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

WRITTEN STATEMENT OF SUSAN N. KELLY ON BEHALF OF
THE AMERICAN PUBLIC POWER ASSOCIATION

The American Public Power Association ("APPA") first wishes to thank the Commission for holding this technical conference to discuss the centrally-administered capacity procurement mechanisms operated by ISO New England Inc. ("ISO-NE"), the New York Independent System Operator, Inc. ("NYISO") and the PJM Interconnection, L.L.C. ("PJM") (together, "Eastern RTOs"). By holding this publicly noticed conference, the Commission and the participants now have a forum in which they can have a long-needed policy level conversation about whether these mechanisms are meeting the needs of the Eastern RTOs, market participants, and electric consumers, and how they might be revamped and improved.

APPA also wants to thank the Commission for granting its request to speak at this Technical Conference. As a trade association with affected members in all three Eastern RTOs, and an active litigant in a number of the administrative dockets listed in the Commission's August 23 Supplemental Notice for all three RTOs, APPA has a unique vantage point on the questions raised for Panel Four ("Considerations for the Future"). APPA very much appreciates the opportunity to share its perspective.

1. What are the main challenges facing centralized capacity markets today or that can be anticipated going forward? Are the current centralized capacity market designs able to effectively manage those challenges? If not, what change in current design elements should be pursued going forward?

The main challenge facing RTO-administered centralized capacity mechanisms today is that they have not been able to attain a mature, or even stable, state. To the contrary, as the large number of pending dockets listed in the August 23 Supplemental Notice (at 2-3) illustrate, these mechanisms have proven to be a veritable fire hose of market rule revisions, contested proceedings, contested settlements and a number of court proceedings. APPA believes that this is because the basic capacity procurement construct is flawed, and has been since inception. The basic construct is not a "market" in any meaningful sense of the word. It is centralized procurement based on a heavily administered pricing structure, whether an explicit "demand curve" or a price floor embellished with increasingly complicated mechanisms intended to signify "locational value."

As APPA told the Commission in 2006 with regard to PJM's proposed Reliability Pricing Model ("RPM"):

> Since its formation as an Independent System Operator and later as an RTO, PJM has been in the forefront of industry experimentation with pricing regimes intended to elicit investment in new generation and transmission facilities through "market" mechanisms. . . . Recent history demonstrates that PJM's reliance on "price signals" as a vehicle for eliciting desired investments has not in practice necessarily served consumers well. And the RPM proposal is in fact a partial departure from PJM's past efforts to rely on market forces. Notwithstanding certain auction components of the proposal, PJM would determine capacity prices under RPM in part using administratively established demand curves. (This perceived need to return at least in part to a form of regulatory construct itself raises important questions about how well PJM's underlying market is working, and whether other forms of regulation would in fact do a better job of assuring that the needed generation capacity in fact is available when and where needed.) But RPM, like PJM's prior experiments, is based on the same underlying assumption: higher payments to generators can be counted on to bring forth the right investments in the right places at the right times. In APPA's view, there is

> no reason to expect that RPM will yield better results than any of PJM's prior efforts to elicit specific investment behavior through pricing schemes. But, like its predecessors, it is likely to produce increased profits for generators, new risks and burdens for [Load-Serving Entities ("LSEs")], and higher costs for electric consumers.[[1]]

What APPA lacked the experience to appreciate in 2006, however, is that centrally-administered capacity constructs such as PJM's RPM would not only fail to work well for electric consumers, they eventually would not work all that well even for incumbent generators. The impact of low natural gas prices, demand destruction due to the recession, and increased demand response ("DR") and energy efficiency ("EE") on recent auction prices has been substantial—even incumbent merchant generators with depreciated base-load generation (such as nuclear, coal or oil-fired steam turbine units) are feeling the impact.[2]

The electric utility industry, however, remains a capital intensive one. New wholesale electric generation capacity of almost every sort—coal-fired (although it is doubtful whether there will be much new coal-fired capacity, given current and promised environmental regulations), natural-gas fired, on-shore and off-shore wind, utility scale solar, small scale nuclear, etc.—requires some type of cost recovery over a period of years to support financing and construction. Even DR and EE measures require some level of capital investment and concomitant cost recovery, although over a shorter time horizon. Yet the current RTO-

---

[1] *PJM Interconnection, L.L.C.*, Docket Nos. ER05-1410-000 and EL05-148-000, Post-Technical Conference Comments of the American Public Power Association, filed March 2, 2006 at 4-5. APPA's fears were well founded. As detailed in APPA's briefing paper, "Money for Nothing in the Power Supply Business" (March 2012), available at http://www.publicpower.org/files/PDFs/MoneyForNothingMarch2012IB.pdf, after the RPM was implemented in 2007, it cost customers in PJM's service territory approximately $50 billion through the end of 2011, while only about 7,000 MW of new capacity was built in the region during that same timeframe (the total installed capacity of PJM then being nearly 180,000 MW). More than 93 percent of the revenue went to existing generators.

[2] *See, e.g.*, "PJM Capacity Prices: Light Dims at the End of the Tunnel," Fitch Ratings, August 20, 2013. These problems point to more than capacity construct design deficiencies—they highlight the interconnections among the various RTO-run markets and the need to evaluate RTO market performance in a more holistic manner. For example, deficiencies in the performance of energy or ancillary services markets can trigger increases in the requirements that must be obtained through capacity constructs.

administered capacity constructs are generally shorter-term in nature, and are subject to the short-term economics existing at each auction interval (*e.g.*, low natural gas prices) as well as arbitrarily ordained "locational" constructs that create additional price volatility. Hence, they are not well-suited to support longer-term investments. (Ironically, the time horizons of some current RTO capacity constructs can also present problems for DR providers, which have problems lining up customer commitments three years in advance of the relevant auction year.[3])

The "classic" way to finance capital intensive investments is through long-term bilateral contracts that support financing by providing assured cost recovery.[4] But such contracts have now been labeled "out-of-market subsidies" and have become grounds for "mitigating" the bids associated with such resources upward under applicable Minimum Offer Price Rules ("MOPRs").[5] Such bid mitigation exposes the bidder to potential double cost exposure, making

3 August 23 Staff Report at 13. APPA members in New England, for example, report that some DR providers have exited the market due to the inability to acquire customers and/or comply with the ISO's requirements. As a result, the level of DR resources outside of Maine has been reduced to approximately 200 MW.

4 In September 2012, APPA, the National Rural Electric Cooperative Association, and the New York Association of Public Power jointly released a study of the NYISO capacity market. The study found that there are numerous drivers of the construction of new generation other than the NYISO capacity market, including utility obligations to serve, reliability standards, renewable portfolio requirements and environmental regulations. Specifically, 77 percent of the new generation planned through 2016 is being constructed under long-term bilateral contracts or utility ownership, and has not been financed by volatile market revenues. The study, entitled "New York State Capacity Market Review," and authored by Christensen Associates Energy Consulting LLC, is available on APPA's website at: http://www.publicpower.org/files/PDFs/CAEnergy_NY%20Capacity%20Market%20Study_120919_Final.pdf.

5 *See, e.g., Astoria Generating Co., L.P. and TC Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL11-50-000, Order on Complaint, 140 FERC ¶ 61,189 at P 135 (2012), *on rehearing* ("Here, we agree with Complainants' assertion that the power purchase agreement itself, which is an out-of-market payment available only to Astoria II, will lower the project's risk, enabling it to attract debt and equity capital investors on more favorable terms inconsistent with a competitive offer. We further agree that the contracting process that awarded the power purchase agreement to Astoria II was discriminatory – because the process was limited to new resources – and thus, the resulting lower financing costs do not reflect competitive market processes. Because the contracting process was discriminatory, the lower financing costs associated with the power purchase agreement fall into the category of 'irregular or anomalous' cost advantages that are 'not in the ordinary course of business;' so, consistent with *PJM*, we find that NYISO should use the proxy cost of capital.").

it much more difficult to finance such resources in the first place. As a result, RTO-administered centralized capacity constructs have over time generally proved better at funneling revenues to existing resources (some of which are of questionable value on public policy grounds, given their age and operating efficiency) and to demand-side resources than supporting new, more efficient generation. And now, even revenues to existing generation resources are less than their owners would like.[6]

APPA has two primary recommendations as to how to change RTO-administered centralized capacity constructs going forward. The first recommendation relates to the ability of public power LSEs to self-supply their own needs, while the second is more global in nature.

Restoration of Public Power LSEs' Self-Supply Rights.

APPA's first recommendation is admittedly directly aimed at APPA's members in the Eastern RTOs. It stems directly from the need for public power systems to continue serving their retail electric customers under their not-for-profit, cost-based business model.[7] As the Commission knows, most of the states in the Eastern RTOs' respective footprints implemented retail access for their investor-owned utilities ("IOUs"). As a result, the IOUs no longer have

6 For example, the just-announced closure of the Vermont Yankee nuclear plant was blamed by its owner/operator, Entergy Corporation, on the inability to collect adequate revenues from the ISO-NE market. "Vermont Nuclear Power Plant to Close in 2014: Energy Prices Spell the End," August 28, 2013 Boston Globe, http://www.bostonglobe.com/lifestyle/health-wellness/2013/08/27/vermont-yankee-nuclear-plant-close/JTX64k3YjBz7yrJnI40bVM/story.html. Whatever one's views on the desirability or feasibility of nuclear power, the closure of the plant is bound to raise concerns for a region already very dependent on natural gas-fired generation. According to the Globe, "the plant's shutdown raises other concerns, increasing the region's dependence on natural gas, said Ellen Foley, spokeswoman for the grid operator, ISO New England. 'We have identified that as a risk.' Natural gas now accounts for more than half the region's net electricity generation, while nuclear plants produced a bit more than a quarter of the power last year."

7 There are more than 2,000 community-owned public power systems in 49 states, serving more than 47 million people, or about 14 percent of the nation's electricity consumers. Hence, Commission endorsement of RTO market constructs and rules that are inimical to these systems' fundamental business model is of grave concern to APPA.

long-term obligations to supply electric power to their customers, aside from default service, which they usually procure through shorter-term auctions. Public power systems, on the other hand, still provide bundled retail electric service to their retail customers. They still have the obligation to provide electric power at the lowest reasonable cost consistent with reliable service and good environmental stewardship, and they take this obligation seriously.[8] They are willing and able to make substantial long-term generation infrastructure investments to support new resources.[9]

At the time RTO-administered mandatory centralized capacity constructs were being considered for ISO-NE and PJM, many of APPA's members in these two regions participating in the discussions had severe reservations regarding the economics of these constructs as applied to public power systems, and the long-term viability of these mechanisms. They therefore participated actively in the development of these mandatory mechanisms, and negotiated specific "self-supply" provisions designed to dovetail with each set of RTO market rules.[10] These

8 The Commission's Staff in its August 23, 2013 Staff Report on Centralized Capacity Market Design Elements ("August 23 Staff Report") mentions (at 1) the existence of the "traditional utility regulation" model, but notes that "[t]he capacity markets of the eastern RTOs/ISOs were implemented against this backdrop of restructuring in the retail electric markets of each region." Not only do public power LSEs in all three Eastern RTOs continue to provide service under the "traditional" model, they do so on a *not-for-profit* basis, as they are owned by the consumers they serve through the medium of state or local government.

9 A case in point: American Municipal Power, Inc. ("AMP"), a multistate joint action agency serving public power distribution systems in PJM, is in the process of constructing four run-of-the-river hydro projects on the Ohio River (Cannelton, Smithland, Meldahl and Willow Island) totaling 300 MW of projected power, representing the largest new hydro generation deployment in the United States at this time. These four projects represent approximately $1.6 billion in capital investment, approximately 1,600 construction jobs and up to 35 permanent jobs, and will provide a long-term reliable source of no-carbon electric power once complete. No LSE could hope to finance or complete such units based solely on the revenues available from an Eastern-style capacity market. Rather, it is the long-term financial commitments of AMP's member communities to purchase the power from these projects that have made this investment possible.

10 In PJM, self-supplying LSEs negotiated a "guaranteed clearing" provision that would permit their new self-supplied generation resources to clear the RTO-run capacity auctions, without fear of having to pay twice for their capacity. In ISO-NE, they negotiated provisions that would allow LSEs to use self-supplied capacity resources to meet their capacity obligations, without paying capacity market costs or receiving

provisions were ultimately approved by the Commission as just and reasonable.[11] However, in 2011, the Commission effectively stripped those previously negotiated self-supply provisions out from the relevant PJM and ISO-NE market rules based on unsubstantiated arguments that these provisions allowed LSEs to exercise unfettered "buyer-side market power."[12] The Commission then interpreted the rules of the NYISO's New York City ("NYC") capacity market zone in such a manner as to create the same dilemma for public power entities with generation resources in that zone.[13] APPA's members have been attempting ever since to regain through both litigation and settlement the protections afforded by their specifically bargained-for, Commission-approved provisions to self-supply their own loads with their own resources using their own economics.[14] APPA has participated in litigation in all three RTOs to that same end.

APPA's membership passed a resolution regarding RTO-administered capacity markets at APPA's 2013 National Conference held in June in Nashville, Tennessee which was sponsored

---

capacity market revenues. The effect in both cases was effectively to insulate self-supplying LSEs by giving them a hedge against price volatility in these markets.

[11] *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 (2006), *rehearing denied*, 117 FERC ¶ 61,331 (2006); *Devon Power LLC*, 115 FERC ¶ 61,340 (2006).

[12] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022 (2011), *on rehearing*, 137 FERC ¶ 61,145 (2011), *appeals pending, New Jersey Board of Public Utilities, et al. v. FERC*, 3rd Cir. Nos. 11-4245, *et al.*; *ISO New England*, 135 FERC ¶ 61,029 (2011), *on rehearing*, 138 FERC ¶ 61,027 (2012), *appeals pending, New England Power Generators Association, Inc., et al. v. FERC*, D.C. Cir. Nos. 12-1060, *et al*.

[13] *See* n. 5, *supra*.

[14] While the August 23 Staff Report (at 2, 8-9, 11, 27-28) discusses LSEs' procurement of capacity through self-supply, the reality is that the current market rules (stripped of the specific self-supply rights that public power LSEs originally negotiated) inject substantial financial uncertainty into the qualification of new (and in some cases, existing) resources in RTO auctions, effectively eliminating this option for public power LSEs. *See, e.g., PJM Interconnection, L.L.C.*, Docket No. ER13-535-000. As not-for-profit entities with long-term service obligations to retail customers, public power systems cannot, and should not be required to, build generation "on spec" or invest in supply resources that might not clear the relevant RTO capacity auctions. The Commission has previously stated that an appropriate balance should be struck between "the need to protect against uneconomic entry while also mitigating parties' concerns about having to pay twice for capacity as a result of failing to clear in RPM." *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145 at P 209 (2011).

by APPA members in all three of the Eastern RTOs (copy attached to this statement). That resolution states in part:

> FERC's increased enthusiasm for mandatory capacity markets and inflexible MOPRs restricts the ability of public power systems to self-supply their capacity obligations and threaten the core of the public power business model: namely, the ability to finance needed power supply, demand response, or energy efficiency resources through long-term contracting or ownership at favorable rates and terms, the benefits of which accrue directly to their customers.

APPA's membership therefore instructed APPA staff in this resolution to take the following policy positions:

> **NOW, THEREFORE, BE IT RESOLVED:** That APPA opposes all RTO tariff provisions that impede the ability of public power systems to obtain through self-supply sufficient power supply and demand-side resources to serve their retail loads at least cost, taking into account short-term and long-term portfolio needs, resource diversification, and environmental considerations; and
>
> **BE IT FURTHER RESOLVED:** That APPA urges FERC to review all capacity market buyer-side mitigation provisions like the MOPR [in] a generic, rulemaking proceeding and to revise those rules that are found to interfere with the ability of public power systems to procure through self-supply generation and demand-side resources needed to serve their load; and
>
> **BE IT FURTHER RESOLVED:** That APPA opposes the creation of any new capacity markets or new RTOs in any region of the country.

Hence, APPA's first suggested market design element change to the Commission is to restore the ability of public power systems in the three Eastern RTOs to self-supply their own loads with their own resources. There are ample grounds for so doing, given that public power systems still retain the long-term obligation to serve their retail customers, unlike the great majority of the LSEs in the three Eastern RTOs. Public power systems (as well as other LSEs with similar business models, such as rural electric cooperatives) have both the desire and the ability to support new generation investment if that is the most cost-effective long-term option for meeting locally-determined requirements of reliability, cost, portfolio diversity and environmental stewardship. The Commission should just let them do it.

If the Commission cannot bring itself to restore the bargains that self-supplying LSEs struck when they agreed by settlement to the institution of mandatory capacity constructs for their RTOs, it can at least require an RTO to demonstrate a showing that a self-supplying LSE specifically intends to exercise "buyer-side market power" prior to mitigating such an LSE's capacity bid. When it comes to the exercise of market power, buyers and sellers are not similarly situated. Self-supplying LSEs could have many sound reasons for developing a new supply-side resource, including the desire to: (1) provide an economic source of electricity for their customers (over a time horizon determined *by the LSE*, not the RTO's capacity construct); (2) diversify their power supply portfolios to include lower/no carbon resources, new and more efficient resources, dual-fuel capable resources, faster-ramping resources to support renewables, or simply a greater diversity of fuels and geographic sources; (3) hedge against shorter-term volatile RTO market prices through the use of a long-term physical asset; (4) support local economic development through the use of "close to home" generation, be it utility-scale or distributed; and (5) provide for local reliability needs.

Such resources could make eminent good sense to the self-supplying LSE developing them, but they might be considered "uneconomic" to an RTO market monitor using the short time horizon and narrow "Cost of New Entry" ("CONE")-based offer floors described in the August 23 Staff Report at 27-28 (which treat each MW as interchangeable with every other MW in that delivery area). Use of mechanistic offer floor mechanisms to derail such projects and the local public policy considerations behind them is contrary to sound public policy, and constitutes the worst kind of federal intrusion into state and local resource planning.

APPA therefore suggests that the Commission look in this instance for guidance to Section 222 of the Federal Power Act[15] and the Commission's Anti-Manipulation Rule,[16] which require a showing of intent (*i.e., scienter*). Such a case-specific showing of intent by a particular self-supplying LSE to effect a scheme to manipulate the capacity markets to benefit that LSE should be a prerequisite finding before implementing buyer-side mitigation.[17]

The imposition of prior pricing constraints to prevent buyers from artificially depressing pricing without any evidence of either anticompetitive intent or the ability to exercise monopsony power is also antithetical to the antitrust policies that the Commission is obligated to consider in carrying out its duties.[18] A mistaken finding that monopsony power is or could be

---

15 16 U.S.C. § 824v.

16 *Prohibition of Energy Market Manipulation*, Order No. 670, 71 Fed. Reg. 4244 (Jan. 26, 2006).

17 For purposes of establishing a violation of the Anti-Manipulation Rule, *scienter* requires knowing, intentional, or reckless misconduct, as opposed to mere negligence. *Id.* at PP 52-53 & n.107. As the Commission has previously acknowledged, a seller would have no incentive to depress prices unless it was a net buyer. *See, e.g., PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022 at P 86 (2011) ("only entities purchasing substantially more capacity than they sell are subject to the MOPR because only entities in this position would appear to have the desire to artificially lower capacity prices"). Moreover, PJM recently conducted a study to assess the potential benefit to an LSE of an uneconomic new entry strategy by analyzing the impact on the RPM clearing prices from the Base Residual Auction conducted in May 2012 for the 2015-2016 Delivery Year. For this purpose, PJM leveraged sensitivity scenario analyses that PJM already had performed for the benefit of stakeholders and included simulations of uneconomic entry, offered at $0, in the PJM Region and various Locational Delivery Areas ("LDAs"). The results, which were based on actual auction simulations and are publicly posted, demonstrate that, for the net short thresholds proposed by PJM for self-supplying customers in Docket No. ER13-535-000, zero-priced new entry by a typical combustion turbine or combined cycle unit would not be a profitable strategy for an LSE at or below any of the relevant net-short thresholds in the RTO or any relevant LDA and that the actual supply curves in the RPM Base Residual Auctions have become notably more elastic in recent years. This would significantly dampen the price reductions any single self-supplying LSE could realistically hope to achieve with an uneconomic new entry offer, reinforcing the conclusion that net short levels at or below the thresholds likely will not provide such an LSE enough potential benefit to make uneconomic new entry profitable. *See, PJM Interconnection, L.L.C.*, Docket No. ER13-535-000, Affidavit of Andrew L. Ott on Behalf of PJM Interconnection, L.L.C. (filed March 4, 2013). Unfortunately, PJM's analysis comes in a docket where rehearing applications are now pending by various parties opposed to any relief for PJM's self-supplying LSEs, which renders the fate of PJM's proposal to assist such LSEs very uncertain.

18 While the Commission does not have the authority to enforce the antitrust laws, it is obligated to consider allegations that its actions or the actions of the entities it regulates contravene antitrust policy and to weigh antitrust concerns against other countervailing public interest factors, if any. *Gulf States Utilities Co. v. FPC*, 411 U.S. 747, 758-59 (1973); *Northern Natural Gas Co. v. FPC*, 399 F.2d 953, 960-63 (D.C. Cir. 1968); *New York Independent System Operator, Inc.*, 127 FERC ¶ 61,136 (2009) at P 6 ("… [W]e agree

exercised in the capacity markets can chill the very conduct – aggressive bidding – that the antitrust laws were designed to encourage.[19] Over-mitigation on the buy-side could smother the possibility that RTO-administered capacity constructs might harness competitive forces to benefit consumers. And while it is easy to explain why a for-profit merchant generation owner that has no obligation to serve load and that operates solely to maximize earnings might engage in actions that increase its profits at the expense of retail consumers, explaining to lawmakers and lay persons why self-supplying LSEs that are able to develop new low-cost resources should have their capacity bids for such projects mitigated *upward*, thus *increasing* the price to retail consumers, will at some point become a political issue for the Commission.

For these reasons, if the Commission cannot see its way clear to restore the self-supply rights of LSEs, it should at the very least limit buyer-side mitigation to cases where a self-supplying buyer is found to have specific intent under the tests articulated by the Supreme Court for predatory pricing to artificially depress clearing prices or exercise buyer market power.[20]

Voluntary Centralized Capacity Procurement Constructs

APPA's second market design recommendation is much more sweeping, and results from APPA's observations regarding the great unhappiness that a great many market participants have

---

with Movants that we do have a responsibility 'to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations,' and 'to give reasoned consideration to the bearing of antitrust policy on matters within [our] jurisdiction.'" [Footnotes omitted.]).

19 *Weyerhaeuser Co. v. Ross-Simmons Hardwood Lumber Co.*, 549 U.S. 312, 320 (2007).

20 *Id.* at 323-324 (Adopting two-part test for predatory bidding, requiring proof of (1) below-cost pricing, and (2) dangerous probability of recouping losses from below-cost pricing through supracompetitive pricing when rivals are driven out of market, and observing that "[p]redatory pricing requires a firm to suffer certain losses in the short term on the chance of reaping supracompetitive profits in the future. . . . A rational business will rarely make this sacrifice. . . .The same reasoning applies to predatory bidding. A predatory-bidding scheme requires a buyer of inputs to suffer losses today on the chance that it will reap supracompetitive profits in the future. For this reason, '[s]uccessful monopsony predation is probably as unlikely as successful monopoly predation.'") (internal citations omitted).

expressed with RTO-administered centralized capacity constructs. While different market participants are unhappy for different reasons at different times, they all seem to be unhappy with the results these constructs produce. Generators in Eastern RTOs are currently distressed by continuing low capacity prices. State regulators in New England (where the MOPR applies to all resources) are deeply concerned about the ability of their states to meet relevant state renewable portfolio standards, without having to pay twice for renewable capacity. Natural gas pipelines interested in constructing new pipeline capacity to serve constrained regions such as New England are concerned by the inability of market participants to sign long-term contracts for new pipeline capacity.[21] Incumbent generators in PJM succeeded in convincing the Commission to implement more stringent MOPR rules to head off what they considered "state-subsidized" new generation units, and yet new generation units continued to clear, leading them to seek further tightening of the rules. At the same time, PJM is using Reliability Must Run agreements to keep coal-burning power plants in operation past their intended retirement date, asserting that their retirements would adversely impact reliability. There are deep doctrinal disputes regarding the slope of the relevant demand curves, the resources that should be included or excluded from MOPR mitigation, the proper way to set CONE,[22] *etc*. And the capacity clearing prices in various RTO zones can rise and fall from year to year in dizzying fashion, leading one to wonder

---

[21] In certain areas, pipelines are already at or near full capacity, or new pipelines need to be constructed to move natural gas from new formations. The business model of natural gas pipeline companies relies on long-term (10-15 year) contracts with transportation customers to secure the financing for new construction, a model that is clearly at odds with the capacity constructs in the Eastern RTOs. A similar situation exists for natural gas storage facilities. Storage, especially storage near a generation facility, can be particularly crucial to the operation of natural gas units used to firm up wind and other variable renewables, given the timing for delivery of the gas to the unit and the extreme variability of such resources.

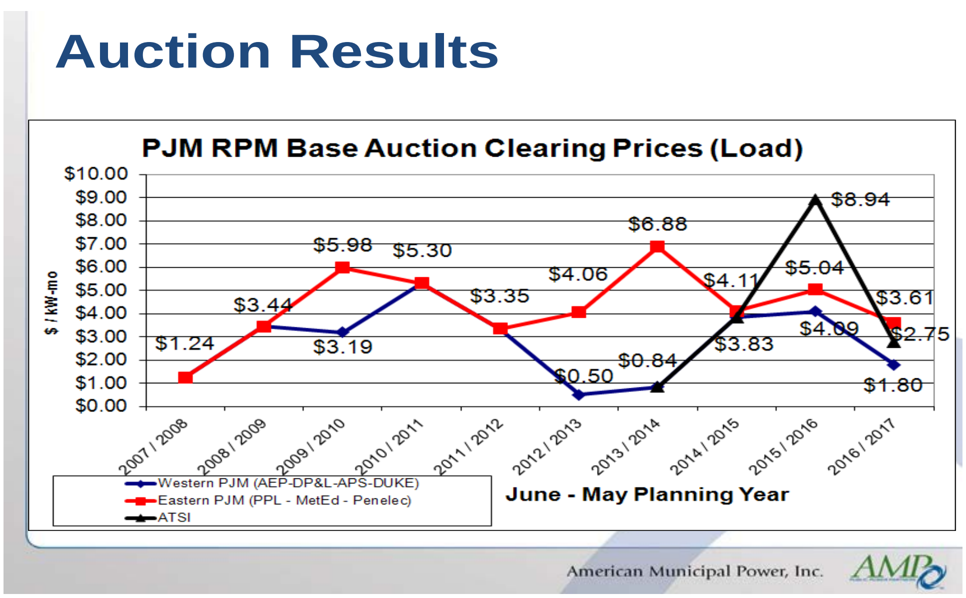
[22] The August 23 Staff Report (at 10-11) correctly notes the highly contentious nature of CONE determinations, as well as the possibility that the choice of generation technology used to set CONE could discourage investment in other types of generation, thus making it more difficult to develop a diverse resource base.

who could actually rely on such signals to make long-term investments.[23] All of these issues create a target-rich environment for disputes and litigation before the Commission (usually after many hours have been spent by market participants in stakeholder processes debating market rule changes without a consensus resolution).

These issues are freighted with such deep meaning and import for one simple reason—the RTO capacity market constructs in PJM and ISO-NE (and in the NYISO's NYC Zone[24]) are mandatory. This raises the heretical yet inevitable question: why should they be mandatory? Why can't they be made voluntary, designed to meet only residual needs? Might it make more sense to allow RTOs, the state regulators in their respective footprints, and the affected LSEs to consider other ways of assuring resource adequacy that do not involve the use of a capacity construct that seems so clearly unsuited for the actual task of supporting new investments? RTO-administered capacity markets could be *one way* to obtain capacity (especially on the

---

[23] *See, e.g.*, Figure 1 of the August 23 Staff Report. APPA member AMP has prepared a comparable graph for the ATSI Zone in PJM, which shows the extreme swings in capacity prices there:



[24] The Commission has recently approved NYISO's request to establish a new capacity zone in the Lower Hudson River Valley as of May 1, 2014, *New York Indep. Sys. Operator, Inc.*, 144 FERC ¶ 61,126 (2013), and separately approved the application of supplier- and buyer-side mitigation measures in that zone (and other new zones). *New York Indep. Sys. Operator, Inc.*, 143 FERC ¶ 61,217 (2013).

margin, or close to the resource year in question). But capacity could also be procured bilaterally, in a real marketplace where willing buyers and willing sellers negotiate arrangements tailored to meet their individual projects and needs, including contract term, fuel type and flexibility of the particular resource, location on the transmission grid, and financial terms. If centrally administered capacity constructs are indeed vital to RTOs' resource adequacy, they will prove their worth even if they are residual in nature and do not have an effective monopoly on capacity procurement. In other words, the Commission should consider exposing RTO-administered capacity constructs to some real competition in the form of alternative ways to procure capacity.

The inevitable answer to the suggestion that these constructs be made voluntary is that RTO-administered capacity constructs will not work unless all market participants are required to use them, no matter what needs those participants have or what business model they employ. The corollary to this answer is that generators will not be able to collect their "missing money." The response to the first point is that these constructs clearly are not working very well as they are—hence, examination of their mandatory nature should not be off-limits for discussion. And the answer to the second point is that there are other ways for generators and other resource suppliers to ensure adequate revenue recovery, including the use of bilateral contracts with contract terms appropriate to the type of resource, its age and environmental attributes, and the concomitant need for capital to support it (which would differ depending on whether the resource is new or existing, demand-side or supply-side). Such a level of refined product differentiation is only available in a bilateral market – it cannot be achieved through a centralized capacity procurement construct.

APPA explored some of these issues in its 2009 "Competitive Market Plan," which it updated and reissued in 2011 in response to some of the controversies ignited by the Commission's spate of capacity market orders.[25] More recently, Cliff Hamal of Navigant Consulting has started a refreshingly entertaining website/blog discussing these issues and presenting his own proposal on how to assure capacity revenue recovery through the use of bilateral contracts.[26] If the Commission signaled its willingness to reexamine the "first principles" underlying mandatory capacity constructs, it would no doubt find that others are also ready to discuss alternatives.

APPA recognizes that the Eastern RTOs' capacity constructs have undergone substantial changes since they were first implemented. It will take time and concerted effort to "unwind" these constructs and the related revenue streams. But these mechanisms clearly are not working well. It is therefore time that the Commission start this conversation. The alternative—continuing to attempt to make these "markets" work through yet more *ad hoc* tweaks and rule changes designed to plug the latest policy and operational leaks,[27] will just bring us all back

---

[25] The 2011 Update to APPA's Competitive Market Plan can be found at: http://www.publicpower.org/files/PDFs/2011CompetitiveMarketPlanUpdate.pdf.

[26] His discussion draft, entitled "Solving the Capacity Market Puzzle: The BiCap Approach," is available at http://www.bicapapproach.com/.

[27] A cautionary tale regarding the alteration of capacity construct rules to meet new challenges is currently playing out in New England. ISO-NE has proposed rule changes, including provision for substantial penalties for non-performance by resources with capacity supply obligations, during periods when the system is short of operating reserves. These performance penalties are being characterized as "performance incentives," because any penalties actually paid by under-performing resources will be shared among all resources actually running during the times of the shortage. These proposed changes would add even greater complexity and confusion to a capacity regime already in dire need of simplification. Unintended consequences of such incentives could include the potential for high penalties resulting in an increased number of generation unit retirements instead of investments in upgrades to achieve performance standards, and the limiting of new entry to only small, quick-start generating units. The outcome will always be uncertain when new layers of complexity are added to already byzantine centralized capacity constructs.

together in another technical conference in another year to ask much the same questions the Commission has asked this panel to address.

2. In order to achieve resource adequacy goals, should centralized capacity markets be expected to meet specific reliability and operational system needs (i.e., accommodating new and emerging technologies such as variable energy resources, distributed resources, or demand-side resources)? If so, how should capacity markets be designed to procure resources with specific operational attributes and what should those attributes be?

At present, RTO-administered capacity constructs have a myriad of market rules that make them difficult to understand even for those in the industry, much less the retail electric consumers that have to pay the bills, or the lawmakers that represent them. The successive attempts to patch each newly emergent failure that results from a construct that is not, in fact a market, has resulted in a set of tariffs and rules worthy of a Rube Goldberg cartoon. And this is when these constructs generally treat each MW of capacity as fungible (*i.e.*, interchangeable with every other MW in the same deliverability zone). Trying to adapt these markets to accommodate specific resource types and attributes, while an admirable goal, would make them only more complex and difficult to administer, potentially leading to further unintended negative results and yet more band-aid market rule changes and exceptions to attempt to address these unintended results.[28] APPA believes that more state and local involvement in development of RTO resource

[28] To its credit, Staff in its the August 23 Report (at 18) notes the additional complexity that redefining capacity products to procure "needed operational attributes" would entail. For its part, APPA believes that more complex is not necessarily better, especially when it comes to RTO markets. *C.f.*, the August 12, 2013 blog post by James Bushnell entitled "JP Morgan and Market Complexity," *available at* http://energyathaas.wordpress.com ("It's worth pointing out that, while making electricity is complicated, and marginal costs don't look like a nice upward sloping line, this is true of a lot of other stuff also. Refining gasoline is complicated. Running an airline network is complicated. But we don't run a single optimization program that simultaneously tries to clear the market and solve everyone's production schedule for them. These markets run the way power markets used to. If a generator got a sale it couldn't meet, it bought replacement power out of a spot market. If a plant ended up running in a way that lost money over the course of a day, it would change its offer price the next day so that didn't happen again. The market software does wondrous things, and solves tremendously complicated problems. It's probably true that having a group of plant owners try to manage these complexities in a decentralized way creates some inefficiencies. But its still garbage in – garbage out. If firms monkey with the complicated parameters that these programs are trying to accommodate, strange things can happen to prices, and

adequacy requirements and greater use of bilateral contracting would be the simpler way to procure resources with "specific operational attributes."

APPA notes that the Commission currently places a high premium on the honoring of state/local "public policy requirements" in RTO transmission planning regimes.[29] The Commission should consider revamping RTO capacity procurement procedures to pay more attention to state/local public policy concerns on the resource side as well. Increased consideration of public policy preferences in resource adequacy determinations could allow for more refined consideration of new developments, such as increased future reliance by LSEs on distributed generation (including combined heat and power installations and distributed solar installations), natural gas/electricity interface-related issues, retail level DR, and EE.

3. Going forward, should centralized capacity markets be designed to meet additional or different goals than those established to date?

For the reasons stated in response to questions 1 and 2 above, APPA believes that the answer to this question is yes. Going forward, RTO-administered capacity constructs should be redesigned to act as residual markets in which both LSEs and resource providers can obtain and lay off capacity resources "on the margin." Other methods and tools such as bilateral contracting should act as the primary method to obtain and sell resources in RTO regions.

---

especially to the types of side-payments earned by JP Morgan. The 'best' solution is not always the most complicated one.").

[29] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, Docket No. RM10-23-000, 136 FERC ¶ 61,051 (July 21, 2011), 76 Fed. Reg.49,842 (Aug. 11, 2011), *on rehearing*, Order No. 1000-A, 39 FERC ¶ 61,132 (May 17, 2012), 77 Fed. Reg.32,184 (May 31, 2012), *appeals pending sub nom*. *South Carolina Public Service Authority v. FERC*, D.C. Cir. Nos. 12-1232, *et al.*

Respectfully submitted,

/s/ Susan N. Kelly

Susan N. Kelly
Senior Vice President of Policy Analysis and General Counsel
American Public Power Association
1875 Connecticut Avenue, N.W., Suite 1200
Washington, D.C. 20009
(202) 467-2933
skelly@publicpower.org

September 9, 2013

Resolution 13-04
Sponsors: Braintree Electric Light Department; New York Association of Public Power; Public Power Association of New Jersey; Delaware Municipal Electric Corporation

In Support of Maintaining Self Supply in the Capacity Markets

Mandatory forward capacity markets have become an increasing source of concern for public power systems operating in wholesale electricity markets run by regional transmission organizations (RTOs). Such concerns have been exacerbated by recent rule changes that threaten the public power business model of relying on long-term power supply resources.

Previously, in RTO regions, public power systems and other load-serving entities could invest in or contract for capacity over the long term to meet their capacity obligations ("self-supply"). The RTOs operated centralized capacity markets to provide a residual market to satisfy any remaining short-term capacity needs. These markets had rules to mitigate supplier market power. Declining energy prices have led merchant generators to increase their reliance on capacity markets as a source of profits. Therefore, suppliers have promoted the notion that RTO capacity markets must be "mandatory," meaning all load serving entities must purchase capacity from the short-term market. This threatens the ability of public power systems to continue to rely on self-supply to meet their RTO capacity obligations. Moreover, suppliers have argued that high capacity market prices need to be promoted, because energy market revenues alone do not support the fixed costs of certain types of new generation. Thus, suppliers have argued for a Minimum Offer Price Rule ("MOPR") or "offer floor mitigation," which establishes a price floor below which new generation cannot offer into the market. These bidding restrictions impose on public power systems considering self-supply the risk of not clearing in the market and then having to pay twice to meet their capacity obligations (once through self-supply and a second through RTO market purchases).

Recent FERC decisions have accepted the suppliers' arguments. The PJM Interconnection, L.L.C. (PJM) and ISO New England (ISO-NE) each operate mandatory forward capacity markets with a MOPR, and the New York ISO (NYISO) operates a capacity market with a MOPR in the New York City zone, and has proposed a MOPR for any new capacity zones.

The PJM capacity market (called the "Reliability Pricing Model" or "RPM") and the ISO-NE market (called the "Forward Capacity Market" or "FCM"), were developed in settlements of highly contested proceedings. Of critical importance to public power systems in those settlements was the ability to self-supply their own capacity obligations and mitigate the high costs these markets were expected to impose. But these crucial self-supply protections were largely jettisoned by two FERC orders issued in subsequent days in April 2011.

The two April orders emerged out of supplier-driven RTO concerns that, although the existing capacity markets were procuring ample capacity, prices were too low. In PJM, guaranteed clearing rights for self-supply were sharply curtailed. For ISO-NE, FERC ordered the development of a new MOPR without any accommodation for self-supply by public power systems.

Meanwhile, in New York City, suppliers filed a complaint alleging that an improper exemption from a MOPR was granted by the NYISO to a new unit financed by a long-term contract with the New York Power Authority. In September 2012, FERC ordered that the unit's actual cost of capital cannot be used when determining its offer because this price is "too low" as a result of the long-term contract (that reduces the risks to investors and lowers the cost of capital).

There are signs of an interest in an expansion of capacity markets to other regions. In 2011 the Midwest Independent Transmission System Operator (MISO) filed for FERC approval for a new capacity market, which included provisions for a MOPR that was supported by generators in the region. In June 2012 FERC approved a new capacity market for MISO, but ruled against a mandatory market and the proposed MOPR. In the California ISO, a number of generators have argued in favor of a mandatory capacity market in that RTO in recent dockets addressing reliability.

FERC's increased enthusiasm for mandatory capacity markets and inflexible MOPRs restricts the ability of public power systems to self-supply their capacity obligations and threaten the core of the public power business model: namely, the ability to finance needed power supply, demand response, or energy efficiency resources through long-term contracting or ownership at favorable rates and terms, the benefits of which accrue directly to their customers.

NOW, THEREFORE, BE IT RESOLVED: That APPA opposes all RTO tariff provisions that impede the ability of public power systems to obtain through self-supply sufficient power supply and demand-side resources to serve their retail loads at least cost, taking into account short-term and long-term portfolio needs, resource diversification, and environmental considerations; and

BE IT FURTHER RESOLVED: That APPA urges FERC to review all capacity market buyer-side mitigation provisions like the MOPR a generic, rulemaking proceeding and to revise those rules that are found to interfere with the ability of public power systems to procure through self-supply generation and demand-side resources needed to serve their load; and

BE IT FURTHER RESOLVED: That APPA opposes the creation of any new capacity markets or new RTOs in any region of the country.

As adopted June 18, 2013, by the membership of the American Public Power Association at its annual meeting in Nashville, Tennessee.