UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

POST-TECHNICAL CONFERENCE COMMENTS OF THE AMERICAN PUBLIC POWER ASSOCIATION

In accordance with the Commission's October 25, 2013 "Notice Allowing Post-Technical Conference Comments" ("October 25 Notice") and the November 27, 2013 "Notice of Extension of Time," the American Public Power Association ("APPA") submits these post-technical conference comments.

I.

EXECUTIVE SUMMARY

APPA has organized these comments into three primary sections. In Section III, it responds to certain of the questions raised in the Commission's October 25 Notice. In Section IV, it presents a proposal to reform mandatory capacity markets. In Section V, it addresses two additional points that were not captured in the questions set out in the October 25 Notice. APPA summarizes some of the main points in Sections III and IV in this Executive Summary, but notes that many important items have of necessity been omitted, and urges the reader to take the time to review the full comments.

Industry Changes and Their Implications for Resource Adequacy. In Section III, APPA notes that the increasing penetration of distributed generation ("DG") such as rooftop and community solar installations, gas-fired micro-turbines, and micro-grids will have substantial implications for future regional transmission organization ("RTO") resource adequacy determinations. Specifically, they will make it increasingly difficult to estimate the actual capacity that must be procured up to four years in the future through an RTO-run centralized forward capacity market construct. Reserve margins will also likely be affected, as there will be multiple ways to meet reserve calls, including many increasingly cost-effective behind-the-meter options. Use of more decentralized capacity procurement methods, such as a load-serving entity ("LSE") contracting bilaterally outside of the RTO-administered markets with both supply-side and demand-side resources, makes increasing sense in such a scenario. Moreover, since LSEs are closer to retail customers in their service areas than the RTO, they will have a clearer picture of the potential future impact of disruptive technologies that might reduce the need for capacity from wholesale resources. These concerns have led public power systems to question continuing with a three-to-four year forward centralized capacity procurement construct, given the high degree of reliance on administrative market mitigation rules, their complexity, and the many judgment calls that market monitors must make.

Restoration of LSE Self-Supply Rights. As the Commission knows, at the time RTO-administered mandatory centralized capacity constructs were being considered for ISO New England Inc. ("ISO-NE") and the PJM Interconnection, L.L.C. ("PJM"), many APPA members in these regions had severe reservations as to how these constructs would affect their future ability to obtain capacity (either contracted or self-built), as well as the long-term viability of these mechanisms. They therefore participated actively in the development of these mandatory mechanisms, and negotiated specific "self-supply" provisions. While the Commission initially approved these provisions as just and reasonable, in 2011 the Commission effectively stripped these 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." The Commission then interpreted the rules of the New York Independent System Operator, Inc.'s ("NY ISO") New York City capacity market zone in such a way as to create the same dilemma for public power entities with generation resources in that zone. APPA and its members have been attempting ever since to regain through both litigation and settlement the protections they specifically bargained for and the Commission approved – protections that would allow them to self-supply their own loads with their own resources using their own economics.

The primary concern of APPA's members, of course, is with the relevant Minimum Offer Price Rule ("MOPR") provisions. APPA members fear that an LSE's self-supply resource will not clear the relevant capacity auction due to upward bid mitigation, leaving the LSE in the position of having to pay twice for the same increment of capacity: once for the self-supply resource, and again for an allocation of the centrally procured capacity that must be purchased from the RTO's capacity market if the self-supply resource does not clear. 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.

Ironically, the very behavior that MOPRs and similar provisions discourage might be just what the ISO-NE, NY ISO and PJM (together, "Eastern RTOs") capacity markets should be incenting. Robert Ethier, who appeared at the Technical Conference for ISO-NE, opined that it would be helpful to RTO markets if there were more LSEs using such a long-term business model. He noted that if "you serve load and you also own generation, so that makes you have a more balanced perspective on the market, and also just sort of facilitates the market transactions." APPA therefore believes that the Commission should implement changes to the current capacity market designs to facilitate LSE self-supply arrangements, both self-builds and power supply agreements. Doing so would at least support those load-side interests in the Eastern RTOs that still have a "balanced perspective" on the market, and avoid making an already unbalanced load/resource equation even more dysfunctional than it already is.

Actual experience in both the PJM and ISO-NE regions teaches that it is unlikely the restoration of prior market rules permitting LSEs to self-supply will, standing alone, have a substantial adverse impact on capacity prices. Even assuming *arguendo* that the actions of self-supplying LSEs could somehow "move the needle" and unduly lower auction prices on the margin, it should not automatically be assumed that this is an undesirable result. Use of long-term contracts, *e.g.*, power purchase agreements, better supports the financing of new generation resources. Such arrangements allow financing at a lower interest rate, which in turn leads to lower ultimate costs to consumers than generation resources built "on spec." Use of Cost of New Entry ("CONE") estimates that are inflated with assumptions based on the higher financing costs associated with speculative merchant projects increases costs to consumers, and, because of the single clearing price structure of the capacity auctions, results in higher payments to *all resources*, existing and new. Institutionalization of the merchant resource development model through biased CONE estimates (especially when coupled with MOPRs that arbitrarily increase the bids and the risks associated with resources constructed under other, lower-cost business models) artificially skews the marketplace in favor of the merchant business model with its higher risks and high returns, rather than a lower risk, more stable price paradigm. For all of these reasons, APPA argues in Section III that restoration of the self-supply rights that its members negotiated at the time mandatory capacity markets were instituted is appropriate, just and reasonable.

Showing of Specific Intent to Exercise Buyer-side Market Power. While APPA prefers restoration of the original self-supply provisions in the relevant RTO market rules, it also suggests as an alternative requiring the RTO to demonstrate that a self-supplying LSE specifically intends to exercise "buyer-side market power" prior to mitigating that LSE's capacity bid in a particular auction. Such a showing would be appropriate because 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 single-year 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.

Use of a Fixed Resource Requirement. The Commission asked in its October 25 Notice about the possibility of implementing a Fixed Resource Requirement ("FRR") regime for self-supplying LSEs. The FRR regime was developed through settlement negotiations to address a narrow set of circumstances facing the PJM region at the time the Reliability Pricing Model ("RPM") tariff provisions were negotiated. The FRR Alternative as formulated under the PJM tariff may be a viable option for a select few LSEs that are net long on capacity resources and capable of supplying all of their capacity obligations plus reserve requirements for their entire FRR Service Area for a five-year period. But most public power LSEs do not have unlimited capacity resource options for self-supply and would be placed at disproportionate risk if required to meet the FRR Alternative criteria. Among the specific problems with the FRR option that public power systems see are: (1) the variability of public power LSE capacity obligations from year to year; (2) the inability to make residual capacity purchases even in unforeseen circumstances (*e.g.*, an unanticipated extended outage at a major generation unit); (3) the unavailability of reasonably priced bilateral contract options in RTO regions that have centralized capacity constructs; (4) the disparate penalty regime; (5) the substantial restrictions on the sale of excess capacity; (6) the potential for changing Locational Delivery Area ("LDA") boundaries that could impose unanticipated locational capacity requirements; and (7) unanticipated RTO migration by Transmission Owners in whose service areas public power system loads and resources are embedded. While no doubt the Commission, RTOs and stakeholders could spend endless hours debating potential modifications to the current FRR construct to make it minimally usable by public power and other self-supplying LSEs, APPA does not favor institutionalization of an FRR-type regime. Doing so would send the signal that self-supplying LSEs must be isolated to prevent their business model from somehow infecting the rest of the market, by effectively ring-fencing them out of regional markets.

<u>Procedural Vehicles/Next Steps for the Commission</u>. APPA would not favor enforcing "consistency in the approach to capacity markets across the Eastern RTOs" through a "standard capacity market design" or institutionalization of "best practices." APPA fears that any such effort would turn into an effort by generators to take the specific market rules from each market most favorable to their own economic interests and institutionalize them across all Eastern RTOs, effectively creating a "Franken-market." Each of the RTO regions is different, and those differences must be respected. On the other hand, the *status quo* of unlimited RTO filings and complaint cases to address specific capacity market-related issues on an *ad hoc* basis (and the stakeholder processes that usually precede them) requires a huge expenditure of time and resources by each RTO, this Commission and the affected market participants. A possible middle path might be for the Commission to order one or more of the Eastern RTOs to address issues of substantial concern, *e.g.*, the need to develop clear market rules that adequately support LSE self-supply and state/local resource policy decisions. Another possible course of action might be to hold a series of "follow-on" technical conferences to explore further specific aspects of the Eastern RTO capacity markets of concern to the Commission and to jump start discussion of potential alternatives. But whatever course is chosen, the Commission needs to be sensitive to the concerns of stakeholder classes with limited resources to devote to RTO stakeholder deliberations and Commission proceedings.

Other Issues for Consideration. The Commission in its October 25 Notice asks whether the Commission has omitted or overlooked any relevant questions regarding capacity markets. APPA is most appreciative of the Commission's initiation of this docket, but believes that if anything is missing from the Commission's inquiry to date, it is the foundational inquiry that the Federal Power Act ("FPA") requires the Commission to undertake – are the Eastern RTOs' capacity markets procuring the right amounts and types of capacity at just and reasonable rates? While many of those speaking at the September 25 Technical Conference had ideas about how capacity markets could better support their own policy goals, *e.g.*, more revenues for existing generation, better support for flexible capacity needed to support renewables, more certainty for investors, *etc*., few spoke to this fundamental question.

Proposal to Transition Mandatory Capacity Markets to Voluntary, Residual Markets. APPA believes that the industry needs to find a way forward, given the many issues with the current mandatory locational capacity constructs. APPA in Section IV of these Comments therefore sets out a proposal to transition mandatory RTO capacity markets to voluntary residual markets. The Commission could require affected RTOs to work with their stakeholders and state commissions to develop an appropriate transition period (*e.g.*, five years) that would commence after the next relevant annual mandatory capacity market auction. The transition period would have to be lengthy enough for all outstanding capacity obligations incurred in prior mandatory capacity auctions to be fulfilled, and for LSEs in the RTO region to develop, either jointly or severally, resource adequacy plans for review and approval by the relevant authorities. At the end of the transition period ("zero day"), the annual capacity market auctions would become voluntary and residual for both buyers and sellers.

The features of the residual market would include: (1) short-term, voluntary markets intended to supplement other, primary methods of procuring capacity; (2) annual/monthly auctions; (3) no buyer-side or seller-side mitigation (unless found necessary for specific sellers due to the potential for the exercise of market power); (4) an RTO-wide resource adequacy requirement; (5) individual LSE resource adequacy requirements; (6) severe penalties for non-compliance; (7) implementation prior to zero day of the most economic and efficient options to relieve transmission constraints which create separated load zones with insufficient generation/resource competition; and (8) convening of a work group with state commissions in the relevant RTO region to ascertain whether any resource suppliers do in fact have sufficient seller-side market power to affect price outcomes and development of appropriate limitations on the market activities of such pivotal sellers.

This proposal has several benefits that make it worthy of serious consideration, including: (1) fewer moving parts and administrative judgments, resulting in reduced stakeholder processes and litigation; (2) harmonization of state/local resource portfolio and public policy choices, without bias in market rules towards or against specific resource types; (3) avoidance of jurisdictional disputes, by appropriately involving state and local authorities in the resource adequacy, constrained zone mitigation and market power issues; (4) increased flexibility for individual states within RTO regions to deal with the resource adequacy issues for their retail customers created by their prior decisions regarding retail access; (5) choices for merchant generators/resource suppliers either to enter into individualized bilateral supply arrangements with LSEs or to rely on the residual capacity market (in addition to the energy and ancillary services markets) to obtain their revenues, or to pursue any combination of these approaches; and (6) more customized arrangements to procure resources that would enable the development of tailored products and services to meet specific needs, rather than relying solely on generic, lowest common denominator type capacity products.

APPA understands that this end state could take a substantial period of time to attain in PJM and ISO-NE, given just how far down the mandatory centrally procured capacity market rabbit hole these two regions have already gone. (The capacity market administered by the NY ISO is a different case, given that it is shorter term in nature, and better supports long-term contracting.) But many market participants have expressed great unhappiness with centralized mandatory capacity constructs, albeit for different reasons and at different times. Moreover, the barrage of *ad hoc* band-aid filings attempting to deal with perceived specific shortcomings of these markets continues apace. APPA therefore presents this reform proposal in an effort to contribute positively to the policy debate.

II.

INTERESTS OF APPA

APPA is the national service organization representing the interests of not-for-profit, publicly owned electric utilities throughout the United States. More than 2,000 public power utilities provide over 15 percent of all kilowatt-hour sales of electricity to ultimate customers, and do business in every state except Hawaii. All APPA utility members are LSEs, with the primary goal of providing customers in the communities they serve with reliable electric power and energy at the lowest reasonable cost, consistent with good environmental stewardship. This orientation aligns the interests of APPA-member electric utilities with the long-term interests of the residents and businesses in their communities. Collectively, public power systems serve over 47 million customers.

APPA has members located in the footprints of the Eastern RTOs. These members must operate within the constraints created by the centrally-administered capacity procurement mechanisms that these Eastern RTOs have implemented.[1] Moreover, past experience has shown that in many cases, what happens in the Eastern RTOs does not stay in the Eastern RTOs – hence, APPA members in other RTO regions can also be adversely impacted by developments in the Eastern RTOs. APPA filed a Written Statement in this docket on September 9, 2013.[2] Susan N. Kelly, APPA's Senior Vice President of Policy Analysis and General Counsel, appeared on Panel IV at the September 25, 2013 Technical Conference. For all of these reasons, APPA has a significant interest in this proceeding, which has been established in part to determine whether these capacity procurement mechanisms can be revamped and improved to better meet the needs of market participants and electric consumers.

APPA very much appreciates the Commission's initiative to hold the Technical Conference and to request comments on the issues raised there. Capacity markets have been among the most controversial issues that the Commission has had to deal with in the

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1 *See* Transcript of the September 25, 2013 Technical Conference ("Tr.") at 243-48 and 269 (Kelly) (discussing the reasons why public power entities in the Eastern RTOs as a practical matter must participate in their markets).

2 "Written Statement of Susan N. Kelly on Behalf of the American Public Power Association," Accession No. 20130909-5278, Docket No. AD13-7-000 (submitted Sept. 9, 2013) ("APPA Statement").

last few years. They certainly merit the increased attention the Commission is now paying to them.

APPA has organized its comments into three primary sections. In Section III, it responds to the questions raised in the Commission's October 25 Notice. In Section IV, it presents a proposal to reform mandatory capacity markets. In Section V, it addresses certain points raised at the Technical Conference that were not captured in the questions set out in the October 25 Notice.

APPA stands ready to further assist the Commission in this inquiry in any way it can do so.

III.

ANSWER TO QUESTIONS POSED IN THE OCTOBER 25 NOTICE

The Commission in its October 25 Notice posed a substantial number of questions to commenters, noting, however, that "[c]ommenters need not address every question." For the convenience of the reader, APPA has reprinted those questions and bullets to which it is responding. APPA notes that a number of its members and groups of members, both within and outside the Eastern RTO regions, will also be filing comments in this docket. APPA is deferring to those members' comments regarding a number of questions that the Commission has raised, and commends their responses to the Commission.

1. Role of Capacity Markets and Definition of the Capacity Product

Panelists discussed the definition of the capacity product and, in particular, the relationship between the capacity and energy and ancillary services markets, both today and in the future as electric system needs change. In particular, panelists addressed the importance of properly defining the capacity product, and whether additional capacity products should be

defined to recognize future system operational needs. Some favored retention of the current design, procuring a single capacity product focused on meeting basic resource adequacy requirements, with any operational attributes needed to meet system requirements procured in the energy and ancillary services markets. Others favored an approach that would procure differentiated products in capacity markets, incorporating attributes that meet specific operational needs. In addition, panelists discussed how different categories of resources (traditional generation, new resources vs. existing resources, demand response, energy efficiency, distributed generation, etc.) should be valued and accounted for in centralized capacity markets.

- **When procuring a single capacity product, as under current market designs, are there certain fundamental performance standards that capacity resources should be required to meet in the delivery year to ensure resource adequacy? Should any such requirement change depending on the type of resource (traditional generation, new resources vs. existing resources, demand response, energy efficiency, distributed generation, etc.)?**

As a general rule, if supply or demand resources bid into RTO capacity markets and their bids clear, they should perform when called upon in accordance with the characteristics of those resources, barring a *force majeure* event. If specific resources have a continuing record of sub-standard performance, the RTO's designated market monitor(s) should investigate and take appropriate action to ensure that these resource providers are not gaming the capacity market tariff provisions.

APPA is aware that the performance of capacity resources has been an issue in the ISO-NE region. In October 2012, ISO-NE distributed a White Paper proposing to add a Performance Incentive ("PI") component to its Forward Capacity Market ("FCM"). This proposal was triggered by ISO-NE's observation that "at times of high system stress, a significant share of the region's generating fleet fails to respond to ISO dispatch instructions according to their offered capabilities."[3] ISO-NE also observed that these reliability risks were being further exacerbated by the region's growing dependence on natural gas-fired generation. To address these concerns, ISO-NE proposed its PI construct (although it appears to be more in the nature of a performance penalty rather than an incentive). Under the proposed PI regime, ISO-NE would assess substantial penalties (as high as $5,455 per MWh) on resources that do not run when called upon during scarcity conditions.

APPA understands that the NEPOOL Participants Committee ("NPC") took this proposal up at its December 6, 2013 meeting and voted overwhelmingly to reject it, with only around 10 percent stakeholder support. Among those opposing the proposal were all of the region's public power systems and most of the New England state regulators.[4] More significantly, the great majority of the NEPOOL Participants voted in favor of an alternative proposal which would focus on improving capacity resource performance by enhancing price signals in the energy and operating reserve markets and modifying the

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[3] ISO-NE, "FCM Performance Incentives" at 1 (Oct. 2012), *available at* http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/fcm_performance_white_paper.pdf.

[4] One reason why these sectors may have voted against ISO-NE's PI proposal is that it requires the capacity suppliers to take on all risk of unavailability, regardless of the underlying cause, during any unpredictable "Shortage Event" during the relevant Capacity Year. Because the risk of unavailability is largely random, capacity sellers likely would charge a risk premium that would be passed on to all customers as a uniform mark-up in all bidders' prices. Adding insult to injury, the fact that the risk of loss would have to be collateralized under ISO-NE's Financial Assurance Policy also means that self-supplying public power utilities would have to deposit substantial amounts of money with the ISO for the privilege of relying on their owned generation. This item was considered at the December 6, 2013 NPC meeting. The Financial Assurance requirements proposed by ISO-NE in connection with its PI program can be found at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/budgfin_comm/budgfin/mtrls/2013/nov252013/1a3_fcm_fa_1a_redline.pdf. An explanatory memorandum summarizing the operation of those proposed changes can be found at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/budgfin_comm/budgfin/mtrls/2013/nov252013/1a2_fcm_pi_fa_memo.pdf.

current availability metric to reduce capacity ratings if a resource fails to perform during certain critical high-priced hours. The NEPOOL alternative proposal received strong support from all six voting Sectors. (While no public power systems opposed the NEPOOL alternative, a number of systems abstained on this vote.) In addition, a majority of the States indicated support for the NEPOOL-approved alternative over ISO-NE's PI approach. APPA understands that both the ISO-NE proposal and the NEPOOL-approved alternative will be presented to the Commission for its review on an equivalent legal footing, under the "jump ball" provisions that govern arrangements between the NPC and ISO-NE.

Moreover, as this Commission is aware, APPA has expressed reservations in the past regarding the "wholesalization" of certain retail activities, such as Demand Response ("DR"). Doing so creates a host of legal[5] and operational issues, some of which are obliquely raised by this question. It is only when DR and Energy Efficiency ("EE") are defined as wholesale products that their respective attributes are spotlighted, and direct comparisons made to the attributes of generation-side resources. Transforming what are essentially retail level decisions and activities (which APPA and its members strongly support) into wholesale products, and paying them the full Locational Marginal Price ("LMP") in energy markets and the market-clearing price in capacity market auctions,

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5 APPA is a petitioner in the appeal of the Commission's Order No. 745, currently before the United States Court of Appeals for the District of Columbia Circuit in *Electric Power Supply Association, et al., v. FERC,* D.C. Cir. No. 11-1486 (oral argument heard September 23, 2013). APPA petitioned for review of Order No. 745 because it believes the Commission exceeded its jurisdiction under Section 201(b) of the Federal Power Act when it effectively transmuted a decision by a retail customer not to consume retail electric service in a particular hour into a wholesale product (DR), to the detriment of LSEs, including many APPA members, that must stand by to provide retail electric service in every hour.

creates uneconomic and inefficient price signals.[6] These price signals in turn have created perverse economic incentives, and in some cases, potentially illegal behavior.[7]

- **Should existing capacity products be modified to reflect various operational characteristics needed to meet system needs? If there is a need for additional capacity products, how should those products be defined and procured in light of the current one day in ten year resource adequacy approach?**

- **Alternatively, if it is more appropriate to rely on energy and ancillary services markets to obtain needed operational characteristics, how can market participants and regulators be confident that resources capable of providing such ancillary services will be available in future periods? To what extent are the existing categories of ancillary services adequate to meet current and future operational needs without a forward market?**

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6 *See, e.g.,* Statement of Andrew Ott, Executive Vice President—Markets, PJM Interconnection, L.L.C. (filed Sept. 9, 2013) ("PJM Statement") at 11 ("Although this product [Limited Demand Response] has some capacity resource value, by definition, its value is more significantly limited. Yet, it is paid the same as unlimited demand response and generation resources despite the obvious lack of comparability with those other resources."); Tr. at 51 (Bowring) ("In PJM, another issue is that the limited DR and the unlimited DR products actually don't meet the product definition tests. In my view, again, and I've said this more than once, those products are inferior in that they only have a very limited obligation to respond, only a very limited obligation to provide energy. They don't fit as well as other capacity products in the energy market design."); Tr. at 103 (Snitchler) ("And we're treating all capacity products equal, whether it's iron in the ground versus the willingness to terminate or suspend service, or even energy efficiency -- all of which are laudable goals. And energy efficiency, as I note in my comments, really is a cost savings, and that in and of itself ought to have some inherent value where it doesn't need to be compensated at the same level as an entity that may be willing to invest hundreds of millions or billions of dollars in a new generating facility that's in the ground.").

7 *See, e.g., Competitive Energy Services, LLC,* 140 FERC ¶ 61,032 (2012) (Order to Show Cause issued against Competitive Energy Services, alleging fraud in ISO-NE's day-ahead load response program); "Petition for an Order Affirming the Federal Regulatory Commission's August 29, 2013 Orders Assessing Civil Penalties Against Richard Silkman and Competitive Energy Services, LLC," *FERC v. Richard Silkman, Competitive Energy Services, LLC,* Case No. 1:13-cv-13054 (filed Dec. 2, 2013, D. Mass.); *Enerwise Global Technologies, Inc.,* 143 FERC ¶ 61,218 (2013) (Approving a Consent Agreement between FERC's Office of Enforcement and Enerwise in connection with its registration and the participation of the Maryland Stadium Authority as a demand response customer); *North American Power Partners,* 133 FERC ¶ 61,089 (2010) (Approving a Consent Agreement between FERC's Office of Enforcement and North American Power Partners relating to its activities as a Curtailment Service Provider in PJM's markets in 2007 and 2008).

If RTOs require resources with specific operational characteristics, reliance on energy and ancillary service markets would be one way to support such resources. Tr. at 40 (Ott), 50-51 (Bowring), 146 (Curran), 264 (Ethier), 265 (Hogan), 228, 259-60 (Wilson), 255-57 (Schnitzer); *but see*, Tr. at 168 (Moore), 170 (Judson). For example, if fast-ramping resources are needed to support intermittent renewables, a new ramping service might be developed for resources such as fast-ramping natural gas turbines and storage facilities. Bids to provide such services, however, would have to be co-optimized across the various products and markets, creating additional software development issues (as well as potential arbitrage opportunities if double payments can be obtained).

Another way to address this issue, in addition to properly structured energy and ancillary services markets, is to have the RTO set overall technical specifications that LSEs (either individually or collectively) must meet in developing their own resource portfolios for forward procurement. The LSEs would then be responsible for developing portfolios of resources that meet the RTO's specifications, either through use of the appropriate centrally procured RTO products and services or through alternative methods developed by the LSEs themselves. This would give the LSEs both the direct signal that they are responsible for their share of flexible resource needs and the ability to develop (together or separately, as they choose) a set of resources that supports RTO resource adequacy.

It would be a mistake for the Commission to assume that all LSEs will have resource portfolios that place similar integration burdens on the grid. For example, in the California Independent System Operator's ("CAISO") efforts to craft flexible capacity requirements for possible implementation in 2014, APPA's members in California demonstrated that their renewable resource mix was more diversified (and less dependent on intermittent resources) than the system average. Specifically, their resource mix included significantly more small hydropower, biomass, geothermal, firmed imports and landfill gas facilities than the CAISO Balancing Authority as a whole, which is highly dependent on unfirmed wind and solar renewable resources. In response, the CAISO has crafted proposals that impose bilateral obligations to make flexible capacity available as part of its Resource Adequacy requirements, commensurate with the individual LSE's portfolio and load burdens placed on the CAISO grid.

Any proposals that the Commission considers should therefore recognize the ability of specific LSEs to procure resources that track their defined and specified system needs, rather than to be presumptively bound to an inflexible centralized capacity procurement construct that requires them to subsidize the "lowest common denominator" procurement choices of others.[8]

- **What improvements are needed in how centralized capacity markets determine qualification as a capacity resource? Do the requirements to participate in the centralized capacity markets accommodate all resources (whether supply-side, demand-side, or imports) that are technically capable of providing the traditional forward capacity product?**

The question of how best to assess a specific type of resource's ability to act as a capacity supplier has come up in the case of intermittent wind and solar resources. A number of RTOs have dealt with this issue by simply assigning a percentage reduction

[8] As APPA's representative noted at the Technical Conference (Tr. at 236), "[b]uilding the entire market around the assumption that variable resources are going to be loaded first, and that everybody needs to pay for that variability, is not necessarily the right way to go in all cases, because there are some people out there who are trying to bury their own dead and deal with variability on their own, and they should not be penalized for having done that."

from peak/nameplate generating capacity to these resources – in essence, a capacity category discount factor.[9] As generation technologies improve over time, it may well be necessary to revisit these across-the-board assumptions, to ensure that any improvements in the ability of these types of resources to supply capacity are incorporated into the RTO's capacity planning assumptions. In addition, if a specific intermittent generation resource believes that its performance is substantially superior to the assumptions incorporated in the RTO's capacity planning models, it should have the opportunity to make an appropriate technical showing to the RTO. If superior performance is proven, the resource should be assigned a more representative capacity discount factor.

- **As changes in technology and markets drive new system needs, are modifications needed to existing methods for determining resource adequacy requirements (i.e., the reserve margins centralized capacity markets are designed to procure)?**

Increasing penetration of distributed generation such as rooftop and community solar installations, gas-fired micro-turbines, and micro-grids will have substantial implications for RTO resource adequacy determinations. Specifically, they will make it increasingly difficult to estimate the actual capacity that will need to be procured up to four years in the future through an RTO-run centralized forward capacity market

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[9] For example, PJM assigns a 13 percent capacity factor to wind resources and a 38 percent factor to solar resources to determine the portion of the nameplate capacity of these resources eligible to meet capacity requirements. *See* "PJM Manual 21: Rules and Procedures for Determination of Generating Capability at 6, *available at* http://www.pjm.com/~/media/committees-groups/committees/mrc/20130926/20130926-item-05-wind-capacity-credit-calculation-draft-manual-21-revisions-secondary-option.ashx; 2016/17 RPM Base Residual Auction Results, PJM Interconnection, L.L.C., May 24, 2013, http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx. For the Midcontinent Independent System Operator, Inc. ("MISO"), "[t]he system-wide wind resource capacity credit for Planning Year 2013 is 13.3 percent." MISO Planning Year 2013-2014 Wind Capacity Credit Report at 3 (Dec. 2012), *available at* https://www.misoenergy.org/Library/Repository/Study/LOLE/2013%20Wind%20Capacity%20Report.pdf.

construct. Reserve margins will also likely be affected, as there will be multiple ways to meet calls for higher-priced reserves, including many increasingly cost-effective behind-the-meter options. The use of more decentralized capacity procurement methods, such as bilateral contracting outside of the RTO-administered markets by LSEs with both supply-side and demand-side resources, makes increasing sense in such a scenario. Under such a regime, if an individual LSE "misses" its own resource adequacy target, there is less chance of an RTO-wide capacity shortfall than if the entire RTO misses the regional resource adequacy target. Moreover, since LSEs are closer to retail customers in their service areas than the RTO, they will have a clearer picture of the potential future impact of disruptive technologies that might reduce the need for capacity from wholesale level resources. RTOs will need to communicate more closely with their LSEs to obtain accurate data about retail customers' behind-the-meter DG and account for this in their overall demand projections so as not to over-procure capacity.

These concerns have led some public power systems to reconsider the appropriateness of continuing with a three-to-four year forward procurement construct. The high degree of reliance on administrative market mitigation rules, their complexity, and the many judgment calls that must be made by internal and external market monitoring groups certainly helps to highlight these concerns.

- **What is the role(s) of centralized capacity markets? Should the centralized capacity markets function as a mandatory market for procuring capacity or a residual market that entities only need to use to meet their resource adequacy obligations that they cannot otherwise meet through self-supply?**

As noted in its Statement at 11-17, and further discussed in Section IV of these Comments, APPA believes that the most appropriate end state role for RTO capacity markets is as a residual, voluntary market. APPA understands that this end state could take a substantial period of time to attain in PJM and ISO-NE, given just how far down the mandatory centrally procured capacity market rabbit hole these two regions have already gone. (The capacity market administered by the NY ISO is a different case, given that it is shorter term in nature, and better supports long-term contracting.[10]) But as APPA noted in its Statement at 11-13, many market participants have expressed great unhappiness with centralized mandatory capacity constructs, albeit for different reasons and at different times. Moreover, the barrage of *ad hoc* band-aid filings attempting to deal with perceived specific shortcomings of these markets continues apace. Even in the short time since the Technical Conference, PJM has made filings to modify the terms of DR and generation import participation in the RPM,[11] while ISO-NE has made (or is in the process of finalizing) two filings, one to implement its proposed PI construct for FCM capacity resources and another proposing rule changes for the next auction to deal with the "exigent circumstances" arising from an increase in generation retirements and a resulting projected resource deficiency.[12] For its part, the New England Power Generators Association ("NEPGA") has also filed a complaint asserting that the

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10 Tr. at 29 (Mukerji) ("The other feature which is important is the New York market allows bilateral contracts and self-supply, so we expect the load-serving entities to procure long-term and give the generating companies who are looking for a long-term financial commitment the ability to do that. Our market allows that. It allows load-serving entities into long-term contracts.").

11 "Revisions to the PJM OATT and Reliability Assurance Agreement Regarding Clearing Limited and Extended Summer Demand Resources," *PJM Interconnection, L.L.C.,* Docket No. ER14-504-000 (filed Nov. 29, 2013); "Revisions to the PJM OATT and Reliability Assurance Agreement Regarding Capacity Import Limit," *PJM Interconnection, L.L.C,* Docket No. ER14-503-000 (filed Nov. 29, 2013).

12 "Exigent Circumstances Filing of Revisions to Forward Capacity Market Rules," *ISO New England Inc.,* Docket No. ER14-463-000 (filed Nov. 25, 2013). APPA understands that ISO-NE will make its PI filing on or about January 10, 2014, but the concepts are discussed in the following document: Key Project: FCM Performance Incentives, http://www.iso-ne.com/key_projects/fcm_perf_incentives/.

administrative pricing rules allowing the ISO to pay lower capacity prices to existing resources than to new resources under certain circumstances where the FCM construct itself breaks down (such as insufficient competition) are unjust and unreasonable and seeking rule changes to increase prices to existing resources.[13] Where does it all end?[14]

For these reasons, APPA has in Section IV of these Comments set out a proposal that could be used to transition mandatory RTO capacity markets to voluntary residual markets. Under such a voluntary approach, RTOs, the state regulators in their respective footprints, and the affected LSEs could 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 substantial new investments. RTO-administered capacity markets would be *one way* to obtain capacity (especially on the 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.[15] If centrally administered capacity constructs are indeed vital to

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13 "Complaint of the New England Generators Association, Inc. and Request for Fast Track Processing," *New England Generators Association, Inc. v. ISO New England Inc.*, Docket No. EL14-7-000 (filed Oct. 31, 2013). Both the ISO-NE and NEPGA filings would exacerbate the problems consumers in the region face due to the post-qualification withdrawals of approximately 2500 MW of existing generation, which take the existing capacity in the region from surplus to deficit.

14 *See*, "Tranche Warfare," Public Utilities Fortnightly, December 9, 2013, *available at* www.fortnightly.com/fortnightly/2013/12/tranche-warfare (discussing the most recent controversies and filings regarding RTO capacity markets).

15 This concept is not far-fetched; in fact, it is used for other commodities. Tr. at 69 (Patton) ("Just in general, the way most commodity markets work is, you have a spot market that is physical, and there's price there. The forward markets are entirely voluntary. So people engage in a variety of forward contracting, based largely on the volatility of the spot

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.[16]

2. Accommodating state policies and self-supply by load serving entities

As discussed at the technical conference, States have policies to maintain resource adequacy and procure specific resources to meet environmental objectives. In addition, load serving entities are often interested in supplying their own resource adequacy requirements; some load serving entities (LSEs) have suggested that current centralized capacity market designs do not allow them to do so effectively. Incorporating States' policies and LSE preferences in the design of capacity markets has raised challenges for the Commission in ensuring the integrity of its wholesale markets.

- **In what ways do the current centralized capacity market designs facilitate, or hinder, the ability of market participants to enter into arrangements to supply their own resource adequacy requirements? Should the Commission consider changes to the current capacity market designs to facilitate these arrangements? How would any potential changes impact capacity market prices paid by LSEs and the price signals provided to capacity resources?**

As APPA explained in its Statement (at 5-7), public power systems in the three Eastern RTOs have continued serving their retail electric customers under their traditional not-for-profit, cost-based business model. (The same holds true for rural electric cooperatives in these RTO regions.) However, most of the states in the Eastern RTOs' respective footprints implemented retail access for their investor-owned utilities ("IOUs"). As a result, the IOUs in these states no longer have 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

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(footnote continued from previous page)

price and the expectation of what the spot price is going to be in the future. So therefore, gas markets and oil markets and so forth.").

16 *C.f.*, Tr. at 96 (Patton) ("A private capacity market would have been really, I think, useful to focus on first, and then figure out what residual role a capacity market needs.").

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. They are willing and able to make substantial long-term generation infrastructure investments to support new resources.

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 how these constructs would affect their future ability to obtain capacity (either contracted or self-built), as well as 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.[17] While the Commission initially approved these provisions as just and reasonable,[18] in 2011, the Commission effectively stripped these self-supply provisions out from the relevant PJM and ISO-NE market rules based on unsubstantiated arguments that these provisions

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[17] 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 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.

[18] *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), *order on rehearing*, 117 FERC ¶ 61,133 (2006), *remanded in part sub nom. Me. Pub. Utils. Commn v. FERC*, 520 F.3d 464 (D.C. Cir. 2008), *rev'd sub nom. NRG Pwr. Mktg. LLC v. Me. Pub. Utils. Commn*, 558 U.S. 165 (2010), *on remand sub nom. Me. Pub. Utils. Commn v. FERC*, 625 F.3d 754 (D.C. Cir. 2010), *on remand, Devon Power LLC*, 134 FERC ¶ 61,208, *reh'g den.*, 137 FERC ¶ 61,073 (2011), *rev. denied sub nom. New England Pwr. Gens. Assn. v. FERC*, 707 F.3d 364 (D.C. Cir. 2013). This string cite alone provides a clue as to just how controversial these constructs can be.

allowed LSEs to exercise unfettered "buyer-side market power."[19] 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.[20] APPA and its members have been attempting ever since to regain through both litigation and settlement the protections afforded by APPA members' specifically bargained-for, Commission-approved provisions to self-supply their own loads with their own resources using their own economics.

The primary concern, of course, is with the relevant MOPR provisions.[21] APPA members fear that an LSE's self-supply resource will not clear the relevant capacity auction due to upward bid mitigation, leaving the LSE in the position of having to pay

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[19] *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, Inc.*, 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*.

[20] *Astoria Generating Co., L.P. and TC Ravenswood, LLC v. New York Independent System Operator, Inc.*, 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."). The Commission has more recently approved NY ISO'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). The Commission also 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).

[21] APPA understands that an *ad hoc* group called the Supplier/Customer Coalition will file comments in this docket urging the Commission to eliminate the use of MOPRs in the Eastern RTOs and to abandon notions of spreading them elsewhere. APPA agrees with many of the points made in these comments.

twice for the same increment of capacity: once for the self-supply resource, and again for an allocation of the centrally procured capacity that must be purchased from the RTO's capacity market if the self-supply resource does not clear. This concern was succinctly stated by Patrick E. McCullar, CEO of APPA member Delaware Municipal Electric Corporation ("DEMEC"), in a written statement prepared in July 2011 for the Commission's Technical Conference in the PJM MOPR docket:

> It has been the standard practice of LSEs that self build capacity resources as self-supply to satisfy their capacity obligations for future years by being price takers in the RPM auction. That is, these LSEs offer their resources in at $0 to assure the self-supply resources clear the auction each year. This practice is utilized by the LSEs to obtain the necessary certainty that the resource will clear the auction each year because the RPM construct has shown significant price volatility from year to year and produces unpredictable results. Since irreversible major financial commitments have to be made by the LSEs that self build (because of the long lead times caused by regulatory rules and the PJM generation interconnection process), they must know that they will not be put in the position of paying for their self built resources and still being forced to pay RPM prices for their capacity obligation to PJM because the resource did not clear the RPM auction. This essential certainty was destroyed by PJM's Section 205 filing and the Commission's MOPR Order. This will endanger the ability of LSEs to develop and finance new generation resources subject to the MOPR.[[22]]

Mr. McCullar in his Statement (at 2-3) then described DEMEC's own near-death experience getting its new gas-fired generation resource located on the Delmarva Peninsula (a PJM load pocket) qualified in the RPM Base Residual Auction ("BRA") held in 2011 for the year 2014:

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[22] "Statement of Patrick E. McCullar on Behalf of the Delaware Municipal Electric Corporation and the American Public Power Association," *PJM Interconnection, L.L.C., et al.,* Docket Nos. ER11-2875-001, *et al.,* filed July 28, 2011, at 4 ("McCullar Statement").

My company was one of the first entities surprised and adversely affected by the unreasonably sudden PJM Section 205 filing to revise the MOPR and the subsequent issuance of the MOPR Order. Because DEMEC serves load in a constrained portion of the PJM footprint, it decided in 2007 to take action to build additional generation to self-supply a portion of its load obligation, to mitigate the impact on its load of continued high RPM auction prices. After extensive discussions with existing suppliers over several years, DEMEC could not find a bilateral contract arrangement to satisfy its long-term energy and capacity needs at a cost that was less than the self-build option. Therefore, DEMEC decided to self build. It subsequently made irreversible major financial commitments to undertake the expansion of its existing Beasley Power Station in Smyrna, Delaware to serve the load growth in its communities on the Delmarva Peninsula and to meet its ever-increasing capacity obligations to PJM. DEMEC had already advanced significantly through the PJM generation interconnection process and had the right to offer this new generation resource into the 2014 BRA under the previously applicable rules for self-supply resources set out in the MOPR.

In the wake of the [Commission's April 2011] MOPR Order, however, PJM required DEMEC to submit a cost-based justification in order to make a capacity offer that was less than the 90% of Cost of New Entry (CONE) specified by PJM in its filing. As a reference, the PJM-calculated CONE for a Combustion Turbine-Combined Cycle facility was $247.52/MW-Day. DEMEC's own cost-based calculation, using the CONE format as the only methodology available from PJM (as nothing was provided as guidance in complying with the new MOPR provisions), was a small fraction of the CONE.

The Independent Market Monitor (IMM) was the entity that was supposed to review and approve such cost-based offers, as set out in PP 118-121 of the MOPR Order. The IMM, however, was opposed to almost every point in DEMEC's initial cost justification offer. He stated that our financing model was "all wrong" and that the financing cost set out in DEMEC's *pro forma* financials was lower than what would be available to a merchant generation project that received no "subsidy." The IMM felt that DEMEC's access to tax-exempt financing as a not-for-profit public power system constituted a "subsidy," even though this was DEMEC's actual cost of financing. I also should note that DEMEC's A bond rating from Standard & Poors and the long-term requirements type contracts DEMEC has with its distribution system members also played a major part in DEMEC's ability to float bonds to finance its generation upgrade at the cost that it did. These features are fundamental components of the public power not-for-profit business model, and they enable public power systems to keep costs and rates to their members low.

> Nonetheless, the IMM wanted to add 200 basis points to DEMEC's actual financing rate without any justification, among other upward adjustments proposed. It was clear to DEMEC that the cumulative impact of the IMM's proposals would be to raise its offer number as high as possible. Such an upward mitigation of DEMEC's offer price, however, clearly created a high risk of stranding its already-made investment in DEMEC's new resource. DEMEC therefore strongly challenged the proposed mitigation. After intensive discussions, DEMEC and the IMM agreed to a mitigated offer that was still substantially higher than DEMEC's initial factually-supported, cost-based calculated offer. Fortunately, DEMEC's offer price for the new resource did clear the 2014 BRA. However, had DEMEC acceded to the IMM's original proposed upwardly mitigated offer price, DEMEC's generation resource would not have cleared the 2014 BRA, thereby stranding DEMEC's investment and causing irreparable harm to DEMEC and its communities. Surely this was not the intent of PJM and FERC, but this is what almost happened.

DEMEC's experience sent a shudder through the entire public power community. 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.[23] 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."[24] And to its

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[23] Lee Davis of NRG Energy questioned at the Technical Conference why an exemption for self-supply units is necessary, noting that state-sponsored entry has been able to clear the minimum offer price rule in New York. Tr. 131-32. The short answer is that, given what has happened both in New York and PJM with public power systems' self-supply units, public power LSEs will much less likely to undertake the development of new self-supply resources, due to the substantial uncertainty the MOPR provisions create. As Mr. Jablonski of the Public Power Association of New Jersey ("PPANJ") noted (Tr. at 138), "[w]e're facing great risk and uncertainty about whether we can go forward and be involved in the capacity market in terms of construction. . . .And if you're prevented in some way, shape or form by these rules, by saying to us, well, yeah, we understand that you can legitimately build for – just throw a number out, $100 a megawatt day, but we're going to mitigate that up to $175, just because of the market. Then we have to walk away."

[24] *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145 at P 209 (2011).

credit, PJM has attempted to address this situation. The Commission's approval of a subsequent PJM settlement attempting to implement a compromise for self-supplying LSEs, however, has engendered still more controversy and is even now being opposed by other PJM market participants on rehearing.[25] Accordingly, APPA and its members believe that Mr. Ott of PJM may have been channeling Pollyanna[26] when he said that "the issue of the self-supply, we're in a good spot. I think will coexist within the market." Tr. at 78.

Ironically, the very behavior that MOPRs and similar provisions discourage might be just what the Eastern RTO capacity markets should be incenting. Robert Ethier, who appeared at the Technical Conference for ISO-NE, opined that it would be helpful to RTO markets if there were more LSEs using such a long-term business model (Tr. at 91-93):

> I think if there were one thing I could change -- and I don't have a good way to go about doing this – it would be a more robust demand side of the market. What I see, a lot of the problems that arise with capacity markets, and the reason they're so controversial, is because the ISO is taking the role of the demand side, what ought to be the demand side of the market.
>
> A world with more robust bilateral engagement, with more robust load-serving entities, with long-term sort of obligations, frankly, to serve load, or at least long-term market interest in serving load, I think would facilitate this discussion a lot. Right now, what we have in New England is, we have the load-serving entities for a range of reasons, some of them

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25 *PJM Interconnection, L.L.C.*, Docket Nos. ER13-535-000, *et al*., 143 FERC ¶ 61,090 (2013), *rehearings pending*. As Mr. Jablonski noted regarding this docket (Tr. at 139): "So, you know, it just seems again the best solution is to go back to the 2006 provisions, notwithstanding what happens with the rest. Because we're in double jeopardy with the self-supply challenge and the somewhat unit-specific exception that's now evolving at PJM."

26 http://en.wikipedia.org/wiki/Pollyanna ("*Pollyanna* is a best-selling 1913 novel by Eleanor H. Porter that is now considered a classic of children's literature, with the title character's name becoming a popular term for someone with the same optimistic outlook.")

> regulatory, some of them market-driven, presumably, have a relatively short-term focus, and so that tends to prevent them from entering into long-term agreements with the supply side of the house.
>
> That makes these discussions much harder when you have one side and you have another side. I think these discussions, and the market, would be much more successful if you had that long-term counter-party to go with the resource side, which tends to be long-term in nature because these are long-lived investments.
>
> COMMISSIONER LA FLEUR: What would they do differently? They'd make more long-term contracts?
>
> MR. ETHIER: Yes. I think there are a lot of models out there. It could be long-term models. I think one model we're seeing evolving somewhat in New England is more of, you serve load and you also own generation, so that makes you have a more balanced perspective on the market, and also just sort of facilitates the market transactions. You're in the capacity market more for the spot, you know, sort of incremental long-short adjustments than you are for the entirety of your load.

APPA therefore believes that the Commission should implement changes to the current capacity market designs to facilitate LSE self-supply arrangements, both self-builds and power supply agreements. Doing so would at least support those load-side interests in the Eastern RTOs that still have a "balanced perspective" on the market, and avoid making an already unbalanced load/resource equation even more dysfunctional than it already is.

The Commission asks how any such potential changes would impact "capacity market prices paid by LSEs and the price signals paid to capacity resources."[27] There is past history here that the Commission could look to for answers—for example, as Mr.

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[27] This question seems to imply that any fall in prices would be attributable to self-supply. But it should not be automatically assumed that self-supply is the culprit when prices are low. Rather, low prices may be the natural consequence of a functioning "market" where prices drop when demand drops. Further, if the capacity construct is truly residual, it should come as no surprise that leftover capacity prices may be low (or high, depending on supply and demand conditions on the margin).

McCullar noted, the BRAs that PJM ran from RPM's inception until the 2011 auction were run under the "guaranteed clearing" provisions of the original RPM settlement. Despite the presence of guaranteed clearing, the PJM IMM determined annually that although "the potential for the exercise of market power continues to be high," because of mitigation measures, the prices resulting from the PJM RPM auctions were consistent with competitive outcomes, based on his application of mitigation measures.[28] Interestingly, one of the market structure features the IMM has identified each year as contributing to the potential for the exercise of market power is the "relatively small number of nonaffiliated LSEs" – an issue that will only be exacerbated by restrictions on those nonaffiliated LSEs' ability to self-supply their needs.

And ironically, while the Commission held that bidding by new self-supply capacity could adversely impact price formation in the ISO-NE region,[29] after new self-

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28 In all of his State of the Market Reports since the inception of RPM in 2007, the IMM reported that "the market design for capacity leads, almost unavoidably, to structural market power. . . .Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues." As a result, the IMM found that for each year, "the Capacity Market results were competitive." *See* PJM State of the Market Reports 2007 through 2012, Capacity Markets, Section 5 (2007 – 2010) or Section 4 (2011 and 2012), *available at* http://www.monitoringanalytics.com.

29 The Commission's most complete explanation of the thought process that led it to require "offer floor mitigation" for new self-supply, and concomitantly limit or eliminate rights for which New England's public power systems had bargained in the region's 2006 FCM Settlement, appears in its order on rehearing in the New England FCM Redesign Paper Hearing. *ISO New England Inc.*, 138 FERC ¶ 61,027 at PP 71-81 (2013). In that discussion, the Commission explicitly re-balanced the bargain struck in the 2006 FCM Settlement to the detriment of self-supply (*id.* at PP 74-75) and concluded that New England's public power systems that had lost the benefit of their 2006 bargain "may avail themselves of the internal market monitor's case-by-case cost justification process for new entry offers that are below their asset-specific benchmark, and may work through the stakeholder process to further address their concerns" (*id.* at P 78). On the former point, the Commission's encouragement to ISO-NE and its stakeholders "to consider whether further refinement of this cost justification process will address the Commission's concern that mitigation of self-supply not automatically deem suspect long-standing and well-recognized business models" has been completely neglected in ISO-NE's

supply capacity was made subject to Offer Review Trigger Prices under the FCM market rules, the market appears to have anticipated the effect of Commission-ordered elimination of the New England Forward Capacity Auction's price floor to be capacity prices falling to a point where substantial incumbent generation resources, *e.g.*, Entergy's Vermont Yankee nuclear plant (604 MW) and Energy Capital Partners/EquiPower's Brayton Point generating station (1545 MW), submitted requests to ISO-NE to retire after the close of qualification evaluation for New England's next Forward Capacity Auction. A total of 7,851 MW of capacity resources in New England submitted delist bids for Forward Capacity Auction No. 8 ("FCA 8") at prices above the $1 per kW-month dynamic delist bid threshold. Subsequently, a total of 1,907 MW from 98 of these resources converted these delist bids into Non-Price Retirement requests. ISO-NE has also reported anecdotally that it was surprised by the number of proposed new resources that filed Show of Interest certifications for FCA 8 but ultimately withdrew from the auction during the qualification process. Given that self-supply in New England is currently subject to Offer Review Trigger Prices, these events cannot be attributed to its allegedly price-suppressive tendencies.

Hence, experience teaches that, given LSEs with the motive and opportunity to self-supply are currently in the minority in the Eastern RTOs, it is unlikely that the restoration of prior market rules permitting them to pursue their business model will,

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development of its Offer Price Review Trigger system (*ISO New England Inc.*, 142 FERC ¶ 61,107 at PP 38, 56 (2013)), and the ISO-NE stakeholder process has failed in any other respect to restore any reasonable equivalent for the new capacity self-supply rights eliminated in New England's FCM Redesign exercise.

standing alone, have a substantial adverse impact on capacity prices. Rather, it is more likely that any such price effects will be lost in the price volatility "noise."

In spite of this real world experience, APPA is aware the Commission has found in the case of PJM that a small amount of capacity offered at low prices could have a significant impact on the market, particularly in the context of a vertical demand curve.[30] APPA does not concede that this finding is correct. But in any case, the Commission has since accepted a new self-supply exemption in PJM and found that PJM's net-short thresholds adequately protect the market against the price impacts of uneconomic new self-supply.[31] Hence, even the Commission has acknowledged that allowing self-supply does not trigger the death knell of capacity market price signals.

Even assuming *arguendo* that the actions of self-supplying LSEs could somehow "move the needle" and unduly lower auction prices on the margin, it should not automatically be assumed that this is an undesirable result. It is well established that the use of long-term contracts, *e.g.*, power purchase agreements, better supports the financing of new generation resources. Use of such arrangements results in financing at a lower interest rate, which in turn leads to lower ultimate costs to consumers than generation

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[30] *PJM Interconnection, L.L.C and PJM Power Providers Group v. PJM Interconnection, L.L.C*, 135 FERC ¶ 61, 022 at P 196 (2011)(rejecting *de minimis* self-supply exemption for municipal utilities and cooperatives by reasoning that "the sloped demand curve used in PJM's base residual auctions is very steep, and as a result, even small amount of additional supply can result in large price reductions."); *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145 at P 62 (2011) (PJM met its FPA section 205 burden by demonstrating that eliminating the MOPR impact test would "prevent uneconomic entry, particularly given its observation that even a small change in the clearing price from a below-cost offer can harm competition").

[31] *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090 at P 107 (2013), *rehearing pending*.

resources built "on spec." [32] Use of CONE estimates that are inflated with assumptions based on the higher financing costs associated with speculative merchant projects increase costs to consumers, and, because of the single clearing price structure of the capacity auctions, results in higher payments to *all resources*, existing and new. Institutionalization of the merchant resource development model through biased CONE estimates (especially when coupled with MOPRs that arbitrarily increase the bids and the risks associated with resources constructed under other, lower-cost business models) artificially biases the marketplace in favor of the merchant business model with its higher risks and high returns, rather than a lower risk, more stable price paradigm.[33] While it is clear that merchant generators benefit from this regime, it is less clear that retail electric consumers do.

Since their business model is more supportive of investments in new resources of all types at lower costs, APPA questions why public power LSEs interested in self-supply transactions must wear the buyer-side equivalent of the Scarlet Letter. Public power LSEs' self-supply resources seem to be automatically suspect, such that they must be carefully reviewed and potentially mitigated, even when they can show their costs are

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[32] Tr. at 106 (Dumoulin-Smith) ("The cost of capital is inversely related with the duration of the contract allowed for."). Especially in the case of renewable resources, long-term contracting is extremely important for generation development. For example, the American Wind Energy Association reported that of the 2,327 MW of wind power resources under construction as of September 30, 2013, or at least 1,650 have long-term power offtake agreements in place. AWEA U.S. Wind Industry Third Quarter 2013 Market Report, *available at* http://awea.files.cms-plus.com/AWEA%203Q%20Wind%20Energy%20Industry%20Market%20Report%20Executive%20Summary.pdf.

[33] Courts have not been concerned with monopsony (buyer-side) low prices unless they are predatory (*i.e.*, below marginal cost), and that happens only rarely. Measures that consumers take to protect themselves from high prices are not anticompetitive – they are procompetitive. *See Kartell v. Blue Cross/Blue Shield of Massachusetts*, 749 F.2d 922, 930-931 (1st Cir. 1984) (Breyer, J.).

indeed lower. In the Commission's efforts to protect an administrative centrally procured capacity market construct of questionable benefit to consumers, it threatens to fundamentally undermine the long-standing business model of public power entities. This is ironic, given that the express purpose of forming public power entities in the early part of the last century was to provide a check on the greed of privately-held power providers. Franklin Delano Roosevelt, who had an important hand in the formation of many public power entities, expressed it this way:

> Again we must go back to first principles: A utility is in most cases a monopoly, and it is by no means possible, in every case, for Government to insure at all times by mere inspection, supervision and regulation that the public get a fair deal--in other words, to insure adequate service and reasonable rates.
>
> I therefore lay down the following principle: That where a community--a city or county or a district--is not satisfied with the service rendered or the rates charged by the private utility, it has the undeniable basic right, as one of its functions of Government, one of its functions of home rule, to set up, after a fair referendum to its voters has been had, its own governmentally owned and operated service.
>
> That right has been recognized in a good many of the States of the Union. Its general recognition by every State will hasten the day of better service and lower rates. It is perfectly clear to me, and to every thinking citizen, that no community which is sure that it is now being served well, and at reasonable rates by a private utility company, will seek to build or operate its own plant. But on the other hand the very fact that a community can, by vote of the electorate, create a yardstick of its own, will, in most cases, guarantee good service and low rates to its population. *I might call the right of the people to own and operate their own utility something like this: a "birch rod" in the cupboard to be taken out and used only when the "child" gets beyond the point where a mere scolding does no good.*[[34]]

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[34] Works of Franklin D. Roosevelt, "The Portland Speech—A Campaign Address on Public Utilities and Development of Hydro-Electric Power," given in Portland Oregon on September 21, 1932 (emphasis supplied); *available at* http://newdeal.feri.org/speeches/1932a.htm.

The Commission should not break across its knee the "birch rod" that FDR worked so hard to give our nation's citizens.

Finally, self-supply is only one of many resource choices and retail-level policy decisions that can affect capacity auctions. This was the subject of an exchange between Commission LaFleur and Robert Erwin of the Maryland Public Service Commission at the Technical Conference (Tr. at 213-16):

> COMMISSIONER LA FLEUR: Mr. Erwin and Mr. Bentz, among others, both argued that state renewable contracts, or purchases made pursuant to state renewable rules, should be exempt from minimum-offer pricing requirements, because there's no intent to suppress the market. They're not being done intentionally to suppress the price. I'll grant that. They're being done to meet environmental standards for environmental reasons.
>
> But my question is: don't they have the same effect nonetheless on reducing the price we're relying to send the investment signal? So, I mean, regardless of benign intent -- more than benign, very worthy intent -- don't they have the same effect on the market?
>
> * * *
>
> MR. ERWIN: Commissioner, the answer to your question is, yes. Another megawatt in the market has an effect on prices, and it will depress them.
>
> But I would also point out to you that it's no different than a state which now says, we're going to have emissions limits on power plants. A power plant closes because they can't meet them, reduces the amount in the market, and that's going to help raise them.
>
> Yes, they're going to have [an] effect on prices. But it's going to work both ways -- or it could work both ways. Let me phrase it that way.

For all of these reasons, APPA believes that restoration of the self-supply rights that its members negotiated at the time mandatory capacity markets were instituted is appropriate, just and reasonable.

- **Some panelists suggested other potential modifications to the existing centralized capacity markets to accommodate self-supply and/or state policies, including limited or resource class-specific exemptions from**

buyer-side mitigation rules, or offsetting reductions in the amount of capacity procured in the centralized capacity market. What are the advantages or disadvantages of such changes? Are there additional potential changes to particular design elements that should be considered to accommodate self-supply and/or state policies? How would any potential changes accommodate the long-term price signals that several panelists argued are necessary for capacity investment?

APPA in its Statement (at 8-11) suggested two alternatives to accommodate self-supply: (1) to restore the original self-supply provisions in the market rules of the Eastern RTOs, in particular reversing the 2011 PJM and ISO-NE MOPR Orders;[35] or (2) require the RTO to demonstrate a showing that a self-supplying LSE specifically intends to exercise "buyer-side market power" prior to mitigating that LSE's capacity bid in a particular auction.[36] As APPA explained, 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

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35 *See also,* Tr. at 163-164 (Tatum) ("I think that's the right way to go. I think that that is the sweet spot, if you will, and we actually did indeed initially set [a residual market] up in the original 2006 [PJM] settlement. Now, I heard a lot of folks on the previous panel talk about compromises. Well, I think compromise is a good thing, especially when you're marrying a theory of economics to the practical realities of the grid, and the number of different players and business models that come through there. And we came up with something that was indeed workable, but a major component of that original construct was: self-supply would clear. There was a mechanism in there whereby, if the price was affected, that we'd be able to adjust it. And then both buyers and sellers would bear some of the responsibility for that, and our friends at the states had an ability, based upon reliability issues, if they needed, to move forward as well. That was residual to me.").

36 *C.f.,* Tr. at 184 (Tatum) ("I think another thing that I really would like to happen is, I would like us to stop looking behind every tree for that monopsony power bogeyman. In 2006, in the eleventh hour when we were negotiating this, our folks came back and told us, after Judge Brenner locked us in, that they were concerned about -- types of organization like the Old Dominion Electric Cooperative, exercising monopsony power. I said, 'They think I'm going to do what?' It was incomprehensible. But nonetheless, we continued to work through this. It's very, very difficult, as you have to think about intent. You have to think about incentive and ability. It's a very, very risky, risky business for someone to try to get in there and actually do something solely to tank that price. So that's another concern I have.").

determined *by the LSE*, not the RTO's single-year 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.[37]

Such resources could make eminent good sense to the self-supplying LSE developing them, but they might appear to be "uneconomic" to an RTO market monitor using a short time horizon and narrow CONE-based offer floors, as Mr. McCullar experienced in his negotiations immediately prior to the April 2011 PJM BRA.[38] 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 an unwarranted federal intrusion into state and local resource planning.[39]

There are obviously other steps that can be taken to make the path for self-

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[37] Just one example: during the 2003 blackout, some municipal power systems in the affected region learned that the availability of local generation could be quite important to continuation of their sewage treatment and potable water system operations.

[38] *See also*, "Written Statement of James A. Jablonski on behalf of the Public Power Association of New Jersey" ("PPANJ Statement") at 4-5 (discussing the uncertainties created for PPANJ member City of Vineland, NJ, and other PPANJ members due to the loss of guaranteed clearing and current challenges to PJM's most recent self-supply tariff provisions).

[39] APPA thus questions the assertions of some witnesses at the Technical Conference that it is acceptable to mitigate self-supply bids while allowing a merchant generator to "make a judgment different from the rest of the market" and "put their funds at risk," such that such generators can make an unmitigated bid under a "competitive entry" exemption. Tr. at 113 (Shanker). If these market participants can be allowed to make unmitigated bids, then consumer-owned self-supplying LSEs should be permitted to do so as well. As noted above, there may be many very legitimate reasons why such an LSE might make a "judgment different from the rest of the market."

supplying LSEs easier, including the "net short/net long" tariff provisions that PJM proposed and the Commission approved in Docket Nos. ER13-535-000, *et al.* APPA's observation, however, is that incremental tariff provision packages such as the one PJM developed are never free from controversy. Even assuming that the Commission finally approves them, they are subject to constant review and potential revision in RTO stakeholder processes. APPA believes that the preferred approach would be to have a clear Commission policy that LSE self-supply is not just to be tolerated through narrow tariff exceptions, but should be affirmatively encouraged, for the reasons that Mr. Ethier enumerated. A return to the originally negotiated self-supply provisions that public power and cooperative systems in PJM and ISO-NE had originally negotiated would go far towards providing such clarity. [40]

APPA questions the wisdom of implementing "resource class-specific exemptions from buyer-side mitigation rules," even if those provisions are well-intentioned. Conferring preferred status on certain classes of resources involves judgment calls that federal policy makers should be leaving to individual decision-making by state and local resource planners. One need think no further than the ill-considered federal policy embodied in the Powerplant and Industrial Fuel Use Act of 1978,[41] which substantially restricted the use of natural gas as a fuel for electric generation. This policy led to increased reliance on coal-fired generation in many regions of the country—regions that

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[40] Tr. at 116 (Jablonski) ("But I believe I speak for [municipals] and rural electric coops: we don't want an exception or an exemption. We just want you to put back the way it was the 2006 provision under the [PJM] settlement. We don't bother you, you don't bother us -- however you want to put it. But that gives us the opportunity to fulfill our mission.").

[41] For an explanation of this Act and its subsequent repeal, see http://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/repeal.html.

are now attempting to deal with the cumulative adverse impact of a suite of current and proposed federal environmental regulations adversely impacting that very same coal-fired generation. State and local resource planners should be free to develop diversified resource portfolios without having to deal with artificial constraints imposed by arbitrary federal policies and discriminatory capacity market rules for specific types of resources.

The Commission expresses concern that potential market rule changes to accommodate self-supply might disrupt "the long-term price signals that several panelists argued are necessary for capacity investment." APPA was among the parties at the technical conference arguing that long-term price signals are necessary for capacity investment. But those price signals do not come from the Eastern-style mandatory capacity markets, which generally provide a one-year capacity price signal three or four years in advance. Long-term bilateral contracts provide a better price signal for long-lived, capital-intensive generation assets. Hence, market rule changes to accommodate self-supply should not disrupt such price signals—if anything, they might better support them, by creating a more hospitable environment for bilateral agreements for both buyers and sellers. As Mr. Ethier noted, under such a regime "[y]ou're in the capacity market more for the spot, you know, sort of incremental long-short adjustments than you are for the entirety of your load." This is the appropriate role for capacity markets and the price signals they provide.

- **PJM offers LSEs the alternative to opt out of its capacity auction by using the Fixed Resource Requirement (FRR) option. Should such an alternative be offered in other eastern Regional Transmission Organization (RTO)/Independent System Operator (ISO) centralized capacity markets? Given that the FRR option was originally developed to address a narrow set of circumstances facing the PJM region and its market participants at that time, would modifications to this alternative be appropriate to meet the needs of regions and**

> **market participants today? For example, are there changes to the current FRR option that could be adopted to allow increased flexibility for entities looking to partially self-supply their capacity requirements while preventing adverse impacts on the competitiveness of the market?**

APPA does not favor institutionalization of an FRR-style regime, as it would effectively isolate self-supplying LSEs from regional markets. As the Commission notes, the FRR regime was developed through settlement negotiations to address a narrow set of circumstances facing the PJM region at the time the RPM tariff provisions were negotiated. The FRR Alternative as formulated under the PJM tariff may be a viable option for certain LSEs that are net long on capacity resources and capable of supplying all of their capacity obligations plus reserve requirements for their entire FRR Service Area for a five-year period. But most public power LSEs do not have unlimited capacity resource options for self-supply and would be placed at disproportionate risk if required to meet the FRR Alternative criteria.

Public power distribution utilities are units of state and local governments. Many of them in the Eastern RTO regions have formed joint action agencies ("JAAs") to obtain wholesale power supply and transmission services on their behalves. Most public power distribution utilities are "full requirements" customers of their JAAs, but there are some that are "partial requirements" customers, and still others that participate in specific power supply projects. Hence, JAAs develop their own diversified portfolios of wholesale power supplies and other resources, including self-supply projects, bilateral contracts of varying lengths and terms, market purchases and behind-the-meter generation, to meet the needs of their member distribution utilities. All, however, have the same objective: to procure a reliable supply of power for each member utility's citizen-owners at a reasonable and stable cost.

APPA understands that certain of its members with loads and resources in the PJM footprint will be filing specific comments dealing with the FRR issue. APPA therefore directs the Commission to those comments. In addition, APPA notes that the difficulties a PJM-style FRR presents for public power LSEs include:

- **<u>Variability of Capacity Obligations</u>**: The FRR Alternative is designed for LSEs that are net long on capacity resources. It requires the subject LSE to supply all of its capacity obligations plus its reserve requirements for its entire FRR Service Area[42] for a five-year period. Some public power LSEs in the Eastern RTO regions do not have sufficient self-supply and contracted for resources to meet this requirement. Moreover, maintaining such a substantial net long position could risk incurrence of

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[42] PJM defines the FRR Service Area as, "(a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within such area. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above." PJM Reliability Assurance Agreement ("RAA"), Article 1, Section 1.31.

stranded costs, if public power LSE loads decline year-to-year due to adverse economic conditions, increased use of EE and DR, or increased penetration of third-party DG. Capacity arrangements should be able to vary from year to year, depending on the projected and actual loads and obligations of participating distribution member utilities, and the assumptions used in regional resource adequacy calculations. The five year FRR commitment fails to accommodate the potential variability in demand in the ordinary course of business.

- **No Residual RPM Purchases**: LSEs electing the FRR Alternative may not purchase capacity in the RPM BRAs or the incremental auctions. PJM Reliability Assurance Agreement ("RAA"), Schedule 8.1(B). Even if a public power LSE (especially a smaller one) were to have sufficient resources owned or under contract to meet the FRR provisions, unforeseen circumstances, *e.g.*, an unanticipated extended outage at a major generation unit, could create real problems with FRR compliance going forward. Moreover, when public power utilities in PJM and ISO-NE agreed to the original RPM and FCM settlement provisions, it was clearly understood by all, *including the Commission*, that these markets would be residual in nature, and available to LSEs on that basis.[43] To now require

[43] PJM's Base Residual Auction was intended to supplement capacity that LSEs would obtain elsewhere. RPM was to provide "price signals and price stability" that would allow LSEs to "make their own business decisions about how much capacity to build or procure in long-term contracts and at what cost, and how much to obtain through PJM's auction." *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 at P 169. The Commission even noted that "[u]nder RPM, LSEs may procure capacity in advance and outside of the … procurement auction… . [C]apacity that is procured in advance would be offered into

self-supplying LSEs to abide by the draconian provisions of an FRR construct would constitute a fundamental (and unfair) retrading of their original bargain.

- **<u>Unavailability of Bilateral Contract Options in the Marketplace</u>**: While bilateral contracts may be included in an LSE's FRR supply plan to cover any shortfall that would otherwise be purchased through RPM, APPA members report that it is difficult (if not impossible) to find existing generators in PJM today willing to sell capacity in bilateral arrangements at competitive prices that reflect their long-run cost of investment. Prior to implementation of the RPM regime, bilateral deals from existing generating facilities were generally available in PJM for self-supply. Since PJM's implementation of RPM, excess capacity from existing generators has been extremely limited for bilateral deals, either because there is no excess or because existing generators prefer selling any excess that does exist into the short-term, one-year RPM auctions, particularly in LDAs with high clearing prices. While an LSE might be able to find sufficient available bilateral opportunities to satisfy a portion of its capacity obligations, the requirement to obtain enough capacity through bilateral arrangements to self-supply all of its capacity obligations not met through owned capacity carries significant risks for public power LSEs.

(footnote continued from previous page)

the auction at a price of $0, but it would receive the applicable market-clearing capacity price established in the auction." *Id.* at P 91.

- **<u>Non-Compliance Penalty</u>**: Another deterrent to an LSE's ability to use the current FRR Alternative to self-supply its capacity obligations is the disproportionately higher penalty for non-compliance under the FRR Alternative, as compared with the "standard" penalty for non-compliance with RPM auction rules.[44]

- **<u>Restrictions on the Sale of Excess Capacity</u>**: The lumpy nature of investment in generation results in a risk to the LSE using the FRR Alternative that the capacity in the early life of the resource that may be in excess of the LSE's needs, will become stranded given the significant restrictions under the FRR rules on an LSE's ability to sell that excess capacity into RPM auctions. PJM RAA, Schedule 8.1. Specifically, while an FRR entity is permitted to sell excess capacity into the RPM auctions, the sales are limited by both a minimum and a cap. An FRR entity may only offer to sell its capacity that is in excess of the "threshold quantity," which essentially is the unforced capacity ("UCAP") equivalent of the installed reserve margin multiplied by the forecast peak load plus the

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[44] An LSE using the FRR Alternative that fails to submit its annual qualified plan demonstrating that it can satisfy 100% of its reliability requirements in any year is subject to a penalty of 2 times the gross CONE for each MW of deficient capacity. PJM RAA, Schedule 8.1(D)(7). The LSE also may be subject to an FRR Capacity Deficiency Charge for failure to satisfy its Daily Unforced Capacity Obligation of 1.2 times the weighted average RPM clearing price for all RPM auctions for the zones covered by the FRR plan. PJM RAA, Schedule 8.1(F)(2). These penalties likely will influence the price of the bilateral purchase, assuming capacity is available for a bilateral transaction. In contrast, the penalty for falling short of capacity commitments under RPM is the RPM auction clearing price plus the greater of 0.2 times that price or $20/MW-Day times the amount of the capacity deficiency, a lower charge than either of the deficiency charges imposed under an FRR plan. PJM Tariff, Attachment DD, Section 8.2, referencing the Daily Deficiency Rate in Section 7.1(b) of Attachment DD.

lesser of 3% of the UCAP or 450 MWs. RAA 1.82 Threshold Quantity; RAA Schedule 8.1 E. 2. However, the FRR entity may not offer to sell excess capacity that exceeds an amount equal to the lesser of: (1) 25% times the UCAP equivalent of the installed reserve margin for the delivery year times the forecast peak load; or (2) 1,300 MWs. RAA Schedule 8.1 E. 2. Thus, the threshold quantity creates a nominal amount of capacity above the required peak load forecast plus reserve margin that the FRR entity is not allowed to sell. And, even if the FRR entity has capacity above and beyond that extra reserve margin, it is restricted to selling only the excess capacity up to that limit. For most public power LSEs under the FRR option, these limitations would effectively strand substantial capacity in excess of the LSE's needs. This would be an uneconomic and suboptimal use of capacity resources.

- **Changes in LDA Boundaries**: The potential for changing LDA boundaries with differing internal minimum resource requirements, in combination with the five year length of the existing FRR Alternative rule, makes the use of FRR a riskier option for public power LSEs serving loads in constrained LDAs. LDA boundaries can be modeled and potentially altered under the existing RPM rules for a variety of reasons, including PJM discretion. PJM Tariff, Attachment DD, Section 5.10(a)(ii). A change in such boundaries during a five-year FRR plan may well result in a requirement to obtain a greater percentage of resources to satisfy capacity obligations from resources within the new LDA boundaries than existed at the time the LSE developed its initial five year FRR resource plan. Such a change would impose on the LSE a potentially significant risk that excess capacity from internal resources in the newly defined LDA may not be available for a bilateral transaction or that the owners of those resources may not be willing to sell that excess capacity in a bilateral transaction at reasonable and economic prices.

- **<u>Unanticipated RTO Migration</u>**: The five year FRR plan requirement also adds risk resulting from transmission owner migration between RTOs. JAAs with public power system members embedded in the transmission system of a migrating transmission owner must be able to export power from resources in one RTO for the beneficial use of that JAA's members located in another RTO or in non-RTO areas.[45]

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[45] For example, APPA member American Municipal Power, Inc. ("AMP") has public power distribution system members that it serves using the American Transmission System Inc. ("ATSI") transmission system and the Duke Energy Ohio ("Duke") transmission system. These "embedded" AMP members were forced to transition from MISO to PJM because of migration decisions made by ATSI and Duke, although AMP itself continues to have a substantial portfolio of existing and planned generating resources located within the MISO footprint, including several existing and planned hydroelectric generating plants located along the Ohio River in Kentucky and AMP's 23 percent ownership interest in the 1,600 MW Prairie State Energy Center, located in Southern Illinois. Importantly, in spite of the resulting separation of AMP's generation resources from its loads, these generating resources continue to be dedicated to serving the needs of AMP's members, including those members that were effectively pulled from MISO into PJM by the decisions of ATSI and Duke. AMP had to spend considerable time and energy negotiating the necessary arrangements to achieve this result, including the negotiation of firm point-to-point transmission service over the MISO transmission system and payment of the associated study costs. It has had to pay unanticipated ancillary service charges to MISO to transmit power from these long-planned resources to the MISO-PJM border. And the November 29, 2013 filing by PJM to limit capacity imports from MISO into PJM could make it even more difficult for AMP to serve its members in PJM with these generation resources. *See*, "Protest and Motion for Suspension and Other Relief by American Municipal Power, Inc." filed on December 20, 2013, in *PJM Interconnection, L.L.C.,* Docket No. ER14-503-000.

As the above bullet points illustrate, the FRR provisions are intricate and complex, presenting public power LSEs with substantial ongoing difficulties and imposing significant risks upon them. And of course, the FRR provisions (like so many other RTO tariff provisions) can be revised at any time, even while a public power LSE is attempting to comply with the current provisions, including the five-year time limitation.

While no doubt the Commission, RTOs and stakeholders could spend endless hours debating potential modifications to the current FRR construct to make it minimally usable by public power and other self-supplying LSEs, APPA does not favor institutionalization of an FRR-type regime. Doing so would effectively ring-fence self-supplying LSEs out of regional markets, sending the signal that these participants must be isolated to prevent their business model from somehow infecting the rest of the market. Instead, as noted in response to previous questions, self-supplying LSEs should be supported and their business model encouraged, for all of the reasons Mr. Ethier noted. Implementation of an FRR-type regime for self-supply would effectively penalize these LSEs for undertaking responsible actions to ensure their future resource adequacy. The Commission therefore should not adopt such a policy measure.

3. Market Design Elements

Throughout the technical conference, comparisons of the RTO/ISO capacity markets and market design elements were made, including whether there is a need for consistency in the approach to capacity markets across the eastern RTOs/ISOs and the interaction of the capacity market with other RTO/ISO markets. Panelists suggested that consistent approaches with respect to some design elements could improve the ability of market participants to participate in multiple markets.

As noted at the Technical Conference (Tr. at 280-81), APPA would not favor enforcing "consistency in the approach to capacity markets across the Eastern RTOs" through a "standard capacity market design" or institutionalization of "best practices."

APPA fears that any such effort would turn into an effort by generators to take the specific market rules from each market most favorable to their own economic interests and institutionalize them across all three RTOs.[46] Such a "Franken-market" might maximize generator revenues, but would constitute a capacity market race to the bottom that would not benefit consumers.

Moreover, the circumstances on the ground in the three RTO regions are very different. New England is facing the limits of increased reliance on natural gas and the retirement of substantial carbon-free base load resources. PJM, on the other hand, is facing the retirement of substantial coal-fired capacity as a result of increasing EPA regulation and low natural gas prices. New York is in the midst of a very substantial state-sponsored effort to plan its energy future. Each RTO should have the flexibility to address the issues facing it, without having to rebut assertions that specific capacity market design features from other markets should be imported wholesale because they are "best practices."[47]

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[46] APPA members in the ISO-NE region have already experienced the negative impact of one such export of a "best practice" from another RTO region, when the Commission ordered a MOPR instituted in New England, but did not limit the application of the MOPR to specific types of generation resources (as had been done in PJM), instead making it apply across the board to all new generation resources.

[47] *C.f.,* the "Capacity Suppliers Initial Brief" filed in *Midwest Independent Transmission System Operator, Inc.*, Docket No. ER11-4081-001, on October 11, 2013 at 11-12 ("A MOPR is a very important tool to ensure efficient and competitive markets, but a MOPR alone cannot prevent the unlawful exercise of buyer market power and uncompetitive markets. To protect competition, it is necessary to have a workable, competitive construct in the first place. Just as the [Fixed Resource Adequacy Plan] can be used to bypass the MOPR, so too can MISO's voluntary capacity market be used by buyers to bypass any MOPR to manipulate capacity prices. Indeed, to ensure a competitive, just and reasonable capacity market in MISO that can effectively mitigate buyer market power, *it is essential for the Commission to adopt a mandatory market as in the Eastern RTOs*.")(footnotes omitted)(emphasis supplied).

Finally, there is a fundamental tension between the "standardization" of a uniform capacity product across regions with centrally administered capacity markets and the other stated objective of centralized capacity markets: to "appropriately value and compensate capacity in constrained and unconstrained regions."[48] It is certainly possible to debate the construct, and the efficacy of current centralized market mechanisms at attaining that stated objective. The tension between "standardization" and the "locational value" rationale for centralized capacity markets should, however, be acknowledged and addressed. Otherwise, the dysfunctions already apparent in these administered pricing constructs will only be further exacerbated.

- **Derivation of Net Cost of New Entry (CONE). Panelists did not focus extensively on the derivation of Net CONE, although it was discussed in the staff white paper. Are there improvements to the derivation of Net CONE that would improve the functioning of capacity markets? How do differences in the derivation of Net CONE across the RTOs/ISOs impact the markets?**

As previously noted, CONE estimates that incorporate financing assumptions based implicitly on the merchant generator model inappropriately exclude from legitimate consideration the use by at least some market participants of other business models, including models that rely on the use of long-term contracts to support needed new generation infrastructure at a lower cost to consumers.[49] APPA believes that the merchant generator bias in CONE calculations effectively insulates this class of market participant from competition from other, more stable business models, and should be

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[48] *Devon Power LLC*, 109 FERC ¶ 61,154 at P 44 (2004).

[49] *See, e.g.*, *Astoria Generating Co., L.P. and TC Ravenswood, LLC v. New York Independent System Operator, Inc.*, 140 FERC ¶ 61,189 at P 135 (2012). APPA and the New York Association of Public Power, as well as many other load-side representatives and other interested parties (such as the Natural Resources Defense Council), sought rehearing of this order in July 2012. These rehearings have now been pending before the Commission for more than a year.

addressed.[50] APPA also notes that concerns were expressed at the Technical Conference about substantial increases in estimates of CONE from auction to auction, which modifies the relevant demand curves, increasing clearing prices.[51]

- **Length of forward period. Panelists debated the merits of a longer or shorter forward period in centralized capacity markets. Some argued that a longer forward period can aid in managing retirements; others argued that a shorter forward period facilitates bilateral contracting. What are the advantages, disadvantages and related considerations that may support longer or shorter forward periods? Should the length of the forward period vary for different categories of resources (traditional generation, new resources vs. existing resources, demand response, energy efficiency, distributed generation, etc.**

APPA believes that a shorter forward period better supports long-term contracting.[52] Potentially disruptive technologies could soon affect RTO resource adequacy requirements in unanticipated ways. Locking an entire RTO region into a long-term mandatory capacity market construct would rob LSEs in the region of needed

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[50] On the other hand, one could argue that the prevalence of offer floor mitigation, MOPRs and similar administrative limits on the free interplay of supply and demand make estimates of CONE largely redundant.

[51] Tr. at 185 (Tatum) ("Panel 1 today talked about the long-term view, and net CONE over the long term. I'm an engineer, so I don't have the horsepower a lot of the other folks have, but I don't know that we've had the wrong results over the past few years. I don't know if we haven't solved the missing money. I worry that the missing money might now actually be coming out of my pocketbook -- (Laughter.) -- because our net CONE has increased, almost doubled, since the time we actually put it in, and that has changed the shape of the curve.").

[52] As David Patton noted (Tr. at 62) (emphasis supplied): "Lastly, I'll just hit forward procurement quickly. It's important -- I think there's a problem sometimes that I run into in talking to people in this industry, and that is they have this notion that if the ISO does not run the market, the market doesn't exist. So if people say things like, 'I need to be able to lock in revenue in order to build a unit, and I need to be able to lock that in three years in advance, four years in advance,' sometimes there's the notion that, 'Well, the ISO needs to facilitate that market.' *Well, there actually is a forward bilateral market, and the kind of lock-in most investors are looking for is lock-in of five, ten, fifteen years' worth of revenue. So they want a contract. The important thing for the RTO to do is to facilitate markets, or to have markets that will facilitate that efficient contracting process. And the RTO markets that do that don't have to be procured three years in advance.*"

flexibility to take steps to manage their individual resource portfolios to deal with such changes.

Shorter forward periods would also have the salutary side-effect of allowing DR resources better to participate in capacity markets. As noted in APPA's Statement at 4 and n.3, this has been an issue in the New England ISO.[53] It was noted at the Technical Conference that DR resources generally work on "much shorter time frames in terms of both how quickly we can build, and also how quickly we can recoup the investments." Tr. at 129 (Curran). This would also help to address any potential arbitrage concerns raised regarding DR resources that clear at higher prices in the annual three-year ahead auctions subsequently buying out of their capacity obligations at a lower price in subsequent annual incremental auctions. Tr. 45-46 (Ott); Tr. at 51-52 (Bowring).

- **Zones. Some panelists at the technical conference asserted that capacity market zones are not sufficiently granular and do not change often enough to reflect important market and system changes. Are there advantages or disadvantages associated with increasing the granularity of capacity zones? If so, what are they? What are the challenges, advantages or disadvantages of a dynamic approach to establishing capacity zones?**

APPA members in PJM have had experience with neck-snapping BRA price movements in discrete LDAs. One such example was shown in footnote 23 of APPA's Statement, illustrating the price movements between annual BRAs in the ATSI Zone of PJM. Another was set out in the PPANJ Statement at 2, showing the clearing prices in

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[53] *C.f.,* Tr. at 196 (Holodak) ("One of the things that I get concerned about dealing with some of the demand-side resources, especially in New England -- they tend to want to play in the market when there's money to be had, but they're not really there for long-term commitment, necessarily. To the extent that they've got another business that they're in the business of running, you know, depending on the price signals, they're either in or they're out. When you're comparing a demand-side resource to steel in the ground, I mean, you're trying to plan a system for the long term, and DR jumping in and out of the market seems to me not to be necessarily the best thing. If you can count on it, that's fine, but how do you count on a resource for a business that may not be in business in two or three years.").

the annual BRAs for the PSEG North Zone. While such LDAs have been developed on the rationale that more price "granularity" is better, it comes at a price—including the opportunity for arbitrage. Market participants would be unwise to make new capacity investments based on such price signals, since what is here today in one BRA could easily evaporate in the next year's BRA.[54]

The creation of many small LDAs also increases the generation market power of the incumbent generators located in those LDAs. In some cases, it can be difficult to construct new generation resources in the relevant LDAs, leading to ongoing opportunities for the exercise of market power and the resulting need for mitigation. APPA member AMP has had substantial concerns about this very issue with regard to PJM's Cleveland LDA, because it is a non-attainment area for purposes of the Clean Air Act, making it more difficult to build new generation there.[55] RTOs should work through the regional planning process to eliminate the need for such LDAs through transmission additions where the economics merit them and encouragement of both supply side and demand-side solutions.

- **Coordination of transmission planning and capacity market. Price signals in the capacity markets also provide information to transmission planners to the extent that transmission may substitute for capacity resources. How can**

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54 *C.f.,* Tr. at 22 (Ethier) ("Price formation is sort of a nice way of saying, price volatility in our market is an issue. With a vertical demand curve, you're very likely to see a boom-bust cycle. One of the reasons we've had a price war for, unfortunately, seven auctions is the fear of exactly that sort of price volatility; that all of a sudden, a lot of capacity will leave the market at once, and we'll have very high prices. But until we get to that point, we'll have extremely low prices, and that volatility is not good for the kind of long-term investment that you need in these markets.").

55 *PJM Interconnection, L.L.C.,* 142 FERC ¶ 61,008 (2013) (accepting PJM's proposed tariff changes to establish the new Cleveland LDA and rejecting AMP's and Cleveland Public Power's concerns regarding the difficulties of building new generation in the LDA); *See also,* Tr. at 153 (Jablonski) for a discussion of the difficulty of building new generation in certain constrained LDAs.

investment in capacity and transmission planning be better coordinated? Should the capacity market planning process and transmission planning process use common assumptions and common planning horizons?

APPA has long called for better coordination of transmission planning and LSE capacity resource procurement. Not only does this make common sense, it is statutorily required by FPA Section 217(b)(4). In the Energy Policy Act of 2005 ("EPAct 2005"), Congress amended the FPA to add this new section, which states:

> The Commission shall exercise the authority of the Commission under this Act in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.

In the case of LSEs in RTO regions, Section 1233(b) of EPAct 2005 required that "[w]ithin 1 year after the date of enactment of this section and after notice and an opportunity for comment, the Commission shall by rule or order, implement section 217(b)(4) of the Federal Power Act in Transmission Organizations."

The Commission carried out this statutory obligation in Order No. 681.[56] As the Commission noted in Order No. 681-A (at P 2), "[t]he Commission allowed regional flexibility in setting the terms of the rights, but required that long-term firm transmission rights be made available with terms (and/or rights to renewal) that are sufficient to meet the reasonable needs of load serving entities to support long-term power supply arrangements used to satisfy their service obligations." APPA reads both Section 217(b)(4) itself and Order No. 681 as making clear the express rights of LSEs in RTO

[56] *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, 71 Fed. Reg. 43564 (Aug. 1, 2006), FERC Stats. & Regs. ¶ 31,226 (2006), *on rehearing,* Order No. 681-A, 117 FERC ¶ 61,201 (2006).

regions to employ long-term power supply arrangements to meet their service obligations, without being subjected to discriminatory (indeed in some cases punitive) RTO tariff requirements.

APPA explained to the Commission in Docket No. RM10-23-000 (the docket that resulted in Order No. 1000) [57] that state and local resource procurement policies (such as renewable portfolio standards and increased reliance on energy efficiency measures and distributed generation) are inextricably intertwined with the FPA's federal policy requiring the Commission to support the long-term resource needs of LSEs with service obligations in transmission planning. Renewable generation and demand response are needed not as ends in themselves, but as resources to meet loads. State and LSE energy efficiency goals and plans to develop or rely on distributed generation will likewise be incorporated in LSE integrated resource plans. By concentrating on the planning of transmission facilities that are required to support the planned resource needs of LSEs as they carry out the relevant state and local resource policies, the transmission facilities actually needed to support market-selected renewable resources would be necessarily included. Reductions in reliance on transmission facilities due to increased reliance on EE and DG would likewise be taken into account.

Unfortunately, in Order No. 1000[58] (at P 215), the Commission relegated FPA Section 217(b)(4) to the status of a mere "public policy requirement," to be considered

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[57] "Comments of the American Public Power Association," filed in Docket No. RM10-23-000 on September 29, 2010, at 9-14; "Reply Comments of the American Public Power Association," filed on November 12, 2010, at 19-20.

[58] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011), 76 Fed. Reg. 49,842 (August 11, 2011), *on rehearing,* Order No. 1000-A, 139 FERC ¶ 61,132 (2012), 77 Fed.

(and potentially rejected) along with a myriad of other such requirements in Order No. 1000-compliant transmission planning processes. APPA has petitioned for review of this ruling to the United States Court of Appeals for the District of Columbia Circuit, and its petition has been consolidated with many others for hearing and decision.

APPA still believes that transmission planning, both inside and outside of RTOs, should be based on a "bottom-up" model that looks first to the resource plans of LSEs and the resource policy choices of the relevant states. Common sense dictates laying the sidewalks where the footpaths already go—so it only makes sense to construct the transmission that supports the capacity resource decisions that LSEs make. In the same vein, RTO capacity auction rules should support (or at least not impede) implementation of these resource choices.

- **Retirement notice. What role do retirement and mothballing decisions and notification play in the operation of the eastern RTO/ISO centralized capacity markets? Is there an ideal approach to retirement or mothballing notification? What is the impact of different retirement or mothballing notice procedures across the eastern RTOs/ISOs on the market, resource adequacy and reliability?**

APPA will leave this question to its members in the relevant Eastern RTO regions, but notes the recent issues with generation retirements in the ISO-NE region and the sudden unanticipated reliability and market viability concerns they have created.

4. Regulatory certainty

Several panelists stated the importance of regulatory certainty in achieving capacity market stability. Regulatory certainty reduces risk and thereby lowers barriers to entry in capacity markets. Conversely, some panelists identified significant market design issues that, if resolved, could improve capacity market efficacy. While recognizing that regional differences may be necessary, some panelists suggested that a minimum level of best practices across the three eastern RTO/ISO centralized

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Reg. 32,184 (May 31, 2012), *appeals pending, South Carolina Public Service Authority, et al., v. FERC*, D.C. Cir. Nos. 12-1232, *et al*.

capacity markets also would lead to greater regulatory certainty and provide inter-regional benefits.

- **How should the Commission strike a reasonable balance in adopting market rule changes when necessary without creating undue regulatory uncertainty?**

There is no question that the continued flood of filings to modify capacity market rules and the litigation that comes with it has led to "capacity market fatigue" among many APPA members. During APPA's consultations with its members to formulate its positions in this docket in advance of the technical conference, one APPA-member employee noted:

> Every time we turn around the capacity market rules are being changed again. They are changed so often it is hard to tell what impact if any the last set of changes had on the market other than to drive up the price. Very often the changes are solutions in search of a problem.

APPA believes such frequent rule changes are requested because the underlying capacity construct is itself unstable, since it is administrative in nature and is not a market. APPA believes that the Commission should therefore be encouraging RTO capacity market filings that simplify the underlying construct, by making these markets more voluntary and residual in nature, as discussed further below.

5. Next steps

Conference panelists indicated that further direction from the Commission could help to inform the development of appropriate eastern RTO/ISO centralized capacity market design elements in the future.

- **What Commission action would be an appropriate next step with respect to those markets?**

As APPA's representative at the Technical Conference noted (Tr. at 280-81), APPA would not favor "the mother of all rulemakings on standard capacity market design, that says we're going to adopt best practices." Each of the RTO regions is different, and those differences must be respected. On the other hand, the *status quo* of unlimited RTO filings and complaint cases to address specific capacity market-related issues on an *ad hoc* basis (and the stakeholder processes that usually precede them) requires a huge expenditure of time and resources by each RTO, this Commission and the affected market participants. Tr. at 281 ("[APPA's] members don't have the same resources to participate in these processes that many other sectors do. So just sending us off to endless stakeholder death is something I would really beg you not to do.")

A possible middle path might be for the Commission to order one or more of the Eastern RTOs to address issues of substantial concern, *e.g.*, the need to develop clear market rules that adequately support LSE self-supply and state/local resource policy decisions. Doing so would avoid imposing "cookie-cutter" solutions on all three RTOs, while at the same time giving needed direction to each RTO and its stakeholders, to allow for a more targeted use of their resources. Observation of meetings by Commission staff and the filing of periodic progress reports with the Commission could also provide a way for the Commission to monitor stakeholder processes to ensure that they are moving forward in an appropriate fashion. To minimize demands on participants' scarce staff time and resources, the Commission could perhaps strongly suggest that the RTOs employ dedicated single-day forums to address issues of interest, rather than endless hours of stakeholder deliberation.

Another possible course of action might be to hold a series of "follow-on" technical conferences to explore further specific aspects of the Eastern RTO capacity markets of concern to the Commission and to jump start discussion of potential alternatives. But whatever course is chosen, the Commission needs to be sensitive to the concerns of stakeholder classes with limited resources to devote to RTO stakeholder deliberations and Commission proceedings. Any new initiatives will no doubt come on top of the ongoing stakeholder processes in each RTO and continuing litigation before the Commission in myriad dockets. Unless such new initiatives hold out the concrete promise of improving the lot of the consumers that LSEs in the Eastern RTOs serve, APPA would not urge the Commission to undertake them.

Finally, APPA notes the market reform proposal set out in Section IV of these comments. APPA stands ready to assist the Commission with further proceedings as appropriate.

- **Are there outstanding issues or questions raised by, but not fully discussed at, the conference that should be considered in this proceeding?**

APPA believes that the Commission has taken a big step forward in scheduling and holding this Technical Conference, and strongly supports the Commission's inquiry. It has been the received wisdom at the Commission for the last few years that both RTOs in general and these markets in particular are absolutely necessary and working well, even though many market participants have expressed strong doubts about their performance.

This phenomenon is best illustrated by the Commission's development in 2010 of metrics to measure RTO performance. The Commission will recall that the RTOs themselves largely developed those metrics. As APPA noted in its reply comments filed in Docket No. AD10-5-000 on March 19, 2010, jointly with the Electricity Consumers Resource Council:

> APPA/ELCON have long been on record as supporting rigorous analysis of the centralized wholesale electric power markets that RTOs administer.

> As APPA/ELCON noted in their Initial Comments (at 1), the Commission has overseen the creation of centralized RTO-administered markets over the past 15 years, but has never attempted to determine whether these changes have produced net benefits to end-use consumers. Despite this, APPA/ELCON found the metrics proposed under the category of "Markets" to be of very limited use and generally duplicative of data that are already available. *Id.* at 9. Given that the Commission has the responsibility under Sections 205 and 206 of the Federal Power Act ("FPA") to ensure that wholesale power supply rates are "just and reasonable," no matter what method is employed to develop those rates, the proposed metrics must be substantially improved if the Commission is going to use them as an analytical tool to meet its statutory responsibilities.

Unfortunately, the proposed metrics were adopted and applied largely as originally proposed, without including the bulk of the modifications that APPA and ELCON had requested. APPA regards that docket as a missed opportunity for the Commission. APPA is unaware of any subsequent Commission effort systematically to evaluate RTO performance.

Hence, if anything is missing from the Commission's inquiry in this docket to date, it is the foundational inquiry that the FPA requires the Commission to undertake – are the Eastern RTOs' capacity markets procuring the right amounts and types of capacity at just and reasonable rates? While many of those speaking at the September 25 Technical Conference had ideas about how capacity markets could better support their own policy goals, *e.g.*, more revenues for existing generation, better support for flexible capacity needed to support renewables, more certainty for investors, *etc*., few spoke to this fundamental question. APPA hopes that the Commission will not lose itself in esoteric discussions regarding the optimal slope of capacity demand curves, and in so doing so, miss what should be the essential purpose of the entire inquiry.

- **Are there other issues that, if addressed, would help the centralized capacity markets ensure resource adequacy in a just and reasonable**

and not unduly discriminatory manner (e.g., enhancements to the energy and ancillary services markets) that should be considered by the Commission in another forum?

APPA is aware that certain APPA members in the Eastern RTOs support a holistic reevaluation of their RTO's energy, ancillary service and capacity markets, and will file individual comments regarding this topic.

IV.

POSSIBLE CAPACITY MARKET REFORM PROPOSALS

For a number of years, APPA has had substantial concerns with certain aspects of RTOs' markets and operations. In response to the concerns that many of its members in RTO regions were then expressing, APPA in 2006 started its Electricity Market Reform Initiative ("EMRI") to assess RTO markets and operations and advocate for improvements to them.[59] For the last few years, APPA has focused its EMRI-related advocacy efforts on RTO-administered capacity procurement constructs. In particular, the Commission's actions in 2011 to eliminate the self-supply provisions in PJM's and ISO-NE's tariffs and to expand/institute the MOPRs applicable to their self-supplying LSEs spurred APPA to increase its advocacy efforts in this area.

Among other EMRI-related activities, APPA in 2009 released its "Competitive Market Plan" ("CMP"). The CMP was APPA's attempt to develop a comprehensive blueprint for reform of RTO markets to ameliorate the worst aspects of those markets, without dismantling the basic RTO market framework. In 2011, APPA updated and re-released its CMP, in part because of its increasing concern about the problematic

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[59] Extensive information regarding APPA's EMRI effort can be found on its website at http://www.publicpower.org/Programs/interiordetail2col.cfm?ItemNumber=38695&navItemNumber=38586.

direction the Eastern RTO capacity procurement constructs were taking.[60] At the close of the Preface to the 2011 Revised CMP (at x), APPA once again called for an industry dialogue on RTO market issues:

> In short, APPA believes it is now even more important than it was in 2009 that the industry begins the honest dialogue among its participants in RTO regions that will be needed to manage this transition to a lower-carbon generation future. APPA is therefore updating and re-releasing its CMP as its contribution to the debate. It urges other sectors of the industry to see this as a new opportunity to discuss the huge challenge before all of us, rather than to continue the partisan battles now taking place in RTO stakeholder processes and Commission proceedings. Such a result would be the triumph of hope over APPA's past experience with its release of the first version of the CMP, but hope survives nonetheless.

The challenge that APPA cited in 2011 is now before us.[61] Moreover, the resource adequacy equation may soon become more complicated and less RTO-centric, due to the increased penetration of DG and lower rates of low growth (or even no load growth).[62] Calls for fundamental reexamination of capacity market rules are coming not

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60 The 2011 Revised CMP can be found at http://www.publicpower.org/files/PDFs/2011CompetitiveMarketPlanUpdate.pdf.

61 Tr. at 12 (Commissioner LaFleur) (". . .[T]he country is undergoing really significant changes in power supply due to the boom in natural gas, due to environmental regulations, and due to the renewable standards in so many states. So I think we're entering a period where we just can't count on being long, and we'll start stress-testing our capacity markets. So it's appropriate to look under the hood and see how they're working."); Tr. at 225-27 (Tierney) (Noting the need for states to develop implementation plans to deal with EPA's greenhouse gas rules, including what they will do with their resource mixes).

62 ISO-NE has recently stated in a press release that "[e]nergy consumption, unadjusted for energy-efficiency (EE) programs, is projected to grow an average of 1.1% annually through 2022, while summer peak demand is expected to grow by 1.4% per year. Because of the increased investment in EE programs sponsored by the New England states, ISO New England developed the first multistate EE forecast methodology. When the energy-saving effects of EE are included, the forecast shows essentially no long-run growth in electric energy use and 0.9 % annual growth in annual summer peak demand." ISO-NE, "2013 Regional System Plan Details Power Grid Progress and Initiatives" (Nov. 8, 2013); *available at* http://www.iso-ne.com/nwsiss/pr/2013/rsp13_press_release_final.pdf. In the U.S. Energy Information Administration's ("EIA") Annual Energy Outlook, the 2014 reference case projects very little growth in total electric sales from 2012 to 2040. EIA projects total sales to increase from 3.8 billion kWh in 2012 to

only from the "usual suspects," but from some unexpected corners.[63] Finally, these markets are substantially interfering with state/local resource decisions and policy choices, thus creating needless friction between state and local authorities on one hand and this Commission, as well as extremely controversial litigation.[64]

APPA believes that the industry needs to find a way forward. With that in mind, APPA offers the following thoughts on a possible proposal to reform mandatory capacity markets.

Possible Elements of a Supply Proposal. APPA believes that the Commission should strongly consider reforming current RTO mandatory capacity market constructs to allow them to serve as voluntary, residual capacity procurement mechanisms. APPA acknowledges that doing so would require a substantial transition period and the close cooperation of RTOs, market monitors, this Commission, market participants and state regulatory authorities. After making the appropriate legal finding (as discussed further below) the Commission could require affected RTOs to work with their stakeholders and

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4,954 billion kWh in 2040, or a 0.9% annual growth rate. Sales in the residential sector are projected to increase at a slightly lower annual rate of 0.7%, from 1.375 billion kWh in 2012 to 1,657 billion kWh in 2040. *See* http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014ER&subject=0-AEO2014ER&table=8-AEO2014ER&region=0-0&cases=full2013-d102312a,ref2014er-d102413a.

63 "Motion to Intervene and Comments of Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, L.L.C. Urging Broad Review of ISO New England Inc.'s Market Rules," filed November 27, 2013 in Docket Nos. EL14-7-000 and AD13-7-000.

64 *E.g., PPL Energy Plus LLC v. Hanna,* Fed. Dist. of NJ, Civil Action No.: 11-745 (October 11, 2013), *on appeal*, 3rd Cir. No. 13-4330; *PPL Energy Plus LLC v. Nazarian,* Civil Action No. 1:12-1286 MJG (October 24, 2013), notice of appeal filed with the United States Court of Appeals for the Fourth Circuit by the Maryland Public Service Commission on November 22, 2013.

state commissions to develop an appropriate transition period (*e.g.*, five years) that would commence after the next relevant annual mandatory capacity market auction. The transition period would have to be lengthy enough for all outstanding capacity obligations incurred in prior mandatory capacity auctions to be honored and fulfilled, and for LSEs in the RTO region to develop, either jointly or severally, resource adequacy plans for review and approval by the relevant authorities. At the end of the transition period ("zero day"), the annual capacity market auctions would become voluntary and residual for both buyers and sellers (subject to the market power review discussed below).

- Short-term, Voluntary Nature. These residual markets would be short-term, voluntary markets intended to supplement other, primary methods of procuring capacity (*e.g.*, bilateral contracting or self-builds), and to lay off or procure marginal supply.[65]

- Annual/Monthly Terms. The term of these auctions would be one-year, conducted one year ahead. They could be divided into monthly tranches, or could be supplemented with monthly auctions during the delivery year conducted one month to three months ahead of the relevant capacity

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65 Tr. at 286 (Wilson) ("And I think in anything we do, it probably would be useful to kind of raise the question of, where do we really see the role of the capacity market going. And my view is, you really want it to shrink over time. We've talked about how the energy and ancillary services markets should be further developed, of course. The more revenue there is there, the less you would have to have in the capacity markets. And on the other end, you want the bilateral markets to live again to rise again. Long-term resources like a new power plant or a major rebuild to an existing power plant – it's a long-term resource, and it's naturally supported by some kind of long-term commitment on a bilateral basis. So if you have both of those, energy and ancillaries, in a bilateral market, the role of the residual spot capacity market, sitting between them, can be small. And I think you ought to start that conversation, of whether that's really what you want to be shooting for.").

availability month, to allow for “just in time” adjustments to capacity portfolios.

- Mitigation-Free. These auctions would have no buyer-side or seller-side mitigation (unless found necessary for specific sellers by the market power review discussed below); there would be no MOPRs, no percentage of CONE requirements applicable to bids, or other limitations on buy or sell side bids.
- RTO-wide Resource Adequacy. During the transition period, the RTO, in close consultation with state commissions and affected LSEs, would develop overall resource adequacy/forward load projections by year for the RTO region (note that these load projections should reflect projected reduced demand due to increased EE, DR and DG). These projections would be done sufficiently in advance of the relevant post-zero day delivery year to identify and address potential capacity shortfalls, but would be revisited and revised periodically to take into account intervening events and trends up until the relevant delivery year.
- Individual LSE Resource Adequacy Requirements. Each LSE in the RTO region would have to meet individual load ratio share-based resource adequacy requirements if it chooses to continue to serve retail customers past zero day. Such LSEs would be required to produce resource plans in advance of zero day for year one that meet minimum resource adequacy requirements for year one (and then on a yearly basis thereafter). State-regulated LSEs would have their plans reviewed by their state

commissions and the RTO; LSEs not subject to state commission jurisdiction would submit their resource plans to the RTO for review to ensure sufficient resources are available to maintain reliable operations. If the RTO finds that such LSEs' plans will not meet the relevant resource adequacy targets, the RTO could require that the LSE procure sufficient capacity and recommend strategies to assure adequate capacity. However, such review should not transform public power LSEs into FERC-jurisdictional utilities, or empower RTOs (or this Commission) to dictate how public power LSEs must meet their capacity obligations, or at what cost. Special provisions may also be necessary for "small utilities" as defined by the Small Business Administration ("SBA") for purposes of the Regulatory Flexibility Act.[66] As locally owned utilities subject to local control, public power systems must retain the flexibility to serve their communities as those communities deem best.

- Severe Penalties for Non-compliance. LSEs failing to meet their resource adequacy requirements by the month ahead of the relevant delivery year would be subject to a very substantial monetary penalty, one set at a level high enough to enforce compliance by producing substantial economic pain. Narrow but appropriate exceptions would be included for truly

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[66] 5 U.S.C. §§ 601, *et seq., as amended*. The SBA recently revised the size criteria for entities in the electric power generation, transmission and distribution industry (Sector 22, Utilities). Effective January 22, 2014, electric power distribution entities are considered small if they have 1000 or fewer total employees. SBA Docket No. RIN 3245-AG24, Final Rule (amending 13 C.F.R. Part 121), 78 Fed. Reg. 77,343 (December 23, 2013).

unanticipated *force majeure* events, *e.g.*, catastrophic equipment failures. In addition, appropriate notice-and-cure provisions consistent with the relevant regional reliability requirements should be implemented. Default penalty levels could be set after consultations with the relevant Regional Reliability Entities, which could advise as to the potential adverse reliability impacts of a failure to supply capacity at times of system need.

- <u>Examination of Constrained Areas and Needed Facilities to Eliminate Constraints</u>. The RTO, in conjunction with relevant state commissions, would determine (with appropriate technical support from market monitors and input from market participants) the most economic and efficient options, considering transmission expansion, generation supply, DR and EE solutions,[67] that can be constructed/implemented by zero day to relieve transmission constraints which create separated load zones with insufficient generation/resource competition to keep market-based rates/capacity market prices at competitive levels within the zone.[68] These

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67 *C.f.*, Tr. at 199 (Holodak) ("One of the issues that we've seen operating in these markets, as a customer and as a transmission owner, is that transmission, especially in New England, is considered just a backstop. So if there's a capacity shortfall, the market's supposed to resolve that capacity shortfall. But that doesn't mean that, through a new generator, that that shortfall is satisfied in the most cost-efficient way. We've had price separation in NEMA Boston, and then we've got a new generator that cleared at $1499 a kilowatt month for five years. The price separation there relative to the rest of ISO New England, that increase was about $250 million a year to customers, and we've got a potential transmission solution that is $200 million, and that could help satisfy and relieve that constraint."); Tr. at 283 (Schnitzer) ("I think there's a set of issues there that I think should have a high priority, including the interplay between transmission into a load pocket and new entry in the load pocket. You know, Bob described this circumstance, I think, in the Boston load zone about the new entrant, and the price was talked about. But what wasn't mentioned was that on the transmission plan is a set of investments which will de-bottleneck that constraint.").

68 In so doing, the RTO might wish to consider having a tighter correlation between transmission planning standards and reliability standards. *See* Tr. at 95 (Bowring) ("One

efforts should be coordinated with the RTO's Order No. 1000 transmission planning process to ensure compliance with the dictates of FPA Section 217(b)(4) (as discussed above), and should continue past zero day to ensure that constraints are dealt with on an ongoing basis as they arise.

- Market Power Review. Addressing constrained delivery areas should do much to alleviate the generation market power issues that inevitably arise in the context of capacity markets. However, as the extensive seller-side mitigation that RTOs' IMMs must currently implement for each mandatory auction clearly shows, generation market power is a persistent concern. And since it is that same capacity that presumably would form the backbone of a regional bilateral contract regime, it is possible that market power issues could arise in bilateral contracting as well if left unaddressed.[69] Moreover, the associated jurisdictional issues are thorny:

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related matter on that, which is: I would have a tighter link between the reliability standards applied under the transmission system – n-1-1 – rather than just n-1 in the reliability market, so you don't get into [Reliability Must Run (RMR)] situations. You have the LDAs actually reflect the same reliability criteria that the RTO would apply when deciding whether to let some of them retire.").

69 In its Final Rule in *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, 72 Fed. Reg. 39,904 (July 20, 2007), the Commission held (at P 122) that it need not require different product analyses for short-term or long-term power in deciding whether to grant an applicant market-based rate authority, as "absent entry barriers, long-term capacity markets are inherently competitive *because new market entrants can build alternative generating supply*." (Emphasis supplied.) APPA and the Transmission Access Policy Study Group ("TAPS") sought rehearing of this holding. In Order No. 697-A, 123 FERC ¶ 61055, 73 Fed. Reg. 25,832 (2008), at P 280 the Commission granted rehearing in part, providing an opportunity for sellers that could not pass the relevant market power screens to show on a case-by-case basis that they did not have market power with respect to long-term contracts. But the Commission at P 285 held that cost-based mitigation should not be imposed on long-term contracts entered into by sellers with market power in RTO/ISO markets. The Commission found that "[i]n RTO/ISOs, buyers have access to centralized,

while the Commission has jurisdiction over wholesale electric rates, the states retain jurisdiction over many aspects of generation planning and siting. To address this crucial issue, APPA therefore suggests that the Commission form a cooperative work group with state commissions in the relevant RTO region. The purpose of convening such a work group would be to attempt to head off subsequent litigation by specific states that might otherwise disagree with the Commission's ultimate findings regarding the competitiveness of bilateral contract and residual capacity markets in the RTO region, through up front collaboration with and consideration of the individual affected states' views.[70] This work group, assisted by the staffs of the various commissions, the RTO and market monitors, and with the input of market participants, would undertake a region-wide assessment of the available and projected capacity resources and their potential deliverability to all points in the RTO footprint, as well as separate

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bid-based short-term markets which will discipline a seller's attempt to exercise market power in long-term contracts because *the would-be buyer can always purchase from the short-term market if a seller tries to charge an excessive price*." (Emphasis supplied.) Of course, with the advent of mandatory capacity markets and barriers to LSE self-builds in the form of MOPRs, the rationale for these rulings is now questionable at best.

70 The Commission might in fact consider convening a federal-state Joint Board under Section 209 of the FPA, 16 U.S.C § 824(h), for this purpose. That section states in part: "(a) Composition of boards; force and effect of proceedings--The Commission may refer any matter arising in the administration of this subchapter to a board to be composed of a member or members, as determined by the Commission, from the State or each of the States affected or to be affected by such matter. Any such board shall be vested with the same power and be subject to the same duties and liabilities as in the case of a member of the Commission when designated to hold any hearings. The action of such board shall have such force and effect and its proceedings shall be conducted in such manner as the Commission shall by regulation prescribe. The board shall be appointed by the Commission from persons nominated by the State commission of each State affected or by the Governor of such State if there is no State commission."

assessments of generation capacity and other resources in constrained delivery areas (see discussion of such areas above).[71] If it is found that certain resource suppliers do in fact have sufficient seller-side market power under the relevant tests (*e.g.*, the three pivotal supplier test or more traditional market share analyses) to affect price outcomes in the bilateral contract market, a residual capacity auction, or a constrained LDA, then appropriate limitations on the market activities of such pivotal sellers should be developed and implemented prior to zero day. Periodic reevaluations of the market power issues should be conducted to ensure that changed circumstances (*e.g.*, reduced demand, increased penetration of DR, EE and DG, construction of new generation or other resources, generation unit retirements, construction of new transmission facilities to relieve constrained delivery areas, *etc*.) are reflected and that market power mitigation is applied only where necessary to discipline prices in the bilateral and residual capacity markets to competitive, just and reasonable levels.[72]

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[71] David Patton explained the issue of generation market power in a constrained area as follows (Tr. 62): "Lastly, it's critical to address market power. In almost every narrow area you have a pivotal supplier, which means you can't meet your requirement without that supplier. You have to mitigate that form of market power."

[72] While some might argue that such a seller-side market power review is unnecessary, events in New England during the late 1990s and early 2000s illustrate the need for such an inquiry. At that time, ISO-NE had a residual capacity auction with a "backstop" default rate for entities that failed to satisfy their Installed Capability Responsibility obligation of $8.75 per kW-month. ISO-NE concluded that, in January 2000, a single generation owning participant bought up substantial excess capacity and was able to use its resulting market position to dictate that the residual portion of the market would clear at $10 per kW-month, the maximum price permitted in ISO-NE's Installed Capacity ("ICAP") market. *ISO New England Inc.*, 91 FERC ¶ 61,311 at 62,080 & n. 97 (2000). This drove up market prices for two subsequent auction periods, requiring ISO-NE to

Benefits of Market Reform Proposal. This proposal has several benefits that make it worthy of serious consideration, including:

- Fewer Moving Parts and Administrative Judgments. Because the primary procurement construct is decentralized and bilateral, it eliminates stakeholder processes, disputes and subsequent litigation over discrete features of mandatory capacity constructs, *e.g.*, the calculation of CONE, the scope of exceptions, specific MOPR features, *etc*.
- Harmonization with State/Local Public Resource Policies. This proposal appropriately honors state/local resource portfolio and public policy choices,[73] and does not bias market rules towards or against specific resource types.

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step in and reset the default rate to $0.17 per kW-month. *Sithe New England Holdings, LLC v. FERC*, 308 F.3d 71, 74-75 (1st Cir. 2002); *Central Maine Power Co. v. FERC*, 252 F.3d 34, 39-40 (1st Cir. 2001). The Commission rejected this level of deficiency charge, which had been based on an average of clearing prices in ICAP auctions prior to the ISO's discovery of the alleged market manipulation, as a "token payment" and directed ISO-NE to develop a different administrative deficiency charge. *ISO New England Inc.*, 93 FERC ¶ 61,290 at 61,975 (2000). Eventually, ISO-NE reset its capacity deficiency charge at $4.87 per kW-month. *ISO New England Inc.*, 96 FERC ¶ 61,234 at 61,944-945 (2001). Ultimately, in apparent frustration with efforts of merchant generators to use RMR agreements to toggle between the higher of cost-of-service or market rates for capacity and the resulting price suppressive impacts of RMR agreements in New England's energy market, the Commission determined that a different approach to ensuring resource adequacy would be necessary, leading to ISO-NE's Locational Installed Capacity ("LICAP") proposal and, eventually, the FCM. *ISO New England Inc.*, 125 FERC ¶ 61,102 at P 46-48 (2008); *Devon Power LLC*, 103 FERC ¶ 61082 at P 37 (2003). This experience illustrates the need for strong market mitigation measures, such as the application of pivotal supplier tests and restrictions on bidding behavior for resources that fail such tests, to ensure the integrity of a residual capacity market.

[73] Tr. at 127 (Snitchler) ("[E]ven as an economic regulator, I think we have some obligation to make sure we're monitoring and being aware of over-reliance on any one fuel source. Because at the end of the day, we need fuel diversity, and states like ours have some fuel diversity. It's growing, whether it's renewables, nuclear, coal or natural gas. To simply solely focus on the absolute bottom dollar at the expense of system reliability and price stability over a long term is one of the things that I think we need to keep in mind as we make some of these economic decisions. There are broader policy forces that are also on the table that need to be considered by regulators."); Tr. at 188 (Moore) (". . .[C]apacity markets

- Avoidance of Jurisdictional Disputes. By appropriately involving state and local authorities in the resource adequacy, constrained zone mitigation and market power issues, it sidesteps controversy over respective limits of state/federal jurisdiction in the capacity market area created by recent court decisions.
- Gives Individual States Flexibility. This proposal allows individual states within RTO regions the flexibility to deal with the resource adequacy issues for their retail customers created by their prior decisions regarding retail access. An RTO-administered, centralized voluntary residual capacity market construct would still be available.
- Provides Merchant Generators a Choice of Business Models. This proposal provides merchant generators/resource suppliers a choice as well: they can enter into individualized bilateral supply arrangements with LSEs, rely on the residual capacity market (in addition to the energy and ancillary services markets) to obtain their revenues, or pursue any combination of these approaches.
- Allows for Product Differentiation. The allowance of bilateral contracting and other customized arrangements to procure resources enables the development

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should be a means to an end, not an end in themselves. And I feel like one additional point even could be worked on more in the mostly deregulated markets of the east, is more coordination with state planning. And I think the planning that takes account of these state actions needs to be fed into the resource adequacy/capacity markets in some way, so that you don't overprocure. I think Order 1000 said, let's take public policy requirements into consideration in the planning process. I think a lot of those public policies that occur need also be reflected in, say, net resources that you're seeking through the capacity markets.").

> of tailored products and services that will meet specific needs rather than relying solely on generic, lowest common denominator type capacity products. For example, resources with desirable characteristics, such as dual fuel capability, could be appropriately valued and supported.[74]

Legal Requirements to Implement Market Reform Proposal. Because the current mandatory capacity constructs are features of RTOs' FERC-approved tariffs, it would be necessary for the Commission to make a finding under FPA Section 206 that the currently-effective tariff provisions are unjust and unreasonable and must be reformed to render them just and reasonable. Doing so would be well within the Commission's statutory authority.[75] It was, after all, the Commission that first approved centrally-administered mandatory capacity constructs.[76] It initially blessed and continues to regulate these constructs, pursuant to its exclusive authority over the "transmission of electric energy in interstate commerce" and the "sale of electric energy at wholesale in interstate commerce" by public utilities (including RTOs).[77] The Commission also is required to address, and has the authority to remedy, undue discrimination and

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74 This is currently an issue under ISO-NE's FCM construct. Tr. at 20-21 (Ethier) (". . . [W]e've seen a notable reduction in dual fuel capability in New England. We talked to the resource owners and they say, 'There's no money in it. Why would I keep it? I don't get paid for keeping this. There's no real economic incentive for me to keep it around.'").

75 In Section 201 of the FPA, 16 U.S.C. § 824b, Congress delegated to the Commission the "exclusive authority to regulate the transmission and sale at wholesale of electric energy in interstate commerce." *New England Power Co. v. New Hampshire*, 455 U.S. 331, 340 (1982) ("*New England Power*"). Congress further vested the Commission with the power to determine whether wholesale electricity rates are "just and reasonable" and not unduly discriminatory or preferential. 16 U.S.C. §§ 824d(a)-(b), 824e(a); *see also Mississippi Power & Light Co. v. Mississippi*, 487 U.S. 354 (1988).

76 *Supra* note 18.

77 16 U.S.C. § 824(b)(1); *see also, New England Power Co.*, 455 U.S. at 340.

anticompetitive effects in the wholesale markets.[78] The price for capacity is set through Commission-approved market auctions administered by the relevant RTOs. The Commission regulates these auctions through its consideration of and ongoing acceptance of modifications to the RTOs' tariffs. Therefore, the Commission has the authority and obligation to make changes to these centrally-administered capacity constructs, including the market reform proposal presented in these comments, if it finds that these constructs are producing unjust and unreasonable rates, terms and conditions.

Finally, Congress itself has expressed reservations regarding RTO-administered capacity markets. In EPAct 2005, there was a specific "sense of the Congress" provision regarding the LICAP proposal that ISO-NE was then advocating before the Commission:

> SEC. 1236. SENSE OF CONGRESS REGARDING LOCATIONAL INSTALLED CAPACITY MECHANISM.
>
> (a) Findings.--Congress finds that--
>
> (1) in regard to a proposal to develop and implement a specific type of locational installed capacity mechanism in New England pending before the Federal Energy Regulatory Commission; and
> (2) the Governors of the States have objected to the proposed mechanism, arguing that the mechanism--
> (A) would not provide adequate assurance that necessary electric generation capacity or reliability will be provided; and
> (B) would impose a high cost on consumers and have a

[78] 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 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.]).

significant negative economic impact.

(b) Sense of Congress.--Congress--

(1) notes the concerns of the New England States to the proposed mechanism; and
(2) declares that it is the sense of Congress that the Federal Energy Regulatory Commission should carefully consider the States' objections.

More recently, 13 members of Congress sent a letter to the Commission supporting the Commission's stated reasons for opening the instant docket.[79] Hence, there is clear evidence of Congress's interest in having the Commission exercise strong oversight of these markets and to consider objections to them, especially if affected states express concerns.

APPA does not claim to have all the answers when it comes to reforming mandatory capacity markets. The issues are complex and thorny, and not susceptible to glib solutions. But it is clear that there are serious flaws in the current markets which call for serious discussion of alternatives. One illustration of this is the comments filed in this docket on December 18, 2013, by Cliff W. Hamal of Navigant Economics. He opines in the very first paragraph of his comments (at 1) that "mandatory, centralized annual capacity markets do [a] poor job of serving the many constituents of the electricity markets." He contrasts the extensive discussion at the September 25 Technical

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[79] Letter from Rep. Ed Whitfield (R-KY), Chairman, Subcommittee on Energy and Power, Committee on Energy and Commerce, *et al.* to Jon Wellinghoff, Chairman, Federal Energy Regulatory Commission at 1 (Sept. 23, 2013); *available at* https://energycommerce.house.gov/sites/republicans.energycommerce.house.gov/files/letters/20130923FERC.pdf. On page 2 of this letter, the signatory Representatives stated that the Commission should assess and address several issues related to centralized capacity markets, including "the equitable treatment of all generation resources and business models," "impacts on state and local resource planning" and "customer benefits and protection."

Conference on "shoveling money to suppliers to procure desired product," with the scant discussion of "squeezing the desired performance from the market at the lowest cost possible to consumers." *Id.* at 2. He presents a proposed alternative to mandatory capacity markets (at 11-13), which he calls the "BiCap approach." While not endorsing the particulars of the BiCap approach, APPA believes that Mr. Hamal has done a service in both calling out the problems with the current mandatory capacity market constructs and floating a proposal to address those problems.

V.

OTHER ISSUES

<u>PJM's Claims Regarding New Investment</u>. A determination of whether and how to reform mandatory capacity markets requires a careful scrutiny of the performance of these constructs. The Eastern RTOs have made assertions about the success of the capacity markets that are not supported by the available data, rendering it difficult to obtain an accurate measure of the performance of these markets. This section deconstructs such RTO claims, focusing on statements made by PJM, as exemplified by the following portion of the PJM Statement:

> Over the period covering the first 10 RPM Base Residual Auctions, 28,177.8 MW of new generation capacity was added along with 14,370 MW of new demand response resources and 1,113 MW of new energy efficiency resources. When compared against the generation retirements during this period, RPM netted over 23,342 MW of new installed capacity in the PJM footprint despite significant retirements and [a] relatively slack economy.[[80]]

APPA would caution the Commission to take these claims with a large quantity of salt, for a number of reasons.

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[80] PJM Statement at 9.

First, not all of these MW are created equal. As Mr. Ott noted, "PJM has experienced a large operational discontinuity because of the marked difference in operational comparability between generation and demand response given the notice requirements and emergency-only status of most of the demand response resources."[81] One must ask whether the dollars paid through RPM BRAs for these resources are fully justified, given their limitations.

Second, while APPA has been unable fully to deconstruct the numbers, it has found evidence that much of the new generation Mr. Ott attributes to the RPM was in fact constructed for other reasons. Consider the following information APPA has been able to assemble. The first table shows megawatts (MW) of new installed capacity (ICAP) broken down by new construction, upgrades and reactivations of plants.[82]

New Generation	**20,450.6**
Upgrades	7,167.5
Reactivated	559.7
Total	**28,177.8**

Because there is a limited amount of upgrades and reactivations that can be accomplished, the number to focus on is the **20,450.6 MW** of new generation. As explained below, this new generation capacity construction cannot be entirely attributed to the PJM capacity market. This number is only the amount of new generation offered into the capacity auctions and not necessarily what was or will be built. The new generation that actually cleared the auction is a better measure of what will be built. This

81 *Id.* at 11.

82 Data obtained from PJM's "2016/17 RPM Base Residual Auction Report," Table 10, *available at* http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx.

equaled **15,930.8 MW of Unforced Capacity (UCAP)[83]**, or **about 17,316 MW of ICAP.[84]** UCAP reflects the amount of capacity actually available, net of outages. (Data on upgrades and reactivations are also offered, not cleared, but there is little difference between the two.)

The central question is how much of the approximately 17,000 MW of new cleared generation capacity was initiated because of the price signals of the capacity market and how much was driven by other factors. Because of limited data transparency, APPA has been unable to determine precisely how much of this capacity was built for sale into the capacity market and how much was constructed under a vertically integrated business model or pursuant to long-term contracts. But the available data shows that a substantial percentage of the new capacity construction was not likely driven by the market itself. The following plants were all built under a contract or utility ownership, but are included in the total new generation attributed by PJM to the capacity market (in MW of ICAP):

2016/17 Dominion Brunswick Plant	1,432.5
2015/16 Vineland, NJ (See the Written Statement of James A. Jablonski on behalf of the Public Power Association of New Jersey at 4 and Tr. at 116)	57
2015/16 NJ LCAPP Woodbridge	721
2015/16 NJ LCAPP Newark	670
2015/16 Waldorf, MD PSC LT Contract	718

83 Equal to the total of all cleared new generation reported in the Base Residual Auction Reports for each year, *available at* http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx.

84 ICAP calculated using the average 8 percent forced outage rate for January through September of 2013 provided in the "PJM State of the Market Report" at 139, *available at* http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013/2013q3-som-pjm-sec5.pdf.

2015/16 Dominion Warren Plant	1,329
2014/15 DEMEC Beasley Unit 2 (See discussion above regarding this DEMEC unit)	51
2012/13 AMP Fremont Unit	685
2011/2012 Dominion Bear Garden	590
2011/12 Calpine York Energy Center*	565
Total	**7,404**

*Six-Year Tolling Agreement with Exelon

Given that at least 7,404 MW were built for reasons other than the support provided by PJM's capacity market, the net new generation potentially attributable to the market is **9,912 MW** (17,316 minus 7,404) or less than half that claimed by PJM.

Even this 9,912 MW is likely to be an overestimate, because not all of the of generation projects built under long-term contracts or ownership are known. But available data indicates that it may be much greater than estimated here. For example, APPA conducted a study[85] of the new generation capacity constructed nationwide in 2011, and found that 98 percent was built under a long-term contract or utility ownership in both RTO and non-RTO regions.[86] Further, new renewables are highly likely to have

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[85] "Power Plants Are Not Built on Spec—An Analysis of New Electric Generation Projects Constructed in 2011," March 2012, *available at* http://www.publicpower.org/files/PDFs/PowerPlantsArenotBuiltonSpecMarch2012_1331649529309_2.pdf.

[86] Comparable results exist for the NY ISO. In September 2012, APPA, the National Rural Electric Cooperative Association, and the New York Association of Public Power jointly released a study of the NY ISO capacity market. That study found that 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.

been constructed to meet renewable portfolio standards and under either utility self-builds or long-term contracts, which are critical to financing such projects.[87]

Third, to evaluate these claims fully, the Commission must not only consider the new MWs, but the cost of obtaining them. Over the first 10 BRAs, consumers in PJM have committed to pay $64 billion in capacity payments. That is a very hefty bill to pay to support this level of new resources.

APPA notes that in the most recent BRA for the 2016/17 delivery year, a significant amount of merchant natural gas-fired generation did clear the auction. Generating units that received the newly created Competitive Entry Exemption from the MOPR amounted to 3,482 megawatts, equal to 71 percent of all new generation clearing the auction. (The remaining 29 percent of new generation is likely to be Dominion Power's Brunswick County generating station, which entered the BRA under the self-supply exemption.)

While capacity market revenues may be one factor in the decision of these merchant generators to construct new merchant plants without a contract, APPA understands that two primary reasons for the decision to build much of the new

[87] For example, the American Wind Energy Association's "US Wind Industry Third Quarter 2013 Market Report" states that: "Activity is now picking up, however, with utilities issuing at least 28 RFPs for wind, renewables or other capacity. These 2013 RFPs have already led to at least 3,900 MW of contracts for new wind builds, with more results forthcoming. Since January, nearly 6,000 MW of long-term power purchase agreements (PPAs) have been signed, utilities have announced more than 1,800 MW of self-builds, and as of September 30, 2013, 2,327 MW were under construction in thirteen states." http://awea.files.cms-plus.com/AWEA%203Q%20Wind%20Energy%20Industry%20Market%20Report%20Executive%20Summary.pdf.

generation in PJM are the plants' proximity to low-cost natural gas from the Marcellus Shale[88] and an expectation of higher prices as coal plants retire.[89]

The significant amount of non-contracted merchant natural gas generation clearing the 2016/17 BRA is not necessarily a totally positive development for consumers. Nor does it demonstrate that these markets are "working" to provide reliability at least cost. Much of the new merchant generation is no longer financed by commercial bank Term Loan A debt as in the past, which depends upon a steady stream of revenue, such as that provided by a long-term contract. Newer merchant power plant construction is now often financed by a combination of equity and Term Loan B financing, both of which require higher returns than Term Loan A debt and are riskier investments. Introducing such greater and riskier returns means that there is now a larger pool of investors with a strong interest in higher prices and a tighter supply. Because investors are less protected, it is not clear whether power plant owners will keep the plant in operation if the returns do not measure up to what was projected. In May, Moody's Investor's Service reported that:

> As investors and lenders emphasize yield over risk, they appear willing to accept loosened covenants… The tradeoff for this extra yield has been a loosening of

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88 Presumably these merchant generators are premising their investment on a steady supply of reasonably priced shale gas from Pennsylvania formations such as the Marcellus Shale. Given the recent decision by the Pennsylvania Supreme Court that municipal governments are not barred by statute from regulating fracking in their respective communities, this assumption may soon be tested. *Robinson Township, et al., v. Commonwealth of Pennsylvania et al.*, Nos. 63 MAP 2012, *et al.*, Middle District of the Supreme Court of Pennsylvania (decided December 19, 2013), *available at* http://www.post-gazette.com/attachment/2013/12/19/PennsylvaniaSupremeCourtMarcellus-pdf.pdf.

89 As an example of the trends in financing supporting these new merchant plants and the rationale for constructing them, see *Panda Power Funds Finances 829-MW Pennsylvania Power Project*, Panda Power News Release, http://newsroom.pandafunds.com/press-release/panda-power-funds-finances-829-mw-pennsylvania-power-project.

> project finance features that protect lenders, especially lenders in the Term Loan B market.[[90]]

Hence, while these new merchant plants may have cleared in the most recent PJM auction, the ultimate cost of this new generation may prove to be higher, and its continued participation in markets at risk if the units do not meet the financial expectations of the investors in them.

If this is the actual level of performance of the mandatory capacity construct PJM administers and the new generation that it produces (or does not produce), then APPA has to wonder about the efficacy of the underlying model. At the very least, the Commission should question the implication that PJM's capacity construct is working so well that PJM can afford to compare itself favorably with "[o]ther regions [that] are facing forward uncertainty, and some other regions [that] are actually resorting to surveys of their members to determine if they have enough resources in the future because they're dealing with such uncertainty." Tr. 37 (Ott). Having a mandatory capacity market in place provides no iron-clad assurance of future resource adequacy, as the current

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90 "Announcement: Moody's: US power project loans becoming covenant-lite," May 8, 2013, https://www.moodys.com/research/Moodys-US-power-project-loans-becoming-covenant-lite--PR_272684.

circumstances in ISO-NE illustrate.[91] Given the potential for additional generation resource retirements in PJM,[92] more humility may at some point be required.

General Acknowledgment that Capacity Markets Are Not in Fact Markets. Finally, APPA would be remiss if it did not point out the general agreement at the Technical Conference among the RTO and IMM speakers that the capacity markets that the Eastern RTOs they administer are not, in fact, "markets" as any layperson would use that word. Rather, they are administrative constructs, and elaborate ones at that. They freely acknowledged this fact:

> Robert Ethier (Tr. at 17): I know there's a lot of concern about capacity markets. There's a lot of concern that they have administrative aspects to

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91 As ISO New England explained in its November 25, 2013 "Exigent Circumstances" filing in Docket No. ER14-463-000 (at 3): "Well after the deadlines for qualifying new resources to participate in [Forward Capacity Auction] 8, however, the New England capacity supply situation changed dramatically. In August, after prevailing in its litigation with the State of Vermont, Entergy announced the retirement of the 604 MW Vermont Yankee nuclear plant and submitted a non-price retirement request ("NPRR"). [Footnote omitted.] In October, an additional 2,500 MWs left the FCM by submitting NPRRs. These events changed the supply-demand balance from a surplus of existing resources of over 2,000 MWs to a deficiency of existing resources of over 1,000 MWs….").

92 In December 2013 alone, NRG Energy announced plans to retire five generation units at two coal-fired power plants in Maryland (Chalk Point and Dickerson) totaling 1,200 MW in mid-2017. "NRG Energy files to deactivate coal-fired units at Chalk Point, Dickerson," SNL Energy Electric Utility Report, December 16, 2013 issue at 32-33. It apparently did so despite the assertion of NRG Energy Witness Lee Davis at the Technical Conference that his company was "investing hundreds of millions of dollars now in restoring facilities" in PJM due to the market signals provided by the PJM BRAs. Tr. 122-23. *See also*, "Potential Coal Plant Retirements: 2012 Update," by Metin Celebi, Frank C. Graves, and Charles Russell, The Brattle Group, Inc., October 2012, http://brattle.com/system/news/pdf2s/000/000/095/original/Potential_Coal_Plant_Retirements-2012_Update.pdf, *cited in* The Brattle Group Inc.'s November 2013 Discussion Paper, "Coal Plant Retirements Feedback Effects on Wholesale Electricity Prices," as the most recent source of retirement estimates; and "Coal under fire: Assessing Risk Factors and Market Impacts for Upcoming Coal Retirement Decisions," Jesse Gilbert and Andrew Gelbaugh, Senior Analysts, SNL Energy, December 2013, www.snl.com, Subscription Required.

them. But fundamentally, capacity markets are needed to address reliability standards, and those are administrative in nature. So it's not a surprise that we need some sort of market superstructure to ensure that we meet those reliability standards.

Rana Mukerji (Tr. at 26): The capacity market, as Bob mentioned, is based on a planning construct. It's based on assumptions, forecasts, and it is in fact a planning artifact. So whenever you have a planning artifact and you're doing a market based on assumptions and constructs, you will have -- inherently you have no [sic?] controversy. That's a good thing, that's a salient point to recognize.

Joseph Bowring (Tr. at 46): My view is that the combination of scarcity pricing and capacity markets is the best way to go. . . . Of course, these are administrative structures. But given the administrative structures, and that applies to scarcity pricing and nearly all the other solutions, the goal within those administrative structures is to rely on market signals as much as possible.

David Patton (Tr. at 58): Vertical demand curve. This is an extremely damaging aspect of capacity markets. We talk a lot about administrative aspects of these markets, but you have to recognize that, because demand is not fully participating, at this point the provision of reliability has to be administrative. We have to be procuring reliability on behalf of consumers. So virtually everything on the demand side is administrative. How much reserves we procure in real time is administrative. What value we put on the reserves, which determines how high the energy price will be when we can't procure enough reserves, is administrative. The requirement for capacity is administrative, and how we represent the demand.

APPA is compelled to make this point, because some on the other side of these capacity market debates have attempted to paint market participants questioning the ability of these administrative constructs to assure resource adequacy as the philosophical descendants of Karl Marx. For example, in the September 10, 2013 oral argument held in the United States Court of Appeals for the Third Circuit in *New Jersey Board of Public Utilities, et al. v. FERC,* Nos. 11-4245, *et al.,* the following exchange took place:

THE COURT [Judge Jordan, to Counsel for the PJM Power Providers]: So is it PJM's position that these bilateral contracts, these long-term supply arrangements, these decisions that states, for example, are making about how to avoid rolling blackouts, that that's all bad policy, bad

> decision making because the only game in town is the base residual auction and if you were sensible people you would come here to our auction because that's where sensible decisions are made?
>
> MR. SHEPHERD: I think, your Honor, at some point you have to make a decision about whether or not you believe that capitalism works, whether the markets work or whether the markets don't work.[[93]]

APPA does not believe that in questioning the workings of RTO mandatory capacity constructs, it is launching a full frontal assault on capitalism. To the contrary, APPA supports increased reliance on bilateral contracts and self-supply arrangements because it believes RTO capacity markets are not markets. Despite the theory behind these constructs, no one bids their marginal costs, or even their "missing money." And real markets do not have artificial price floors in the form of MOPRs. Bilateral markets might in fact better harness competitive forces for the benefit of consumers, by requiring capacity sellers to compete directly with each other for contracts with LSEs.

[93] Third Circuit Rough Draft Transcript of Oral Argument (James DeCrescenzo Reporting) at 127-28.

VI.

CONCLUSION

APPA respectfully requests the Commission to consider the foregoing comments, and to take affirmative steps as suggested above to revamp and improve RTO-administered mandatory capacity procurement mechanisms to better meet the needs of market participants and electric consumers.

Respectfully submitted,

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