# Electricity Resource Adequacy: Matching Policies and Goals

*Policies designed to ensure resource adequacy in electricity markets have been rooted in a disparate set of policy goals. Differences over the appropriate goals and focus of such policies have produced different views about what the appropriate means are for achieving these goals. This article explores the motivations for resource adequacy policies and discusses how different RA policies address, or conflict, with these goals.*

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## I. Introduction

The means for providing adequate supply of electricity is one of the dominant policy issues under consideration in restructured electricity markets in the U.S. Even in regions with restructured electricity markets, there is great discomfort with leaving the final decisions for investment up to unregulated market actors. Yet regulatory requirements for the investment in production capacity are extremely rare, even in regulated industries. To the extent that electricity resource adequacy policies are motivated by a desire to prevent cascading outages, there are parallels in banking reserve requirements. To the extent they are motivated by a desire to smooth the revenues of suppliers and reduce volatility, they resemble agricultural price supports. In fact, requirements for resource adequacy in electricity are the most extensive and complicated seen in any industry.

First and foremost, the desire for resource adequacy standards is driven by a belief that electricity supply interruptions should be very rare, or preferably non-existent. For nearly a hundred years, planning in the electricity industry has been centered upon the notion that all customers should be able to consume as much electricity as they want at a constant price at any given time. Investment was targeted to meet forecasts of ''peak'' demand plus a reserve margin. Electricity prices rarely played an important role in these forecasts. Thus the notion that prices could be used to balance supply and demand has been a foreign concept in the industry.

The problem with the resource standards approach is that it treats all customers as if they had the same value for consuming electricity, and therefore the same preferences for reliability. There is overwhelming evidence that this is not true. Attempts to measure customers' interruption cost, or value of lost load (VOLL), through surveys or other means consistently reveal wide disparities between customers.[1] For example, commercial and industrial customers in general have much higher VOLL than do residential customers. Even more important than the disparities in inter-customer value of electricity, however, is the intra-customer value. Most customers utilize electricity for both critical and discretionary purposes.[2] Critics of traditional resource planning approaches have emphasized that such approaches often take the most critical usage of the most critical customer and apply that as the standard upon which to base system reserve requirements.

With the advent of restructuring, the process of resource planning became much more complicated. While planners could forecast system needs, no individual firm bore direct responsibility to ensure that those needs were met. Instead of a regulated utility building to meet a capacity target, restructured markets featured a diverse set of ''merchant'' suppliers building generation plants in response to expectations about future market prices, or to fulfil power supply contract obligations. However, the ebb and flow of market-based investment decisions means that, at any given moment, investors' decisions could overshoot or undershoot the planner's optimal target. This increases the need to deal with supply shortfalls more efficiently than through random blackouts.

Proposals for regulatory resource adequacy standards have been the subject of considerable controversy in California, New England, Texas, and the regions covered by the Midwest and PJM independent system operators (ISOs). A leading policy option is the creation of a capacity market. With a capacity market, suppliers receive periodic (i.e., annual or monthly) payments for providing ''reliable'' capacity to a system. Load-serving entities (LSEs) are required by the regulatory standard to purchase the capacity. Variations of such markets have operated in New York, New England, and PJM for many years and have been revised several times.

These two competing paradigms, market-based versus regulatory standards, really lie at the heart of the debate about resource adequacy policies. Many economists have articulated a vision where tight supply conditions are managed through temporary reductions in demand, rather than through the production of seldom-used ''peaker'' generation units. If consumption is managed in this way, then periods of ''under-investment'' imply high prices, rather than involuntary interruptions. Absent a rational approach to dealing with tight conditions by reducing low-value consumption, the costs of underinvestment can be much higher – e.g., blackouts – motivating the desire for a mechanism to ensure that underinvestment cannot happen.

While proponents of the regulatory standards approach often express enthusiasm at the prospect of demand-side resources helping to manage tight supply conditions, they usually treat them as an alternative source of reserve supply. The result is an emphasis on more centralized forms of ''dispatchable demand'' programs that can be monitored and committed by system operators. The alternative would be a more decentralized, price-based response by consumers who make individual choices to shift or reduce their demand based without direct communication with their utility or a system operator. The regulatory standards approach to resource planning often discounts such decentralized forms of demand response, and can even discourage it by suppressing spot electricity prices. An important issue is whether restricting demand response options only to those that are dispatchable, as is likely under the regulatory standards approach, forecloses the opportunity for much broader and more effective demand response.

It is also important to remember that supply interruptions are quite common in the industry. The average northern Californian experienced about 1.5 blackouts a year during the late 1990s. The causes were distribution problems – a tree on a wire – rather than a shortage of generation capacity. The level of reliability often raised as a target for generation planning is one interruption in 10 years, yet if you include distribution outages, the actual interruption rate is about 16 in 10 years. Thus, cutting the generation reliability standard in *half*, to two in 10 years, would really constitute only a 7 percent decrease in overall reliability – from 16 to 17 in 10 years including distribution.[3]

## II. Motivations for Resource Adequacy Policies

Beyond the desire to maintain the kinds of planning standards that existed under cost-of-service regulation, there are several more detailed arguments for the need for a resource adequacy policy in electricity markets. These arguments reflect different goals for resource adequacy policies, and often motivate different ''solutions'' to the perceived problems. It is useful to discuss these goals as they are somewhat diverse and specific resource policies that have been proposed often reflect an emphasis of one goal over the others.

Each of the following goals encompasses what is perceived as a failure with the market-based investment approach that can be addressed through resource adequacy regulatory standards. In discussing these points, it is useful to consider three questions. First, does the issue truly represent a failure of the market-based approach? Second, do resource adequacy standards actually address the problem? Third, are there alternatives to resource adequacy standards that would more effectively address the problem, or create less unwanted side-effects?

**1. Ensure that producers receive sufficient revenues to cover long-run average costs and thereby support investment.**

It is widely believed that market-power mitigation policies and the operational practices of ISOs restrain spot prices below levels necessary to sustain investment. Therefore, resource adequacy policies are designed to provide additional revenues to make up for the ''missing money.'' Several studies have pointed out that over the last several years, revenues from energy and ancillary services alone have been insufficient to make contributions toward the recovery of investment costs. Between 1998 and 2002, there was an enormous amount of investment activity in generation.[4] Much of this is no doubt playing a role in depressing current prices. Yet even in regions where planners anticipate shortages, such as southern California and southwestern Connecticut, prices have apparently remained low. Further, Joskow shows that energy prices in New England remained low during periods of extremely tight markets, in part due to the operational practices of system operators.[5]

In a sense, there is no question that generators will recover their average costs in the long run. If prices are too low to sustain a given level of capacity, then there will be exit (or at least a lack of new entry), and prices will increase until they can sustain the remaining suppliers.[6] The question is how much capacity would remain when the market reaches that point of equilibration? Again, there is a strong belief in the industry that it would be inappropriate to allow this process to yield more than a trivial probability of supply shortfall.

The level of the energy price cap plays a key role in determining how much capacity can exist in a market and sustain sufficient revenues. Another key element is the process for allowing the price to go to the price cap. It seems obvious that prices should go to the cap if capacity is short to the point of curtailing demand. To the extent that a system runs an increased risk of cascading outages when it runs on lower operating reserves, it also seems appropriate for prices to rise to the cap when operating reserves fall below some level.

It is worth noting that there are other alternatives to capacity markets to ensure generators receive enough revenues. The most straightforward is to increase the energy price cap. Many parties oppose this solution out of fears over market power or price-volatility. Yet it is not at all clear that resource adequacy mechanisms are the most cost-effective means for dealing with market power or volatility. In fact, in many cases the opposite is likely true. In several cases, rigid regulatory requirements for capacity purchases have created the opportunity for suppliers to exercise market power in the sale of capacity. To the extent that capacity markets are viewed as a substitute for energy contracts, they can increase the potential for market power in energy markets by reducing the amount of energy sales sold forward by producers.

The appeal of capacity payments may stem from the fact that it is easier to construct a ''fair'' maximum payment for capacity than a ''fair'' maximum hourly price on energy. Fundamentally both capacity payments and peak energy payments are directed toward the recovery of capital costs. An annual capacity payment can be linked directly to estimates of the amortized annual cost of generation capacity. It is much more difficult to determine whether a given energy price is sufficient for recovery of capital costs, as one needs to know how often energy prices will reach those maximum levels. A potential solution to this difficulty would be to lower energy price caps from a higher level, say $10,000, to a lower level, say $1,000, whenever the annual average energy price exceeds some capacity cost target level.[7]

Another straightforward way to increase supplier revenue is to increase the purchase of ancillary services such as non-spinning reserve or ''reliability'' reserve. These products provide ''stand-by'' services to system operators. In many cases suppliers have to burn little or no fuel to provide these services. An increase in the demand for operating reserves would drive up the prices of those reserves and, to the extent that energy suppliers are drawn to the reserve market, also the price of energy. Thus, even without adjusting the level of energy caps, the definition of ''scarcity'' would be modified to allow prices to more frequently reach those capped levels.

No matter which approach is taken to increase revenues, it will be necessary to codify the role that dispatch decisions of system operators play on prices. In most markets, operators can call upon reserves or ''out-of-market'' purchases for energy supply when reliability needs deem such actions necessary. However, in many markets the very act of drawing supply from these non-market sources will depress the energy price, even though the additional supply was motivated by a form of shortage. In order for prices to accurately provide information and incentives to suppliers and customers, the exact meaning of ''scarcity'' needs to be clarified and prices need to be allowed to rise to price-cap (or ''value of lost load'') levels during these periods.

**2. Prevent competing retailers from ''free-riding'' on the resources of other retailers.**

A common feature of retail service in restructured U.S. electricity markets is the policy of randomizing customer interruptions amongst customers of different retail providers. Thus it is nearly impossible for retailers to differentiate amongst themselves in terms of quality of service. The application of real-time pricing or other forms of pricing that would ration electricity use according to its value, rather than randomly, is also extremely limited. Under these circumstances, it has been argued that competitive retailers have a perverse incentive to underinvest in supply since underinvestment could lower cost and there is no distinct reliability penalty borne by the customers of that retailer.

On the other hand, the *financial* consequences of underinvestment, or equivalently a lack of hedging, can be severe for an individual retailer. Simply put, it can be extremely expensive for a retailer to be ''short'' on power if price caps are sufficiently high or if a large shortage penalty is applied to such retailers. This is not necessarily true for the customers of those retailers however. In some markets, customers of non-utility retailers that are no longer financially viable can return to a default service offered by the incumbent utility provider. To the extent that this default service is comparable to (or even more attractive than) that offered by responsible competitive retailers, there is no penalty for customers having chosen the cheap, ''fly-by-night'' retailer.

This is not the case if customers of a bankrupt retailer are left to find a new retailer at market prices. Alternatively, if the customer is allowed to return to regulated service, it should be at as a pass-through of current wholesale costs. The unpleasant prospect of searching for a new retailer during unfavorable market conditions should motivate direct access customers to procure service from responsible, financially viable retailers. In this way, RA policies are integrated with, and even substitutes for, sound policies for managing the migration of retail customers between competitive and regulated retailers. A retail policy in which individual retailers and their customers bear the financial consequences for any shortfalls for which they are responsible largely eliminates any incentive to free ride on system resources.

Similar arguments apply for utility retailers whose ''core'' customers do not have choice, including regulated and municipal utilities. In integrated electric systems, individual utilities have to be discouraged from taking more power off the network than they are providing in the form of energy and reserves. This has been a long-standing issue in the operations of electric network that long predates the advent of restructuring. While planning targets for integrated systems are at least coordinated through reliability agencies such as the National Electricity Reliability Council's (NERC) subregions, these systems recognize the need for incentives for reliable operations in real time. One of the criticisms of resource adequacy policies in the eastern U.S. is that, after the evaluation of the advanced plan, individual load-serving entities, whether they passed or failed the evaluation, have little incentive to work to prevent a shortfall on the actual days on which they occur. Thus a LSE that is deemed ''short'' in expectation at the beginning of a month pays a penalty, but does not suffer any further consequences if an actual shortfall happens.

Of course, in the case of non-overlapping regulated control areas it is easier to assign the physical consequences of a shortfall to the responsible utilities. In 1990, a shortfall caused by underprocurement by SDG&E would not have been borne by PG&E customers. In the absence of physical curtailment, utility control areas are liable for financial penalties if their operations violate NERC reliability standards or in the extreme, take more energy off the grid than they are putting in.

**3. Promote or require long-term contracting and hedging by load-serving entities (LSEs).**

In all restructured electricity markets, the majority of customers continue to get retail service from their incumbent utility. Regulated retail electricity providers (''utilities'') may have a distorted incentive to rely too much upon spot market purchases. One reason for this is that these providers believe that they are entitled to a guaranteed recovery of their procurement costs, and therefore do not share their customers' risk aversion to volatile spot prices. Another reason is that regulated providers fear that long-term contracts are more vulnerable to being second-guessed by local regulators and deemed imprudent than are spot purchases.

In systems with retail choice, the risk of customer migration has also been raised as a barrier to contracting by both regulated and unregulated LSEs. A retailer that contracts for energy supply may find its customers have switched away, leaving it ''long'' on the wholesale market. It is unclear how important a long-run problem this will be. Even if a retailer is long, it can still resell its contracted energy on the wholesale market. Many information industries with far higher ''churn rates'' of customer migration have managed to finance capital expansion.[8]

One last problem with forward contracting is the ''deliverability'' of the energy or capacity that is contracted for. Although the western U.S. currently appears to have excess capacity, sub-regions such as the L.A. basin are forecasted to have tight margins in the near future. This is despite the fact that southern California LSEs all claim to have adequately contracted for their supply. In this case, the problems caused by inefficient transmission pricing, which can be addressed by a transition to locational marginal pricing (LMP) of electricity, need to be distinguished from general barriers to forward contracting. A more transparent system of pricing transmission congestion will allow for a more reliable evaluation of the purchasing practices of utilities by regulators and a more direct assignment of energy and transmission costs to all LSEs.[9]

A paucity of buyers of forward contracts means suppliers are also forced to rely more upon volatile spot markets. This makes it more difficult (or even impossible, according to many merchant generation firms) for firms to raise the capital necessary for investment in generation. Another motivation for capacity standards is therefore to offset this distortion by, in effect, requiring LSEs to acquire capacity in a forward market.

Regulation may indeed skew the procurement incentives of utility retailers. However, even if regulatory standards are necessary to require increased forward procurement, one needs to be careful about defining what exactly is being procured. Capacity markets by themselves may not provide sufficient revenues to producers, in the absence of energy contracts, to stimulate investment. The revenue stream produced by capacity markets or resource obligations are influenced to varying degrees – in most cases very strongly – by regulation. Capacity prices are set annually, monthly, or daily, and revenues allocated on similar time frames. There is a serious question about whether a short-term

**Table 1:** WSCC Forecast of 2000 California Reserve Margins

| Month | April | May | June | July | Aug. | Sept. | Oct. | Nov. | Dec. |
|---|---|---|---|---|---|---|---|---|---|
| Reserve | 45.0 | 39.1 | 26.3 | 17.7 | 17.4 | 21.3 | 44.3 | 47.5 | 44.4 |

revenue stream that is potentially highly vulnerable to changes in regulatory whims provides the kind of financial commitment necessary to raise capital for investment.

Even more troubling is the fact that the capacity obligation taken on by sellers is very weak in many markets. Thus the buyers are not hedging much price risk by procuring capacity alone. Equivalently, the mere existence of capacity does not guarantee reliability, particularly if the buyers in the market are financially unstable. Table 1 presents the WSCC evaluation of planning reserve capacity for the California region for 2000.[10] At that time, planning margins were expected to exceed 17 percent in every month, and over 45 percent in December 2000 when the first crisis-induced blackouts occurred. This illustrates that an anticipated 17 percent reserve margin by no means guarantees reliable operations in an electric system.

To the extent that the financial solvency of LSEs in general, and regulated utilities in particular, is the motivation for resource obligations, the focus on capacity alone does not satisfactorily address the motivation. In fact a standard for energy procurement, whether in the form of firm contracts, options, or swaps, is necessary to address the concerns about inadequate hedging by utilities. But if a standard requiring energy purchases is in place, is a process for remunerating physical capacity necessary?

**4. Reduce the volatility of prices and the revenues of producers.**

As it is currently configured, the electricity industry has extremely inelastic end-use demand. This fact, combined with the relatively long lead times in construction and long-lived nature of power plants, implies that prices would be expected to be extremely volatile. If the market were competitive, prices would fluctuate between short-run incremental costs (on the order of \$50/MWh) and the price cap (on the order of \$1,000/MWh). Contributions to capital recovery would have to be concentrated in a relatively small number of extremely high-priced hours. Under these circumstances, it is natural to expect that suppliers relying upon spot market revenues would go many years without contributing to their capital cost recovery, followed by years where substantial contributions are made.[11]

Almost no one in the industry is comfortable with the volatility implied by a purely market-based investment process under these conditions. Suppliers, consumers, utilities, policymakers, and regulators would all prefer a more stable pattern of prices and revenues. Under normal circumstances, these preferences would work towards the desired outcome as both buyers and sellers, seeking more stable prices, would transact primarily in long-term contracts, rather than the more volatile spot markets. However, as described elsewhere, the quasi-regulated state of the retail sector of the industry interferes with this process.

While it is not always stated as an explicit goal, another important effect of RA policies is the dampening of volatility in both the revenues received by producers and those paid by retailers. This is often cited as a meritorious effect. Periodic reports of how short-term energy and ancillary services revenues are insufficient for recovery of total costs are common. Underlying such arguments is the notion that suppliers should be earning revenues sufficient to contribute to their fixed cost recovery *every year*. Resource adequacy requirements provide such an avenue. To the extent that RA policies are motivated by a desire to maintain low energy price caps, there is an underlying desire to reduce the volatility of costs to retailers by replacing more-volatile energy prices with capped prices combined with smoothed capacity charges.

The distinction between price *volatility* and price *risk* is usually lost in the discussion of resource adequacy, or electricity policy in general, yet the distinction is an important one. Price risk may not be desirable, but price volatility can be critically important to the efficient construction and operation of electric systems. Electricity prices are volatile because the underlying value of the service is volatile. During most hours, the opportunity cost of generation from one source is the replacement of its power from another source of relatively similar cost. Relatively rarely, the opportunity cost of generation from an operating source is value of service enjoyed by a customer who would otherwise have to be interrupted. Most surveys put this ''value of lost load'' between \$2,000/MWh and \$50,000/MWh. Thus, under current operations, much of the time electricity has an underlying value in the \$20/MWh-\$100/MWh range, and at other times the value is 100 times this.

The *risk* of purchasing all of one's power at the marginal valuation is clearly high, but that does not change the fact that this volatility is reflecting the true economic facts of system operation. The efficient way to deal with this circumstance is to insure that most purchases are made under relatively stable, long-term commitments that reflect the averages of these volatile prices, *but to still preserve the volatility that is truthfully reflecting the facts of the market*. At its worst, the resource adequacy solution does not hedge against price volatility, but instead eliminates it by expanding resources to the point that prices are no longer volatile. This raises overall costs to pay for the capacity necessary to eliminate the volatility.

It is important to recognize that the underlying ''true'' volatility of today's electricity markets is itself an artifact of the way systems deal with supply shortages. Although individual customers may have VOLL upwards of \$2,000/MWh, each customer has individual uses of much less value. Thus the system focuses on interrupting a few customers *entirely*, rather than sending signals for a broad set of customers to partially reduce their consumption forces a dramatic increase in the costs of interruption and therefore contributes to the volatility of prices. A system, such as real-time pricing for end-use customers, that more effectively identifies low-valued usages and curtails them, instead of high-valued ones, during times of shortage would greatly reduce this volatility.

**5. Provide a mechanism for the commitment of specific generation needed for local reliability purposes.**

There is an additional goal that is considered important in the California context. It is hoped that a RA policy will provide a mechanism for ISO control over the commitment of generation resources necessary to meet local reliability needs. The mechanism used for this goal today is the must-offer requirement on generation, and its associated waiver denial process, which has become a form of centralized unit-commitment in California.

Currently, under authority granted by the Federal Energy Regulatory Commission during the crisis of 2001, the ISO has the ability to compel generation units to schedule their production as a bilateral energy transaction or to offer their supply into one of its energy or ancillary services markets. Under this must-offer obligation, generation has the responsibility to operate their plant in a manner that makes them available in case the ISO calls upon them, and must perform when called upon by the ISO. This means, among other things, that units must be operating at minimum operating levels that allow them to ramp up production at a reasonable rate. If a generation unit does not want to remain operating at these levels, it must petition the ISO for a waiver of its must-offer obligation. If the ISO denies the waiver, the generator is obligated to be operating in a manner that makes it ready to perform under short notice.

Although the California ISO operated its system from 1998 through 2000 without the existence of a must-offer obligation, operators have expressed concern that the current system could not be operated reliably without this obligation. Suppliers have complained that the obligation amounts to an uncompensated provision of reserve, or ''stand-by'' services.[12] Suppliers have argued that units denied must-offer waivers should receive a market-based payment for making their capacity available on a stand-by basis. The capacity market has been viewed as providing an avenue for defining such a payment.

It is also the case that a new service, called ''residual unit-commitment'' (RUC) will be added under the proposed revision of the California ISO's market rules, known as the Market Redesign Technology Upgrade (MRTU). This service allows ISO operators to commit units that do not otherwise clear the day-ahead market process, and creates a mechanism for compensating those units. This RUC service and its associated payment appear to provide an avenue for the replacement of the must-offer obligation once MRTU is in place.

**6. Develop a framework for compensating units subject to local market-power mitigation.**

The development of resource adequacy mechanisms and, more specifically, recent developments in capacity markets, have been influenced by the perceived need for a comprehensive approach to regulating units with ''local'' market power. These are generation units located in transmission-constrained regions that face little or no competition for their output. Because of this, ISOs have developed mechanisms that restrict the bidding of generators when they are deemed to have local market power. This mitigation has in turn raised concerns that some generation units will be unable to recover their fixed costs through market revenues.[13] Historically, such ''frequently mitigated units'' have signed ''reliability must-run'' (RMR) agreements with their ISOs. These contracts provide fixed payments to ''local'' generation unit owners in exchange for the ISO's ability to call upon that unit at a predetermined (usually cost-based) price under certain conditions.

FERC has expressed frustration with RMR contracts and has called for them to be replaced by ''market-based'' solutions to the problem of compensating locally constrained units. Since the problem is essentially the same as that affecting other units, this goal has been absorbed into the broader resource adequacy process.

Despite the similarities, however, there are important differences between generic motivations for resource adequacy policies and the question of compensation for frequently mitigated units. Most importantly, while it is reasonable to believe that entry is possible over a three- or four-year time horizon to meet generic resource needs, such entry is often very difficult or impossible in locally constrained regions. A strategy of utilizing long-term contracts can play off potential new entrants against incumbents in generic markets. This strategy likely will not work in many locally constrained regions, such as San Francisco. Entry barriers are simply too great to expect new entry to sufficiently mitigate the market power of incumbents in either energy or capacity markets.

Thus, while one could make a reasonable argument that market power in the capacity (or energy) market can be mitigated by firms contracting over a long-enough time horizon. In the case of locally constrained markets, this is not a reasonable expectation. Simply put, the price of capacity and/or of energy needs to be overseen by regulatory authorities to achieve a reasonable price.[14] This is an important consideration when one examines the specific mechanisms for pricing capacity as some rely on competition and some utilize administrative pricing formulae that do not depend upon supply competition at all.

## III. Summary

In this article, I have attributed the motivations for a resource adequacy mechanism to six goals: (1) ensuring adequate revenues for suppliers, (2) preventing the free riding of individual LSEs on the investments of others, (3) ensuring adequate forward contracting by LSEs, (4) reducing revenue and price volatility, (5) providing operators a means for physical control over critical generation resources, and (6) producing a source of supplemental revenues for generation units frequently subjected to local market power mitigation. When one views resource policy proposals through the lenses of these categories, one begins to understand the motivation behind specific resource policy proposals. An important dimension of these disputes is the extent to which such policies are directed at financial goals, such as the solvency of suppliers and of LSEs, or physical goals, such as the dispatch control of specific generation units.

The critical question is how resource policies address the overarching goal of providing reliable electricity service at the lowest possible cost. Critics of capacity markets point to the reduction in price volatility as a source of *increased* cost. The supplementing of revenues and elimination of LSE free-riding on their own do little to ensure reliability if suppliers do not also take on an obligation to provide energy during the high-demand periods when it is most needed. In many ways, the reliability contribution provided by mechanisms focused on installed capacity can prove illusory. The experience with capacity markets in the eastern U.S. has illustrated that certified capacity may not be able to deliver power to locations where it is needed, or even generate electricity at all, due to lack of fuel, energy limitations, or forced outages.

At the opposite end of the policy spectrum, stakeholders have been reluctant to embrace a system designed around energy-only payments, despite the fact that such approaches are the norm in most industries and have to date produced adequate investment in the Australian and U.K. electricity markets. This is partly due to fears of increased market power and price risk. To the extent that these are the primary reasons for avoiding an energy-only model, policies to directly address these concerns through hedging of energy prices would likely be more cost-effective than policies designed to eliminate high prices through institutionalized excess capacity.

The question also remains as to whether the prospect of higher energy prices alone would be enough to reverse the apparent lack of forward contracting experienced in the industry over the last few years. It may be that regulatory intervention is necessary to guarantee adequate energy contracting, but regulatory oversight of utility hedging policies would ideally take a different form than resource adequacy policies. These are questions directly impacted by regulatory policies about retail choice and procurement. Ideally, resource adequacy policies would not be deployed solely as a means to overcome shortcomings in these other areas.■

**Endnotes:**

**1.** For example see Lawton, Sullivan, Van Liere, Katz, and Eto, *A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys*, Report LBNL-54365. Lawrence Berkeley National Laboratory, Nov. 2003.

**2.** This can most easily be seen in the utilization of air conditioning, which accounts for nearly one-third of California's peak electricity demand. While a complete disconnection of air-conditioning can be extremely inconvenient and even life threatening, the incremental value of lowering a building temperature from 72 to 68 degrees is relatively minor. One of the main criticisms of traditional demand-side management programs is that they tend to focus on the complete interruption of a small number of customers rather than on small reductions in consumption by large numbers of customers.

**3.** See Kristina Hamachi LaCommare and Joseph H. Eto, Understanding the Cost of Power Interruptions to U.S. Electricity Consumers, Report LBNL-55718, Lawrence Berkeley National Laboratory, Sept. 2004. Distribution level reliability varies greatly by customer class. Large customers with a high value of reliability take their service at the transmission level and provide their own distribution services. This allows for a differentiation according to reliability preference that has not been attempted in the context of supply-based reliability.

**4.** The EIA reports that over 200,000 MW of new capacity came on line in the U.S. between 1998 and 2004. This constitutes a nearly 50 percent increase in the installed base of U.S. generation capacity.

**5.** Paul Joskow, *The Difficult Transition to Competitive Electricity Markets in the United States*, in ELECTRICITY DEREGULATION: CHOICES AND CHALLENGES, Griffin and Puller, eds. (Chicago: Univ. of Chicago Press, 2005).

**6.** This discussion assumes the generation unit is allowed to retire. In practice, several units have threatened to retire and have instead been signed to reliability must-run contracts at cost-based rates because they were deemed essential to grid operations.

**7.** It is important to note that such a reduction in the price cap can also create inefficiencies. The lower price cap could discourage demand-response and potential supply just as it would under a regulatory resource adequacy standard.

**8.** These industries also lack organized spot markets, so the resale of excess capacity in say, fiber optic cable, is more difficult than would be expected in electricity.

**9.** Efficient transmission pricing systems, such as LMP, allow for a quick evaluation of the deliverability of *energy* consumed since transmission costs are reflected directly in the energy price. By contrast, the *ex ante* assessment of the deliverability of *capacity* is not nearly as straightforward and has been the subject of much controversy in the eastern U.S. ISOs.

**10.** Taken from the *WSCC Assessment of the Summer 2000 Operating Period*. Figures shown are for the U.S. portion of the California/Mexico subsystem of the WSCC (at 17).

**11.** One must therefore use caution in interpreting analyses about the capital recovery of suppliers, since it is not clear what the appropriate time frame for such an analysis should be. Clearly, suppliers should not be expected to cover their full costs every month, or even every year. The petroleum refining industry in the U.S. went many years without earning substantial returns on its investments in refining capacity.

**12.** To call the service completely uncompensated overstates the matter. Generation units that have their waivers denied are eligible to collect their costs related to the commitment of the unit and maintaining output at minimum operating level. However, beyond this cost-based compensation, there is no explicit payment for being denied a MOO waiver, as there is for providing spin or non-spin ancillary services.

**13.** This concern is just a special case of the generic concern that energy price caps limit the ability of firms to recover their fixed costs. When properly implemented, the local market power mitigation essentially restricts the generation unit to offer its power at its incremental costs (with some additional padding). This cost-based offer is cycled through the locational pricing algorithm along with the offers of all the other units. In periods of ''scarcity,'' once that is defined, the locational price earned by the local generator would rise to the price cap, even if its offer were unconstrained. Thus there is a restriction on investment only when the hourly cap is set too low. Following this logic, an increase in the price cap would eliminate the need for side payments to compensate the fixed cost of mitigated units.

**14.** An important consideration is the impact of local market power mitigation in the spot market on the cost of resource adequacy requirements.