United States of America

Federal Energy Regulatory Commission

Technical Conference on Capacity Market Design

Prepared Remarks of Commissioner Paul A. Centolella

Of the Public Utilities Commission of Ohio

Mr. Chairman and Members of the Commission, thank you for this opportunity to comment on current capacity market designs and alternative approaches to achieving long-term resource adequacy. My comments address the inherent limitations of current approaches, the importance of transitioning to market designs in which demand participation and market-based forward purchases increasingly replace RTO capacity requirements, the necessity of cooperation between FERC and State regulators in this process, and recommendations for specific reforms.

I. Current Capacity Market Designs

Current capacity market designs continue to reflect their historical antecedents: the installed capacity requirements of tight power pools and some regional reliability councils, standards such as a one in ten year loss of load expectation which are observed with little analysis of their economic consequences,[1] and the organization of wholesale markets prior to the development of significant demand response.[2] Based on an assumption of inelastic demand, capacity markets were a response to a so-called "missing money" problem that would occur if energy and ancillary service prices did not reach the level needed to support new investment.

The rationale for capacity markets is tied to the fact that most consumers still do not see time varying prices and to limited price responsive demand. As demand becomes price elastic – flattening load shapes, limiting price spikes, and moderating price volatility and related investment risk – the capacity payments required to achieve any given level of resource adequacy decline.[3]

RTO "capacity markets" are regulatory incentive mechanisms. The capacity product, which by itself provides the buyer no assurance of future prices, is a function of regulatory requirements. While the determination of LSE capacity requirements has become more complex with the inclusion of "demand curves" and locational deliverability areas, the product, minimum quantities, and timing of LSE forward purchases are set under RTO tariffs. Variable Resource Requirements are based on RTO estimates of the Cost of New Entry and the result of regulatory determinations, not elasticity in consumer demand. With all PJM subregions and the RTO as a whole failing the Three Pivotal Supplier Test, market power in

---

[1] For alternative views, see: Telson, Michael L. "The economics of alternative levels of reliability for electric power generation systems." *The Bell Journal of Economics 6, No. 2*, (1975): 679-694; and Keane, Dennis M., & Woo, Chi-Keung. "Using customer outage costs to plan generation reliability." *Energy*. *17, No. 9*, (1992): 823-827.

[2] It is well established that a large portion of the potential benefits of competitive power markets are associated with the development of demand response. P. Centolella and J. Parmelee, *The Structure of Competitive Power Markets,* Final Report for the U.S. Department of Energy (January 1997); FERC Staff Report, *Assessment of Demand Response & Advanced Metering*, Docket No. AD06-2-000, August 2006; and FERC Staff Report, *Assessment of Demand Response & Advanced Metering*, Docket No. AD06-2-000, September, 2007.

[3] Borlick, R. 2003. "Mandatory Reserve Margins Good Idea or Not?" *26th IAEE International Conference,* June 4-7, 2003.

PJM's RPM auctions has led to offers from all existing units being mitigated.[4] RPM auctions, in which LSEs are required to participate and existing generator offers are mitigated, are markets with few willing buyers and sellers at the market clearing price.

Capacity markets have proven to be expensive for consumers and, thus far, have not been shown to produce significant new generation. We should not simply assume that the path to resource adequacy is to increase the Cost of New Entry to funnel more dollars through capacity markets, without seeking answers to fundamental questions regarding their design and performance.

- Do year-by-year auction payments create price expectations comparable to those in a competitive market in which demand and supply respond dynamically to price?
- Given the sensitivity of capacity market prices to resource requirements and uncertainty regarding future RTO administration of these incentives, do capacity markets impede long-term contracting needed to finance new generation?
- Do capacity markets distort resource choices, increasing investment in low first cost combustion turbines over a more diverse resource portfolio?
- With most customer outages attributable to problems in the distribution system, would consumers be better served by investments in the development of a smart grid than by the marginal generation investments to meet RTO capacity requirements?
- Given the wide range in customer outage costs between and within customer classes,[5] what are the consequences of planning based on a single uniform resource adequacy requirement?
- What are the impacts on demand response, unit availability, and congestion and the resulting cost and reliability implications of diluting shortage price signals in energy and ancillary service markets?

These questions should give us pause regarding long-term reliance on capacity markets as the means to ensure resource adequacy. RTO capacity markets remain a substitute for efficient markets with robust demand and supply participation.

II. Market-Based Resource Adequacy

This Commission should facilitate a transition toward market-based solutions where states and utilities enable consumer demand response and provide for consumer choice regarding forward resource and contract positions, consistent with maintaining the operational reliability of the power grid.

There is broad agreement that increased demand participation would have a positive impact for consumers and on market performance.[6] As demand participation grows, the role of capacity markets in maintaining resource adequacy can and should be progressively reduced.

Over the last year, Ohio has laid a foundation for significant changes in the power sector.

Last Thursday, Ohio Governor Ted Strickland signed new electricity legislation.[7] Among other things, the new statute:

- Makes it State policy to encourage advanced metering and time-differentiated retail pricing;
- Authorizes incentive regulation for grid modernization;
- Directs the Public Utilities Commission to develop rules for revenue decoupling;
- Sets standards for demand reductions and energy efficiency improvements; and

[4] PJM, *2010/2011 RPM Base Residual Auction Results* (Feb. 1, 2008).
[5] P. Centolella, et al., *Estimates of Customer Outage Costs for the Midwest Independent System Operator* (April 2006).
[6] FERC Notice of Proposed Rulemaking: Wholesale Competition in Regions with Organized Electric Markets, Docket Nos. AD07-7-000 and RM07-19-000, February 21, 2008.
[7] Substitute Senate Bill 221.

- Requires utilities to file electric security plans ensuring the availability of cost-effective and reliable standard offer service. Such plans may include competitive procurements for new generation when resource planning demonstrates the need for new capacity.

The legislation adopts a hybrid approach allowing consumers to continue to shop for alternatives to standard offer service, while protecting consumers from abrupt and significant increases in prices.

The Ohio Commission has held a series of technical conferences exploring the deployment of an advanced metering infrastructure and time-differentiated retail pricing. Ohio utilities have proposed installation of advanced metering to as many as 150,000 customers this year, with three companies proposing to deploy advanced metering to all their customers no later than 2015. We expect such deployments to support two-part time-differentiated pricing, such as a critical peak rebates, in which consumers receive discounts for cutting consumption below baseline levels when wholesale prices are high, and two-part real-time prices, in which customers pay for incremental (or are credited for decremental) usage above (or below) baseline levels based on spot prices.

Utility applications addressing recovery of investments in advanced metering and implementation of time-differentiated pricing are expected to come before the Ohio Commission within the next few months.

We face significant challenges ensuring the availability of affordable and reliable service, in a time of falling reserve margins, rapidly increasing generation construction and fuel costs driven by the global demand for power, carbon constraints, aging infrastructure and the need in a digital economy to reduce the high cost of momentary outages and power quality problems. Neither states nor the FERC can meet these challenges acting alone.

As state regulators, we look at the power system as a whole and evaluate the investments in generation, transmission, distribution, and demand-side measures. We are keenly aware of the need for new resources. We hear the individual concerns of our utilities, of businesses deciding whether to invest in our states, and of families who too often must choose between paying an electric bill and meeting other essential needs. Issues related to retail rate design, metering, forward contract and resource portfolios, financial guarantees for new power plants, and most of the reliability problems impacting consumers (which typically are distribution related) are within the authority of the states. For this reason, Congress wisely reserved to the states standards related to resource adequacy, and this Commission, at least in some instances, has indicated a willingness to defer to states where state approaches to this issue are consistent with ensuring the operational reliability of the transmission system.

Assuming the case for advanced metering and time-differentiated pricing is made, the resulting advanced metering and rate designs will fundamentally change power markets. We would expect to see an elastic demand curve and consumers making choices regarding the extent to which they hedge price risks with forward contracts and manage their use in response to price changes. As the systems are implemented and experience gained, load serving entities increasingly will know the price points at which loads are programmed to curtail and be able to forecast precisely how and where load will change as a function of the visibility of wholesale prices in retail rate designs.

If our Commission is to approve the required investments, we need to be confident that Ohio utilities and consumers will be able to capture the full value of enabling price responsive demand. Changes may be needed to move from a focus on RTO demand response programs, which treat demand response as the resale of energy back into to the wholesale market, to economic dispatch based on a sloping demand curve reflecting the preferences of millions of individual consumers.

III. Recommendations for Capacity Market Design and Resource Adequacy

Allowing demand response to bid into capacity markets has been a positive development, with demand response comprising a significant percentage of the new resources offered into these markets. Further adjustments are needed to facilitate a transition to a more efficient, market-based approach to resource adequacy. The following additional steps are needed:

1. For purposes of determining an LSE's forecast demand requirement, the LSE should be permitted, consistent with state regulatory requirements, to supply a forecast demand curve in which expected demand varies as a function of peak hour prices. For LSEs that pursue this option, planning reserves should be calculated at the price point which produces the lowest total LSE resource requirement or such other point as may be specified by the LSE's state commission. The accuracy of an LSE's forecast curve should be evaluated in a manner consistent with the evaluation of a point forecast, taking into consideration both uncertainty about demand response and known set points at which loads will curtail. An LSE whose weather normalized loads remain to the left of its expected demand curve should not be considered deficient.
2. Demand which can be interrupted in a generation emergency should not be included in an LSE's forecast requirement and the LSE should not be required to carry a planning reserve margin with respect to these loads. This clarification appears to be consistent with the Commission's Order on MISO's Module E long-term resource adequacy requirements.[8]
3. With respect to generation that is interruptible in an emergency, states and utilities should be allowed to develop curtailment priority markets and integrate those markets with transmission operations to optimize system operations. Such markets would allow partial interruptions to occur on an efficient basis.
4. Demand bids should be allowed to set prices under the shortage pricing provisions in RTO tariffs.

Additionally, federal and state regulators need to consider that competition will not be limited to generation-on-generation competition. Meaningful competition increasingly will be between providers of central station generation on the one hand and demand response, energy efficiency, and distributed generation and storage on the other. Utilities that own, either directly or through affiliates, both generation and distribution are potentially in a position to impede the development of these competitive market forces. In the emerging environment, market based pricing of generation affiliated with distribution companies may create perverse incentives to retard new forms of competition and push the market towards shortage. State and federal regulators need to begin considering how to address the issue of utilities which have not effectively opened their distribution systems to demand response and distributed resources. One alternative may be to limit the ability of utilities that have not opened their systems to such competition, and their generation affiliates, to obtain market-based pricing in capacity markets and during high price periods.

[8] Midwest Independent System Operator, 122 FERC ¶61,283 (March26, 2008) at 96.