UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators.	:	**Docket No. AD13-7-000**

MECHANICS OF CURRENT CENTRALIZED CAPACITY MARKETS

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Public Utilities Commission of Ohio

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MECHANICS OF CURRENT CENTRALIZED CAPACITY MARKETS

Todd A. Snitchler, Chairman
Public Utilities Commission of Ohio

Good morning. My name is Todd Snitchler and I am the Chairman of the Public Utilities Commission of Ohio. Thank you for inviting me to explain the Ohio Commission's views of the centralized capacity markets.

DISCUSSION

1. How effective are the existing centralized capacity markets in assuring that resource adequacy needs are met at just and reasonable rates?

Ohio is a retail choice state for electric generation service. Generation service in Ohio is deregulated, and we have been monitoring the outcomes of PJM's reliability pricing model (RPM) auctions with great interest. To say the least, the auction results have lacked consistent outcomes from year to year. The results of our monitoring lead me to conclude that it is now time for FERC to initiate a proceeding to review the policies affecting RPM auctions. The Ohio Commission is becoming more and more concerned that the price of capacity for merchant generation is below economic levels as a result of FERC policies for other capacity products in the RPM auctions. I am today, therefore, respectfully requesting that FERC initiate comprehensive proceedings for each regional transmission operator (RTO) to: (1) review whether payments to demand response and energy efficiency

resources are reasonable, (2) examine whether additional safeguards should be established to ensure against financial arbitrage through the purchase of replacement capacity, (3) reevaluate whether the MOPR exemptions are unfairly eroding the price of capacity for merchant generators, (4) determine whether the seams rules should be amended, and (5) decide whether a long-term RPM market should be established.

2. What modifications, if any, would you recommend be made to capacity markets in general or to specific capacity market design elements?

The Ohio Commission has identified four distinct areas that merit attention. As markets have evolved to include Demand Response (DR), Energy Efficiency (EE) and other products, it is in our best interest for FERC to ensure that auction bidders are competing on a level playing field. It is also appropriate to view these comments in proper context. First, DR, EE and other products have a place in the energy marketplace and are helpful in mitigating costs at peak demand. Second, successful operation of a reliable energy grid must be built around long-term, stable, high-capacity resources and should not overly rely on peak-shaving tools to design and operate the grid. Finally, long-term successful operation of the grid

requires that the system be designed to deliver power to those who seek to use it, rather than encourage a reduction in productivity simply to achieve a larger policy goal.

a. Demand Response

In comments within the past 12 months, the Ohio Commission has requested in two separate proceedings that FERC initiate a comprehensive rulemaking investigation of demand response in the PJM region. The Ohio Commission maintains that the unlimited Annual DR product has an important and valuable role in ensuring reliability via its participation in the RPM BRA as an element in the capacity resource mix, as does generation. The Ohio Commission is concerned, however, that other DR products are contributing to DR oversaturation to the overall detriment of reliability because these resources have fewer obligations to deliver, compared with actual generation and the unlimited Annual DR product.

I am today, therefore, renewing the Ohio Commission's previous requests that FERC initiate a rulemaking investigation to review whether it should significantly reduce or begin to phase out all reduced DR capacity resources (i.e., the Limited and Extended Summer DR products). The Ohio Commission maintains that FERC should review whether all capacity products participating in the BRA should ultimately be subject to the same availability requirements as generation, in

that they must be physically available and respond on par with generation. FERC's investigation also should work to ensure that penalties for nonperformance are uniform for both DR and generation and such penalties are sufficiently stringent to ensure that all capacity resources meet their respective obligations for delivery.

Until the phase-out of the Limited and Extended Summer DR capacity products is effectuated, I recommended that FERC move to significantly reduce the level of compensation for these products. As noted earlier, these DR products, because of the fewer obligations placed on them, are not comparable with physical generation capacity resources. Specifically, until FERC can phase out these lesser DR products, FERC should move in the short term to reduce the annual compensation to DR capacity resources available on a limited basis. For example, because the Extended Summer product is only required to be made available at 10-hour increments for an unlimited number of interruptions during a six-month period, the full capacity clearing price should be adjusted downward by at least 50 percent to take into consideration that the product is only available as a capacity resource for a limited number of hours. FERC should also ensure that the Extended Summer DR product is only eligible to receive compensation for the six-month period that the product is made available for delivery.

Because the Limited DR capacity product is only required each delivery year to be made available ten times for up to a six hour-period over a four-month period, the price for this capacity product should be materially reduced. Even taking into consideration the fact that the Limited DR product will be called to deliver only at peak usage times, I believe a 70 percent discount to the full RPM capacity price should be considered. Consistent with my recommendation concerning compensation for the Extended Summer product, I maintain that compensation for Limited DR should only be made during the four-month period it is required to deliver as a capacity resource. Finally, once the reduced DR capacity products are eliminated, FERC should move to ensure that the Annual DR product is made available on an unlimited basis beyond its 10-hour performance requirement.

As discussed in more detail later concerning replacement capacity, FERC should: (1) limit the proliferation of DR buy-back financial trades in the RPM; (2) establish credit requirements for DR participants that are adequate to cover commitments in the event of a default; and (3) FERC should require DR providers to demonstrate that DR quantities offered and cleared in the RPM auctions are physically available and actually deliverable to the LDA to which it has offered or committed.

b. Energy Efficiency

Similar to demand response, payments for energy efficiency also deserve scrutiny. FERC should seize this opportunity to investigate whether capacity payments to energy efficiency should be adjusted to ensure more economic payments for physical generation resources. After all, the cost saving associated with investing in energy efficiency should be sufficient monetary incentive to secure such new technologies. Offering a secondary source of compensation has the potential to distort market prices and impact long-term system reliability. Taking into consideration that energy efficiency is not comparable to physical generation that produces electrons I believe that FERC should seek to reduce EE's RPM compensation to a reduced percentage of the BRA's clearing price.

c. Replacement Capacity

Concerning replacement capacity, I recommend that FERC generically investigate this issue and whether it is being used more frequently as a financial tool to generate additional cash flows through financial arbitrage, rather than to provide physical resources intended to promote reliability. That is, FERC should move to ensure that those offering into the RPM auctions actually intend to deliver the physical dispatchable capacity product that is offered and cleared in the RPM administrative process. The capacity market has been premised on maintaining

reliability by procuring physical capacity products. Consequently, I believe that FERC should consider placing a 10 percent cap on the purchase of replacement capacity for the various capacity products. FERC should also establish penalties for the purchase of replacement capacity for the purpose of meeting RPM commitments (i.e., replacement capacity purchases in excess of 10 percent). Finally, to take into consideration the potential for a legitimate anomalous event, FERC should adopt rules establishing a waiver process so RPM participants can demonstrate that any excessive purchase of replacement capacity is a unique one-off situation resulting from an unexpected exogenous occurrence, such as a forced generation outage resulting from an act of nature. For those market participants who routinely rely on replacement capacity in excess of 10 percent, FERC should, in the very near term, determine whether such behavior warrants the imposition of more stringent credit requirements in the case of default.

d. Minimum Offer Price Rule

I am increasingly concerned about the application of the minimum offer price rule (MOPR) and its long-term consequences on merchant generation in PJM. Specifically, under PJM's recently revised MOPR, vertically integrated utilities and municipal-owned utilities receive exemptions from MOPR while merchant and state-sponsored generation must qualify for the more onerous competi-

tive exemption test or unit-specific exemption from MOPR. As the Ohio Commission previously commented to FERC, it is inherently contradictory to allow state-subsidized generation to bid into a competitive market. I submit, however, that there is no difference between generation receiving state subsidies and vertically integrated utilities which were built with ratepayer support. The existence of any subsidies serves to erode the market while failing to send the appropriate price signals for the construction of new, unsubsidized, merchant generation. At a minimum, I believe all capacity providers should be subject to the same rules to ensure that merchant generation offers are on par with all other generation offers in RPM.

Under the current MOPR exemptions, Ohio's capacity payments are potentially subsidizing new vertically integrated generation. This is essentially the situation that FERC was attempting to avoid by approving the MOPR. For example, the results of the last base residual auction highlight that RPM continues to provide, through imports, a high level of subsidy to vertically integrated and non-physical participants, while failing to provide for a significant increase in new generation within PJM's borders. Specifically, the 2016/2017 Base Residual Auction results reflect a significant increase in capacity imports. However, there was only 116.60 MW of new generation (including existing generation uprates) as compared

to the previous auction year, which saw a record for new generation.[1] If existing generation uprates are removed, then the new generation is actually less than the amount that cleared in the previous auction. In light of the significant number of coal plant retirements, this represents a low and potentially unacceptable amount of new generation, with the potential to impact system reliability to such an extent that transmission solutions will not be sufficient to correct the deficiency.

I question whether the RPM is failing to send the proper economic price signals to incent merchant generators to build within PJM. Instead of parsing out participants as MOPR currently operates, FERC should focus on ensuring that all participants in a centralized capacity market are subject to the same rules in order for that market to function appropriately. Consequently, I submit that discriminatory treatment of similarly situated facilities should not be allowed. That is, PJM's MOPR currently provides an automatic exemption to vertically-integrated and most municipal-owned generation; while requiring merchant generators to seek an essentially open-ended waiver under different requirements. To the extent that some vertically-integrated participants are unwilling or are unable due to membership rules to be subject to the same MOPR rules as merchant generators, FERC

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[1] See PJM's 2016/2017 RPM Base Residual Auction Results: http://www.pjm.com/sitecore%20modules/web/~/media/committees-groups/task-forces/cstf/20130626/20130626-item-03-2016-2017-base-residual-auction-report.ashx.

should consider if such entities, subject to the varying manners in which different organizations operate, should function as Fixed Resource Requirement (FRR) companies outside of the RPM market.

3. Centralized capacity market design elements necessarily interact with each other and with the energy and ancillary services markets. Are there problems created by this interaction that should be addressed to improve the functioning of centralized capacity markets or energy markets?

The Ohio Commission is unaware of problems in the interaction between the centralized capacity market and energy markets.

4. Regional capacity markets also interact with each other. What are the implications of regional differences in capacity market designs?

It is inherent that regional capacity markets have differences; this is a function of how each regional market developed over time and FERC's approval of separate market designs proposed by each region. There are very limited ways to rationally reconcile the current regional differences between capacity markets; one is to create a single RTO market. The Ohio Commission avers that FERC should not take such an action. Moreover, there is value in allowing each region to have its own capacity market based on each region's individual geography, generation, fuel and natural resources, load and other characteristics.

The seam between two RTOs, especially those with separate market designs, does create issues for capacity market participants. For example, 7,493.7 MW of capacity imports offered into PJM's 2016/2017 Base Residual Auction represents an increase of 90.4 percent, or 3,558.4 MW, over the imports offered into the 2015/2016 auction. All but 11 MW of the 7,482.7 MW of offered imports cleared the auction and nearly two thirds of them, or 4,723.1 MW, came from MISO. Because MISO is predominately served by vertically integrated utilities in a developing centralized capacity market, PJM's more mature capacity market with higher prices and longer bidding horizons is attractive to imports. The result is that PJM's RPM is increasingly providing funding to participants that fail to provide "iron in the ground" within PJM while further eroding the PJM capacity price. This market behavior reduces the value of membership in PJM and makes participation in the annual auction uncertain and has detrimental impacts on PJM members and ultimately energy consumers. As stated previously, I believe that subsidized generation offers, such as those submitted by MISO's vertically integrated utilities, are detrimental to a fully competitive centralized capacity market design and should be further evaluated by FERC. Furthermore, with only 64 percent of the imports having confirmed firm transmission service at the time of the auction, it is possible that some of the imports may prove to be not only uneconomic, but undeliverable as well. This potential for a serious reliability issue is a cause for caution and con-

cern. Therefore, I recommend that FERC require all external resources to have firm transmission service approved by PJM prior to submitting offers into PJM's RPM.

With the rising level of imports from MISO to PJM, I am concerned whether there is a capacity deliverability issue between MISO and PJM. Thus, I support the joint comments filed by OPSI and OMS in FERC Docket AD-16 for the FERC Technical Conference on Capacity Deliverability held on June 20, 2013. Specifically, the OPSI/OMS comments call for a more in-depth analysis and initial fact-finding on the following critical issues: (1) the possibility and significance of any cost shifts between the two RTOs; (2) the reliability impact of any proposed revised deliverability schemes; (3) whether further work on capacity deliverability is cost effective; (4) the overall additional incremental joint deliverability benefit over that currently occurring; (5) whether any proposals can be cost effectively and realistically implemented, and (6) the long-term rate impact on each RTO's retail customers. It is important to conduct an accurate fact finding that provides RTOs and all stakeholders with the requisite information to advance vital coordination, while still allowing RTOs to maintain their unique characteristics.

5. What is the impact on centralized capacity markets of transmission system upgrades and expansions? Can transmission planning be more effectively integrated with or accounted for in the design elements of centralized capacity markets?

In Ohio, the capacity markets have spurred substantial investments in transmission but at the expense of new generation to replace retiring coal plants. Many generators see price volatility and too much risk in the one-year capacity market to commit to new generation projects. In contrast, transmission expansion offers a guaranteed rate of return. Because the RPM lacks financial certainty for generation from year to year, it is apparent that companies are relying more on transmission upgrades to relieve congestion and constraints. That was shown in the 2015/2016 RPM in the constrained ATSI zone when the clearing price exceeded the (MOPR) rate. For example, utilities are pursuing transmission expansion to resolve the constraints in the ATSI zone, as opposed to building new generation facilities in that LDA. Given that companies are almost exclusively pursuing transmission solutions, I believe that FERC should determine whether a long-term market for new generation capacity resources is warranted. Specifically, I recommend that FERC investigate whether the three-year-out, one-year-ahead market for capacity should be extended beyond the one-year time frame to three, five, or even seven years. FERC should also determine whether a longer RPM timeframe should apply to only new generation resources, to both new and existing

facilities, or whether new, individual long-term capacity markets should be established separately for existing and new generation capacity resources to ensure long-term system reliability. The need to monitor both generation and transmission solutions requires greater cooperation between FERC and state regulators to ensure a proper balance is struck in ensuring system reliability.

The Ohio Commission maintains that additional time for guaranteed longer term funding will allow for more certainty in the RPM, will reduce risk, will correspondingly reduce the cost of capital, and will incent the construction of more new generation resources.

CONCLUSION

I believe FERC should examine four distinct areas of the capacity market: (1) demand response, (2) energy efficiency, (3) replacement capacity, and the (4) minimum offer price rule. In regards to demand response, I request that FERC review whether it should significantly reduce or begin to phase out all reduced DR capacity resources. Similarly, I believe FERC should investigate whether capacity payments to energy efficiency should be adjusted to ensure more economic payments for physical generation resources. Concerning replacement capacity, FERC should move to ensure that those offering into the RPM auctions actually intend to deliver the physical dispatchable capacity product that is offered and cleared in the RPM administrative process. In regards to MOPR, I believe that FERC should

make every effort to ensure that all capacity providers are subject to the same rules.

In addition, FERC should initiate a comprehensive proceeding to determine whether seams rules should be amended. This proceeding should be an in-depth analysis and initial fact-finding that provides RTOs and all stakeholders with the requisite information to advance vital coordination, while still allowing RTOs to maintain their unique characteristics.

Finally, FERC should determine whether a long-term market for new generation capacity resources is warranted. Specifically, I recommend that FERC investigate whether the three- or five year-out, one-year-ahead market for capacity should be extended beyond the one-year time frame.

/s/ Todd A. Snitchler

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