

**Resource Adequacy and the Cost of Reliability:  
The Impact of Alternative Policy Approaches on  
Customers and Electric Market Participants**

**RESOURCE ADEQUACY  
FINAL REPORT**

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Center for the Advancement of Energy Markets  
and the Distributed Energy Financial Group, LLC*

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## Executive Summary

During the 1990's, governments around the world implemented reforms to increase the reliance of the electric sector on market forces. Some new market structures introduced planning reserve requirements that were not supported by system engineers and operators. These changes heighten concern about whether generating resources will be adequate in the future to provide reliable electricity at low cost. Regulators now express concern about power shortages, price spikes and volatility, and rising (not falling) energy costs. There is a concern that generation resources are inadequate, where capacity resources are viewed as insurance against the physical non-delivery of energy and against significant price increases. Policy makers are responding with regulations to ensure that enough generating capacity will be built. At issue is whether efforts to increase generating capacity are warranted in terms of the cost imposed on consumers compared to the benefit of increased reliability. The paper examines approaches to resource adequacy, including their costs to customers and enhancements in reliability.

The main conclusions of this study are:

1. Empirical estimates presented here indicate that more reliance on competitive processes and efficient prices would reduce the average cost of electricity by more than one cent per kilowatt-hour in certain regions of the U.S. This price reduction would produce a \$19 billion annual benefit to ultimate U.S. customers. The benefit would result from avoiding unnecessary capacity reserves, and encouraging price-demand response.
2. The optimum level of reliable service (and minimum electricity cost) is obtained by equating the value and cost of reliability at the margin. Efforts to encourage investment in additional generation capacity in the name of "resource adequacy" tend to increase costs to customers beyond the value of improved reliability.
3. Regulations that require an annual capacity obligation and recover the cost from all customers, inhibit the development of efficient electricity markets and preclude price-demand response. Restructuring will fail to produce its potential benefit to customers without efficient pricing.
4. Reliability has both public good and private good characteristics. A competitive market for reliability relies on price-demand response, distributed energy resources, and numerous, competing technologies and services. Focusing resource adequacy and reliability on generation is inappropriate because most electrical outages result from distribution system failures.

We recommend that electric markets be designed to achieve economic efficiency. In an efficient electric market, generation should be priced at its marginal cost. This marginal cost will approximate the long run average cost (which includes capital cost) over time, which ensures an adequate level of investment. Annual capacity obligations should be replaced with an optimum capacity reserve margin that equates the costs and benefits of reliability at the margin.

Economically efficient markets provide reliable electric service at a minimum cost to customers. Price-demand response contributes to meeting peak demand by encouraging conservation and other substitutes for peak power plants. Price-demand response requires time to develop; therefore, the transition to a more efficient market may require a larger capacity reserve margin in the near term, than would be required over the long run.

We recommend:

1. The matching of capacity reserves to expected peak generation plus a reserve margin, during a short planning period (months, not years).
2. The linking of the marginal cost and marginal value of reliability to customers, as opposed to setting a reserve margin by a rule of thumb.
3. Floating wholesale prices that accurately reflect the marginal cost of supplying electricity.
4. Elimination of barriers to a highly responsive demand market.
5. Larger capacity reserves during the transition (for example, when prices are capped), and reduction or elimination of capacity reserve requirements once the market is competitive.

### **A Model of Cause, Effect and Public Response**

A popular view of resource adequacy connects recent events to the need for rules and regulations that maintain a high level of installed generating capacity. The popular model adopts the following line of reasoning:

**Figure ES-1**



As the story goes, recent events, such as the blackout in 2003, raise serious questions about the reliability of the electricity network, which in turn focuses concern on the generation market. The likely result is a regulatory requirement for a large generating capacity reserve margin.

### **Challenging the Model**

We show that each link expressed in this model is subject to serious qualification. The implication is that regulatory efforts that encourage capacity additions to improve reliability are not justified in terms of reliability benefits and required cost. These efforts have counterproductive effects of reducing market efficiency and increasing costs to customers.

Concerns about reliability that arise from recent events, such as the 2003 blackout in ten U.S. states, relate to the short run *operational reliability* of the electricity system, not to *resource*

*adequacy.* The cascading effect of the 2003 blackout emphasizes this operational aspect of reliability. The reliability of the electricity supply system depends not only on adequate generating capacity, but also on the reliability of the transmission and distribution systems, price response and distributed resources. Historically, most disturbances, such as outages in the electricity network, are caused by adverse weather conditions and falling tree limbs that affect the distribution system (low voltage) and are not related to resource adequacy in the generation market. The least reliable link in the electricity network is the distribution system, not generating capacity.

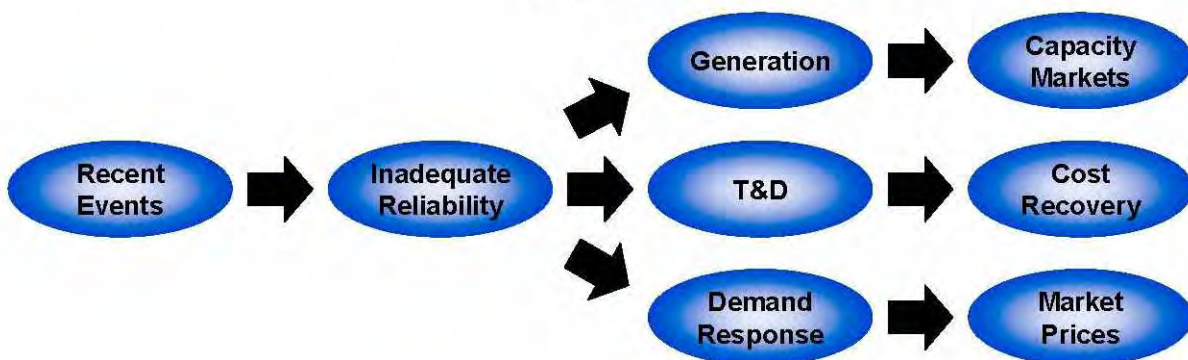
### **Generation Capacity**

Historically, the amount of available generation capacity has exceeded capacity in use by a wide margin. Projections of future capacity by the North American Electric Reliability Council and by the Energy Information Administration document that future generation capacity is likely to be adequate if not more than adequate. Concerns about insufficient generation capacity appear unwarranted, at least from a national and large regional perspective.

### **T&D and Pricing and Demand Response**

Concerns about resource adequacy and long-term reliability typically emphasize the need for generation capacity. However, electricity is supplied by a network that includes the transmission and distribution (T&D) systems, as well as generation. Reliable service depends on the reliability of the network, including T&D. Inadequate investments in T&D can result in “load pockets” that limit the ability of existing generation to reach customers. Reliability is also enhanced by the use of price demand response. Historically, the electric sector has considered load a given, and not subject to efficient pricing and demand response.

**Figure ES-2**



All three resource options need to be considered and optimized in order to achieve an economically efficient system.

## **Regulatory and Competitive Approaches to Resource Adequacy**

Several approaches to resource adequacy are being considered and implemented. For purposes of this report, these approaches differ in their reliance on rules and regulations to encourage capacity additions. We distinguish four approaches: two that place primary reliance on competition, and two that place primary reliance on regulation. The competitive approaches include an energy market only model (which has no separate capacity market), and a capacity reserve margin approach (which maintains a capacity market to provide reliability). The regulatory approaches include one that retains an annual capacity obligation, and the traditional regulatory approach.

The key characteristics of the regulatory approaches are that electricity prices reflect *average costs*, market adjustments are *quantity adjustments*, and large reserve margins that rely on *engineering criteria* are required. In contrast, the key characteristics of the competitive approaches are that electricity prices are based on marginal cost, electricity prices float and thereby contribute to market adjustments, and reserve margins are determined by equating the marginal value of reliability with its marginal cost. Market prices and a reliability reserve margin provide adequate investment incentives.

### **System Reliability as a Public Good**

These principles elucidate the connection between resource adequacy and the alternative market approaches. In the regulatory approach, generation, transmission and distribution capacity must be adequate to meet peak loads. Additional capacity, in the form of a reserve margin, must be available to meet demand during critical periods, such as during the outage of a significant asset or during extreme weather. Resource adequacy has a physical interpretation: either generating resources are adequate and can be delivered to customers, or they cannot. The regulation model obtains reliability from “iron in the ground,” and indeed, load forecasting models in use today by system operators treat load as a function of weather and GDP growth. The regulatory model has always treated load as independent from the marginal cost of serving load, and reliability has therefore taken on a public good characteristic. This one-size-fits-all-approach provides each customer with the same level of reliability and requires all customers to pay for it. The resulting price regime stifles competitive markets for reliability.

### **Market-based Reliability Services**

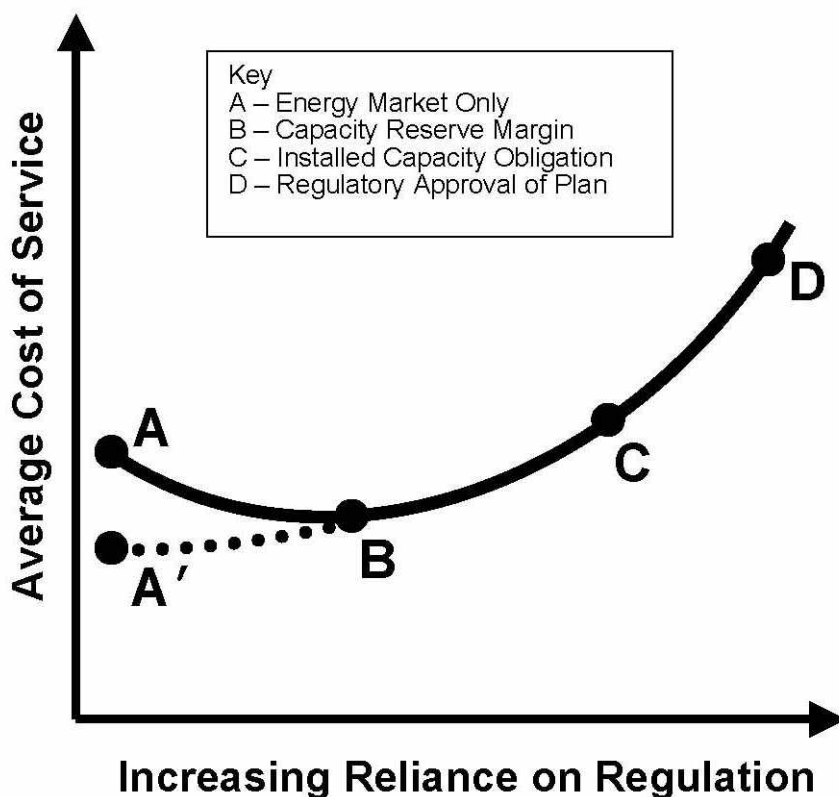
In more competitive approaches, substantial increases in demand or losses in supply are met by supplying more energy and by allowing demand to respond to price. With floating prices, resource adequacy is no longer a physical constraint, because demand is always met at some price (or voluntarily reduced in response to higher prices). The issue of resource adequacy now becomes an issue of obtaining optimum reserve margins and responding to price volatility, and providing price-risk management tools. The more competitive models allow for numerous ways to meet peak demand and maintain reliability other than simply building more power plants. Customers can engage in price-induced conservation or load curtailment, the use of distributed generation, and load storage and shifting. The competitive models also allow for numerous technological and financial approaches to providing reliable service and price stability. Peak

demand can be met at a lower cost than by relying exclusively on high reserve margins and additional power plants.

### Four Models of Resource Adequacy

Approaches that fall into the regulatory category include the traditional regulation of electric utility planning (Model D) and models requiring an installed capacity obligation, such as ICAP (Model C). Models with more competitive elements include: an energy market only and no capacity obligation (Model A), and various capacity reserve margin models (Model B). Our classification is intended to emphasize the regulatory elements that impair efficiency, and the competitive elements that enhance efficiency. The figure below depicts the net costs to consumers from these models.

**Figure ES-3**  
**Average Cost of Electricity**  
**Under Different Levels of Regulation**



We present quantitative evidence showing that an annual capacity obligation (ICAP) (Model C) increases costs to customers compared with an optimum capacity reserve margin model (Model B) with little to no increase in reliability. Using results from DOE’s Energy Information Agency (EIA) modeling analysis, in some regions that are restructuring but still use the fixed capacity approach, electricity prices may exceed those of the more efficient model by one cent or more,

and impose billions of dollars of unnecessary costs on customers. For the U.S. on average, the regulatory reserve margin approach adds about one-half cent per kilowatt-hour of electricity. This high reserve margin model adds about \$19 billion per year to the electric bills in the entire U.S. when compared with to a scenario where reserve margins are optimized and electricity is priced at marginal cost.

### **Application of Standard Engineering Practice**

The explanation for the high costs of the regulatory, flat-rate-pricing model begins by noting that reserve margins are determined by standard engineering practice, which is typically the “one-day in ten year rule” (i.e., reliable power 99.97% of the time). This approach is an historical rule of thumb that does not include the cost of adding reserves or the marginal value that customers place on any increased reliability. In contrast, the more competitive model solves for an optimum level of reliability, which is determined by equating the marginal cost of adding reliable capacity with the marginal value of reliability that it provides. The traditional engineering practice is not only inefficient; it is likely to be applied with a bias towards high reserve margins. The cost-risk priority of regulators and system managers is likely to reflect a “principal agent problem” whereby applying the rule results in reserve margins with costs that exceed their value in reliability. Further, traditional regulation of electric utilities imposes a capacity obligation based on expected peak demand, and maintains that level more or less throughout the year.

### **Average Cost and Marginal Cost Pricing**

Maintaining a constant level of generating capacity throughout the year provides justification for the allocation of capacity costs to all hours of the year, with the resultant flat electricity prices. These flat rate prices do not reflect the actual marginal cost of meeting peak demand; hence customers use an inefficient amount of a scarce resource. By recovering peak-related costs during non-peak times, the average price exceeds the marginal cost during most hours of the year. This pricing inefficiency further explains the high cost of the regulatory model relative to the competitive model. The lack of price-demand response is widely recognized as the limitation in current restructuring efforts.

The unnecessary high cost produced by the regulatory model is only part of the story. The regulatory model further produces flat-rate prices that preclude the development of efficient wholesale and retail markets. The deregulation of several industries in the U.S. has produced enormous benefits where price declines often exceed 50%. Benefits of this magnitude do not characterize any electric restructuring effort in the U.S. Restructuring efforts in the U.S. include the use of auction markets and retail access to power suppliers, but some such efforts are superimposed on the old regulatory model of flat-rate pricing and large reserve margins. The inefficiencies inherent in the regulatory model preclude restructuring efforts from providing the potential benefits to customers.

### **Current Trends Toward More Regulation**

We find that concerns about resource adequacy are motivating policy changes in the direction of the regulatory model and away from the competitive model. The evidence reviewed here

indicates that administrative requirements for investments in generating capacity—in both fully regulated and restructured markets—produce a level of generating capacity where the marginal costs exceed the marginal value of reliability. This result is consistent with the history of electric utility regulation and current market conditions. Current and historical reserve margins produce unnecessarily high prices for customers and impede the development of efficient markets.

### **Failure to Achieve Benefits of Competition**

The restructuring of electricity markets has failed to achieve benefits even approaching the cost reduction benefit achieved in other markets. The failure of various restructuring efforts to achieve the full benefit of an efficient market probably owes to the market design that retains the regulatory inefficiency of average-cost pricing and the use of a large amount of installed capacity to meet peak demand. Restructuring efforts, such as auction markets and retail competition, imposed on a base of an inefficient capacity market, cannot enhance efficiency in a major way. The apparent reliability and security of large reserve margins and stable prices precludes the development of an efficient market that would provide the large potential benefits to customers.

### **Transition Issues**

Resource adequacy and reliable service can be achieved through competitive markets. However, some states and regions adopt price caps and requirements for installed capacity. Other states and regions are considering ICAP or are revising existing requirements. The situation is dynamic, and each state and region will adopt an approach that is practical and politically feasible.

The transition period to a competitive electric sector may require a decade or longer. Concerns about price volatility may result in price caps, and a need for a capacity reserve margin. To stimulate investment in generation, the authorities can establish a larger-than-economically-efficient capacity reserve margin. Such requirements should be limited in scope (perhaps affecting only a portion of the system), planning horizon (months, not years), and duration. As reliability and confidence in the market increase, the capacity reserve margin can be eliminated.

The application of a competitive approach will reduce cost, and will enable the private markets to provide reliability services. A competitive approach will enable electric restructuring to provide the benefits to customers that we have observed in other deregulated markets.

## Section 1: Introduction

Throughout electric industry restructuring debates, a shout of “Reliability!” has been like yelling “Fire!” in a crowded movie theatre—scaring participants away from real problem solving and often resulting in higher consumer costs with little if any likelihood of improvements in reliability. —Hanger and Adels<sup>1</sup>

This report analyzes the Hanger and Adels thesis: that some market participants are advocating unnecessarily high reliability standards that will increase costs to consumers while providing little customer value in reliability. The evidence presented here supports the view that flawed models of restructuring impose large and unnecessary costs on customers. Restructuring efforts imposed on top of the existing regulatory structures limit the development of efficient markets.

During the 1990’s, many of the world’s electric markets underwent “restructuring” reforms to increase the reliance on market forces. In some jurisdictions, vertically integrated electric utilities were replaced with transmission and distribution utilities, competitive energy suppliers, power marketers and generation companies. Some markets use a power pool approach where the output of many generating units is combined and purchases are executed through bidding. Other markets rely on bilateral contracts for energy transactions and central control of a limited set of transmission services. In both instances, independent system operators (ISO) ensure that the transmission grid functions safely and efficiently. Both approaches relax the traditional planning reserve requirements imposed in the past. Through new market structures, entrepreneurs should find sufficient incentives to make investments in power plants.

The market structures and the resulting experiences in different parts of the world vary. In the US, the initial exuberance towards electricity markets reflected the significant efficiency gains achieved by deregulating other markets. However, some recent events have placed restructuring efforts on hold in several states. Regulators now express concern about power shortages, price spikes and volatility, rising (not falling) energy costs, and many other social issues. Market oversight offices closely examine the behavior of the stakeholders in the newly structured industry. Capped prices impose a ceiling for wholesale markets, and regulators examine the behavior of a limited number of very large entities. Regulators work to maintain traditional reliability levels (or better) for their constituents.

A perception exists that network reliability problems are new and are caused by increased electric industry competition. A few market skeptics point to the Energy Policy Act of 1992 (requiring more wholesale market competition), and electric retail choice (pursued by seventeen states), as the cause of reliability problems. Others state that reliability problems are inherent because of the nature of the electric commodity. Most stakeholders agree that some level of

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<sup>1</sup> John Hanger and Peter Adels, “Throwing a Curve,” *PennFuture*, Vol. 5, No. 12, June 18, 2003.

regulatory intervention is appropriate to create the rules of the game, and to ensure system reliability.

The motivation for this study is that several models and proposals are being considered in regional (PJM) or state (New York and California) markets that would require an increasing amount of generating capacity under the presumption that more generating capacity enhances reliability. The impact of these proposals on competitive market structures, and the potential increase in electricity costs from larger reserve margins is not being adequately considered. Current efforts to address resource adequacy may increase the cost to customers with little or no improvement in electric reliability. Some resource adequacy approaches may rely on market-mechanisms, but do little to improve market efficiency or to create a truly competitive market.

Current regulatory proposals that are rationalized under the guise of capacity adequacy and reliability suggest a return to government selection of resources comparable to traditional cost-of-service regulation. The traditional model relies on government oversight of utility planning activities, with different levels of review and approval prior to construction of large generating units. Once a power plant is completed, the costs are “placed in rates” to allow cost recovery during the expected useful life of the asset. Regulation appears to function very well when the nation pursued electrification and when each new generating unit reduced the average cost of service. When energy costs increased during the 1970’s and the economies of scale of large power plants ceased, competition appeared as an opportunity to reduce costs to customers. Integrated resource planning in its ideal form required utilities to examine all demand-side and supply-side options in formulating a plan. However, this approach was costly. A greater reliance on market forces to provide adequate power became the goal in the 1990’s with success in several jurisdictions.

During the past five years there is increasing concern that the structures for wholesale competition and retail competition are flawed, and that market forces are not building enough capacity to meet the growing needs of customers. A variety of stakeholders communicate their concerns and exert their preferences on policy makers.

- Merchant generators are interested in a market structure that reduces the risk of power plant ownership and establishes a steady revenue streams for power generation. They would support payments for generating capacity, and the participation of generators in ancillary services markets.
- Power marketers are concerned with market rules that limit their ability to interact with all market players, including generators, retail energy providers and utilities.
- Retail energy providers are concerned with access to power supplies and customers, and they are worried that resource adequacy requirements will impose costs and risks on them without any corresponding benefit. They advocate the construction of new transmission facilities so that wholesale market function more efficiently.
- Utilities that do not own generation, yet maintain an obligation to serve customers, are most concerned with guarantees for cost recovery for the power purchased on

behalf of customers. They are concerned with how price-demand response could affect revenues.

- Equipment manufacturers and vendors, who provide renewable, distributed and other alternative energy technologies and on-site services, are interested in open markets for their products and services. They seek standard regulations for meters, controls, and interconnection of small generating units, as well as pricing that rewards customers for the value that these devices and services provide to the network.

Electric service reliability is often described as a public good because each customer obtains the same degree of reliable service, and customers usually cannot obtain more or less reliability by private transactions. Actually, however, reliability has significant private elements as some customers sell interruptible service, others purchase backup for their computer systems or purchase on-site generation. The public good characteristic of service reliability results from traditional utility regulation and its reliance on average cost pricing and large reserve margins to obtain reliability. Competitive markets rely upon price and quantity adjustment and the issue of physical reliability is affected by price volatility and customer response to price. Indeed, efficient electricity markets could provide highly reliable service by relying on price adjustment and price-risk mitigation.

A key problem in the design and implementation of electricity markets is lack of attention to pricing. Retail customers lack the price signals that would give feedback about the value of electric reliability during peak periods. Regulation creates stable retail prices that reflect average costs. Almost all market adjustments (to satisfy high usage) are generation capacity (quantity) adjustments. Electric demand is inelastic in the short term, and customers lack financial incentives and have few alternatives. In the long term, customer awareness and education, marginal cost pricing, and distributed energy technologies can increase price elasticity and allow demand adjustments during peak periods.

While the capping of prices eliminates the politically sensitive perception of windfall profits, the reality is that price caps limit the profitability of generation assets, and affect investment decisions. Changes in the distribution of risks and rewards and profitability affect the willingness of investors to build new facilities. Without new power plant construction there is a concern about the adequacy of resources that provide electricity. Tightening reserve margins raise the specter of power outages and lowered reliability. Policy makers respond with efforts to replace traditional regulatory planning oversight with new market structures and rules to ensure that enough capacity is built.

Government policymakers and market participants are raising concerns that the resources used to supply electricity may be insufficient to ensure a high level of supply reliability. The reliability of the system depends in part on an adequate level of resources for generation (G), transmission (T), and distribution (D) to customers. Much of the recent concern focuses on generation, and on the need to increase reserve margin, the amount of generation capacity (in reserve) above

expected demand. However, inadequate investment in transmission infrastructure is a key problem in US electric markets.<sup>2</sup>

Some states and regions are developing new approaches to enhance resource adequacy, with the objective of increasing system reliability. These efforts tend to focus on increasing the reserve margins by providing economic incentives for new generation capacity. We estimate the costs to customers from maintaining a capacity obligation where costs exceed benefits at the margin.

Customers are currently paying the price for past planning and cost overrun mistakes through stranded costs and competitive transition charges. If capacity adequacy concerns increase costs in excess of the value of increased reliability, customers end up paying those costs. Hence there is a need to estimate whether the concern for resource adequacy translates into increased reserves, whether more reserves enhance the reliability of electricity, and whether customers value any increase in reliability.

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<sup>2</sup> U.S. Department of Energy, *National Transmission Grid Study*, May 2002. Available online: [http://tis.eh.doe.gov/ntgs/gridstudy/main\\_screen.pdf](http://tis.eh.doe.gov/ntgs/gridstudy/main_screen.pdf).

## Section 2: Reliability and Resource Adequacy

This section provides a brief discussion of the meaning of reliability and resource adequacy. Our purpose is to lay a foundation to assess whether various levels of reliability provide net benefits to customers.

The amount of electricity supplied and demanded over any period of time is subject to significant random variations. Supply uncertainties result from outages or other disturbances in the transmission and distribution system, and perhaps from insufficient generating capacity due to low reserves or unavailability generation units. Demand uncertainties result mostly from temperature variations affecting heating and cooling needs, but also from the volatility of economic activity. Maintaining reliable service in the presence of randomness of both supply and demand for electricity requires that the electricity market is able to adapt to major short run disturbances and to long run requirements of providing low cost and reliable service. Historically, supply and demand changes are met almost entirely by reserve margin above expected use. Recent events in the U.S. increase the concern with the reliability of the nation's electric power supply, with the result that even higher reserve margins are being considered.

An examination of costs and benefits of proposed levels of reliability requires a definition and metric of reliability. First, we define reliability, and then place a monetary value on incremental reliability, and establish that the cost of increasing reserves to achieve reliability exceeds the resulting increase in reliable service. This section discusses issues relating to providing a definition and metric of reliable electricity service. If the customer's monetary value of service reliability can be defined and measured and related to reserve margin, this value can be compared with the increased cost of providing reserves. Unfortunately, defining service reliability is not a simple task. This section relies on economic research studies of service reliability summarized in Appendix B and obtains the following overall findings:

- There is no simple, unambiguously correct, definition of service reliability.
- The value of service reliability varies between customer classes for commercial, industrial and residential classes, and varies significantly within each class.
- The historical reliability rule, where expected outages occur up to one day in ten years, is a supply side model with no basis in economic analysis, and does not reflect reliability that customers are willing to pay for.
- Optimum reliability is obtained by reserve margin that equates the marginal cost of reserves with the marginal benefit of reliability.
- An economically efficient approach to achieving optimum reliability uses micro approaches that include end-use technologies, and does not rely totally on capacity reserve margin. Micro approaches reflect the importance of customer classes, specific end uses, and specific time periods.

An analysis of resource adequacy and reliability should reflect underlying definitions of resources, reliability, as well a definition of adequacy. This section provides such definitions. Several government agencies and private organizations have in interest in the Nation's electric power system. At the national level, the North American Electric Reliability Council (NERC) has perhaps the most important role in ensuring reliability. At the state level, the state public utility commissions regulate reliability of the electric utilities within their jurisdiction.

NERC is a not-for-profit corporation whose members represent most segments of the electric industry and account for almost all electricity supplied in the U.S., Canada and part of Mexico. As its name implies, NERC's main focus is monitoring and ensuring that the North American bulk power system is reliable. It develops standards, guidelines and criteria for ensuring reliability. As a private organization, NERC does not have regulatory enforcement powers, but instead relies upon voluntary compliance.<sup>3</sup> In its annual assessment of the reliability of bulk electric systems in North America, NERC defines the reliability of the bulk electric system in two ways:<sup>4</sup>

- Adequacy—The ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- Operating Reliability—The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated failure of system elements.

Operating reliability is often referred to as “security” because operational reliability provides a secure system in day-to-day operations. Operational reliability is a short run concern that involves maintaining system integrity in the event of a disturbance. Adequacy refers to resource adequacy, which is the ability to meet demand, particularly when there are large random changes in demand or supply conditions. Resource adequacy includes providing the appropriate level and mix of resources for transmission, distribution and generation. Resource adequacy also includes providing incentives to attract investment in capacity in T, D and G that provides reliable service over the long term. Resource adequacy also reflects a longer time frame where long lead time investments in generating capacity and transmission and distribution will be sufficient to meet demand.

The blackout of August 2003 increased concerns about the operating reliability of the system, because this event was a failure of the security of the distribution system. This blackout and other major disturbances are studied at length, and the NERC is implementing recommendations to improve operating reliability. Indeed, much of the current interest in reliability is with operational reliability of the existing system. A main concern with operational reliability is preventing disturbances from cascading into a widespread loss of load.

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<sup>3</sup> See Richard P. Sedano, *Dimensions of Reliability: A Paper on Electric System Reliability For Elected Officials*, The Regulatory Assistance Project, Montpelier VT, 2001, p. 10.

<sup>4</sup> North American Electric Reliability Council, *2004 Long-Term Reliability Assessment*, September 2004, p. 11.

Each of the ten area councils defines the reliability standards for its region. The Mid-Atlantic Area Council (MAAC) defines its network resource capacity requirement as:

Sufficient network resource capacity shall be provided in the form of firm contracts on installed generation and shall be deliverable to system load to ensure that in each year for the MAAC system the probability of occurrence of daily peak load exceeding the available network resources shall not be greater, on the average, than once in ten years.<sup>5</sup>

This definition, which applies explicitly to the PJM region, expresses the one-day-in-ten-year rule that is the commonly applied reliability standard of electric utilities.

State public utility commissions regulate electric utility operations within their boundaries with the objective of ensuring reliable service at lowest reasonable cost. Thirty states use specific reliability metrics that reflect either the duration or the frequency of outages. These metrics include measurement of the average frequency and duration of outages.<sup>6</sup> These reliability metrics do not measure the economic value of service reliability, the cost of providing reliable service, or the economic impact of an outage.<sup>7</sup> The metrics do not reflect the customer value of service reliability, and instead are merely mechanical performance measures of the distribution system.

In this report, we use the resource adequacy definition of reliability. Our interest is whether electricity markets provide the optimum level of reliability, and particularly whether recent concerns over resource adequacy impair or contribute to the development of efficient markets. The brief discussion of NERC and state approaches to reliability indicates the importance of an historical and engineering perspective, and a lack of economic analysis. An economic optimization approach, that reflects cost and customer value, would likely indicate a different level of reliability and reserve margin than is recommended by the NERC area councils, or by the state regulatory authorities. This economic analysis behind this approach is developed in Appendix B.

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<sup>5</sup> Mid Atlantic Area Council (MAAC), *MAAC Reliability Principles and Standards*, Document A-1, July 18, 1968, revised June 28, 2004.

<sup>6</sup> The metrics include SAIDI (System Average Interruption Duration Index), CAIDI (Customer Average Interruption Duration Index) and MAIFI (Momentary Average Interruption Frequency Index).

<sup>7</sup> Humphrey, Bruce, "Mixed Signals Cloud Reliability Picture," June 30, 2003, <http://www.energypulse.net>.

## Section 3: Economic Aspects of Reliable Service

### Reliability Has Public Good and Private Good Characteristics

Private markets can provide an efficient amount of private goods, but provide an insufficient amount of public goods, which instead require collective action. The public good characteristic of reliability implies the need for rules and regulations to establish a capacity market, and to provide a level of capacity in reserve that optimizes reliability.

National defense and lighthouses are the common example of public goods. A characteristic of a public good is that consumers cannot be excluded from deriving its benefits by a market price. The reliability of the electricity supply system has non-market characteristics, and some level of reliability is a public good. Reliability cannot always be priced according to customers' willingness to pay for this reliability. Hence, either authorities set reliability standards, or stakeholders agree to a standard.

The view of reliability as a public good is common in the literature of reliability. As stated in a Lawrence Berkeley National Laboratory report by Lawton, "Most important of all, reliability has always been a shared responsibility because it is a public good."<sup>8</sup> In a report on reliability for elected public officials, Sedano describes the public good characteristic of the electric system reliability as, "... most aspects of electric reliability are provided to everyone, or to no one, and everyone is required to pay for it."<sup>9</sup> Reliability cannot readily be priced to individual customers because reliability comes from the network, regardless of whether customers pay for it. The significance of this public good characteristic is to require regulatory authorities to determine a reliability standard.

This public good characteristic of reliability is common knowledge. However, the critical point is that reliability is to a significant extent not a public good, but a private good. For example, many utility customers sell the right to interrupt their service for a price. Utilities pay for the right to interrupt service by reducing rates or providing a direct payment. Some customers sell their rights to reliable service and many customers pay for a reliability level that exceeds that provided by the distribution company by purchasing reliability in private markets. Surge protectors and battery backup are often purchased for personal computers. Hospitals, hotels and numerous other customers enhance their reliability by purchasing backup generation. The

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<sup>8</sup> Lawton, Leora, M. Sullivan, K. Van Liere, A. Katz, and J. Eto, *A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys*, Lawrence Berkeley Laboratory, LBNL-54365, November, 2003, p. 1.

<sup>9</sup> Richard P. Sedano, *Dimensions of Reliability: A Paper on Electric System Reliability For Elected Officials*, The Regulatory Assistance Project, Montpelier VT, October, 2001, p. 1.

reliability provided by the electric distribution utility is largely a public good, but the reliability levels obtained in the market have significant price elements, and customers can choose the service levels that suit their needs. Certainly, some customers sell reliability (interruptible rates) and buy increasing levels of reliability for computer systems and other end uses that require higher levels of reliability than obtained from the network.

Reliability is considered a public good when referring to the short run operational reliability of the network. Even in the short run, however, it is possible to make components of operational reliability—such as voltage control—an element of the competitive market. Customers can sell short-notice interruptible capability to the system as they do in Texas. However, much of the benefit of these ancillary services is shared by all customers, and is not priced separately to specific customers.

The public good characteristic of resource adequacy is, to a large extent, artificially created by traditional utility regulation. As noted above, the reserve margin approach to reliability is a product of historical utility regulation. This regulation has historically imposed average cost, flat rate, pricing where major variations in demand are met by maintaining large reserve margins. Reliable service is not maintained by increasing electricity rates as reserve margins decline, but by maintaining a large reserve margin above peak demand that provides reliability at fixed prices. In the market design where reliability is provided by large generating reserve margins, reliability becomes a public good. Of course, competitive and efficient markets do not function in this manner, and in competitive markets reliability is a private good.

If electricity were sold in a spot market with floating prices, the market would generally clear where kWh produced would equal kWh purchased. There would be no shortages that require a reserve margin. In competitive markets, floating prices contribute to market adjustments; hence less capacity and capacity reserve is needed than is required in regulated electricity markets. Hence, it is the regulation of electricity providers, and the resulting flat electricity prices and large reserve margins that create the need for additional regulations to produce adequate resources.

One implication is that a market design employing marginal cost pricing for generation and reliability would reduce costs to customers relative to a fixed price market that relies on a large reserve margin. With price-demand response in the generation and reliability markets, the need for a large regulatory determined resource margin declines. Stated differently, under regulation (including ICAP) the burden of providing reliability is met by constructing an enormous amount of capacity. With floating prices that accurately reflect marginal cost, much of the burden of meeting peak needs can be met at lower costs than simply constructing more power plants.

In a fixed price model where only quantities adjust, a large reserve margin is required and it has a public good property. Reliability refers to the physical availability to provide electricity. In a floating price model, a much smaller reserve margin is required and it potentially becomes a private good. Reliability now has a price stability interpretation rather than a physical

availability attribute.<sup>10</sup> In a market with floating prices, a reserve margin does not enhance reliability of physical supply, but instead achieves reliable supply with less price volatility.

In sum, the public good aspect of reliability appears to justify collective action to provide reliable service. However, by realizing that this public good is artificially created by inefficient regulations, it becomes apparent that restructuring could place greater reliance on private actions and floating prices to provide reliable service.

### **The Principal-Agent Problem and Excessive Reserve Margins**

Concern over reliability and resource adequacy is inherent in electricity market regulation, be it private, e.g., PJM, or government, such as the state utility commissions. This concern is likely to result in rules or regulations that increase reserve margins and cost to customers beyond that achieved by competitive markets. This priority of very high reliability is an inherent tendency that results from the principal agent problem.

The principal agent problem is a regulatory failure that distorts resources, just like air and water pollution are market failures that preclude economic efficiency. Customers (the principal) use agents for expert advice and decision making; but the agents reflect their own self-interest rather than the interest of the principal. Examples are common: stockbrokers churning their clients' portfolios to receive commissions, surgeons recommending unneeded surgery, auto mechanics performing unnecessary work. In electricity markets, the principal agent problem results in regulatory authorities requiring a larger reserve margin, and corresponding higher costs, than characterizes competitive and efficient markets.

The principal agent problem indicates that the regulatory system will opt for higher reserve margins, where the marginal cost to customer exceeds marginal benefit of reliability. That is, the preferred cost-risk tradeoff of regulatory officials does not necessarily correspond with the preferences of utility customers. Electricity customers are the principals; the market regulators are their agents. Ideally, regulators would act on behalf of customers and try to achieve reserve margins consistent with competitive markets. However, the incentives of public officials differ from the priorities of the customers. A high priority of market regulators is to maintain a very high level of service reliability, and to avoid the risk of unmet demand. A reliable electric system is particularly important to public officials, because reliability is their responsibility and because they avoid criticism from system failures. If reserve margins are too low, producing occasional service disruptions, the public blames the utilities, commissioners and perhaps

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<sup>10</sup> Oren, Shmuel S., "Ensuring Generation Adequacy in Competitive Electricity Markets," Paper #007, *Energy Policy and Economics Working Paper Series*, University of California Energy Institute, Berkeley, June 2003. Oren makes the point that reliability has this price stability property.

legislators. If reserves are too high, policy makers pay little cost, but customers pay higher rates.<sup>11</sup> Customers are therefore likely to prefer much lower reserve margins than policy makers.

Recent concerns over capacity adequacy, along with the principal agent problem, indicate that reserve margins may be excessive. The principal agent problem has characterized the regulation of electricity markets throughout its long history. The empirical finding that the 1-in-10 rule produces excessive reserves probably reflects this regulatory inefficiency. The implication is that reserve margin requirements impose costs on customers in excess of reliability benefits that customers are willing to pay for.

The principal agent incentives may contribute to the failure of restructuring electricity markets in the U.S. to achieve the benefits that we could reasonably expect. The deregulation of the security brokerage industry and the telephone monopoly has produced enormous benefits to customers. With respect to other industries, a technical analysis of regulation reports that since deregulation:<sup>12</sup>

- Operating costs per vehicle mile have declined by at least 75% in trucking;
- Operating costs have declined 60% in railroads;
- Costs per ton mile have declined by 25% in airlines;
- Costs of electronic deposit have declined by 80% in banking.

Furthermore, as a result of competition, most of these cost savings have been passed forward to customers.

The restructuring of electricity markets has failed to achieve benefits even approaching the cost reduction benefit achieved in other markets. One of the most successful restructuring efforts in the U.S. is in the PJM region.<sup>13</sup> The states in this region have implemented retail competition, and the wholesale market uses auction markets to achieve the efficiency condition of price equal to marginal cost. The retail experience includes numerous instances of marketers exiting the market, instances of customers remaining with their electric utility (choosing not to choose), and a major concern regarding suppliers not serving customers, and hence a need for a provider of last resort. None of these conditions characterize the highly successful deregulation efforts noted above. PJM has experienced some price reduction from restructuring (Sutherland 2003), but not approaching the price reductions from deregulating other industries.

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<sup>11</sup> One view is that state utility commissioners are more sensitive to imposing high costs on customers than are independent system operators of power pools, which implies that the principal agent problem is more serious in power pools.

<sup>12</sup> Clifford Winston "Industry Adjustment to Economic Deregulation" *Journal of Economic Perspectives*, Vol. 12, No. 3, Spring, 1998, pp. 89-110.

<sup>13</sup> PJM refers to Pennsylvania, New Jersey and Maryland, but the region also includes Delaware and Washington DC, to comprise PJM-East. The PJM region recently expanded to include additional areas to the west and south.

## Limitations of a Market-Based Model

The reliability model developed in Appendix B reflects only the generation capacity market. An important assumption in applying this model is that the market for electricity services is initially in equilibrium where reserve margin is optimal. Implicitly, an additional assumption is that reliability obtained by transmission and distribution (T&D), and by end use technologies, is also at an optimal level. Reserve margin is set to meet peak demand, but the T&D systems also must be designed to meet peak demand. So the assumption is that a reserve margin for T, D and G is initially at an optimum level. An increasing concern over reliability (capacity adequacy) is now met with proposals to increase generation capacity. However, we would expect that if T&D and end use reliability technologies were initially at an optimum level, they are now insufficient to meet increasing concerns over system reliability. A reasonable expectation is that an increase in investment in T&D in the entire system is required to achieve an optimum level of reliability. Further, increases in the generation reserve margin above the optimal level may add no value to system reliability if T or D becomes the weak link in reliability.

In actuality, a low cost way to obtain additional reliability may be via increased maintenance of the distribution system, or, by end use technologies that improve the reliability of specific technologies. Electrical outages are usually related to the distribution system, not to a deficiency of generation reserves. As noted above, tree limbs contacting power lines was the initial cause of the blackout of August 2003 in ten states. Current federal regulations require that major disturbances in the electrical power system be reported to the Federal Government. The EIA (2003) provides a list of the 23 major disturbances reported in 2002.<sup>14</sup> At least 14 of the disturbances are related to ice storms, winter storms or other severe weather. Although we cannot determine how many of the disturbances affected the transmission and distribution system, and how many affected generation, it appears that the large majority of serious disturbances are weather related and affect mostly T and/or D, rather than G. Anecdotal evidence, such as trade press, of causes of electrical outages indicates that about 85% are distribution related, 10% are generation related, and 5% are transmission related. Apparently, most outages are distribution related and are often caused by adverse weather conditions, tree limbs contacting power lines, lightning, or vehicles colliding with power poles. The reliability model focuses on generation reserves to improve reliability of the system, but distribution improvements or end use technologies may be a lower cost option for the same level of enhanced reliability.

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<sup>14</sup> Energy Information Administration, *Electric Power Monthly*, U.S. Department of Energy, Washington DC, DOE/EIA-0226(2003/03), p. 194.

## **Section 4: Approaches To Resource Adequacy**

Concern about the adequacy of resources used to meet the demand for electricity may appear to be a new issue. However, concern over resource adequacy is of paramount importance in the history of electric utility regulation.

The first part of this section explains that concerns over reliability of electricity supply are inherent in the traditional model of electric utility regulation, and therefore part of its long history. Next, we present a market-based approach to supplying electricity, which places greater reliance on price flexibility and optimal reserve margins to meet changes in demand. This approach reduces concern over resource adequacy as a physical supply constraint, but may raise an issue about price volatility. We then contrast the regulatory approach to resource adequacy with the optimum reliability model developed above. Finally, there is a discussion of current capacity needs in the US, and of the resource adequacy approaches in four regions of the US. Current approaches to achieve an adequate generation reserve margin use an administratively determined capacity obligation. This installed capacity obligation, termed ICAP, is explained.

The main conclusions reached in this section are:

- Historically, reserve margins are excessive and impose unnecessary costs on customers, while not providing significant increases in reliability. This inefficiency is inherent in the nature of traditional electric utility regulation.
- Inadequate price demand response results from the traditional average-embedded cost-of-service regime.
- A market-oriented approach to achieve an optimum level of capacity would make more use of price flexibility to achieve supply and demand equality, which would reduce required capital investments and the average price of electricity.
- An installed capacity obligation based on peak demand and applied throughout the entire year produces an unnecessarily large economic burden on customers with no commensurate value in reliability.
- The locational and demand curve approaches to capacity obligation may reduce some inefficiency relative to ICAP. However, it appears that the demand curve is designed to increase generation beyond than required by the 1 in 10 rule.

### **Historical Regulatory Treatment of Resource Adequacy**

Historically, the need to regulate electric utilities was assumed to arise from an apparent natural monopoly characteristic of service territories. This natural monopoly meant that a single service provider would have lower average costs than numerous competitors within the service area.

However, electric utility regulation arose, not to protect customers from natural monopolists, but to establish monopolists and protect them from competition. The origin of electric utility regulation in the U.S. can be traced to Samuel Insull, of Commonwealth Edison Company, who, as early as 1898 argued that private electricity companies seek public regulation to achieve legal monopoly status. In the bargain for exclusive rights to a service territory, the utility submitted to public regulation that would produce a fair rate of return.<sup>15</sup> The regulatory authorities approved electricity prices that would produce the fair rate of return to investments in T, D and G.

From the earliest history of electric utility regulation, electricity prices were determined by average costs and not peak marginal costs. Since the early 1900s, utility commissioners approved electricity prices to recover average costs of producing and distributing electricity plus an allowed rate of return on investments in capital equipment.<sup>16</sup> With stable electricity prices, variations in demand were met by the supply of kilowatt-hours, rather than by price increases. Resource adequacy meant obtaining a level of T, D and G that would provide an adequate supply of electricity at peak demand without raising price. With both supply and demand for electricity containing random variations, providing reliable service also required a large capacity reserve margin above peak demand.

A unique feature of the regulated electricity market, that began almost a century ago, is reliance on a large amount of capacity to meet demand and to provide a margin of reserve. Capacity had to be adequate to meet demand throughout the entire year, including extreme summer and winter peaks. The capacity reserve margin acts as the safety net to accommodate variations in the supply and demand for power. The regulation of electric utilities rewarded these capacity investments with that which commissioners judge to be a fair rate of return. Utilities recover a return on investments when the capital equipment is used to produce and distribute electricity, and when it remains idle. One result of this “rate of return” regulation is relatively flat rates to customers, rather than higher rates during peak periods. This type of regulation also encourages utilities to obtain substantial reserve margins. The motivation of the regulatory authorities to approve high reserve margins is their strong preference for ensuring reliable service.

Concerns about resource adequacy are inherent in utility regulation, ever since its earliest days. The industry understood from its beginning that “ruinous” competition would price at marginal cost, which implies that revenues would not support subsequent capital investments. As noted by the EIA “...there was growing concern that downward pressure on prices would prevent investors from making the capital investments necessary to ensure the reliability of electricity supplies.”<sup>17</sup> Rate of return regulation solves this apparent problem by allowing a rate of return on investments and prices that reflect average cost. However, the reliance on flat rate prices

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<sup>15</sup> Hirsh, Robert F. “Regulation and Technology in the Electric Utility Industry: A Historical Analysis of Interdependence”, in Jack High (ed.) *Regulation: Economic Theory and History*, Ann Arbor, University of Michigan Press, 1991, pp. 152.

<sup>16</sup> Energy Information Administration, *Electricity Prices in A Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities*, U.S. Department of Energy, DOE/EIA-0614, August 1997, p. 11.

<sup>17</sup> *Ibid.*, p. 1,2.

requires large market adjustments in kilowatt-hours supplied, and meeting this peak supply requires a large amount of capacity, plus a reserve margin. Unregulated markets ration peak demand with price increases, and thereby require less capacity. Price flexibility reduces the need for capital costs and thereby reduces prices to consumers.

The restructuring of electricity markets in the U.S. supposedly reflects the view that competitive markets are more efficient than markets subject to average rate of return regulation. However, restructuring in some regions is based on the natural monopoly perspective and not on a competitive market model. An auction market reveals prices that equal short run marginal cost. In a competitive market, these prices will, over time, reflect long run average costs. A competitive market will thereby provide resource adequacy. In a market characterized by natural monopoly, marginal cost will be less than average cost. Market prices will be insufficient to attract sufficient investment to ensure resource adequacy. Almost all students of electricity markets now accept that the generation market is potentially competitive.<sup>18</sup> However, restructured markets, such as PJM and NY implicitly adhere to the natural monopoly characteristic of generation. The regulation requiring a large installed capacity margin (ICAP) is based on the view that auction market prices will not cover average costs and will not provide resource adequacy. This point is also developed by professor Hobbs of the Johns Hopkins University, who states, “An important motivation for establishing the ICAP market was to ensure capacity owners that they would recover their fixed cost.”<sup>19</sup>

The historical approach to resource adequacy emphasizes engineering analysis and not economic analysis. The regulatory approach of meeting peak demand by constructing additional power plants with fixed prices is one illustration of this principle. The rule of thumb of designing for outages to accumulate to one-day in ten-years is an engineering rule with no basis in economics. Lawton states: “Historically, generation, transmission and distribution systems investments have been planned using arbitrary defined engineering criteria.”<sup>20</sup> This historical emphasis on engineering suggests that an economics approach to pricing reserves and generation should reduce costs to customers.

An important characteristic of utility regulation is to encourage a level of investment that achieves a high reserve margin. Traditional utility regulation grants investments in capacity an allowed rate of return that is recovered in future revenues. The price of electricity is set high enough to cover operation and maintenance costs, and to provide a reasonable rate of return on investment. With rate of return regulation, utilities had an incentive to maintain a large reserve margin.

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<sup>18</sup> The common view is that the distribution and transmission networks are close to natural monopolies.

<sup>19</sup> Hobbs, Benjamin F. Javier Inon, and Matthew Kahal, *A Review of Issues Concerning Electric Power Capacity Markets*, Maryland Department of Natural Resources, December, 2001, p. 6

<sup>20</sup> Lawton, Leora, M. Sullivan, K. Van Liere, A. Katz, and J. Eto, *A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys*, Lawrence Berkeley Laboratory, LBNL-54365, November, 2003, p. 1.

Electric utility regulation has numerous characteristics such as monopoly service territories and other factors. We summarize the four characteristics of utility regulation that are critical in considering resource adequacy:

1. Utility regulation relies on average cost pricing to provide stable revenues and a return on utility investments.
2. Variations in demand are met by a large amount of capacity, plus a reserve margin.
3. The reserve margin reflects engineering criteria, or, perhaps no analysis at all (rule of thumb).
4. Investment in generation is encouraged in a regulation process that sets the price of electricity to ensure a reasonable rate of return on investment.

### **Market-Oriented Approaches to Resource Adequacy and Reliability<sup>21</sup>**

An electricity market that is economically efficient supplies electricity at minimum cost, it provides optimum reliability to customers, and, of course, it provides maximum benefits to customers over time. The design of an efficient market begins by restating the basic economic conditions of market efficiency. We use these principles as a guide to assess whether various approaches to resource adequacy move in the direction of traditional utility regulation, or, in the direction of improving market efficiency.

An economically efficient electricity market has four characteristics that contrast sharply with the above characteristics of utility regulation:

1. An efficient market relies upon marginal cost pricing, and not average cost pricing.
2. Electricity prices float; hence the market for electricity adjusts to variations in (peak) demand with changes in price and quantity.
3. Capacity reserves are determined by equating the marginal value of reliability with its marginal cost.
4. An efficient market provides adequate investment incentives on the basis of market prices and a reliability reserve margin.

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<sup>21</sup> Our classification of models is similar to that of Hirst and Hadley who develop two approaches to generation adequacy that they explain as relying on markets and relying on the traditional (regulatory) system. The three Northeastern ISOs are examples of the regulatory system. See Hirst, Eric and Stan Hadley, *Maintaining Generation Adequacy in a Restructuring U.S. Electricity Industry*, Oak Ridge National Laboratory, ORNL/CON-472, October 1999, p. 7.

The reliability model developed shows that optimum reliability in generation is obtained at a level where the marginal cost of adding reserves is just equal to the marginal benefit of the reliability obtained from these reserves. This marginal analysis approach contrasts sharply with the regulatory approach of requiring a large amount of capacity based on a rule of thumb. The optimality condition for reliability is the same marginal equality that produces optimality in every other market.

One distinction between the marginal approach to reliability and the regulatory approach is the time period for maintaining the reserve margin. The regulatory approach determines an annual peak and then sets a capacity obligation to maintain this peak throughout the year. This approach provides capacity obligations that can approximately double the amount of capacity in use. The marginal approach would determine a capacity obligation on the basis of an expected peak demand, say, on a monthly basis, and required capacity would be reduced during non-peak, or transition seasons. The regulatory and economic models would produce the same level of reliability and the same peak reserve margin, but the economic model would reduce average rates by requiring less capacity when it is not needed.

Competitive markets produce an economic efficiency that maximizes long run benefit to customers. However, during shorter periods substantial changes in supply or demand require market adjustments. Competitive markets adjust at minimum cost by both price and quantity adjustments. For example, competitive markets meet peak use by supplying more goods and services and by increasing price to ration the supply. The adjustment by both price and quantity to peak use ensures that marginal value will equal marginal cost, and long run average cost is minimized.

In the recommendation of this report, a capacity reserve margin linked to generation may continue to provide a safety net, but floating prices also contribute to ensuring resource adequacy. In contrast, a market adjustment of quantity (kWh) only at fixed prices requires a large amount of capacity that has a low average capacity factor and therefore high average cost. In general, regulation is not conducive to responding to market disturbances; deregulated firms can, in general, respond more effectively to such disturbances.<sup>22</sup>

The history of utility regulation is to rely upon administered prices, regulatory assurances, and long-term fixed-price contracts to encourage investments in capacity. The history of competitive markets is to rely on floating prices and contracts linked to market prices to encourage investment in capacity. In almost every market, floating spot prices send appropriate signals to encourage a level of investment that provides reliability that customers value.<sup>23</sup>

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<sup>22</sup> Winston, Clifford, "Industry Adjustment to Economic Deregulation" *Journal of Economic Perspectives*, Vol. 12, No. 3, Spring, 1998, p.92.

<sup>23</sup> An issue is whether a spot market would provide sufficient incentives to invest, especially with price caps imposed. Price caps are typically a locational issue for critical peak prices that occur less than one percent of the time. With an energy market only, we expect that prices would be lower most of the year but higher during peaks associated with temperatures significantly higher or lower than 65 degrees.

The experience at PJM confirms that spot prices attract investment. The PJM capacity market uses an annual capacity obligation, but uses an auction market to determine the market price of capacity. During the last few years PJM has experienced an oversupply of capacity with spot market prices frequently below long run replacement cost. In the near term, capacity additions will likely decline. In the longer term, the spot price of capacity will vary randomly at about its long run marginal cost. An efficient market would behave similarly, except that the capacity obligation would be tied to the expected level of generation plus a reserve margin for reliability.

A market-oriented model that could provide reliable service is one based on an operating reserves market. Such a market would trade short-term reserves, rather than long-term capacity. Ideally the reserve margin would be determined by the optimization principle of equating capacity costs at the margin to reliability benefits. However, if the system authorities are particularly concerned about reliability, a larger margin could be maintained during critical periods, or during a transition period when a competitive market is developing. An auction market price would provide an adequate incentive to provide supply reliability even if the reserves were not used. The reserves could be used to reduce the spikes inherent in an energy market only model, where such a market does not include a separate market for capacity. The generation reserve model is compatible with the use of wholesale price caps, should price be the chosen policy instrument.

An alternative model presented by Oren, a faculty member at UC Berkeley, is a mandatory call options model.<sup>24</sup> In this model, load serving entities (LSE) are required to meet total load, including peak, plus a reserve margin, but the reserves may include call options. A call option is a financial instrument that provides the owner the right to purchase the underlying commodity at a specified price and quantity and during the specified period of time. Owners of generation could sell such options, and then stand ready to provide energy or settle the option by an offsetting transaction.

The managing authorities would again set a margin above peak demand. A LSE could own generation, or contract for it, or purchase call options. If the LSE required additional reserves to meet its load it would simply call the option. If the LSE had a surplus of reserves it could sell its call option on an open market.

This model is developed in more detail by Professor Hobbs of Johns Hopkins University along with its pros and cons.<sup>25</sup> We mention this model, without recommendation, but as one approach to obtaining a reserve margin that contrasts with the regulatory rule of thumb. The attribute of merit of this call options approach is that reliability can be purchased in an optimal amount, and customers can thereby obtain value for what they pay for.

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<sup>24</sup> Oren, Shmuel S., "Ensuring Generation Adequacy in Competitive Electricity Markets," *Energy Policy and Economics Working Paper Series*, paper #007, University of California Energy Institute, Berkeley, June 2003.

<sup>25</sup> Benjamin Hobbs, Javier Inon and Matthew Kahal, *Op Cit*, 2001, p. 25

## **National Data on Generating Capacity and Reserve Margins**

Current data on generating capacity and reserve margins, and future projections, do not support concerns about resource adequacy in electricity generation. The North American Electric Reliability Council (NERC) presents an annual assessment of resource adequacy for the U.S., Canada and parts of Mexico. The 2004 NERC assessment includes data depicting current and projected summer and winter reserve margins for each of the ten NERC regions. The NERC report indicates that the U.S. overall is expected to have a summer reserve margin of 23.4% and a capacity margin of 19.0%.<sup>26</sup> Each NERC region currently has, and is expected to have in year 2005, an adequate reserve margin. The U.S. regions are summer peaking in terms of electricity use, hence winter reserve margins and capacity reserve margins are larger than summer margins.

The NERC data and analysis indicate that little concern is warranted about resource adequacy for the U.S. as a whole or for any of the NERC regions. Actually, much of the recent interest in reliability relates to operational reliability of the electricity system, not resource adequacy. Concerns about resource adequacy are voiced from within NERC regions, such as from CA and from NY. In this report we do not question the NERC conclusion, and instead examine the issues of resource adequacy within sub-areas of NERC regions.

The Energy Information Administration prepares long term projections of energy related variables on an annual basis in their Annual Energy Outlook (AEO). AEO2004 asserts that recent additions to generating capacity are adequate for the near term, but additional capacity is required for the longer term (through year 2025).<sup>27</sup> EIA projections indicate that sufficient electricity generating capacity will be brought on line from the electric power industry supplemented with combined heat and power and perhaps by other sources owned by customers.

Existing resources and projected generating capacity by both the NERC and the EIA do not support concerns about resources being inadequate to meet demand. If resource adequacy is a concern, the concern probably applies to smaller sub regions and load pockets within regions, such as Los Angeles.

### **PJM's Resource Adequacy Approach (Installed Capacity Market or ICAP)**

ICAP refers to installed capacity, and the ICAP approach to capacity is to establish an installed capacity obligation. Several states and regions in the U.S. use some variation of ICAP to ensure reliable service. As explained above, the history of electric utility regulation is to use a rule of thumb to determine a reserve margin that implies a capacity obligation.

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<sup>26</sup> NERC, September 2004, p. 31. Reserve margin is estimated as the difference between capacity and peak demand as a percent of net demand, whereas capacity margin is estimated as this same difference as a percent of capacity resources.

<sup>27</sup> For the AEO2004 projections of generating capacity additions, see the Energy Information Administration, *Annual Energy Outlook 2004*, U.S. Department of Energy, DOE/EIA-0383, January 2004, pages 81 and 147-48.

The present discussion of ICAP applies to the PJM market, although capacity obligations are common throughout the U.S. As quoted above, the Reliability Principles and Standards of the Mid-Atlantic Area Council of NERC, applies the same one-day in ten-year rule that characterizes traditional utility analysis. Indeed, the PJM report on generation adequacy states further that the "...one day in ten year loss-of-load expectation (LOLE) is the standard observed in most NERC regions and is the basis for determining PJM's required Installed Reserve Margin (IRM)." The report goes on to say that the "... analytical methods and models that PJM uses to assess the generation adequacy of the region ... are based on sound, proven engineering theory and the physics of the bulk electric power grid."<sup>28</sup> In this report, we do not question the engineering or physics of reserve margins. We do question whether reserve margins based on sound engineering also provide maximum benefit to customers by equating the costs and benefits of reliability at the margin. The obvious answer is that customer benefits are not maximized because they do not enter into engineering calculations.

The reserve margin rule is even more seriously flawed because it is applied as a constant throughout the year. In regulated generation markets, capacity obligation is typically determined over a one-year planning period. Peak demand throughout the year is estimated, and capacity obligation is determined to provide reliability to meet this peak demand. The capacity obligation that is required to meet the peak demand is typically maintained throughout the year.<sup>29</sup>

The time profile of electricity use throughout the year is described by a load duration curve. The load duration curve depicted in the figure below is illustrative, but it uses numbers approximating the PJM-East region. As indicated in the figure, the PJM region requires about 20,000 MW to 40,000 MW of capacity to meet base load demand, which occurs throughout most hours of the year. Critical peak demand occurs about 40 to 100 hours per year and requires closer to 60,000 MW to meet demand. These peak hours occur less than 5% of the time, and actually less than 1% of the time. Capacity reserve obligation is based on these peak hours.

The *2002 State of the Market* is an annual report provided by the PJM Market Monitoring Unit. As stated in the Report "A load-duration curve shows the percent of hours that load was at or below a given level for the year."<sup>30</sup> The annual time profile of electricity use is reflected in a load duration curve, illustrated below in Figure 1. Load duration curves typically reveal a gradually increasing level of required capacity, followed by sharply increasing peak use over a very short period. The average load during 2002 was 35,551 MW, and the median load was 34,596 MW. The extreme peak load was almost double the average load. In the PJM region, and in other regions, peak load is much higher than average load, which reflects primarily seasonal plus random variations in the demand for electricity.

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<sup>28</sup> PJM Interconnection LLC, *PJM Generation Adequacy Analysis: Technical Methods*, Capacity Adequacy Planning Department, October 2003, p. 1.

<sup>29</sup> Ronald J. Sutherland, *Enhancing Economic Efficiency in the PJM Electricity Market*, a draft report to the Department of Energy, Office of Energy Efficiency and Renewable Energy, Philadelphia PA, August 2004.

<sup>30</sup> PJM Market Monitoring Unit, *PJM Interconnection State of the Market Report 2001*, PJM Interconnection, June 2002, p. 16.

Electricity is used to meet base load demand for power at a rate that is relatively constant throughout the year. For example, electricity used for refrigerators is part of base load demand. Large seasonal variations in the demand for electricity used for space heating and cooling produce significant increases in intermediate and peaking needs. The PJM region is summer peaking in electricity use, but there is also a large winter demand for space heating.

As indicated in load duration curve in Figure 1, about 20,000 MW to 40,000MW of capacity was required to meet PJM load during most of the year. Plants that perform intermediate duty typically provide electricity during hot summer days for cooling, and during cold winter days for space heating. Critical peak demand days occur relatively infrequently, such as from 40 to 100 hours per year, but also require large amounts of capacity to meet peak demand. Peaking units—usually gas turbines—that have low capital cost, but high operating cost meet this demand.

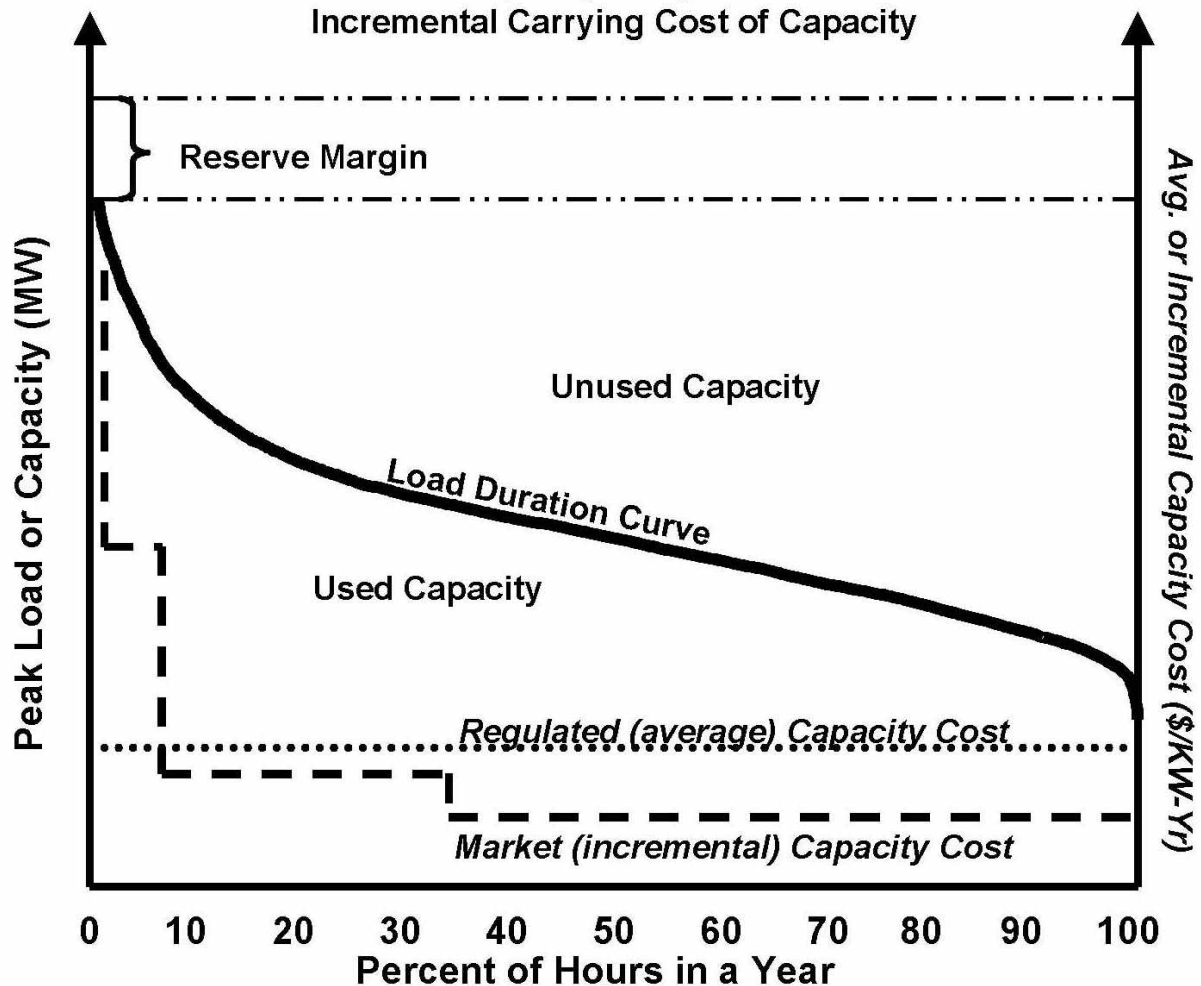
The load duration curve depicts that a capacity target, determined at peak load, is much in excess of required needs during most of the year. In year 2002, PJM capacity was 63,514 MW, which is much greater than the typical load that varies from 20,000 MW to 40,000 MW.<sup>31</sup>

During 2002, the prescribed capacity obligation resulted in unused capacity of 22,961 MW based on average actual capacity, and 22,006 MW based on actual median level of capacity. As noted, peak hours occur less than 1% of the total hours. Clearly, a large amount of unused capacity occurs throughout most of the year. The cost of this capacity is reflected in average wholesale rates throughout the year. With the costs of such a large amount of unused and unneeded capacity being paid customers, average prices are higher than necessary. Further, with all this capacity being required to meet peak needs, that rarely occur, prices during 99% of the year are much in excess of marginal cost.

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<sup>31</sup> Ibid. p. 13.

Figure 1  
 Illustrative Load Duration Curve  
 with Capacity Obligation and  
 Incremental Carrying Cost of Capacity



The above figure depicts alternative price duration curves that derive from alternative reserve margins. The capacity reserve margin under traditional regulation and under ICAP is depicted a horizontal line because reserves are based on expected peak and held constant throughout the year. The corresponding price duration curve is a horizontal line, because a constant level of capacity produces approximately constant average costs. If the reserve margin is referenced to generation or actual capacity in use, the price of capacity, and of electricity will be much lower during much of the year. We provide empirical estimates of the reduction in electricity prices due to a more efficient use of capacity.

The price of capacity, and of electricity, will be higher during a small percent of the time when hot summer days or cold winter periods contribute to peak demand. The above average price results from using peaking units to generate power, where such units must recover much of their capital cost.

The above figure shows that peak prices may look extreme, like price spikes, or may be more moderate, but still quite high. If peak demand were met solely by gas turbine peaking units, electricity prices would appear like price spikes. However, with demand and supply response to these extreme prices, we would observe numerous efficiency measures, from energy conservation, to distributed resources, that would mitigate these high prices. The result would be high peak prices, but not extremely high peak prices.

PJM is in process of revising its approach to obtaining system reliability, as indicated by its development of a Reliability Pricing Model. The PJM website also indicates an interest in very recent work by Inon and Hobbs, from Johns Hopkins University. Inon and Hobbs find that a socially optimal adequacy level of capacity can differ from the engineering criterion of 1 day in 10 years.<sup>32</sup> In personal correspondence, Hobbs stated that this conclusion requires numerous assumptions and may not have practical significance.

A large amount of unneeded and idle capacity is not unique to the PJM region, but instead characterizes the U.S. market. Maloney and McCormick, academic economists from Clemson University, present data from the North American Electric Reliability Council for 1990-1994 showing capacity utilization rates and percent of facilities that are idle.<sup>33</sup> On average for the system, facilities are idle 53.4% of the time. Gas turbines are idle 97.8% of the time and jets are idle 98.3% of the time. These units are used to meet peak demand, and a high percent of unused time is expected. The capacity utilization rate of steam fossil fuel plants is reported as 61.2%, multi-turbines as 48.3%, and combined cycle as 37.0%. With traditional regulation, these plants are paid for the energy they produce, and for the capacity they provide when used and when not used.

The reliability model developed above indicates that an optimum level of reliability is obtained by equating the marginal cost of adding reliable capacity to the marginal value of reliability. If the reserve margin at peak is approximately optimal, then reserve margins during the other 99% of the year are much too high. This result is critical to understanding the success or lack of success of restructuring in the U.S., and is therefore repeated. The annual capacity obligation (ICAP) requires a reserve margin that directly violates the efficiency condition that determines optimum reliability. Maintaining such a large capacity margin imposes unnecessarily high costs on customers.

The constant capacity obligation offers an additional implication. Constant reserves margins—not related to generation—result in flat rate wholesale prices that are passed through to retail markets. Such flat rate prices preclude price-demand response at the retail level. Any market design constructed on top of this regulatory failure cannot achieve efficiency, and cannot maximize benefits to customers. The need for price-demand response in PJM and other markets

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<sup>32</sup> Inon, Javier and Benjamin Hobbs, "Generation Adequacy, Market Regulation and Demand Elasticity in the Electric Industry: A Stochastic Long Run Equilibrium Analysis of Capacity Markets," presented at the 24<sup>th</sup> IAEE Conference, Washington DC, July 10, 2004.

<sup>33</sup> Maloney, Michael T. and Robert E. McCormick, *Customer Choice, Consumer Value: An Analysis of Retail Competition in America's Electric Industry*, Volume 1, Washington DC, Citizens for a Sound Economy, 1996, p. 29.

is widely recognized; less well recognized as that the initial PJM market design precludes such a response. For instance, Benjamin Hobbs, from Johns Hopkins, states:

Demand responsiveness to real-time prices would imply that systems that provide price signals reflecting actual capacity scarcity (such as operating reserves markets) would be preferred to systems that average out costs over time (such as ICAP markets).<sup>34</sup>

This report provides quantitative and qualitative evidence that systems that reflect actual capacity scarcity provide large dollar benefits to customers, and that systems that provide flat rate prices preclude the development of efficient wholesale and retail markets.

Hobbs provides a useful analysis of the pros and cons of ICAP, and begins by recognizing that, “A well-functioning spot market for electric energy should motivate the optimal amount of investment in generating capacity.”<sup>35</sup> However, Hobbs rejects the view of a well-functioning, energy market and argues that some variation of ICAP is efficiency enhancing. An ICAP market provides significant benefits:

1. The willingness to pay for reliability is not reflected in price spikes that occur when capacity is short. A large capacity obligation presumably reduces price spikes, even when prices are not capped.
2. ICAP provides dependable revenue for power developers.
3. ICAP provides assurance to regulators and the public that capacity will “be there” when needed.

A common objection to an energy market only is that the resulting price spikes do not reflect customer willingness to pay because prices remain stable. This point argues more strongly for a floating price model where prices would reflect willingness to pay.

A capacity obligation affecting an entire power pool appears to be an inefficient way to address price spikes because such spikes tend to be location specific. PJM, NY and other regions are using location specific applications to address this issue. Further, the price spikes in the PJM region occur less than one percent of the time. This price risk is either absorbed by load serving entities or diversified away because it is not passed forward to customers.

ICAP does not provide a guaranteed revenue flow when the price of capacity is determined in a real time or day-ahead auction market. Indeed, if overbuilding occurs, real time capacity prices will be less than replacement costs for an extended period of time. The long run policy goal should be an efficient market because such a market maximizes economic value to consumers. If guaranteed producer revenues are a policy objective, a return to rate of return regulation, or

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<sup>34</sup> Hobbs, Benjamin F. Javier Inon, and Steven Stoft, “Installed Capacity Requirements and Price Caps: Oil on the Water, or Fuel on the Fire?,” *The Electricity Journal*, July 2001, p. vii.

<sup>35</sup> *Ibid.*, p. 23.

even a central planning model should be considered. If a fixed capacity margin is the chosen policy tool, then real time prices for capacity are likely to be volatile.

Setting a capacity obligation on a short-term basis, such as a month or less, provides assurance that capacity will “be there” when needed, and it does so without imposing the enormous and unnecessary costs of supporting capacity that is not need to provide reliable supply. Further, ICAP, set on an annual basis, has the “cost” of eliminating any chance of developing an efficient market, and it does so by producing flat rate prices.

The inefficiency of ICAP is inherent in its initial development. As discussed in Hobbs, the capacity requirement in PJM evolved from the operating rules of the former power pool established in 1927.<sup>36</sup> Indeed, the PJM ICAP model is carried over from traditional utility regulation. Flat rate pricing, reliance on quantity adjustments, and reserve margin based on a rule of thumb characterizes ICAP, and is derived from utility regulation.

The lack of sufficient price-demand response is widely understood to be the main impediment in developing efficient electricity markets. PJM has initiated several programs that rely on subsidies or other financial inducements to achieve some demand response. However, subsidy programs are inherently flawed. First, the cost of subsidy programs is typically at least twice the benefits, and second, subsidies provide the greatest benefit to, and most likely attract those, who change their behavior the least. In brief, subsidies attract exactly the wrong participants.<sup>37</sup> The absence of price-demand response in the PJM market is self-inflicted because it derives from traditional rate-or-return regulation, including acceptance of the natural monopoly model.

### **New York’s Resource Adequacy Approach (ICAP with Demand Curve)**

Our initial study design is to assess various approaches to resource adequacy, where we presumed the demand curve approach to differ from ICAP. The demand curve approach to capacity is most often associated with the New York ISO. As applied in NY, the demand curve approach is actually a variation of ICAP. Further, the approach is in process of being developed and implemented and its ultimate effects are yet to be realized. In this report, we offer only a preliminary comment about this approach to obtaining capacity. From our perspective, the issue is whether the NY demand curve approach moves in the direction of the four efficiency conditions stated in our section 2, Market Oriented Approaches to Resource Adequacy, or, whether the demand curve design perpetuates the failures of the regulatory model.

The NY model is based upon an installed capacity obligation (ICAP), and indeed it continues to employ the 1 in 10 rule. In NY, this rule is stated as a resource adequacy criterion of 0.1 days

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<sup>36</sup> Hobbs, Op. Cit., p. 1 and p. 5 plus.

<sup>37</sup> The inefficiency of subsidies is developed in Ronald J. Sutherland, “Income Distribution Effects of Electric Utility DSM Programs” *The Energy Journal*, Vol. 15, No. 4., 194, pp. 103-118. The implications of subsidies is applied specifically to PJM in, Ronald J. Sutherland, *Enhancing Economic Efficiency in the PJM Electricity Market*, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Philadelphia, PA, August 2004.

per year LOLE.<sup>38</sup> Hence the NY approach to restructuring, like that of PJM, is to impose some competitive or efficiency conditions on top of a model of regulatory failure. The goal of the NY demand curve approach is to “...address the flaws in the current ICAP/UCAP market.”<sup>39</sup> Whether this approach ultimately reduces some perceived glitches in the ICAP model is not relevant for this report. We note that ICAP is inconsistent with a competitive model, and tweaking the model will not achieve an efficient market.

An intended objective of the NY demand curve is to, “Increase system and resource reliability by valuing additional ICAP/UCAP above the NYCA and Locational Requirements.”<sup>40</sup> We show in this report that ICAP implies a reserve margin based on engineering criteria that does not value reliability to customers. We conclude that such reserve margins produce negative value to customers. The NY objective of increasing reserve margins appears to be a step in the wrong direction, at least from the perspective of serving customers. John Hanger and Peter Adels reach this same conclusion in their assessment of the NY demand curve.<sup>41</sup> ELCON also argues that the NY demand curve will raise rates to customers and provide unnecessary profits to generators.<sup>42</sup>

The NY demand curve is administratively set, where the NY ISO has made a major effort to estimate such a curve from engineering-economic data. The analysis was conducted by Levitan & Associates, Inc. and is available on the NY ISO website, along with extensive comments from others. Two observations about this approach are striking. First, one application of this capacity demand is to determine a price of capacity that may be above the rate determined in the auction market. Second, comments from the Independent Power Producers (IPP) assert that the NY analysis uses a cost of capital that is too low.<sup>43</sup>

The cost of capital comment by the IPP’s indicates that NY is moving in the direction of traditional rate of return regulation, rather than a market determined rates. The application of the demand curve to increase the rate of return to capital also appears to move towards the old regulatory model and away from the competitive model.

Our impression of the NY market is that it is not based on the market-oriented principles recommended in this report, but instead places increasing emphasis on non-market outcomes.

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<sup>38</sup> Numerous reports from the NY ISO make this point, e.g., New York Independent System Operator, *Determination of NYCA Installed Reserve Margin, Locational ICAP Requirements and External ICAP Rights*, 2002.

<sup>39</sup> New York Independent System Operator, *Proposal for Implementing a Demand Curve Spot Market Auction in the NYCA Installed Capacity Market*, Management Committee Meeting, February 13, 2003.

<sup>40</sup> *Ibid.* page 2.

<sup>41</sup> Hanger, John and Peter Adels “Throwing a Curve,” *PennFuture*, Vol. 5, No. 12, 2004.

<sup>42</sup> Electricity Consumers Resource Council, “NYISO Demand Curve Proposal Should be Rejected, Industrials Tell Court,” *ELCON REPORT*, Number 2, 2004.

<sup>43</sup> Glenn D. Haake, “IPPNY Comments on LAI Final Demand Curve Report,” September 3, 2004. Independent Power Producers of New York, Albany New York.

The NY experience does however suggest an important question: why is it necessary to increase the rate of return on investments to ensure resource adequacy? One approach to resource adequacy is traditional utility regulation. This model produces reliable service, but as we explain, it does so at an unnecessarily high cost to customers. A second approach to obtain resource adequacy is to rely upon a competitive and efficient market. The NY model is based upon ICAP and the 1 in 10 rule. Even so, it apparently requires additional regulatory incentives to ensure a prescribed level of reliability.

### **California's Resource Adequacy Approach**

The California Public Utilities Commission initiated a rulemaking proceeding in October 2001 to address procurement and cost recovery for generating resources.<sup>44</sup> After addressing existing power contracts and short-term planning in 2002, the CPUC turned its attention to long-term planning issues. In January 2004, the CPUC adopted a resource adequacy framework that would include specific reserve level requirements, and adopted a market structure for the utilities' long-term resource commitments. In its decision, the CPUC directed each Load Serving Entity (LSE) to acquire resources to satisfy a reserve margin of 15-17%, directed utilities to forward contract 90% of their May through September peaking needs (loads plus planning reserves) a year in advance; and continued to limit reliance on the spot market (Day-Ahead, Hour-Ahead, and Real-Time energy) to 5%.<sup>45</sup>

In April 2004, the CPUC opened a related proceeding on resource planning to explore the phase in of the planning reserve requirement, the need for a showing of a 90% year-ahead commitment, and numerous technical details.<sup>46</sup> Uncertainty surrounds the timing of resource approval and the performance of studies to determine the impact of resource allocation on the system. This uncertainty and the nature of penalties are a significant issue for the LSE's. In October 2004, the CPUC issued an opinion in the proceeding. The order accelerated the 15% planning reserve margin to June 2006 and set September as the filing date for the following year May to September resource plans. The "90% year-ahead" requirement allows the LSE to acquire a portfolio of long and short-term resources. For the other seven months of the year, 100% of the resource requirements would be required one month in advance.

Additional information and recommendations are provided in Appendix A.

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<sup>44</sup> California Public Utilities Commission, "Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development," Rulemaking 01-10-024, filed October 25, 2001.

<sup>45</sup> California Public Utilities Commission, "Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development," Rulemaking 01-10-024, Decision 04-01-050 (Interim Decision), January 22, 2004, p. 11.

<sup>46</sup> California Public Utilities Commission, "Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning," Rulemaking 04-04-003, filed April 1, 2004.

## Texas' (ERCOT) Consideration of Resource Adequacy

The Public Utility Commission of Texas (PUCT) has authority granted by the Texas Legislature over retail and wholesale electric markets. The authority is applied in two ways: (1) directly through its regulation of transmission and distribution utilities (TDU) and retail marketers (retail electricity providers or REP), and (2) through its regulatory oversight of the Electric Reliability Council of Texas (ERCOT). ERCOT is the ISO in Texas, responsible for wholesale market operations and the coordination of retail market operations (customer switching, settlement, meter reading, etc.). ERCOT operates entirely within Texas and serves approximately 85% of the State's population and electric load. The PUCT has similar jurisdiction over the utilities that are within Texas but outside of ERCOT, and works with those ISO's to improve competition and lower costs. The PUCT's jurisdiction over the State's municipal electric utilities, rural electric cooperatives and river authorities is limited to transmission service and the wholesale market activities.

Texas currently enjoys abundant electric capacity as a result of aggressive construction of merchant power plants in the late 1990s. When Texas opened its wholesale market in 1995, numerous companies determined that there were excellent opportunities to sell into that market, and a large amount of new capacity was constructed. A few of these new generating units have been mothballed due to a lack of customers.<sup>47</sup> There is no mandatory resource adequacy requirement in Texas under the current market structure. ERCOT has adopted a 12.5% reserve requirement, but this does not need to be enforced since the state is presently overbuilt. In general, regulators are not willing to live without a price cap or without a close examination of perceived market power abuses. Therefore, a gap typically remains between what generators could receive for payments in an unregulated market and those they receive in this structured market. This gap may result in a less than adequate price signal for new capacity as Texas moves into the future.

Resource adequacy issues and reserve margin requirements are under consideration in a rulemaking proceeding that was initiated in 2001.<sup>48</sup> Commission staff has conducted workshops, set forth "straw man" resource adequacy proposals, and accepted formal comment on those proposals. The current "straw man" was filed in February 2003. It incorporates elements of central ERCOT procurement of resource capacity through auction, with the costs paid by those who create the peak demand in the future (share of demand in the year). Staff proposes an ERCOT forecast to identify the potential shortfall, and an auction three years in advance for

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<sup>47</sup> The new natural-gas-fueled, combined cycle combustion turbines have heat rates of approximately 7000 BTUs/kWh. Some older natural-gas-fueled generating units with much higher heat rates—10,000 to 12,000 BTUs/kWh—are still operating. One reason for this is that purchased power is not carefully examined as an alternative to fuel in fuel factor cases. As the Texas "price to beat" (default prices) regulations are eliminated, the dominant REPs will be allowed to change their retail prices, and will no longer seek regulatory approval of price hikes. This dynamic may affect the immediacy of resource adequacy if mothballed generating units are brought back on line, and if the old, less-efficient generating capacity remains available for peaking use.

<sup>48</sup> Public Utility Commission of Texas, Project No. 24255, "PUCT Investigation of The Need For Planning Reserve Margin Requirements," opened June 13, 2001.

three capacity products (annual; six month, and three month). The obligation falls on the load serving entity (LSE), but allows the LSE the flexibility to hold call options on capacity.<sup>49</sup>

In its comments, the Lower Colorado River Authority stated that the staff proposal is flawed because it tries to acquire all capacity, not just incremental and new capacity. LCRA is concerned with the potential for gaming. The Alliance for Retail Markets (ARM) contends that that market dynamics, not regulatory mandates, should drive availability of capacity. ARM questions whether all capacity participating in the market deserves compensation for its participation. ARM views resource adequacy as an “incremental ancillary service,” providing only the increment of capacity resources necessary to maintain adequate planning reserves. ARM is concerned that capacity payments to generating units subject to stranded cost recovery results in overcompensation, existing firm energy contracts include compensation for capacity, and bidding out the entire demand curve creates the perfect scenario for the exercise of market power (“hockey stick bidding” strategies).<sup>50</sup>

For now, capacity issues are not a high priority, and the staff of the PUCT has reported to the Commissioners that they plan to return to this rulemaking proceeding in earnest in 2005. Staff estimates that a new rule pertaining to resource adequacy and reserve margins will be adopted by about December 2005. Staff believes that there is a need for a capacity price signal whenever regulators maintain a price cap. In Texas, the price cap is \$1000 per MWH. Under current market conditions the wholesale price seldom reaches that level. Price mitigation is not limited to the price cap, however. The Market Oversight Division of the PUCT recommends price mitigation measures when they determine that there have been increases in market price as a result of the exercise of market power.<sup>51</sup>

### **A Comment on Nodal/Zonal Constraints**

The initial design of this study reflects the suggestion that a nodal or zonal approach to resource adequacy requires serious investigation. However, it is now apparent that locational considerations are an important component of any market model. Our concern with resource adequacy and reliability emphasizes the dollar saving from applying the efficiency conditions stated above. Nodal approaches are not a fundamental new approach to resource adequacy; but are an effort to modify an existing model to reflect market characteristics in specific locations

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<sup>49</sup> Memorandum from Mr. Richard Greffe, Market Oversight Division, Public Utility Commission of Texas, filed February 12, 2003, to interested parties in Project No. 24255, Op. Cit., and personal communications October 25, 2004.

<sup>50</sup> Comments of ARM filed February 27, 2003 in Project No. 24255, Op. Cit. ARM members include Green Mountain Energy Company; Constellation NewEnergy, Inc.; Strategic Energy; Utility Choice Electric; Republic Power; APS Energy Services; and Texas Commercial Energy.

<sup>51</sup> Personal communications with Dr. Parviz Adib, Director, Market Oversight Division, Public Utility Commission of Texas, October 20, 2004.

An electricity market was defined historically as a service territory. As competitive markets develop over larger regions, it became apparent that market determined supply, demand and price differs substantially from one zone or node to another. Some regions, such as PJM, observe significant price spikes that are associated with particular locations. The NY market design also reflects the occurrence of load pockets and the need for specific rules to reflect these nodes. We consider efforts to deal with locational issues to be off our critical path, and hence will not comment further.

## Section 5: Quantitative Analysis

Reserve margins that exceed optimal margins impose unnecessarily large costs on customers. In this section, we estimate the costs of inefficient reserve margins. The previous sections discussed the principal agent problem and a reserve margin rule of thumb that strongly imply the high cost of such reserve. The practical significance of ICAP costs in the PJM region are expressed by Hanger and Adels:

Though an arcane subject to all but insiders, installed capacity (ICAP) charges vacuum billions of dollars from consumers and now, more obviously than ever, are the biggest consumer rip-off in the competitive electricity market place. They unnecessarily add from 0.4 to 1.8 cents per kilowatt-hour to the cost of serving a residential customer, boosting typical bills by \$5.00 to \$15.00 per month.<sup>52</sup>

We cite Hanger-Adels because they are particularly careful observers of PJM and they provide an empirical estimate of unnecessary ICAP costs that we can compare with our modeling estimates. Actually however, Hanger-Adels underestimate the seriousness of ICAP, because ICAP produces the flat rate prices that preclude price-demand response. The billions of dollars of unnecessary consumer costs are minor compared with PJM's failure to achieve an efficient market.

The DOE Energy Information Administration (EIA) provides a price simulation analysis of electricity markets where the underlying assumptions correspond closely to the assumptions of our analysis. In a competitive environment, the reliability reserve margin is determined by the economic marginal equality condition defined above. This reserve margin affects the cost of reserves and hence the price of electricity. The EIA analysis uses a fully integrated electricity market model to compute prices over time. That is, when reserves are priced efficiently, generation becomes priced in real time and markets then adjust to real time prices. The EIA analysis is useful here because it works out the complex interactions of supply and demand.

To most readers—those who do not study the EIA's Electricity Market Module in NEMS—the model is a black box that does not provide an intuitive understanding of the results. We therefore present some back-of-the-envelope calculations to indicate the price change that an efficient reserve margin might produce.<sup>53</sup> If reserve margins were determined by the efficiency

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<sup>52</sup> Hanger, John and Peter Adels "Time for PJM to Dump ICAP Too," *PennFuture*, Vol. 2, No. 3, 2001.

<sup>53</sup> To explain this calculation, we use illustrative EIA data (EIA, 1997, Op. Cit. p. 11) that shows the categories that comprise electricity prices are: capital cost (37%), fuel cost (15%), O&M cost (42%) and wholesale cost (6%). Maloney (1997 Op. Cit.) (use NERC data) report that for the system as a whole, generating capacity is idle about 53.4% of the time. Under traditional regulation, capacity receives payment when it is idle. In an efficient market, capacity receives payment when it generates electricity or produces a reliability value. We assume, admittedly arbitrarily, that the capacity utilization rate increases such that capacity costs decline by 25%. Fuel costs remain unchanged in an efficient market. The EIA assumes that O&M costs are 50% fixed and 50% variable (EIA, 1997,

condition used here, and prices were equal to marginal cost, electricity prices could decline by 14.5% or more.<sup>54</sup> If the price of electricity were 7.1 cents per kWh before the efficiency improvement, it would decline by 14.5%, or 1.03 cents per kWh to 6.1 cents after the efficiency improvement.

We emphasize again the tentative nature of the above calculation. It simply provides a preliminary estimate of what could occur in a more efficient market. To illustrate one source of efficiency gain, a gas turbine peaking plant may be used only 10 hours per year and idle the other 8,750 hours. This plant sells electricity at the average price of all other plants and earns a rate of return on investment. In a competitive market, the peak electricity price increases and the demand for peak power decreases. The need for idle plants diminishes, and so does their cost to customers.

### **EIA Estimates of Electricity Prices in a Competitive Environment**

The EIA (EIA, 1997) provides simulation estimates of the future price of electricity under various assumptions about the degree of competition in electricity markets. One objective of the EIA analysis is to estimate the future path of electricity prices where such prices reflect a marginal cost pricing model rather than an average cost model. In the marginal cost pricing model, reserve margins are determined by equating reliability costs and benefits at the margin. In average cost pricing model, prices reflect average costs determined by variable cost plus an allowed rate of return on capital investments. Reserve margins are determined by administratively determined rules with little basis in economics.

By comparing the estimated price of electricity under a base case, average price scenario with a more competitive, marginal price scenario, we estimate the decline in electricity prices due to a more efficient reserve margin and use of generating capacity. The monetary value of these price declines is an estimate of the cost saving to customers from using generating resources efficiently, including obtaining an optimum amount of capacity resources.

The EIA analysis includes the estimation of 12 different price scenarios ranging from a “No Competition” scenario to an “Intense Competition” scenario. The relevant base case for our purposes is the AEO97 Reference Case, which includes significant competition and “regulated prices, based on average costs, with competition-induced reductions in nonfuel operations and maintenance (O&M) and general and administrative (G&A) costs.”<sup>55</sup> In this Reference Case, customers continue to see average cost (flat rate) prices, and generation is reimbursed at its average cost per year. The degree of competition in this scenario reduces electricity prices

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Op. Cit. p. 17) and the 50% fixed component would also decline by 25%. The decline in capital cost plus the fixed component of the O&M cost produces a 14.5% decline in average electricity prices.

<sup>54</sup> The decline in capital cost plus O&M cost is computed as  $(37)(0.25) + (42)(0.5)(0.25) = 14.5\%$ .

<sup>55</sup> EIA, Op. Cit., 1997, p. 27.

substantially relative to the No Competition Case.<sup>56</sup> This Reference Case of limited competition approximates the power pool markets of PJM, NY, ERCOT and CA, and is the appropriate base case for this analysis.

In an efficient wholesale market, optimum reliability is obtained by equating marginal cost with marginal value. Reserve margin will follow the load duration curve, which in turn results in retail prices reflecting marginal cost of energy plus reliability. In the EIA analysis, marginal costs of generation include operation and maintenance costs and taxes of the highest cost generating unit that just supplies the last required amount of power. During periods of high demand, prices rise above the marginal cost of generation. During these periods, a “reliability price adjustment” is added to marginal generation cost to estimate a competitive price.

In the EIA analysis, the marginal cost of electricity varies by time of day, by season, and by type of day. A total of 108 slices of time are considered: 6 seasons, 3 day types, 3 times per day, and 2 slices per period. The marginal cost and hence price of electricity is computed for each of these slices of time. During the summer months of July and August, the highest peak prices occur during the hottest parts of the day. However, significant peak prices also occur during each of the seasons. An efficient market that we envision would include a reliability reserve margin at all times.

Electricity wholesale and retail markets, like all other markets, tend to be closely integrated. Retail prices typically equal wholesale prices plus a distribution cost. If wholesale prices are flat rate, retail prices will be flat rate. If wholesale prices reflect supply and demand changes, then such prices will be passed through to customers. In the EIA analysis, retail prices reflect various slices of time. Retail customers would also be offered various budget billing schedules that would smooth out monthly bills over the year. In the EIA’s moderate competition scenario, wholesale prices by time period are passed through to customers. In an actual market with real time prices, some customers may be impervious to such prices; other customers may be willing to pay for price risk management.

A key characteristic of the EIA analysis is that the electricity market provides an optimum level of reliability. The EIA analysis is consistent with—virtually identical to—the analysis of optimum reliability presented here. In the EIA analysis:

Target reserve margins are determined in this analysis as the point at which the cost of new capacity (the marginal cost of capacity) just offsets the expected costs that consumers would bear as the result of outages in the absence of that capacity<sup>57</sup>

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<sup>56</sup> In EIA 1997 Op. Cit., Figure 12, p. 33 depicts the price effects of various scenarios, and shows roughly that the AEO97 Reference case reduces prices by about 0.5 cents/kWh relative to the No Competition Case. The High Efficiency Competitive Case reduces electricity prices by about 1.0 cents/kWh relative to the AEO Reference Case.

<sup>57</sup> EIA, Op. Cit., 1997, p. 38.

This equilibrium condition of optimum reserve margin is identical to that of the optimum reliability model in Section 3, and to the third economic efficiency condition stated in Section 4.

The EIA defines the marginal value of improved reliability as the expected outage costs, which corresponds to the value of unserved energy. The EIA simulations use \$3 per kWh unserved as the marginal cost of unserved energy, but uncertainty in this number is reflected in additional simulations using \$6 per kWh for unserved energy. The optimum level of reliability is computed and its cost is termed a “reliability price adjustment”.

The EIA moderate competition scenario estimates an electricity price that achieves not only resource adequacy and reliability, but also the level of generation capacity that reflects optimum reliability.

In the EIA analysis, investments in generation receive no automatic or average cost recovery. Capital costs are recovered through the reliability price adjustment, and by providing energy at a cost below the marginal cost of the most expensive producer. Competitive markets do not provide automatic cost recovery for capital investments. Instead, prices equal marginal cost, and over the long run prices equal long run marginal cost. In a competitive market with real time spot prices and no contractual guarantees, the market provides sufficient incentive to attract capital investment that maintain resource adequacy. Actually, such a market will, over time, minimize the cost of providing electricity and provide optimum reliability at minimum cost.

The EIA presents electricity price simulation results for 13 NERC regions within the U.S. and for the entire country. Figure 2 presents the EIA simulation results for selected NERC regions that reflect California (CNV), the PJM region (MAAC), New York (NY), Texas (ERCOT) and for the entire U.S. The report was published in 1997; hence year 2000 prices are projections. The figure presents projected prices in the AEO97 Reference Case, which is the appropriate base case for this analysis. The figure also presents projected electricity prices for a scenario with optimum reliability that produces efficient pricing for generation services and a moderate consumer response.

The regions of interest are the Electric Reliability Council of Texas (ERCOT), the Mid-Atlantic Area Council (MAAC), the New York Power Pool, and the California Southern Nevada Power Pool (CNV). This figure is reproduced from the EIA.<sup>58</sup> The numbers used in the cost saving simulations are the difference between the simulated marginal cost price and the average cost price.<sup>59</sup> The “moderate competition” scenario is driven by a more efficient reserve margin that in turn produces marginal cost pricing, which in turn produces a modest consumer response to time-of-use prices. The Reference Case is driven by a large and expensive reserve margin that, along with regulation, produces average cost pricing.

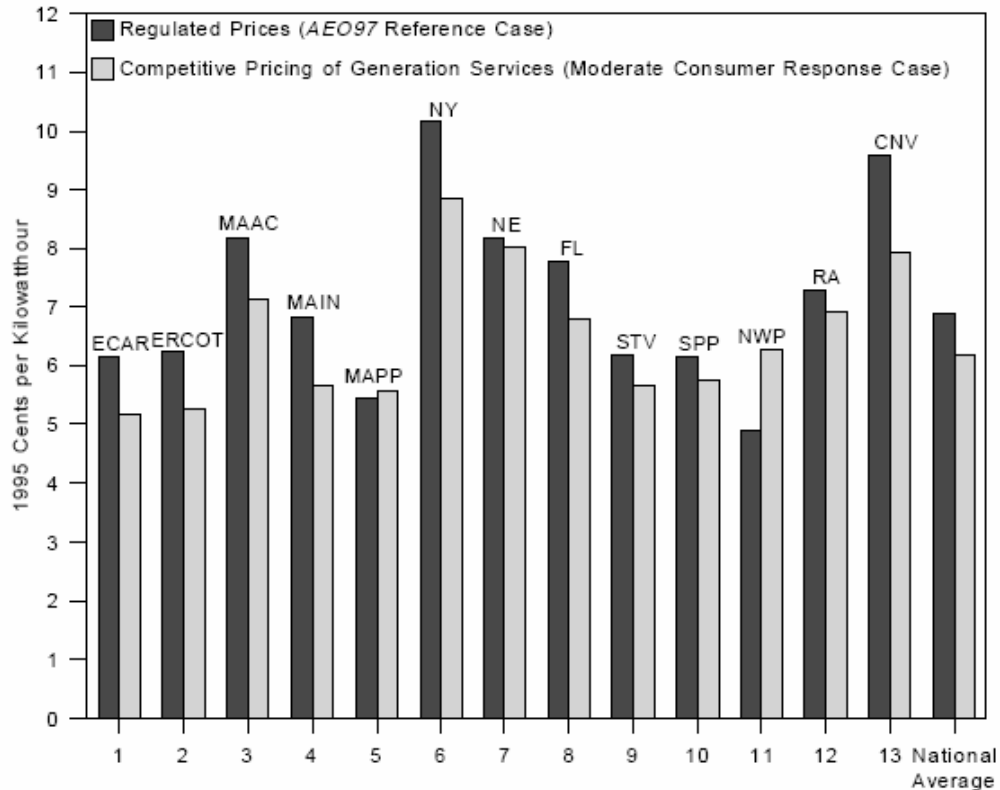
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<sup>58</sup> EIA, Op. Cit. 1997, p. xv.

<sup>59</sup> These simulation numbers are in the figure are prices in year 2000. We obtained numerical data for year 2000 from personal communication with the EIA, Laura Martin, for which we are grateful.

**Figure 2**  
**EIA Simulation Results of Electricity Prices**  
**With Moderate Competition and the AEO2004 Reference Case**

**Figure ES2. Projected Regional Retail Electricity Prices Under Regulation and Competition, 2000**



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System, run AEO97B.D100296K (AEO97 Reference Case) and National Energy Modeling System and Prototype Value of Capacity Model, run set E15V03 (Moderate Consumer Response Case).

### Estimating Customer Benefits from Efficient Pricing

The decline in electricity prices provides a direct net economic benefit to customers in the form of reduced electricity bills. Although this reduction in cost does not correspond exactly to net benefits of producer plus consumer surplus that economists prefer, it is a meaningful measure of the direct benefit to customers. Direct benefits to customers are estimated as the annual reduction in electricity bills and as the present value of these cost reductions.<sup>60</sup> The EIA price simulations of the Reference Case and margin cost pricing scenarios show that the prices tend to

<sup>60</sup> As explained in Sutherland (2003).

be large for the first few years, but the price difference narrows over a 10- the 15-year period.<sup>61</sup> A one-time decline in the price of electricity continues in future years and thereby produces long-term benefits. However, the long-term benefits are subject to uncertainties of load growth and the  $\Delta P$  due to marginal cost pricing. For this reason we show the cost savings for the year 2000, when the simulations begin in year 1995. Although we do not quantify the long-term benefits, such benefits would in fact occur.

We estimate the price reduction benefits to customers in four regions; selected because they are in process of restructuring their electricity markets. The regions are the Mid-Atlantic Area Council (MAAC), which is primarily PJM East, the Electric Reliability Council of Texas (ERCOT), the California component of the Western Electricity Coordinating Council (WECC), and the New York Power Pool. We also estimate price reduction benefits to the total U.S.

Table 1 presents the price reduction benefits. The first column identifies the four regions, the entire U.S., and includes three states within the MAAC (or PJM) region. The next column presents EIA data on net generation for the electricity industry in year 2000, which includes utilities and non-utilities. The next column shows average revenue per kilowatt-hour using the same EIA report, although these data apply to electric utility ultimate customers. Annual revenue is computed as the product of the price times quantity (col.2 \* col. 3) and expressed in millions of dollars. The purpose of this column is to indicate the cost saving relative to total customer costs. The price decline due to efficient reserves is obtained from the EIA simulation analysis discussed above. The EIA analysis is regional; hence we use the estimated price decline in the MAAC region to apply equally to three states. The cost saving in year 2000 is estimated from the previous columns.

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<sup>61</sup> The EIA results show the moderate competition prices to be less than the Reference Case prices over time, but the gap narrows. In the EIA high competition case, this price gap maintains over time, but we are reluctant to adopt the more ambitious high competition case as appropriate for our analysis.

**Table 1**  
**Estimated Electricity Cost Saved in 2000**  
**With Competitive Scenario**

NERC Region/State	Net Generation Mil. kWh	Average Revenue per kWh in Cents	Annual Revenue Year 2002 (millions of dollars)	Price Decline c/kWh	Cost Saving Year 2002 Millions of \$
MAAC					
Pennsylvania	205,505	6.6	\$13,563.33	1.08	\$2,219.45
New Jersey	58,204	9.1	\$5,296.56	1.08	\$628.60
Maryland	50,204	6.7	\$3,363.67	1.08	\$542.20
Total	313,913	7.08	\$22,223.56	1.08	\$3,390.26
ERCOT					
Texas	379,756	6.5	\$24,684.14	0.97	\$3,683.63
WECC (CA)					
California	207,047	8.5	\$17,599.00	1.91	\$3,954.60
NY					
New York	138,038	11.2	\$15,460.26	1.32	\$1,822.10
<b>Total U.S.</b>	<b>3,799,944</b>	<b>6.68</b>	<b>\$253,836.26</b>	<b>0.5</b>	<b>\$18,999.72</b>
Source: net generation obtained from EIA, August 2001, p. 26					
Average revenue per kWh obtained from EIA, August 2001, p. 39					
Price decline obtained from EIA August 1997, p. xv, numerical data obtained from personal communication.					

## Discussion of Results

The EIA estimates that a cost saving of one cent per kWh, or more, would result from a market design that produces an efficient reserve margin in the selected regions. This result is somewhat expected from the literature review that shows a reserve margin determined by a rule of thumb, and a principal agent problem that suggests that a reserve margin determined by regulation will exceed an optimal margin. The average estimated price decline in the U.S. is only 0.5 cents per kWh, which is less than that of selected regions. A possible explanation is that the regions that are restructuring are the high cost states and those that expect the largest potential gains from competition.

The intuitive explanation for these benefits is straightforward. First, with reserve margin paid according to its marginal value to customers, reserve margin will decline during most of the year, as will capital costs. Peaking units will have to cover costs when they are used or are providing reliability, hence the demand for these expensive units will decline. Customers will consider all options for meeting peak demand: energy conservation, recycling load, interruptible rates, various new technologies, and distributed resources. With generation priced at its marginal cost, instead of embedded average cost, only the generating stations that are operating or providing reliability reserves are receiving revenues. The large amount of unused and not useful capacity (see Figure 1) would no longer receive revenue. The numerous plants that initially operate at 50% capacity factors, or less, either increase their capacity factor or are retired. With reduced

electricity prices there is an increase in the demand for electricity and the capacity utilization rate of many plants will increase. By freeing customers from paying for unused capacity, costs, and hence prices, decline. The capacity reserve margin is now obtained from an optimum reliability model, and therefore one that provides value to customers. The initial high peak prices encourage a reduction in peak demand, and less generating capacity is now required to meet peak demand. A reserve margin is provided during non-peak months, but that margin is determined by the reliability that it provides and customer value of that reliability.

The above calculations are tentative, and there are some reasons for believing the numbers are too high, but other reasons for believing the numbers are too low.

The above calculations overstate actual benefits because:

- The cost reductions do not include the adjustment cost of adapting to efficient prices. These costs include the cost of metering, the cost of end use control technologies and other transaction and information costs.
- The cost reductions to customers are partially offset by declining revenues to owners of generation. However, producer revenues are partially offset by producer costs; hence net gains by customers exceed net losses to producers. Over time, generation is retired or used more efficiently, or used to meet the growing demand for electricity. Producer losses are short term, relative to customer gains that are long term.

The above calculations understate actual benefit because:

- The benefit to customers includes the additional benefit from purchasing an increasing amount of electricity at a lower cost (the welfare triangle).
- The net economic benefit includes the economic stimulus to the region from a more efficient electricity market and lower average prices. This benefit would roughly double the estimated benefit estimated here.
- The benefits estimated here apply to only one year, but a one-time price decline produces cost saving in perpetuity. If future annual benefits were constant, and discounted at a 10 percent rate, the present value of benefits in perpetuity would 10 times annual benefits, or \$190 billion.

Although customer bills decline during most months of the year, periods of peak use result in high peak prices. Some of these peak prices will be smoothed out during the month, July and August bills are likely to be higher for many customers. Some customers will simply pay these high peak prices, but still enjoy overall lower annual energy bills. An increasing number of customers may participate in various budget-billing programs that average monthly bills over a twelve-month period.

With high peak prices, customers have a financial incentive to shift part of their load to non-peak periods where prices are lower. Customers also have the incentive to invest in technologies that automatically shift load away from high cost periods. These high peak prices also send a

powerful market signal to providers of distributed generation and various other customer technologies that mitigate the effects of these high peak prices. The exact mix of responses to higher peak prices is not easy to anticipate. However, consumers who are averse to price volatility will have numerous options to avoid these risks and still enjoy lower average prices overall.

## **Section 6: Qualitative Analysis**

This portion of the report addresses the pros and cons of alternative approaches to resource adequacy from a policy perspective. The previous section of the report addressed matters quantitatively and shows that the cost to consumers of maintaining high levels of resource adequacy tends to exceed the benefit of any resulting increase in reliability. However, there are also important qualitative matters—issues that are not easily quantified, but which may affect public policy goals.

We begin with a discussion of the public and public policy response to undesirable events, and how these influence the decision making process. In an effort to take action, government may make decisions in the best faith that do not achieve the desired change. We argue here that the move toward competition (“restructuring”) has been unfairly blamed and targeted for reform, and that the resulting return toward regulation of resource planning will have unintended negative consequences. In addition to cost consequences, it is appropriate to understand the other public policy objectives that are negatively affected.

Next we discuss the public policy goals that must be balanced by decision makers. In addition to the cost versus reliability issues discussed above, we seek (1) the attraction of capital to various portions of the electric sector, (2) the fostering of competition in wholesale and retail markets, and (3) the promotion of efficient customer choice with respect to retail energy services. The health of competitive markets is important at the wholesale level, because competition is valuable in its own right, and because competitive wholesale markets are required under the Energy Policy Act of 1992. Further, the health of competitive retail markets is important to 16 states.

Third we describe the tradeoffs between market forces and reliance on regulation. Four models are described. Finally, a summary matrix presents the results of the analysis in a manner that is easy to present to decision makers. This analysis, coupled with the quantitative analysis from Section 5, presents strong evidence in support of more customer participation in efficient markets coupled with a monthly reserve margin requirement.

### **Policy Response to Unexpected Events**

When unanticipated and unpopular exogenous events occur, there is a call for government intervention. As noted above, government agents acting on behalf of consumers are predisposed to err on the side of caution with respect to the need for reliability. They are willing to impose high costs of physical insurance on electric customers. This section discusses types of government intervention that can provide benefits to customers.

From the 1970’s through 1990’s the electricity sector was slowly moved toward more reliance on market forces in response to the perceived “energy crisis,” and in response to the preference for

more competition in other sectors of the economy. “Qualified facilities” provided limited competition in the 1980’s and demonstrated the technical capabilities of non-utility generation. During the 1990’s, the implementation by FERC of the Energy Policy Act of 1992, and the actions of about two dozen states to examine retail competition, gave many observers a sense that a competitive electric marketplace was nearly in place. There developed a perception that the entire electric sector had been restructured. Subsequent events—blackouts, price spikes, market manipulation and corporate malfeasance—were viewed as occurring as a result of the move toward more competitive markets. It is not surprising that there is now a demand for greater oversight and more regulation of the electric sector.

There is a common view that connects recent events with a need for more regulation (e.g., administrative payments for installed generation capacity as discussed here). A popular model of public perception begins with a triggering event. This leads to the identification of a problem, and the search for a solution. The solution often requires government action.

**Figure 3**



The public supports the government action in anticipation of a solution to the problem, and in the hope that the undesirable events will be avoided in the future. Applying this model to recent events such as blackout and price spikes looks like this:

**Figure 4**



In other words, events—such as blackouts and price spikes—raise questions about the reliability of the network and the robustness of the infrastructure. Because reliability is considered inadequate, the engineers focus their attention on technical solutions to the problem.

During the past several years, a number of jurisdictions have determined that generation capacity may be inadequate during peak periods. Price caps reduce the incentive to build a peaking unit because regulations limit the revenues just at the time that generation owner is planning to make money to earn a return on the investment.<sup>62</sup> In order to overcome the problem—inadequate

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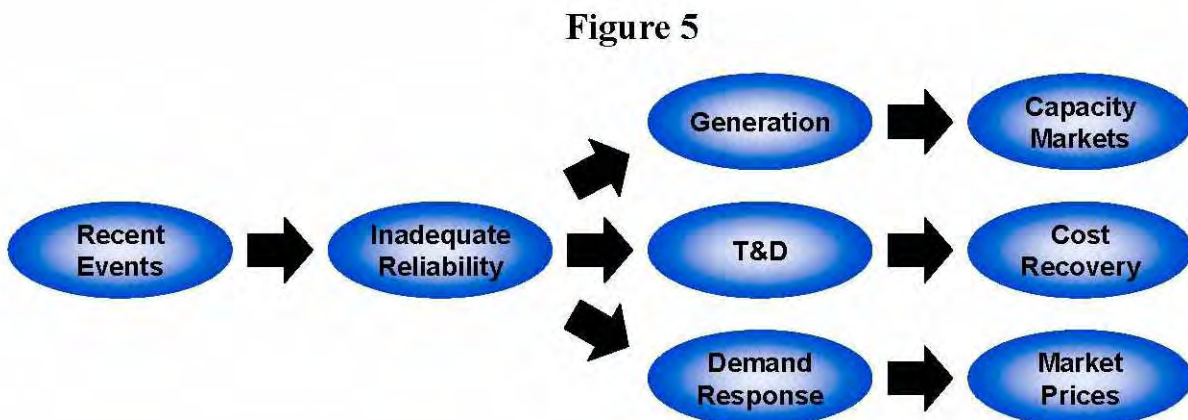
<sup>62</sup> Price cap arguments typically apply to a real time energy market where prices follow the inverted hockey stick path, i.e., with extreme peaks a few hours per year. In a truly efficient market prices would be higher during peak summer days than during most of the year, hence peaks would be of longer duration and less extreme than at present.

generation—the regulators determine that a payment for installed capacity is the appropriate action. The certainty of stable payments for particular peaking resources is designed to eliminate the uncertainty of occasional spike prices—prices that should reward market-based behaviors (the lower in cost of options such as curtailment or operation of distributed generation).

We can show that each link in this model is subject to qualification. The first error is the movement from step one to step two. Concerns about reliability that arise from recent events relate to the short-run operational reliability of the electricity system, not to the long-term planning reliability issues also called resource adequacy. The cascading effect of the 2003 blackout emphasizes this operational aspect of reliability.<sup>63</sup> As discussed in Appendix B, the reliability of the electricity supply system is a function of the reliability of the high-voltage transmission system, the low-voltage distribution system, the amount, types and location of generating units, and the various types and operation of distributed energy resources. Historically, most disturbances, such as outages in the electricity network, are caused by adverse weather conditions that affect the distribution wires system. The least reliable link in the electricity network is the distribution system and most outages occur when there is plenty of generating capacity available.

Regulatory efforts to encourage capacity additions through an administrative payment will not result in the desired improvement of reliability. The reliability benefits are not sufficient to justify the required administrative cost. The government action has counterproductive effects and reduces market efficiency.

We have already suggested the alternative. In a deterministic model, the following alternatives to central power plant construction can be identified.



If most electric outages are not related to resource adequacy in the generation market, then it makes sense to look to other network elements for a solution. It should be evident that the

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<sup>63</sup> U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004.

electric system needs to closely examine the capabilities of T&D assets and the role of loads as participants in the marketplace.

The need for additional transmission and distribution investments is well documented. The federal government's *National Transmission Grid Study*, issued in May 2002, estimated that wholesale power transactions on the electric transmission system are saving consumers \$13 billion per year, but that at least another \$500 million would be saved if existing interregional transmission congestion were removed in just four regions of the US.<sup>64</sup> It is likely that this figure substantially underestimates the potential savings. As demand for transmission service grows, congestion increases, and higher-cost local supplies meet local demands. In the Pennsylvania-New Jersey-Maryland (PJM) Interconnection (which relies upon locational marginal pricing), congestion costs increased from \$53 million in 1999 to \$430 million in 2002.<sup>65</sup>

Insufficient T&D investment occurs for a variety of reasons. In part, regulatory reform and increased uncertainty regarding cost recovery may discourage such investments. Rate cases to justify increased costs are themselves costly administrative battle. Some utilities that own generation are less interested in transmission service than generation service. Improved transmission could increase competition with existing, utility-owned generating units. Generating units in load pockets may receive payments as "reliability must run" (RMR) units. From the perspective of the utility and its shareholders, it may make sense to proceed cautiously in transmission line construction.

Demand response as a resource is an entirely different issue. While some advocates of demand-side resources may disagree, it is generally understood that demand-response can flourish without new government programs. Achieving a price-demand response merely requires (1) the development of an efficient wholesale market that produces efficient prices, and (2) the termination of existing monopoly restrictions on customer behavior. The exposure of market participants to wholesale prices will induce them to identify low-cost alternative resources. Customers may choose to participate, either through curtailment of load during critical periods, or through the installation of new equipment (generators, capacitors, sensors, meter, controls, storage devices, etc.) to allow the customer to meet the load requirements in other ways. Each customer has unique load requirements and potential solutions. The market is the appropriate place for the detailed matching of technologies, financing tools, and related energy services to the customer's exacting needs. The electric system needs to unbundle its services in sufficient detail in order to allow customers to make a match that will be economical to that customer.

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<sup>64</sup> U.S. Department of Energy, *National Transmission Grid Study*, May 2002, p. xi. Available online: [http://tis.eh.doe.gov/ntgs/gridstudy/main\\_screen.pdf](http://tis.eh.doe.gov/ntgs/gridstudy/main_screen.pdf).

<sup>65</sup> *Foster Electric Report*, No. 297, March 12, 2003, p. 14.

## **Key Policy Objectives Identified by Regulators**

Legislators and public utility commissioners must weigh the importance of several competing goals when establishing a structure for the electric market. Typically, not every goal is discussed explicitly, but there is an implicit understanding that many goals are at play in these decisions. The resulting system—designed either through legislation, administrative law or standards rules and business practices among the market participants—balances competing objectives. Together, the sum of the statutes, regulations and practices constitutes an operating environment for competitive enterprises and regulated utilities.

It should be instructive to attempt to identify the most important public policy goals and objectives, and to analyze alternative institutional arrangements and their impact on competitive goals and objectives. Stated differently, it should be possible to list several approaches to the problem of resource adequacy, and to understand how each approach will affect each important public policy objective. Certain approaches are better suited to certain objectives, while others fall short.

The time dimension is important here, as certain approaches may take more time to achieve the objective than others. The time frame under which different stakeholders operate may affect their view of alternatives. Profitable opportunities ten years from now are of little use to firms that—absent immediate action—will be out of business next year. An alternative approach may enhance near-term opportunities, and result in a more practical solution.

Each stakeholder may have different preferences with respect to the best approach to resource adequacy. Analysis will not resolve these differences. However, analysis can help different parties to communicate with each other, and potentially can allow different parties to agree which approaches are the least preferable of those under consideration. In that way, the decision making process may avoid a “lowest common denominator” approach. Policy makers sometimes gravitate toward an approach that is not socially beneficial, but which stakeholders accept because the alternatives seem to favor their opponents.

We have considered four broad policy objectives in terms of long-term and short-term impact:

1. Attraction of capital (to all portions of the system: G, T&D, and customer premises),
2. System reliability (measured on the T&D network),
3. Customer costs (as average cost per kilowatt-hour), and
4. Competitive market (considering competition among power providers in the wholesale market, as well as competition for peak and critical resources provided through central power plants and local resources).

### **Attraction of Capital**

Attraction of capital refers to a set of market rules that supports efficient capital investments in all sectors of the electric system such that the marginal cost of investment is equal to the

marginal benefit derived from the investment. A well functioning electric system will see investments in generation, transmission and distribution, and customer premises solutions, such as distributed generation, energy storage, advanced metering, sensors and controls.

Long-term attraction of capital. Long-term attraction of capital depends on consistency in the market structure and regulations affecting resource adequacy. “Open markets attract capital based on perception of risks and rewards. The reality of physical market fundamentals will control short term pricing and, in the end, long term prices. However, perceptions will shift the willingness of participants to commit capital to the market.<sup>66</sup> Long term investments require a stable regulatory environment and the ability to manage significant project risks related to fuel cost, technological performances and construction uncertainties.

Near-term attraction of capital. “Near-term attraction of capital” is somewhat of an oxymoron for infrastructure development. By their nature, large capital investments take a long time to design, finance and construct. As the size of generating units decreases, however, the time horizon from planning to construction tends to decrease.

Customer-based options, such as distributed generation and demand responsiveness, have short time frames. Depending on their complexity, many capacity additions on the customer premises can be designed, financed and constructed in less than one year. The time horizon for realizing a return on an investment is longer, and small-scale projects need a predictable regulatory environment.

There is a growing understanding among electric regulators and market participants that the demand side of the market has been neglected. Distributed energy projects can help with both the security and adequacy of the system. To encourage near-term attraction of capital—investments that might occur within a year—the market structure and resource adequacy approach must support a distributed energy vision of the future marketplace. Distributed energy includes both supply and demand alternatives, such as small generating units and controls and meters to provide load curtailment and responsiveness to price signals and contractual agreements. A key problem in distributed energy is the risk associated with regulatory uncertainty and inconsistency in the treatment of distributed energy projects.

### **System Reliability**

System reliability includes both security and resource adequacy.

Long-term system reliability. As discussed previously, “resource adequacy” refers to the long term, and “security” or “operating reliability” refers to the short term. The goal of long-term system reliability is the ability of the electric system to supply the aggregate electrical demand

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<sup>66</sup> Lord, Thomas, *Electricity Regulation As An Exercise in Real Option Management: Comparison of Risks for Infrastructure Investment Under Traditional Cost-of-Service Regulation as Compared to an Open Market Pricing – At-Risk Capital Model*, prepared for CAEM’s Energy Infrastructure, Investment and Incentives Forum by Volatility Managers, LLC, March 2003.

and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Near-term system reliability. The security or operating reliability is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated failure of system elements. Most outages are a result of operational problems such as the loss of a major transmission line or power plant, or the loss of a distribution feeder as a result of a tree limb or squirrel. This report does not attempt to examine operational reliability in detail, or to discuss in any depth the contribution of small-scale resources to enhance reliability.

### **Customer Costs**

For years, electric utilities operated in a declining cost industry. As that changed, pressure grew to rely more on competitive forces to lower costs through technological innovation and efficiency.

Long-term customer costs. There is a general belief that competitive forces will lower costs over time. However, as the attributes of electric service are better defined and unbundled, it is likely that some customers will see long term increases in cost. For example, customers who require high levels of reliability and power quality for their operations now pay a premium for on-site solutions to supplement the grid power. While some customers will see costs rise and other will see them fall, the average cost of electricity is expected to fall under a market solution.

Near-term customer costs. Customers who are interested in choices and willing to manage price risk may expose themselves to market-based prices and significant price volatility. Some short-term price increases are likely for these customers. Other customers may wish to maintain their “plain vanilla service” and may see stable near-term rates. In a retail market, a customer can choose to take a fixed-price, portfolio, or floating product. The key is that each customer has an opportunity to set his preference and the supplier has an interest in managing its risk exposure.

### **Competitive Markets**

The competitiveness of the electricity market can be assessed and monitored in several ways.

Long-term competitive markets. Market power exists when a firm can affect the price of a product by virtue of its size and scope of operations in the marketplace. Vertical market power results when a utility can use its ownership of the transmission and distribution system to favor the sale of power from its generating units or the sale of particular retail services. (For example, vertical monopoly power could allow a distribution utility to connect utility-owned distributed generation to the distribution wires, but restrict the interconnection of a similar customer-owned unit.) Horizontal market power exists when a firm controls a function (generation, transmission, distribution or energy services) in a geographic region.<sup>67</sup>

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<sup>67</sup> The traditional use of the Herfindahl-Hirschman Index provides an overview of a market sector. The Herfindahl-Hirschman Index (HHI) is a screening tool that can test for market power in the generation sector. HHI is calculated as the sum of the squares of firms’ market share. A HHI measure above the range 1800 to 2500 is considered an

Horizontal market power becomes a particular challenge as the geographic area shrinks. When a portion of a region or state lacks robust interconnections with the larger grid, it is considered electrically isolated. A lack of transmission import capability combined with inadequate local generating capacity creates a load pocket. Load pockets may occur in regions with rapidly growing demands, or in cities where siting a new power plant is difficult. Competition is limited where there are few generating units and concentrated ownership, increasing the likelihood of the exercise market power. For customers to benefit from competitive markets, market prices must reflect the conditions of supply and demand, and not be subject to the exercise of market power.

Near-term competitive markets. Market monitoring functions are necessary to guard against the gaming of the energy markets. To begin with, competitive markets must have clear and enforceable rules with penalties associated with infractions. The rules must reduce the potential for gaming by incumbents and others who own a large amount of generating capacity. Each ISO must use a market monitor to protect against the exercise of market power. Prices must be high enough to attract investment but not high as a result of local market power. The specific approaches that each region will employ to avoid market power abuses will need to be tailored to the region.<sup>68</sup>

### **Graphical Depiction of the Trade-Off Between Regulation and Competitive Markets**

In this report, we document some inefficiency inherent in traditional regulation and explain how these inefficiencies are carried over to a model with an installed capacity obligation. Further, a model that places greater reliance on competition and less on regulation could reduce costs to customers without compromising reliability.

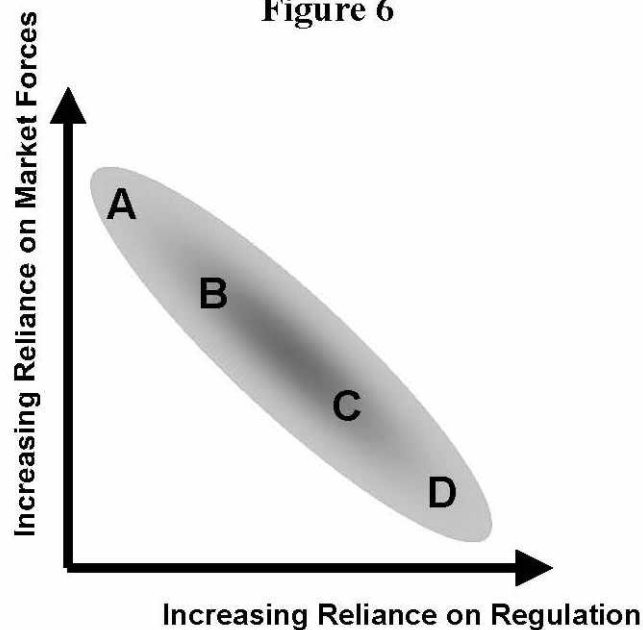
The figure below depicts the simple trade-off between models that rely on market forces and models that rely upon regulation. We depict only four major approaches: a “purely competitive” or “energy-market-only” model (Model A), a capacity reserve margin model (Model B), and installed capacity or ICAP model (Model C), and the traditional regulatory oversight of utility planning (Model D). Numerous models and variations of models appear in the literature that place greater or less reliance on market forces to achieve policy objectives, so these are merely illustrative. Not all models plot cleanly along a single curve, because each model has different mix of competitive and regulatory elements. The range of possible components and characteristics of a model is represented by the gray area. Combinations outside the area are unlikely to be viable. In general, a greater reliance on markets results in a reduced reliance on regulation, and vice versa; therefore the gray area is elongated and downward sloping.

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indicator of a highly concentrated industry. (Five firms, each with a 20% share of the market would give an HHI of 2000 because  $5 \times 20 \times 20 = 2000$ . Four firms, each with 25% ( $4 \times 25 \times 25$ ), would give an HHI of 2500.)

<sup>68</sup> FERC, “Wholesale Power Market Platform,” White Paper, Issued April 28, 2003.

Figure 6



Beginning with the purely competitive model (Model A), the energy market only model is most likely to operate with a real time auction market along with bilateral contracts between energy suppliers and load serving entities. Market forces—not by regulatory authorities—determine the price of electricity and quantity. Regulation is limited to ensuring the operation of the market. Operational reliability remains a public good and a central authority maintains the security of the system.

In the energy market only, the incentive to invest is conveyed by market prices and not by any regulatory mandates. Reliability is ensured in a physical sense of resource availability. However, reliability is not ensured in the sense of price stability, and volatile electricity prices would characterize the energy market only model. Private markets certainly provide price insurance (options markets), however price volatility may impart an external cost to the system.

Several academic researchers, who typically argue for market solutions to regulatory issues, caution against an energy only market. From a practical or political perspective, an energy market only is expected to produce unacceptable price volatility and an insufficient incentive to encourage investment in new capacity.

Experience with natural gas markets provides a counter example. A real-time spot market exists at the Henry Hub and numerous other spot markets locations function as pooling points and market centers. Marketers provide retail customers with some price-risk management and thereby reduce price volatility to customers. Market prices also provide adequate incentives for gas exploration and development.

The capacity reserve margin model (Model B) actually refers to a family of models that rely significantly on market behavior to determine electricity prices as well as to meet current

demand. This model includes a regulatory element in the form of a specified reserve margin based on expected peak demand but determined over a relatively short planning period. Although specified reserve margins may be relatively constant throughout the year, the amount of capacity receiving revenue would be much less during transition seasons than during summer peak periods. This model is reflected in the EIA scenario of moderate competition.

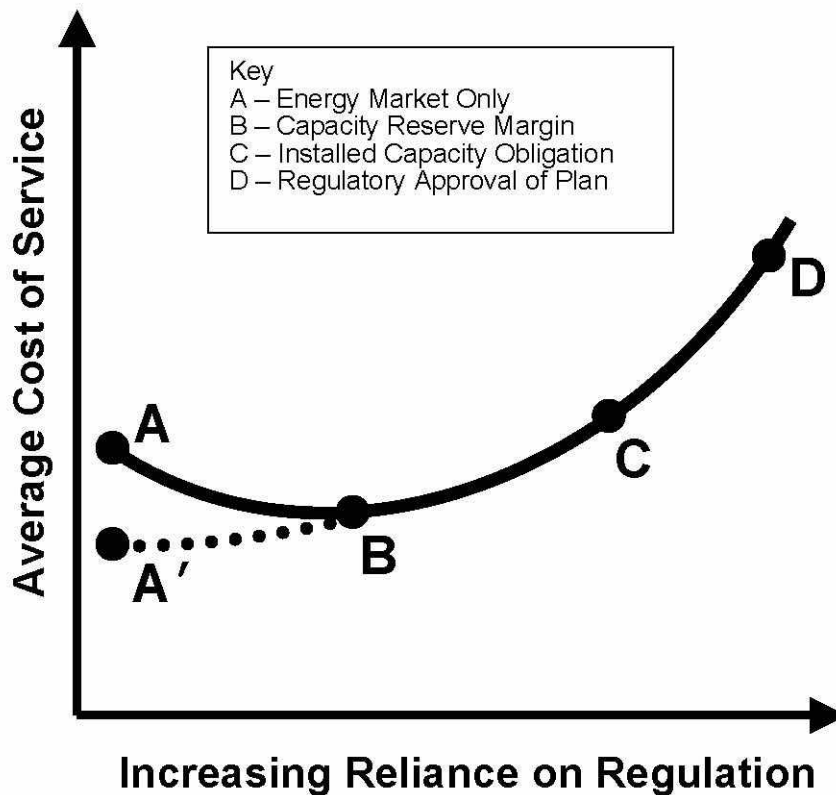
The reserve margin is determined by the efficiency condition of equating the margin cost of reliable reserves with its marginal value to customers. The literature on reliability confirms that customer needs for reliable service vary widely. The reserve margin model reflects the public good component of reliability and provides a base level of reliability to all customers. Customers who prefer increased levels of reliability obtain it from private markets rather than from a regulatory standard.

The ICAP model (Model C) that requires an installed capacity obligation also refers to a family of models that includes the PJM approach and the NY demand curve approach among others. The capacity obligation is based on expected peak demand, but maintained throughout the year. One important regulatory components of this model are maintaining, and financially supporting, a peak level of capacity during most of the year when much less capacity is required. This feature produces a relatively flat average price of electricity across seasons that preclude an efficient price-demand response in retail competition. The second regulatory element of this model is that the amount of capacity maintained is based on engineering criteria (historical “rule of thumb”) that likely provide surplus capacity, even during peak periods. The principle agent problem argues for an inefficiently high level of capacity.

In the ICAP model, the price of capacity may be revealed in an auction market. The incentive to invest in new generation arises from energy market spot prices, capacity market spot prices, and from the large capacity obligation that ensures a continuous revenue flow subject to spot prices.

The traditional regulatory model (Model D) includes the capacity obligation of ICAP along with a reserve margin set through engineering criteria (“rule of thumb”). The regulatory model provides an allowed rate of return on the capital investments, and the recovery of the original capital plus the return in electric rates.

**Figure 7**  
**Average Cost of Electricity**  
**Under Different Levels of Regulation**



The figure above depicts (roughly) the average cost of providing electricity and reliability as a function of the degree of reliance on regulation. The energy only market (Model A) may not minimize costs to customers because of the externality (public good) value of reliability. The figure reflects the conflicting evidence on this point by depicting an alternative average cost (A') of an energy market that may produce minimum average costs. We suggest that the capacity reserve margin model (Model B) minimizes customer cost because it optimizes reliability and uses market forces to minimize customer cost. However, the reserve margin model may be required only during the transition from a regulated utility, or ICAP model, to a competitive model. Hirst and Hadley reach this conclusion:

As the industry gains experience with customer responses to real-time pricing and with operation of competitive intrahour energy markets, these requirement will likely disappear.<sup>69</sup>

<sup>69</sup> Hirst, Eric and Stan Hadley, *Maintaining Generation Adequacy in a Restructuring U.S. Electricity Industry*, Oak Ridge National Laboratory, ORNL/CON-472, October, 1999, p. v.

The ICAP model (Model C) increases customer cost because of its large capital cost requirement. The empirical evidence produced here indicates that the competitive models (point B) reduce costs to customers by more than one cent per kWh in several regions in the U.S. relative to an ICAP model. The traditional regulatory model (Model D) increases cost still further because it maintains the ICAP capital requirement and provides a regulated rate of return.<sup>70</sup>

## Matrix Summary of Observations

The matrix of model categories and their characteristics summarizes many of the findings with respect to the public policy objectives.

Although we do not discuss the energy only market in much detail, it appears that such a model is not the best choice for electricity markets that are moving from regulation to competition. Regulators and other responsible authorities will unlikely have sufficient faith in a pure market process to bet all their chips on this model. Almost all markets in the economy function like an energy market only, including natural gas markets, and provide reliable service. Nevertheless, managers of electricity markets are averse to the various risks. Short term price risks are perceived as untenable and the attractiveness of long term investments is also a concern. Further, many analysts have argued against the energy market only and have pointed out various market failures that require some reserve margin stability.

The reserve margin model is intended to capture the benefits of a competitive market process while providing the stability and reliability expected from a more regulated approach. In this model, regulation is minimized and is used just to obtain a reserve margin that provides benefit to customers. Such a reserve margin would provide some physical reliability, and would mitigate large scale price movements. Electricity prices would normally follow marginal cost, including the cost of the reliability reserve margin. A wholesale price-demand response is obtained which produces the necessary price demand response in retail markets. Customers would not necessarily see real time spot prices, and would instead opt for various price-risk management tools. Customers would, however, see retail prices that are significantly lower than at present.

The reserve margin model minimizes costs to customers because customers only pay for the reserve margin that tracks the value they give to reliability. Price-demand response reduces the need for peak generating units and encourages the use of less expensive measures to meet peak need. The reduction in demand for peaking units also reduces capital costs. The shift in demand from peak to off peak periods increases the capacity factor of non-peaking units, which further reduces their capital cost per unit of energy produced.

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<sup>70</sup> Quantitative estimates of the cost reduction benefits from PJM restructuring are presented in Sutherland, Ronald J. *The Benefits of Restructuring Electricity Markets: A Study of the PJM Region*, The Center for the Advancement of Energy Markets, Fairfax, VA, October, 2003.

We prefer to group the ICAP model and the traditional regulatory model into a class of regulatory models. The basic characteristic of regulatory models is reliance on quantity adjustments, not prices, to address all market disturbances. These models require a large amount of capacity to meet peak demand, and an even larger amount of capacity to provide a reserve margin. All cost of this expensive capital—G, T, and D—must be allocated to the average price of electricity, and thereby recovered on a daily basis. The ICAP model with a capacity auction market produces floating prices that equal short run marginal cost. Over time, this marginal cost will approximate long run average costs, but significant deviations from average cost will be observed. The traditional regulatory model produces more capital cost price stability than the ICAP market with its use of floating prices.<sup>71</sup> The ICAP model produces a gain in efficiency over the regulatory model because of the market pricing of ICAP compared with rate of return regulation.<sup>72</sup>

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<sup>71</sup> A notable exception to this generalization is that some nuclear power investments that were encouraged by regulation and ultimately produced a rate shock. Capacity markets with floating prices would likely discourage investments in nuclear plants.

<sup>72</sup> The benefits of this pricing efficiency are estimated by Sutherland (2003) to be quite significant in the PJM region.

	<b>Capital Attraction</b>	<b>System Reliability</b>	<b>Retail Customer Cost</b>	<b>Competition</b>
<b>Model A Energy Only Market</b>	Near-term regulatory uncertainty and reliance on spot prices make this risky for attracting investment. Some advantage to customer (demand-side) options as customers try to minimize price volatility.	The system is reliable in a physical sense, but reliability becomes expressed as price volatility. Long-term improvements are expected as increasing numbers of demand-side options are installed, and as network interaction improves.	Reduces average cost to customers. Increased wholesale price volatility provides need for price risk management. Costs rise for customers who decide to invest in demand-side options to reduce risk.	Both the wholesale, bulk power market and the demand-side market will experience volatility. Over the long run, supply and demand provide customer value, but short-term volatility may impose externality costs on customers. Concern over concentration of generating asset ownership.
<b>Model B Monthly Reserves</b>	A reserve margin requirement produces stable reserve, but at volatile capacity prices. The reserve margins may dampen retail prices somewhat.	The system is physically reliable, and reserve margins enhance this reliability and can reduce some price volatility. Long-term improvements in reliability as demand-side options are incorporated into the ISO's operating practices.	Average costs decline as system obtain efficient reserve margins and does not require payment for unneeded capacity. Opportunities to encourage a mix of generating units, T&D investment, investments in demand-side options.	An explicit reserve margin would attract sufficient suppliers and could be achieved at minimum cost. Near-term (monthly) reserve margin requirements place a relatively small burden on new entrants.
<b>Model C Installed Capacity Market (ICAP)</b>	ICAP requirements achieve fixed capacity quantities, but at volatile spot prices that average out during the year and produce average cost pricing. Average cost pricing to recover these payments dampens the incentive for investments in demand-side options.	ICAP adds capacity beyond the reliability value because it relies on administrative processes. ICAP, with average cost recovery, reduces the incentive for demand-side options. Small, targeted resources that could enhance reliability are made uneconomic from the customer perspective.	Average costs increase because on non-economic levels of capacity, including reserve margins that exceed customer value, and because of the reduced incentives for demand-side options.	The ICAP obligation attracts sufficient suppliers who earn a competitive return for the level of reserves. Demand side options are suppressed and there is no improvement in the dynamic interaction between demand and supply.
<b>Model D Planning Reserve/IRP</b>	Traditional regulation reduces risk to capital markets so that the cost of capital is apparently low for large-scale projects. IRP requires consideration of all demand and supply alternatives, but uncertainty in execution keeps costs high, and focuses attention on administrative solutions for all resources.	Reliability of the system can be maintained through the application of good planning criteria, but the costs are high. Regulators and utilities will build excess generation and T&D capacity to improve the deliverability of power to all customers at all times. The result is a system that over performs relative to the value that many customers are willing to place on reliability in competitive markets.	The regulatory planning approach relies on cost recovery from a large number of customers over an extended period of time. Costs are "spread thinly" over many customers, hours and kilowatts; therefore the average cost appears low. However, the lack of interaction of demand and supply results in inefficiency. Peak costs are too low and are subsidized by energy costs in all other periods.	Regulatory oversight of planning replaces competitive with an administrative system. Some supply-side price competition is possible if auctions and bidding are well managed. Problems arise in load pockets, where inadequate resources limit competition. Price-demand response is suppressed. Efforts to administer demand-side options are highly inefficient.

## **Appendix A: California Case Study**

This appendix presents background information on resource adequacy in California, the recent proceedings of the California Public Utilities Commission, and recommendations based on the body of the report.

The failure of restructuring in the California market presents a challenge to the competitive model. The California model used an energy market only model and still experienced significant supply constraints. Part of the failure of the California market owes to a “perfect storm” of events that adversely affected available resources. Further, the California market design was seriously flawed in a manner that allowed suppliers to restrict the supply of electricity and game the market.

There is a need for resource adequacy in California in order to create a structure that gives confidence to market participants, politicians and consumers. Resource adequacy is insurance that must be acquired in order to build confidence that the system will have sufficient generating capacity in light of uncertain future events. The Governor’s office has taken an interest in the proceeding on resource adequacy, and has made it clear that adequate generation is a high priority.

At the heart of the issue is whether resource adequacy requirements should be complex, costly, and long-lasting, or whether the state should create a simple, stop-gap measure while it works on other problems that create the need for resource adequacy. We recommend a resource adequacy approach that is efficient, unobtrusive, low in cost, and which allows a phase out when it is no longer needed.

### **California Energy Crisis**

When California created the California Power Exchange and the California Independent System Operator (CAISO) it established hour-ahead and day-ahead markets that provided a market for short-term energy purchases, and a CAISO-managed market for reliability (ancillary) services. Retail customers were able to choose their provider in 1998, and residential customers received rate guarantees. California adopted a model for a volatile, hourly, wholesale market, while trying to pay for wholesale prices with a flat- and fixed-rate retail market model for a significant portion of the total customer load. The largest utilities sold their generating units and were required to buy short-term power from the Power Exchange, rather than acquire a portfolio of long-term and short-term resources through bilateral contracts. Prices shot up less than two years later as a result of 1) natural gas price increases, 2) costly emissions allowances in Southern California, 3) a dry year in the hydroelectric power markets north of California, 4) transmission constraints limiting imports, 5) extreme weather and significant load growth through the West, and 6) poorly designed wholesale markets. Large generating units had not

been constructed during the 1990's to keep up with growing demand, largely because of the regulatory uncertainty associated with restructuring and the challenges in siting new projects.

In a July 2001 report commissioned by the Edison Electric Institute, consultant Eric Hirst made the following recommendations:

- Competition in retail and wholesale markets must be coordinated and coupled together. Competitive wholesale markets require that at least some retail load face time-varying prices. In other words, the market structure and rules should encourage retail customers, on a voluntary basis, to participate in dynamic pricing and load-reduction programs.
- Restructuring requires many more customers' choices for energy services and price-risk tradeoffs than have traditionally been offered. Standard-offer rates with artificial discounts must be avoided. Reliability can be improved with market-based reliability services rather than just considering reliability a monopoly service.
- A favorable investment and regulatory climate for new generation will ensure that enough generation capacity is online and planned to meet growing loads. The financial risks and rewards associated with building and operating power plants must be assigned to investors rather than consumers.
- Electricity suppliers must manage and diversify their supply and price risks with a portfolio of short and long-term resources.
- Regulators must monitor and minimize horizontal market power (generation) and vertical market power (combined ownership and operation of generation and transmission).<sup>73</sup>

Also in July, the Cato Institute offered a policy analysis that suggested that most of the problem arose because of an imbalance in demand and supply. The rise in natural gas prices that led to electricity price increases should have been passed through to consumer, so that they could determine whether or not to consume energy. Looking ahead from mid-2001, the authors stated that, "The only remedy to the crisis is the elimination of the retail rate cap and the institution of real-time pricing mechanisms for the largest segment of demand possible."<sup>74</sup>

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<sup>73</sup> Hirst, Eric, "The California Energy Crisis," Edison Electric Institute, July 2001.

<sup>74</sup> Taylor, Jerry and Peter VanDoren, "California's Electricity Crisis: What's Going On, Who's to Blame, and What to Do," *Policy Analysis*, No. 406, Cato Institute, July 3, 2001.

## California Public Utilities Commission Activities

In October 2001, the California Public Utilities Commission initiated a rulemaking proceeding to address procurement and cost recovery for generating resources.<sup>75</sup> After addressing existing power contracts and short-term planning in 2002, the commission turned its attention to long-term planning. In its January 22, 2004 decision, the CPUC addressed the following threshold issues:

(1) Adoption of a resource adequacy framework, to include specific reserve level requirements; (2) adoption of a market structure for longer term resource commitments by the utilities and a requirement to include long-term investment in their procurement planning; and (3) an analysis of whether each utility will be financially capable of making the longer term investments necessary to meet its obligation to serve its customers. In discussing these issues, we give specific direction for the utilities to follow in their procurement planning and operations.<sup>76</sup>

In its decision, the Commission:

(1) Directs that each Load Serving Entity (LSE) within the utility's service territory (i.e., utility, Energy Service Provider (ESP) or Community Choice Aggregator) has an obligation to acquire sufficient reserves for its customer's load located; (2) adopts a reserve margin for LSEs of 15-17%; (3) directs the LSEs to meet this 15-17% reserve requirement by no later than January 1, 2008, through a gradual phase-in including the establishment of interim benchmarks to become effective in 2005; (4) establishes a requirement that utilities forward contract 90% of their summer (May through September) peaking needs (loads plus planning reserves) a year in advance; and (5) continues the 5% target limitation on utilities' reliance on the spot market (i.e., Day-Ahead, Hour-Ahead, and Real-Time energy) to meet their energy needs.<sup>77</sup>

The 5% limitation on the use of the spot market creates, in essence, a 95% month-ahead resource requirement. The decision was subject to a need for technical conferences and workshops to determine the technical details.

A group of ESP's challenged the decision and the authority of the commission, stating that the commission's powers to regulate ESP's was limited to whether they had the technical and

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<sup>75</sup> California Public Utilities Commission, "Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development," Rulemaking 01-10-024, filed October 25, 2001.

<sup>76</sup> California Public Utilities Commission, "Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development," Rulemaking 01-10-024, Decision 04-01-050 (Interim Decision), January 22, 2004, p. 10.

<sup>77</sup> Ibid. p. 11.

financial means to serve customers in California. The commission disagreed and stated that case law supports the CPUC's claim that it has substantial discretion in the exercise of its authority to do whatever is necessary to ensure the public interest is served. The commission found that the requirement that ESP's contract for 90% of their capacity need for the summer months at least one year in advance as a pre-certification requirement is not an abuse of its authority to ensure that the public interest is served.<sup>78</sup>

In April 2004, the commission opened a related proceeding on resource planning.<sup>79</sup> A joint proceeding workshop report addressed a variety of technical and policy issues. The need for a showing of 90% year ahead commitment of resources by the LSE's, the approval process, and the phase in of the 15% reserve requirement are issues. Uncertainty surrounds the timing of resource approval and the performance of studies to determine the impact of resource allocation on the system. Uncertainty associated with the actual procurement of resources and the nature of penalties is a significant issue for the LSE's. The workshop report also addressed technical issues relating to load forecasts, adjustments for peak demand and non-coincidence, adjustments for losses, energy efficiency, distributed generation, forced outages, etc. There was also consideration of technical issues relating to when resources would count (hours of operation per year; under construction; contractual matters), and deliverability to control areas. The allocation of firm transmission rights and the auction approach to allocation of constrained transmission capacity, and the methods and timing of the allocation of total import capacity to the LSE's. It also remained an issue as to whether the commission should assess deliverability on an aggregate or load pocket basis. Workshop participants also discussed the concept of requiring LSE's to demonstrate that they have entered into forward commitments more than one year in advance. Long-term procurement—one to three years in advance—could support infrastructure construction but would have cost implications due to load uncertainty. Some supported the notion of a "capacity tag," as they stated that a capacity trading market could develop for resources that have already passed a deliverability screen.<sup>80</sup>

On October 28, 2004, the CPUC issued an opinion in its resource adequacy proceeding. The order applied immediately to all utilities and energy service providers, and further directed

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<sup>78</sup> California Public Utilities Commission, "Order Modifying Decision (D.) 03-12-062 and D.04-01-050, and Denying Rehearing of D.03-12-062 and D.04-01-050 as Modified," Decision 04-07-037, Rulemaking 04-04-003, July 8, 2004, pp 14-21.

<sup>79</sup> California Public Utilities Commission, "Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning," Rulemaking 04-04-003, filed April 1, 2004.

<sup>80</sup> California Public Utilities Commission, "Workshop Report On Resource Adequacy Issues," for Rulemaking 01-10-024, *Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development*, and Rulemaking 04-04-003, *Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning*, Sacramento, June 15, 2004.

speedy resolution of technical issues in a Phase 2 of the proceeding. Among the key requirements and clarifications to the previous orders:<sup>81</sup>

- Each LSE must show that it has acquired resources to satisfy load plus 15-17% planning reserve margin. Different resources can satisfy the requirement in different months, thus providing the LSE with flexibility to build a portfolio.
- Year ahead filings are due at the end of September for the following year months of May to September.
- At the urgings of the Governor, the 15% planning reserve margin requirement is accelerated to June 2006.
- The “90% year-ahead” requirement allows the LSE to acquire a portfolio of long and short-term resources.
- For seven months of the year, 100% of the resource requirements would be required one month in advance.
- While the primary goal is resource adequacy, the commission is mindful of its duty to protect consumers from excessive charges. The commission is looking out for collusion and/or the exercise of market power.
- Non-dispatchable demand-responsive programs and tariffs are treated as deductions from the load forecast. Dispatchable, ISO-controlled resources are treated as resources.
- Liquidated damage provisions that have no specific generating unit backing up the contract have issues of uncertain deliverability. However, they provide resources from a portfolio and cannot be entirely discounted.
- Energy-limited resources must provide power for at least four hours per day for three days, and provide resources during the time that peak is expected to exceed 90% of peak.
- Demand response must be able to operate for at least 48 hours during the summer and no reserves are applied to these reserves.
- Local deliverability was recognized as an issue, and the commission determined that the CAISO must determine whether a resource is within a control area, or whether an out-of-areas resource can be imported.

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<sup>81</sup> California Public Utilities Commission, “Interim Opinion Regarding Resource Adequacy,” Decision 04-10-035, Rulemaking 04-04-003, *Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning*, Sacramento, October 28, 2004.

- The commission will require local deliverability in a future proceeding with an eye toward reducing reliability must run (RMR) units. The commission is cognizant of the problems facing small ESPs in acquiring these resources.
- The commission does not restrict LSE in their energy acquisition practices. LSE may acquire low cost energy from whatever sources they identify.

In comments, the CAISO indicated that it supports the month ahead requirement for 100% of capacity needs as this allows time to mitigate the problem prior to the day-head market. Others express concern that requiring 100% a month in advance precludes the ability to secure lower cost resources on the spot market.

Two commissioners filed dissents. Commissioner Karl Wood objected to pushing the 15% reserve margin target back to June 2006 (from 2008). He stated that the majority did not present evidence regarding the increased cost of doing so, and he did not believe the commission would be able to identify and exclude from rates the costs associated with price gouging.<sup>82</sup> He is concerned that the time horizon from now until 2006 precludes the development of new resources that could compete on price with existing resources.

## **Discussion and Recommendation**

The CPUC has determined that all ESP's must meet new resource adequacy requirements. In its simplest form, the recent Interim Opinion requires:

1. A planning reserve requirement of 15% beginning June 2006.
2. A month-ahead requirement for 100% of the resource need.
3. Participation in Phase 2 of the proceeding to address a variety of details that have the potential to impose costs on the ESP's.

ESP's must acquire the resources for 2006 soon, in anticipation of the year-ahead filing that could be required as soon as September 2005. This near-term planning reserve requirement will impose significant costs on ESP's and consumers. ESP's will have to make resource commitments in advance of what they would prefer, thus limiting their flexibility. The month-ahead requirement is equivalent to the monthly reserve margin requirement discussed above as Model B.

We recommend that Phase 2 focus on (1) weakening the requirements associated with the planning reserve requirement, (2) emphasis on market mechanisms to achieve greater demand response and participation of demand-side resources in the planning reserve requirement, (3)

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<sup>82</sup> Dissenting Opinion of Commissioner Carl Wood, Rulemaking 04-04-003, *Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning*, Sacramento, October 28, 2004.

discussion of a phase out of the planning reserve requirement, (4) more emphasis on consistent regulations in order to reduce uncertainty and to make California a place where investments in electric resources are viewed favorably.

We do not claim to have an infallible California strategy, but we have several observations that should help California in the long run.

Given California's recent experience, it would be inappropriate to recommend an energy only market. California has determined that it wants a planning reserve requirement. However, it makes sense to begin a phase out of that requirement, in order to signal that more emphasis will be placed on market signals in the future. The goal is to ensure that adequate generation capacity is constructed. California has determined that a planning reserve requirement is the immediate solution, but it should recognize that regulatory requirements are not appropriate for a long-term solution.

In instituting a month-ahead planning requirement, California should emphasize that marginal costs need to be equal to marginal benefit. The key way to achieve this balance is to achieve participation of loads in the market place. Reliability can be achieved in the market place, and retail customers should have an opportunity to reflect customer preferences for more or less reliability. California has embarked upon programs to increase the use of energy efficiency, renewable resources and distributed generation. The distributed generation working group is proposing changes to the interconnection rules to make it easier to interconnect with distribution utilities. Demand response and load participation are likely to be successful if they rely more on markets and less on administered programs.

The monthly reserve margin approach should ensure that the requirements follow the load duration curve. There should be an approximation of efficient wholesale prices that all customers have an ability to respond to if that is their desire. California should assure that the additional costs associated with reserve margins do not result in flat rate prices. Costs associated with just a few hours each month should be reflected in those few hours, and not spread to all hours in the month or to other months. Overall, California should make sure that its approach does not distort wholesale market prices.

Restrictions on ESP and customer behavior should be avoided. A limitation of 5% spot market purchases may or may not result in a market that reveals efficient prices. The spot market needs to be sufficiently robust because bilateral contracts are compared to spot market prices. A robust spot market reveals information that is important to all market participants.

Another restriction is the 48-hour rule for demand-side resources. On its surface, the rule appears benign. California wants to avoid phony demand-side resources, and a 48-hour minimum is one measure of the performance and value of the resource. On the other hand, all administrative determinations set forth artificial restrictions that may prove unwise as the technologies, economics and customer preferences change. What if technologies develop for viable 30-hour-per-year resources? What is their value, and why have they been excluded from participating? A robust wholesale market will arise when there are substitutes at all times of the year, with prices that induce a resource to participate for just a few hours each year. California

needs to recognize that regulations that set forth specific limitations on behavior introduce the risk of a government failure, without clearly reducing the risk of any market failure.

## **Appendix B: Technical Literature on Reliability**

The case that an increasing level of reliability and hence reserves is warranted requires a definition and metric of reliability. Unfortunately, reliability is not easy to quantify or even define. The North American Electric Reliability Council definition of reliability reflects both the operational reliability of the existing bulk power system, and its resource adequacy. This study focuses on the resource adequacy determinant of reliability.

Some technical literature on reliability reveals that reliability reflects numerous factors, and customers vary widely in their value of these various factors. An electrical outage may impose no costs on some customers, small costs on other customers, and very large costs on still other customers. The ranking of these costs by customers may be entirely different for outages at different seasons, time of day, length of outage, or whether the outage was random or planned. The absence of a single definition and metric for reliability implies that any case that reliability is too high or too low is highly tenuous.

From an economic perspective, capacity should not be merely adequate, but capacity should be optimal. We apply a simple model of optimum capacity obtained from the literature. An optimal level of capacity is defined by the same equilibrium condition that determines the optimal level of capacity to produce any good or service. Generating capacity is optimized when the marginal cost of the next unit of capacity just equals its marginal value. This marginal value is the value that customers place on the incremental level of reliability obtained by the incremental generating unit.

A feature of the capacity market, as opposed to the energy market, is that, in many cases, customers cannot reveal a preference for reliability in their market decisions. Reliability has public good characteristics in that customers cannot readily be excluded from purchasing the provided level of reliability, even if they are not willing to pay for it. This feature of reliability results in regulatory authorities assigning a reserve margin target, or capacity obligation, that presumably provides an optimum level of reliability. However, reliability is also a private good where customers can purchase more reliability to meet their particular needs, or sell reliability back to the system (local distribution utility or independent system operator) in the form of interruptible/curtailable rates or through some contribution to the ISO's ancillary services.

We develop this position that reserve margins are likely to be determined by administrative rules, rather than from market behavior. Customers may expect and hope that regulators, acting as the customers' agent, set a reserve margin target that maximizes customer value. However, regulators are likely to prefer a higher reliability standard than customers, which is the principal agent problem. Further, if the authorities are subject to interest group influence, the providers of generating capacity are likely to advocate large reserve margins in order to obtain stable revenues or an increased return on their investments in generation.

States and regions use various approaches to obtain resource adequacy, as indicated here as the reserve margin. We review the various reserve margin models. We begin with the market-based

model that determines an optimum reserve margin by equating costs and benefits at the margin. This model has conceptual appeal because it provides maximum benefit to customers over time. However, the economic model sees little application in the U.S. The historical-regulatory approach applies engineering criteria (a traditional “rule of thumb”) that produces expected outages that accumulate to 1-day in 10-years. This model has served as the conventional model for utility regulation for several decades.

The installed capacity model, termed ICAP, is simply a variation of the rule-of-thumb where the authorities specify a capacity obligation that may differ from the 1-in10 rule. In the PJM region, the capacity obligation is based on expected summer peak demand and that level is maintained throughout the year. A variation of the capacity model uses a capacity demand curve, where the price of capacity varies. The nodal variation to the capacity obligation reflects the decision that the capacity obligation varies with the location or node.

We provide a quantitative analysis that indicates the costs to customers from maintaining reserve margin in excess their optimum level and pricing electricity at its average cost. An EIA simulation analysis develops the electricity price data under two scenarios. One scenario assumes significant competition, but average cost pricing and high reserve margins. The second scenario assumes marginal cost pricing for generation plus optimal reserve margins determined by equating cost and reliability benefit at the margin. The efficient generation and reserve model produces a price decline of 0.5 cents per kWh for the entire U.S., but larger price declines for the regions that are restructuring. In the regions considered here, more efficient reserve margins would decrease electricity costs by more than 10%.

## Literature Review

In 1988, *The Energy Journal* published a *Special Reliability Electricity Issue* that contains 12 articles that focus on the reliability of electricity supply. In each of these articles, reliability is assessed as resource adequacy, not as operating reliability. Many of the results from these articles are relevant here. More recently, Lawton et al calculate outage costs for residential, commercial, and industrial customers using a combined database of several recent studies.<sup>83</sup> The economic results used here are from the *Special Issue* and from the Lawton report.

The *Energy Journal* articles typically begin with the premise that during the several decades of conventional electric utility regulation, power systems were planned and operated on the basis of ad-hoc reliability standards based on supply considerations, not on customer value (Munasinghe, Woo and Chao, 1988). Munasinghe and Sanghvi (1988) note that historically power systems were designed to meet forecast demand at some level of reliability that was based on an

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<sup>83</sup> Lawton, Leora, M. Sullivan, K. Van Liere, A. Katz, and J. Eto, *A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys*, Lawrence Berkeley Laboratory, LBNL-54365, November, 2003.

historical “rule-of-thumb.”<sup>84</sup> This is referred to as the “1-in-10 rule,” which means that the target level of reliability is to provide electricity service 99.97% of the time, where expected service outages accumulate to 24 hours (1 day) over a 10-year period.<sup>85</sup> Historically, resource adequacy meant providing a level of capacity resources (G, T and D) that would result in a 99.97% level of service reliability. Further, the metric of unreliability is the accumulated hours of outages over a ten-year period.

The historical “1-in-10 rule” is a supply-side engineering construct; it does not reflect the value that customers place on service reliability. Further, this rule reflects a one-size-fits-all concept, where reliability is measured as expected hours of outages per ten years for the system as a whole, not for particular customers. This definition does not distinguish among customers, among customer classes, randomness or predictability of outage, frequency and duration of outage, or the extent of outage over a service territory. Further, the “1-in-10 rule” may not make economic sense.

A reserve margin based on economic principles would equate the value of service reliability at the margin with the cost of obtaining this reliability. Telson (1975), and Chao (1983) demonstrated that the “1-in-10 rule” does not reflect this economic principle. Both Telson and Chao conclude that the optimal level of reliability is far below that of the “1-in-10 rule.”<sup>86</sup> The implication is that the cost to customers of obtaining the level of reliability implied by the rule is much in excess of the value that customers place on that level of reliability. Capacity adequacy, or more correctly the optimum level of capacity, is found to be less than implied by the rule. Considering that the rule was based on supply considerations, and does not consider the customer value of service, the finding of an inefficient “rule-of-thumb” is expected.

The above definition of service reliability considers only the accumulated duration of outages; it does not consider the randomness or predictability of outages. Random or unpredictable outages are likely to impose much higher costs on at least some customers than predictable outages. Polland uses data from Pacific Gas & Electric to estimate alternative reliability targets based on numerous uncertainties.<sup>87</sup> Polland concludes that, in the absence of uncertainties, the economic marginal condition produces reserve requirements much lower than the “1-in-10 rule.” However, by allowing for various planning uncertainties, the rule may not be too conservative, especially for long-term capacity planning. If resource adequacy concerns are translating into a

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<sup>84</sup> Although not stated by these authors, forecast demand means forecast peak demand during the year, and not an average of demand that varies throughout the year.

<sup>85</sup> There are ~87,600 hours in 10 years. One day (24 hours) of outages in ten years means that there is service 99.97% of the time.

<sup>86</sup> Telson, M.L. “The Economics of Alternative Levels of Reliability for Electric Power Generation Systems” *The Bell Journal of Economics*, 1975, Vol. 6, No. 2, pp. 679-694, and Chao, Hung-po, “Peak Load Pricing and Capacity Planning With Demand and Supply Uncertainty” *The Bell Journal of Economics*, 1983, Vol. 14, No. 1, pp. 179-190.

<sup>87</sup> Polland William B. “The Importance of Including Uncertainties in Economic Generation Reliability Planning” *The Energy Journal, Special Electricity Reliability Issue*, Vol. 9, 1988, pp. 19-32.

perceived need for reserves in excess to the “1-in-10 rule,” the cost of these reserves is likely unwarranted.

The Pollard analysis also indicates that the cost of an outage depends on whether it is planned and predictable, or whether it occurs randomly. A real world but unfortunate example illustrates the cost on unpredictable outages. An anonymous consulting economist experienced an electrical outage of a mere second or two. The consequence of this electrical line surge was to destroy the motherboard of the economist’s personal computer, which he depended upon for his economic livelihood. Although the computer was under warranty and replaced at no charge, the true cost includes foregoing the use of the computer for about six weeks. Although the cost was mitigated in part by use of an inferior backup computer, the cost was nevertheless serious. Had the line surge been predictable, simply turning off the computer would have avoided all costs. In this case, the cost of unreliable service relates to its lack of predictability of an outage, and not to its duration.

### **Costs of Unreliable Service**

Numerous studies of the costs of unreliable service present empirical estimates of the costs of service disruptions. The value of these studies is that costs of service disruptions also estimate the marginal value that customers place on increasing reliability. This marginal value is defined as the marginal willingness to pay for service reliability. This marginal value is equated to the marginal cost of adding reliable capacity to determine an optimum reserve margin.

A typical example of unreliable electric service is an electrical outage, which means that the customer receives no power. The costs of unreliable service are described as the costs of an outage. The costs of an outage are defined as “...the economic consequence of service curtailment to the customer when the demand for electricity temporarily exceeds supply capability”.<sup>88</sup> These costs of an electrical outage are analyzed in the literature, usually in terms of specific customer classes. Munasinghe and Sanghvi present a table of outage costs organized by sector: residential, industrial and commercial, and public service infrastructure, and by direct and indirect costs.<sup>89</sup> One result is that costs to residential customers are mostly direct and include inconvenience, stress, out-of-pocket costs, and spoilage. Costs to the public sector are mostly indirect, and include loss of public services. A second result is that costs vary widely between classes and also within each class of customer. Further, costs also depend on whether they are short-run costs of a single outage or long-run average costs of numerous outages. In the long run customers can take mitigating strategies (installing batteries in clock radios) that reduce average costs relative to short run costs.

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<sup>88</sup> Munasinghe, Mohan, and A. Sanghvi, “Reliability of Electricity Supply, Outage Costs and Value of Service: An Overview,” *The Energy Journal, Special Issue on Electricity Reliability*, Vol. 9, 1988, p. 3.

<sup>89</sup> *Ibid.* p. 4.

Munasinghe and Sanghvi note that practically all outage cost studies, including those of foreign countries, reach two common conclusions: (1) the value of reliable service is not distributed randomly but varies with the customer, their usage and business, and (2) the distribution of this value for reliable service varies over a wide range and not over a narrow range.<sup>90</sup> These results indicate a serious reservation about relying on the strategy of increasing reserve margins to increase reliability. The reserve margin approach implies a single service standard for all customers and for all uses. Under a single standard, all customers pay for the increased reliability whether they value it, or not.

The most efficient way to provide the reliability that customers value is to allow customers to purchase the reliability that they need. Hospitals, hotels and some other end users already purchase back-up generation to improve reliability. Computer users often find a need to improve reliability beyond that provided by their electricity supplier.

Numerous studies question the value of obtaining increased reliability via adding generation reserves, even when the purpose of the study is very different. Keane, MacDonald and Woo (1988) estimate the partial outage costs for residential customers who voluntarily cycle their air conditioning load or shed part of this load.<sup>91</sup> Under the cycling option, customers would have their air conditioners turned off for 15 minutes each half hour during the peak air conditioning period. Under the shedding option, customers would agree to have their air conditioning turned off during the entire peak period. Residential customers revealed an average estimated cost of the cycling program to be \$1.63 per kWh, which is much less than the load shedding program. The average cost estimate of \$1.63 per kWh depends on the number of days the program was in effect and the number of months per year. Again, the implication is that the most cost effective program is one that would allow customers to choose their preferred response, rather than target all customers via a capacity reserve obligation.

Outage costs in the industrial sector show a similar pattern of wide variability. Woo and Train find that the direct costs to industrial firms include idle employees, damaged equipment, and lost production and sales.<sup>92</sup> However, the outage costs to any single firm depend on the time-of-day, season, day-of-week, frequency and duration of outage, and whether advanced notice is given to the firm. Woo and Train observed that 39% of their surveyed respondents revealed zero outage costs. On average though, costs of outages are positively related to frequency of outage and duration of outage, but at diminishing rates. A doubling of the frequency or duration of outages less than doubles the total. This result indicates that industrial customers who experience outages adapt by taking mitigating actions that reduce costs. This result also indicates that adding up hours of outages misrepresents the total costs of outages. A small number of brief

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<sup>90</sup> Ibid., p.7.

<sup>91</sup> Keane, Dennis M. S. Leslie MacDonald and Chi-Keung Woo, "Estimating Residential Partial Outage Cost With Market Research Data", *The Energy Journal, Special Issue On Electricity Reliability*, Vol. 9, 1988, pp. 151- 159.

<sup>92</sup> Woo, Chi-Keung and Chao Woo, Chi-Keung and Kenneth Train, "The Cost of Electric Power Interruptions to Commercial Firms," *The Energy Journal, Special Electricity Issue On Electricity Reliability*, Vol. 9, 1988, pp. 161-172.

outages to a very large number of firms would impose high outage costs on customers. However, numerous longer outages to a few firms would impose much lower costs, even where total hours of outage are equal.

The statistical analysis by Woo and Train also shows that outage costs to industrial customers are highest during the weekday and during daytime. These costs are lower where customers have experience with outages and have backup. These results are not surprising and are obtained in other studies. These results are noted here to further support the important finding of wide variability of outage costs between customers. This result in turn indicates the limitation of a single measure of reliability and the inefficiency of trying to obtain optimum reliability via a capacity reserve margin.

Lawton et al acquired 24 independent data bases from recent studies and merged them into three meta-data sets, one for large commercial and industrial (C&I) customers, one for small C&I customers, and one for residential customers.<sup>93</sup> Overall, the results confirm the findings of previous studies noted above. The Lawton statistical analysis concludes that the average cost of a single summer afternoon outage of one hour is approximately \$3 for a residential customer, \$1,200 for a small-medium C or I customer, and \$82,000 for a large C or I customer. Costs increase with the duration of an outage but not linearly, just as found in previous studies.

Like previous studies, Lawton et al conclude that outage costs are higher on weekends for residential customers, but higher on week days for C and I customers. Outage costs are higher in winter than summer for both C and I and residential customers. Outage costs for residential customers are typically associated with “hassle” and “inconvenience” and not with out-of-pocket expenses. However, outage costs for C and I customers are more likely to be direct financial costs. With the category of C & I customers outage costs are widely variable. Such costs are largest for mining and construction, smallest for public sector organizations.

### **Relationship Among G, T, D, End-use Technologies and Maintenance of Reliability**

The optimum level of electrical service depends on the transmission and distribution networks, on the reserve margin of generating capacity and on customer efforts to provide incremental measures to optimize their specific needs. The reserve margin of generating capacity is typically determined by the expected peak demand during the year. However, the capacity of the transmission and distribution networks are also linked directly to this expected peak demand. If enhanced reliability becomes a priority, T, D and G must each be increased. A significant increase in generating capacity, coupled with no changes in the T and D networks will not increase the reliability of the supply system. Rather, an increase in G, with no change in T or D, will just shift the weak link in reliability to T and D.

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<sup>93</sup> Lawton, Leora, M. Sullivan, K. Van Liere, A. Katz, and J. Eto, *A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys*, Lawrence Berkeley Laboratory, LBNL-54365, November, 2003.

While resource adequacy focuses on investments in generation, most reliability problems result from delivery problems. Transmission is configured as a network, and the loss of one major line is planned for and does not typically bring down the entire system. Distribution wires are in a network configuration within dense metropolitan areas and dual supply distribution feeders is common for large customers and industrial parks. The majority of small customers, however, receive electricity through one distribution feeder. As a result, most outages are associated with the distribution system, are of short duration, and affect a relatively small number of customers. The association of outages with the distribution network, rather than reserve margins, is commonly understood, but outages on a larger scale are also likely to be related to distribution, perhaps transmission, but not to generation reserve.

The most dramatic and significant power shortages are blackouts that affect a large region, such as occurred in the Northeast and Midwest during August of 2003. This blackout affected 40 million people in eight U.S. states plus another 10 million in Ontario, Canada. The costs of the one-day blackout included restrictions in the water supply (need to boil water), the temporary closure of factories, reduced transportation availability (closed airports and interstate trains), reduced communications and some spoilage. One of the dollar cost estimates that appeared is \$6 billion. This blackout was not caused by a reserve deficiency. Much of the blame went to FirstEnergy, of Cleveland Ohio, and its lack of power line maintenance policy, because overgrown trees coming in contact with high voltage power lines caused the initial outage.

None of these findings support the use of increasing reserve margins to obtain increasing reliability. Instead, optimum reliability can only be obtained by an efficient combination of T, D and G and end use measures.

### **An Economic Model of Reliable Service**

In this section, we specify a model that determines a reserve margin that produces an optimum level of reliability in an electricity network. One purpose of the model is to support quantitative dollar estimates of the costs saved by obtaining an optimum level of reliability relative to the reserve margin in a regulated market. Secondly, a model of optimal reliability indicates sources of potential inefficiency in models that specify a capacity reserve obligation. The essence of this optimality model is equating reliability costs and benefits at the margin.

Although electricity markets obey the same laws of supply and demand other markets, these markets, especially when regulated, also have some unique features. Market behavior may not send appropriate signals to electricity suppliers to maintain a reserve margin that optimizes the level of reliability. The next section explains that historically regulation has typically mandated a capacity reserve margin. The subsequent section explains that the interest of the regulatory authorities is to ensure a level of reliability that exceeds the interest of customers. The capacity reserve margin under regulation probably exceeds its optimum level. In view of the principal agent incentives, we expect an even larger reserve margin. The main implication of these two results is that an efficient market would reduce costs to customers by a substantial amount.

## Optimum Level of Reliability: Definition and Model Specification

Models of economic reliability begin by stating the equilibrium condition of an efficient market. The optimum level of generation reliability is determined where the marginal cost of additional generation just equals its marginal benefit, which is measured as the marginal value of improved reliability. The marginal benefit is the decrease in expected outage costs, which is the change in expected outages (kWh per year) multiplied by the customer outage cost (\$ per kWh unserved). The marginal cost is the cost of acquiring the last kW of generation capacity (\$/kW year).

Outage costs (OC) are measured as the average cost per outage of unserved energy for the system. As explained above in the reliability section, these costs vary widely between customers and depend on several variables; however, these costs are treated here as a system average. Expected outage cost is equal to the average outage cost multiplied by the expected loss of load (LOLE), measured as expected hours per year. This expected loss depends on the randomness of both electricity supply and demand factors and duration of outage.

The marginal cost of reliability is the marginal cost of adding reliable capacity. The marginal cost of reliable capacity (MCC) is weighted by the availability factor of capacity being added ( $a$ ) which is between 0 and 1. The equilibrium condition becomes:

$$\text{Equation (1) } OC \times LOLE = MCC/a,$$

Where the left hand side is the expected marginal outage cost, and the right hand side is the marginal cost of capacity that is 100% available.

Using highly illustrative data from the late 1980's, the marginal cost of a combustion turbine is \$42.50 per kW, which is the annual carrying charge of the capital cost. With an availability factor of 85% ( $a = 0.85$ ), the annual capital cost of fully reliable capacity becomes \$50 per kW. If outage costs are \$2 per kWh and expected outages are 25 hours per year, the equation indicates optimum reliability. Outage costs of \$2 per kWh are at the low end of most estimates, \$20 per kWh is near the high end. The equation holds if outage costs are \$20 per kWh, and outages occur 2.5 hours per year.

Equation (1) indicates how increasing concerns over capacity adequacy translate into an apparent need to increase generation reserves. To illustrate, suppose the initial equilibrium is one where the average cost of an outage per customer is \$20 per kWh and outages are expected to occur 2.5 hours per year. Hence outage costs are expected to average \$50 per year per customer. The marginal cost of 100% reliable capacity is \$50 per year. The initial reserve margin that produces this level of reliability is optimal. Suppose that recent events, e.g., the 1993 blackout, raise concern that the system is not adequately reliable, and the expected loss of load is to be 3.5 hours per year. Expected outage costs become \$70 per year per customer ( $\$20 \times 3.5$ ), which exceeds the cost of providing reliable service, which remains at \$50. Customers obtain net benefits by adding additional generation reserve until the expected loss of load is reduced to 2.5 hours per year per customer.

This application of a reliability model illustrates an analysis that would support the need for increased generation reserves to increase the reliability of the system. The critical part of this

analysis is that customers obtain a monetary value of increased reliability that exceeds cost. The critical part of the traditional regulatory approach is to apply a rule of thumb, or even worse, to specify a capacity obligation based on no analysis whatsoever. Although the model in equation (1) is just a bare skeleton of a useful model, it provides an important application. If reserve margins are determined with no reference to the costs and benefits of reliability at the margin, such reserve margins will be economically wasteful. Further, applying an optimum reserve margin should provide a substantial cost reduction benefit to customers.

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