Ensuring Sufficient Capacity Reserves in Today's Energy Markets:

Should We? And How Do We?

Study Team Discussion Paper

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The analyses and conclusions in this paper are those of the staff study team and do not reflect the views of other staff members of the Federal Energy Regulatory Commission, any individual Commissioner, or the Commission itself. The staff study team consisted of Jim Akers (team lead), Dave Mead, Kathy Waldbauer, Dick O'Neill (coach) and Larry Greenfield and Alice Fernandez (reviewers).

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Introduction

The transition to competition in the electric utility industry has raised new questions as to the most efficient ways to ensure that needed electric generation facilities, including facilities to provide reserves, are built. Mechanisms that were appropriate under a tightly regulated industry structure may not be the most efficient today. In this paper, the study team discusses the questions of (a) whether in today's world, it is still necessary to take regulatory action to ensure that adequate reserve capacity is provided, and (b) if so, what is the most efficient method of achieving that goal.

I. What are capacity reserves? How did electric utilities ensure sufficient capacity reserves in the past?

A. Capacity reserves

Electric energy must be produced as it is consumed; generally, there is no way to store large amounts of electric energy. Moreover, consumers want electricity when they want it, and in the amounts they want. Electricity is expected to "be there" the moment the switch is thrown. Therefore, in every region, there must be sufficient installed electric generation to supply electric energy at all times as the customers demand it. In an interconnected electrical system, each customer is served by the system rather than by an individual generator. Electricity flows over the transmission lines of an interconnected system according to the laws of physics and cannot be directed from a designated generator to a designated customer. Thus, as the system is currently operated, in order for the electric supply for a particular customer to be reliable, the generation resources in the interconnected system generally must be adequate for the needs of the whole system.

Electrical reserves are simply the capacity of electric generating plants that could be used to generate electricity but that at any particular time is not being used to generate electricity. Spinning reserves (the capacity of a plant which, generally speaking, is generating some power but could generate more) can be called upon almost instantaneously, whereas the use of non-spinning reserves (the capacity of a plant which, generally speaking, is not yet generating power) must be planned from minutes to hours in advance, depending on the characteristics of the particular plant. Due to the fluctuations of electrical demand during the day and from day to day, at certain times a particular plant may be fully utilized in providing power, while at other times it is not and is thus able to provide reserve capacity to the system.

Electrical reserves can also be provided by the demand side, i.e., the customers. A unit of electricity not requested by a customer has the same effect as an additional unit of electricity which is being generated. Thus, if a customer agrees to reduce its demand when called upon, this results in the system being able to meet the remaining demand with less generation. The aggregate amount of load which customers can, and have agreed to, reduce or "shed" when called upon by the system can be considered reserves.

In order to have a reliable system, available generation must equal the system peak demand plus a reserve margin. However, neither electrical demand nor electrical supply is constant or predictable. Over the short term, the weather can change unpredictably and cause higher demand than expected, or other unexpected events can cause unanticipated electric demand. Generating plants can go out of service unexpectedly, as well as transmission lines. Reserve capacity is necessary in order for the system operator to respond to changing, unexpected conditions. Over the longer term, demand might rise faster than expected, or an anticipated new plant might not come on line when expected. Since new plant construction generally takes a period of years to complete, available reserves are needed to take up the slack in those situations.

Electric reserves can be considered insurance against the possibility of not being able to provide power when a customer demands it. The higher the reserves, the more unlikely it is that the customer will not be served. Systems have generally maintained short-term reserves at least equal to the largest plant being operated. They have also generally used standards to limit outages in service to one day in ten years. However, reserves, like insurance, have a cost, and as the reliability provided by increasing the reserves goes up, the cost also rises. Moreover, with current practices, individual participants in an interconnected system cannot choose their own reliability level: the reliability level of the system determines the reliability level of each participant.

B. Provision of sufficient capacity reserves under prior regulatory regimes

In the era of fully-regulated, vertically integrated utilities, those utilities which were under a state-imposed obligation to serve had a concomitant obligation to have sufficient capacity to serve. In fact, state commissions often could specify the desired reserve level.

Within power pools, utilities with less capacity than their expected load and reserve requirements were required to make Installed Capability (ICAP) payments, the revenues from which were paid to utilities with more capacity than their expected load and reserve requirements. Power pools used ICAP as a first-line reliability measure. The pool would forecast electric loads for the pool and determine a desirable reserve level. This aggregate amount would be broken down and allocated to the Load Serving Entities (LSEs) in the pool. If an LSE had load responsibility, it needed electric plant somewhere to produce the electricity to serve that load. If an LSE had an ICAP deficiency, it could buy its requirements from another participant who had a surplus, or be subject to a deficiency charge from the pool. The charge for deficiencies was generally determined by the pool based on the carrying cost of facilities. This mechanism served to focus on the construction needs of the electric utilities and was an important part of the integrated resource planning process of planning electric expansion. As each LSE generally built (and was only required to build) its own plant to serve its customers' needs, the ICAP charge was only intended to cover temporary imbalances and thus only applied to a small fraction of total load. The intent of the ICAP charge was to discourage participants from "leaning" on the capacity of other participants.

When the ISOs formed in the Northeast, they generally carried over the ICAP scheme discussed above. However, by that time many LSEs had sold their generation and had to purchase large amounts of ICAP in the market or face deficiency charges. As reserves became smaller, the ICAP market at times showed signs of market power being exercised, primarily through the economic withholding of ICAP from the bilateral market in the hope of a higher return from receiving deficiency charge payments. The ISOs have sought to address this problem through price mitigation measures and through the reallocation of ICAP payments to all non-deficient ICAP holders, rather than just to the holders of surplus ICAP as had previously been done, so as to make the withholding of ICAP from the bilateral market less rewarding.

II. Is a mechanism to ensure adequate capacity reserves still necessary today, or should we just let the market work?

Can we rely on the market alone to elicit an adequate amount of generation capacity to meet demand and avoid shortages? Or should the Commission require (or allow RTOs and ISOs to require) wholesale customers to acquire a specified amount of generation capacity in advance? The study team believes that the Commission should impose a reserve capacity requirement on electricity customers only if, without the requirement, the market would fail to elicit either sufficient reserve capacity,[1] or an appropriate mix of sufficient reserve capacity and voluntary curtailment, to meet demand and avoid involuntary curtailments.

There are at present at least two problems in the electricity industry that could prevent market forces from providing sufficient reserve capacity:

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[1]The Commission has not imposed capacity requirements for customers in the gas industry. In that system, however, customers must submit balanced schedules, and if they have not contracted for supply, they will not get deliveries.

- Most customers are currently unable to respond to real time prices due to insufficient information, inflexible rate designs and metering limitations. By contrast, if customers were able to respond to real time prices in a meaningful way, no (or at least fewer) customers would be involuntarily curtailed during high demand periods: customers unwilling to pay the real time price would voluntarily reduce their service, and there would thus remain sufficient capacity to serve those customers willing to pay the real time price.

- LSEs are not able to protect themselves against involuntary curtailment through advance contracting, i.e., forward contracts. If total market demand exceeds available supply, the grid operator must curtail some loads. However, the necessary equipment may not be in place to allow the grid operator (or the distribution utility) to target its curtailments on an individual LSE basis; instead, it would curtail all customers within a contiguous area, including both customers with forward contracts and those without them. So some buyers with forward supply contracts may be curtailed, while the supplies underlying those contracts go to serve other buyers without forward contracts.

The technology exists to correct both of these problems. Meters could be installed to permit customers to see and respond to real time prices, and switching devices are available to permit utilities to curtail individual customers. But this equipment is not widely in place for individual consumers (although it is in place for some large individual consumers as well as at the wholesale level for distribution company customers), and installing the equipment is not without costs. Thus, absent these technological fixes, customers are generally unable to insure against supply shortages on an individual basis, and must rely on system-wide protections.

Moreover, in a competitive market, no regulatory body may have the authority to order generation to be built, but the system operator (which today might be a RTO, an ISO or an individual utility) still needs sufficient capacity, including reserves, to operate. The market itself is expected to provide the signals to incent the construction of generation. However, while higher energy prices may incent the construction of new capacity to provide energy, the construction of capacity solely for reserve purposes (which may have limited use in supplying energy and thus receive limited income from energy sales) may sometimes be incented only through such extreme signals as intense price volatility, price spikes, and shortages; and even then, the long lead time between the appearance of such signals and the construction of new plant may mean that customers must tolerate price spikes and shortages for a period of years.[2]

III. What mechanisms are available to ensure adequate capacity reserves?[3]

A. Capacity obligations for energy and reserve capacity -- current ICAP mechanisms

The ICAP obligation as it now operates in the three Northeastern ISOs creates an obligation for capacity for both energy and reserves, and the LSE members of each ISO are penalized if they fail to meet both of those obligations. In theory, the ICAP payments received by generators are intended to incent the construction of new generation or to incent generators to keep existing plants in service rather than retiring them.

While the construction of generation can be based on the expected revenues from energy sales from that unit, units that are primarily held for reserve purposes would receive little or no energy revenues and thus would not be built unless they could expect to receive very high revenues from energy sales when they are run. Thus, if such plants received no revenue from ICAP payments, they would sell their energy only at very high prices, causing energy clearing prices to peak at a higher level than would be the case under an ICAP system. In this way, ICAP smooths out volatility in energy prices. Using ICAP to cover the carrying costs of such units would allow for their construction and thus achieve the desirable level of reserves without contributing to high price spikes.

1. Advantages

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[2]In addition, new projects that are built solely or largely on the basis of prices that only occur during price spikes may have difficulty obtaining project financing. It is one thing to point out to a potential lender that the prices for energy have gently, but reliably, trended upward. It is quite another to argue that a project is deserving of financing because of a price spike that may occur during a few hours or a few days no more than once or twice in a multi-year period.

[3]Because the actions the Commission may take to ensure sufficient reserve capacity are so varied and may involve so many different kinds of participants (ISOs, RTOs, LSEs), any questions related to the Commission's jurisdiction to take those steps must be resolved on a case-by-case basis, and this paper does not address the Commission's authority to take any of the actions discussed here.

The ICAP deficiency charge operates as a cap on the prices of ICAP in the bilateral market. During times of surplus, the bilateral market should clear at a price lower than the deficiency charge, and during periods of tight supply, the market would clear at a higher level but still not in excess of the deficiency charge. Thus during most periods, prices determined by market forces and not the deficiency charge would prevail in the bilateral market.

The Commission gains regulatory flexibility from the range of options available to modify the specifics of the ICAP obligation. The Commission may specify what characteristics the capacity must satisfy in terms of availability, price, and location, which will in turn affect the price that sellers will require to provide the capacity. On the one hand, the Commission could require only modest obligations, for example, that the capacity merely be available during a specified portion of the year, and without restrictions on the capacity's location. However, allowing the capacity to be unavailable during high demand periods, and to be located in areas limited by transmission constraints, would provide only modest benefits for avoiding supply shortages. Alternatively, requiring the capacity to have a higher availability during high demand periods, or requiring customers inside transmission-constrained load pockets to acquire capacity located inside the load pocket, would provide greater reliability benefits. The Commission could impose no limits on the price that the seller charges for energy supplied from the capacity, or require the seller to provide a call option – that is, a requirement to offer to sell its energy at a specified price. Imposing an energy price limit would reduce the severity of energy price spikes; it would also tend to increase the capacity price that the seller would require to sell the capacity.

To enforce the customer's obligation, customers would need to be subject to a penalty for being capacity deficient. As long as the capacity obligation exceeds the amount of capacity that customers would otherwise voluntarily acquire, the level of the penalty charge effectively caps the capacity price, since customers will not pay more for capacity than the penalty charge. (Of course, depending on the nature of the capacity obligation and the supply/demand balance, the competitive capacity price could be lower than the penalty charge – perhaps substantially so.) Thus, to the extent that sellers have market power in the capacity market, the deficiency charge effectively limits the ability to exercise market power.[4]

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[4] To limit market power, the deficiency charge should not exceed the highest price that a competitive market would need to elicit the amount of capacity underlying the aggregate capacity obligation. As explained below, that competitive price depends on the

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2. *Disadvantages*

- # The payment of ICAP is nonspecific to generators built specifically for reserve capacity -- all generators are paid ICAP even if they can achieve their desired return solely from energy sales. Of course these generators can make their ICAP available at little or no cost and at times the ICAP market has cleared at zero. However, there is no mechanism that requires that ICAP payments be adjusted by energy revenues.

- # In order to properly incent new generation construction through ICAP, there needs to be an ICAP system that is certain as to duration and amount. No generator will build units to come on line at some time in the future relying on ICAP revenues to finance those units, unless it knows that those ICAP revenues will be there. Recently, ISOs have been changing their ICAP systems, including payments, frequently, with possible negative effects on financing.[5]

- # The Commission must monitor the capacity market for evidence of possible market power, in particular prices that exceed competitive levels. In a competitive market, the market price would reflect the marginal cost of the most expensive generators needed to meet demand. The marginal cost of providing capacity depends on the nature of the capacity obligation. For example, if the capacity obligation requires the seller to sell energy at its marginal operating costs, a new entrant would require a capacity price that covered its full capital costs. But if the obligation allows the seller to sell energy at the applicable market price, a new entrant would require a lower capacity price – one that merely made up any difference between energy market revenue and its capital costs. If customers can meet the capacity obligation near the delivery date (so that new entrants could not meet the obligation), the competitive capacity price could exceed the annuitized

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[4](...continued)
nature of the capacity obligation. For example, if customers must meet the capacity obligation well in advance of the delivery date and generators must sell their energy at their marginal operating cost, the competitive price (and the deficiency charge) would not need to exceed the capital cost of a new entrant. For other types of capacity obligations, the competitive price and the penalty charge could be higher or lower.

[5]Perhaps a system which would lock in ICAP payments for new plants at the time of their inception would overcome this problem.

capital cost of a new entrant, depending on the details of the capacity obligation and whether there is a deficiency of capacity in the market.

Opportunity costs can also play a role in determining a competitive capacity price. For example, if the capacity obligation in one region caps the energy price that a generator can sell energy and if the energy price in a neighboring region is expected to be above this price cap, then the competitive capacity price would reflect the opportunity cost of foregoing energy sales in the higher-priced region. That opportunity cost could exceed the annuitized capital cost of a new entrant, at least for a short period of time.

Market power could be particularly problematic if the obligation must be met near the date of delivery and available capacity is near the aggregate obligation level. Under those conditions, existing generators whose capacity is needed for customers in the aggregate to meet their obligation can insist on high prices above their costs. The Commission could reduce the potential for market power by requiring the capacity obligation to be met well in advance of the delivery date rather than near the delivery date. Meeting the obligation in advance would increase the supply options available to customers; the obligation could be met not only by existing generators but also by new entrants who could construct capacity in time for delivery.

B. Capacity obligations for reserves only -- forward reserve contracts

In addition to incenting the construction of capacity for both energy and reserve purposes, another possibility would be to focus strictly on the need for capacity reserves. An alternative to the ICAP obligation could be a requirement to obtain generation which will provide reserve capacity at some time in the future. In simple terms, the design could be a call option on energy. The buyer of the options could specify the strike prices at which the energy would be sold if called upon. Sellers would offer various options available at different strike prices. Thus, the system operator could choose the level of reliability which they desired by how much each level cost. An alternative could be options that, if exercised, energy sold thereunder would receive the current market clearing price. The time period for these advance contracts would only be limited by the ability to forecast future requirements.

An individual LSE could contract for its own reserve requirements. However, in an era of retail competition, individual LSEs may not be able to forecast their future loads accurately. Therefore, an alternative could be for the system operator (whether ISO or RTO) to acquire reserve capacity based on what it considers necessary for the market as a whole, and bill individual LSEs for their reserve share. No participant would have to pay deficiency charges nor would one have to be determined. Acquiring capacity on a system basis, involving larger purchases, could also lead to more competitive contracts.

1. Advantages

- Generation owners could finance new construction on the basis of future contracts to supply reserves. The Commission could also require generators to credit any revenues from energy and ancillary services sales against the reserve payments to avoid overpayments.

2. Disadvantages

- This is a new and untried method, and could present problems as yet unknown. Further, if the system operator purchases capacity for the pool as a whole, it might not have a sufficient incentive to estimate accurately the amount of capacity needed, since it would not bear the cost of excessive capacity purchases. Also, having the system operator participate so directly in the energy market could have unintended and potentially anticompetitive consequences.

C. Use of demand side/conservation mechanisms

The Commission could integrate demand side management into the ICAP requirement. It could allow LSEs to meet a part of their ICAP obligations by identifying loads that have the capability to curtail usage when directed by the grid operator to maintain grid reliability. As an added feature, LSEs could be allowed to submit price-sensitive demand bids. The bids would indicate that these loads would be curtailed when the price exceeds a specified level, even when curtailment is solely for economic reasons. Integrating demand side management into the ICAP mechanism would bring more choices to the market. Customers could avoid excessive ICAP capacity prices sought by generators by offering to curtail their usage. In addition, introducing price sensitivity into the energy market would reduce market power and price volatility in that market, by reducing the need to dispatch high-priced generators to meet demand.

1. Advantages

- This mechanism would reduce market power and price volatility in the energy market and reduce ICAP capacity prices.

- Integrating demand side management into the ICAP mechanism would bring more choice to the market. Customers could avoid excessive ICAP capacity prices sought by generators by offering to curtail their usage. In addition, introducing price sensitivity into the energy market would reduce market power and price volatility in that market, by reducing the need to dispatch high-priced generators to meet demand.

2. Disadvantages

Relying on curtailments alone might be problematic, since it is not clear that all of the promised curtailments would, in fact, materialize when requested.

Installation of the equipment necessary for large-scale implementation of demand side management might require state regulatory approval.

Conclusion

The study team finds merit in exploring alternatives to ICAP, particularly systems such as the purchase of forward reserves, which would target efforts more directly to the provision of reserves for capacity, and might avoid the market power problems seen in ICAP programs. The study team also believes that demand side management has the potential for an expanded role in ensuring adequate capacity reserves, and that this possibility should also be explored.

Appendix

The Commission will shortly be considering the following cases which involve ICAP-related questions:

Maine Public Utilities Commission v. ISO-NE, EL00-99

Northeast Utilities Service Company v. ISO-NE, EL00-102-000

Alternate Power Source, Inc. v. ISO-NE, EL00-109-000

United Illuminating Company v. ISO-NE, EL00-100

Bangor Hydro-Electric Company v. ISO-NE, EL00-112

New Power Company v. PJM, EL01-105-000