliers?

In recent years, the uncertainty associated with restructuring has caused utilities to postpone capital investment, including investment in new plants. This has aggravated and precipitated reliability problems. Competitive independent power producers (merchant plants) have demonstrated the ability to respond to market conditions and bring on new plants in very short periods of time, as little as two years. Competitive producers have stepped in where wholesale markets are well developed and have reasonably predictable power or transmission rules. Statutes and practices that discourage or prohibit the development of merchant plants are a barrier to creating a wholesale market that allows competitors to respond to price signals. Removing these obvious (and antiquated) utility and regulatory barriers are important steps.

9. Have you identified and aggressively implemented energy efficiency programs to mitigate peak load demand?

The best way to avoid a reliability crisis is to avoid the demand that creates it. In the early 1990s utilities were fairly skilled at designing and implementing energy efficiency programs aimed at peak shaving. Continuation or resumption of efficiency programs that target commercial lighting and HVAC systems as well as a wide variety of household uses, are undoubtedly the cheapest source of reliability. It is a great loss to our national electric system that the demand-side programs of so many utilities have been greatly diminished or have disappeared altogether in the in recent years. Utility spending on demand-side resources declined by one-third, from $1.6 billion to $1.05 billion, between 1994 and 1996 alone. Incremental energy savings have plunged even more dramatically, from nearly 10 billion kWh in 1993 to 4.3 billion kWh in 1996. Restoring support for investment in energy efficiency should be high on the policy option list for regulators.

10. Do you have a system in place to request (and pay for) voluntary curtailments?

The call for voluntary curtailments need not be a desperate, last moment appeal. Establishing a process for routine requests can create a reliable, voluntary backing down of demand by educating customers as to its value without invoking fear. For example, Central Maine Power Company's routine use of Kilowatt Savings Time (KST) on peak setting winter evenings in the 1980s created a knowledgeable public, reliable damping of peak demand and no sense of public crises. Customers accepted KST as a way of saving money for all customers.

Last summer Commonwealth Edison (Unicom) experimented with a program for making similar public appeals in its Chicago service territory. Edison's program has paid for voluntary curtailments by placing a large sum of money (one million dollars) in a special fund each time an alert day is called. The funds are administered by a specially constituted independent board.

Conclusion

Policymakers should encourage the reliability market to be as broad and interactive as possible by insisting that all cost-effective resources be developed by utilities and others charged with maintaining system reliability. Accomplishing this requires creation of the needed price signals, communication networks and clear procedures that allow both demand- and supply-side market responses to the costs of maintaining reliability.

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