

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Calpine Corporation, *et al.*

Docket Nos. EL16-49-000

v.

PJM Interconnection, L.L.C.

PJM Interconnection, L.L.C.

ER18-1314-000

ER18-1314-001

PJM Interconnection, L.L.C.

EL18-178-000

(Consolidated)

**EVIDENCE AND ARGUMENTS OF
AMERICAN MUNICIPAL POWER, INC. AND
THE PUBLIC POWER ASSOCIATION OF NEW JERSEY**

Pursuant to the June 29, 2018 Order Rejecting Proposed Tariff Revisions, Granting in Part and Denying in Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act, (“June 29 Order”),¹ Section 206 of the Federal Power Act (“FPA”)² and Rules 505, 507, and 508 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (“Commission” or “FERC”),³ American Municipal Power, Inc. (“AMP”) and the Public Power Association of New Jersey (“PPANJ”) (collectively, “Respondents”) hereby submit for the Commission’s review the following arguments and evidence in the above-captioned dockets.

¹ *Calpine Corp., et al. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 (2018). On August 22, 2018, the Commission issued a Notice of Extension of Time to file comments and reply comments until October 2, and November 6, 2018, respectively.

² 16 U.S.C. § 824e.

³ 18 C.F.R. § 385.505, 385.507, 385.508 (2018).

I. BACKGROUND

On June 29, 2018, the Commission rejected two distinct proposals concurrently filed by PJM Interconnection, L.L.C. (“PJM”) that would amend provisions of the PJM Open Access Transmission Tariff (“Tariff”) regarding PJM’s Reliability Pricing Model (“RPM”).⁴ The rejected PJM proposals – Capacity Repricing and MOPR-Ex – were both purportedly designed “to address supply-side state subsidies and their impact on the determination of just and reasonable prices in the PJM capacity market.”⁵ In addition to rejecting the two proposals, the Commission also found that PJM’s existing Tariff, particularly its Minimum Offer Price Rule (“MOPR”), is unjust and unreasonable and unduly discriminatory under section 206 of the FPA⁶ “because PJM’s MOPR does not address subsidies to existing resources.”⁷ The Commission stated that “[t]he records [...] demonstrate that states have provided or required meaningful out-of-market support to resources in the current PJM capacity market, and that such support is projected to increase substantially in the future. These subsidies allow resources to suppress capacity market clearing prices, rendering the rate unjust and unreasonable.”⁸

The Commission’s June 29 Order also stated that they were unable to specifically identify a just and reasonable replacement rate but that one might be crafted by modifying two aspects of the PJM Tariff, namely to: (1) expand the MOPR with few or no exceptions,

⁴ June 29 Order at P 7.

⁵ PJM Capacity Repricing or in the Alternative MOPR-Ex Proposal: PJM Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, Docket No. ER18-1314-000, at 1 (April 9, 2018).

⁶ 16 U.S.C. § 824e.

⁷ See June 29 Order at P 154.

⁸ June 29 Order at P 149.

and (2) employ a resource-specific Fixed Resource Requirement (“FRR”) alternative option for subsidized resources (referred to herein as the “FRR-RS Alternative”).⁹ The Commission then directed interested parties to submit testimony, evidence, and/or argument within 60 days of the date of the June 29 Order, followed by reply comments within an additional 30 days. On August 22, 2018, the Commission granted an extension request to file initial testimony, evidence, and/or argument by October 2, 2018 with reply comments on November 6, 2018.¹⁰ In response to the Commission’s June 29 Order, Respondents submit their comments and arguments herein as well as the affidavit of Christopher J. Norton for the Commission’s consideration.

II. SUMMARY OF POSITION

As discussed above, the June 29 Order establishes two separate tracks for capacity resources depending on whether or not they are considered to have received “subsidies” that are beyond “the appropriate scope of out-of-market support.”¹¹ The Commission retains PJM’s capacity construct for those resources that are not receiving an unacceptable out of market subsidy. Even with an unacceptable subsidy, resources may continue to participate in the capacity construct; however, those resources are subject to the MOPR. The resources that are receiving an unacceptable out of market subsidy but do not wish to be subjected to the MOPR take their resources and some commensurate amount of load and exit the capacity construct under the FRR-RS Alternative.

⁹ June 29 Order at P 157, 158.

¹⁰ Notice of Extension of Time, EL18-178-000, EL16-49-000, ER18-1314-000, ER18-1314-001 (August 22, 2018).

¹¹ June 29 Order at P 165.

In rejecting PJM's repricing proposal, the Commission correctly recognized that was a bad market design. However, accepting the PJM Independent Market Monitor's ("IMM") expansion of MOPR to existing resources and then adding a new resource-specific fixed resource requirement is a sweeping and fundamental change whose magnitude eclipses the 28 prior major rule changes to RPM. Accordingly, the Commission should continue to reject such market design proposals and direct the PJM stakeholders to go back to the proverbial drawing board. Of course, with the Commission's finding that PJM's existing Tariff is unjust and unreasonable, some change must now be made. Those changes need not be as sweeping or as hasty as suggested by some, however, in order to avoid unintended and, frankly, dire, consequences.

Nonetheless, if the Commission proceeds down this two-track path, in considering the threshold issue of what should be considered an actionable subsidy, the Commission should find that Public Power resources are not subsidized. Rather, the Commission should adopt the definition of actionable subsidies offered by AMP in response to PJM's proposal in this docket: "any payments, concessions, rebates, or incentives other than Market Revenue" but not those payments, concessions, rebates, subsidies or incentives that are "consistent with and part of a public power business model."¹² Public Power includes entities comprised of either cooperatives, municipal utilities or both, and joint action agencies. In the June 29 Order, the Commission determined that the threat of out-of-market payments by states amounts to the support of "preferred generation resources that may not otherwise be able to succeed in a competitive wholesale capacity market."¹³

¹² AMP Comments, Docket No. ER18-1314-000 at 25 (May 7, 2018).

¹³ June 29 Order at P 1.

For the reasons discussed herein, Public Power resources do not elicit the Commission's concern of inappropriate state subsidies distorting the capacity construct. Indeed, the Public Power business model is precisely the structure that best fits into the realities of competitive capacity procurement. Public Power's analysis of whether to construct new generation includes a long term projection over the full range of revenue streams for the life of an asset as well as an analysis of the projected "market." Public Power does not proceed with new development and construction of projects without a holistic and long term review.

In the June 29 Order, the Commission posed the question of whether a MOPR "exemption [should] be included for self-supplied resources used to meet loads of public power entities?"¹⁴ Respondents appreciate this suggestion and, to the extent that the Commission deems Public Power resources as receiving actionable subsidies (which it should not), the Commission should find that Public Power self-supply is properly exempted from the expanded MOPR. The MOPR was originally crafted to protect against buyer-side market power that could result in price suppressive behavior that Public Power has no incentive to promote. As more fully discussed below, the Public Power business model prohibits Public Power load serving entities ("LSEs") from building generation for market manipulation reasons. Even so, the proposed net-short/net-long restrictions serve as an additional effective barrier from any attempt to economically benefit from price reductions as a result of Public Power self-supply decisions. Accordingly, it is not unduly discriminatory to exclude Public Power entities from capacity offer mitigation regardless of its form. This reality is reflected in PJM's proposal to continue to exempt Public Power

¹⁴ June 20 Order at P 167.

in accordance with previous exemptions that were approved by the Commission.

Finally, should the Commission find that Public Power resources do receive actionable subsidies (which it should not) and not be exempt from the MOPR (which it should be exempt), Public Power should be permitted to utilize the FRR-RS Alternative and the FRR-RS Alternative rules should properly recognize local jurisdictional authority as separate and distinct from state regulatory authority. In such case, the FRR-RS Alternative rules should account for the unique policy-making and rate-making authority of Public Power Relevant Electric Retail Regulatory Authorities (“RERRAs”) and ensure that the costs of particular state policy decisions are confined to consumers within the state that made that policy decision.

III. ARGUMENTS

A. Expanding the MOPR is unjust and unreasonable.

The June 29 Order held, pursuant to section 206 of the FPA,¹⁵ that PJM’s Tariff, and, in particular, its MOPR, is unjust and unreasonable and unduly discriminatory.¹⁶ The Commission summarizes the basis for its FPA section 206 finding as follows:

[The Tariff] fails to protect the integrity of competition in the wholesale capacity market against unreasonable price distortions and cost shifts caused by out-of-market support to keep existing uneconomic resources in operation, or to support the uneconomic entry of new resources, regardless of the generation type or quantity of the resources supported by such out-of-market support. The resulting price distortions compromise the capacity market’s integrity. In addition, these price distortions create significant uncertainty, which may further compromise the market, because investors cannot

¹⁵ 16 U.S.C. § 824e.

¹⁶ See June 29 Order at PP 150, 157.

predict whether their capital will be competing against resources that are offering into the market based on actual costs or on state subsidies. Ultimately, these problems with PJM's existing Tariff result in unjust and unreasonable rates, terms, and conditions of service.¹⁷

The June 29 Order indicates that adoption of a blanket MOPR applicable to all new and existing resources receiving state out-of-market support is necessary to render the PJM capacity construct rules just and reasonable. On July 30, 2018, AMP, PPA, and the American Public Power Association ("APPA") jointly sought rehearing of the Commission's June 29 Order ("Joint Rehearing").

The basis of the Joint Rehearing was that the Commission's sweeping expansion of the MOPR is not supported by reasoned analysis; the Commission neither substantiates the factual assertions underlying its ruling, nor adequately explains why expansion of the MOPR as suggested in the June 29 Order would be a reasonable response to the growth in state support for new and existing generation. The Commission also failed to quantify the key assertion that certain state support programs within the PJM footprint "allow resources to suppress capacity market clearing prices." The Commission failed to reconcile the claimed need to expand the MOPR with the undisputed fact that PJM currently has a significant reserve surplus, which will continue at least through the 2021/22 Delivery Year.¹⁸ Additionally, the Commission failed to address the fact that extending the MOPR to cover all existing resources benefitting from out-of-market support heightens the risk, in particular, that the MOPR will over-mitigate capacity resources – a concern that the Commission has previously taken great care to

¹⁷ *Id.* at P 150.

¹⁸ June 29 Order at P 149; *see also id.* at P 5 (finding "that it has become necessary to address the price suppressive impact of resources receiving out-of-market support"); *see also id.* at PP 2, 5, 154, 155, 158.

balance against the risk of artificial price reduction. The Commission failed to justify its departure from precedent wherein the Commission has stated that over-mitigation can lead to decreased confidence in the market and “that keeps capacity out of the market over the long-term.”¹⁹ In fact, present proposal notwithstanding, the Commission has only actually mitigated bids upward in the face of allegations of theoretical buyer-side market power by new entry.²⁰ No such claim has been made here.

Without restating each of the arguments made on rehearing,²¹ quite simply, the Commission’s finding under FPA section 206 that PJM’s Tariff is unjust and unreasonable because the existing MOPR is too narrow is unreasonable and unsupported, and has the potential to make the already-flawed PJM capacity construct significantly worse. Rather than continue with this highly compressed paper hearing, the Commission should maintain its rejection of PJM’s Capacity Repricing proposal and the MOPR-Ex proposal, but should make preliminary findings and provide targeted guidance to stakeholders concerning incremental reforms to PJM’s resource adequacy construct, including, potentially, directing consideration of an expanded FRR construct or other alternative frameworks that appropriately accommodates self-supply and state-supported resources.

B. “Actionable Subsidies” should not include Public Power.

In the June 29 Order, the Commission concludes that there are changed circumstances that warrant expanding PJM’s MOPR beyond new natural gas-fired

¹⁹ *Midwest Indep. Transmission Sys. Operator, Inc.*, 115 FERC ¶ 61,158 at P 12 (2006).

²⁰ See, e.g., *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 26 (2013) (finding that PJM’s buyer-side market power mitigation rules “appropriately balance the need for mitigation against the risk of over-mitigation”).

²¹ AMP hereby incorporates by reference the Request for Rehearing of the American Public Power Association, American Municipal Power, Inc., and Public Power Association of New Jersey (July 30, 2018).

resources. June 29 Order at P 155. Specifically, the Commission notes that, while natural gas-fired resources continue to have low construction costs and short development times making them still the most efficient resources to lower capacity prices in PJM by adding additional supply to the supply/demand equation, they are not the only resources with this capability. June 29 Order at P 155. Rather, the Commission concluded that states in the PJM region are increasingly supporting specific resources or resource types, resulting in “price suppression” from state choices.

Setting aside the fact that there is insufficient evidence to demonstrate that increasing state support of specific generating resources is resulting in a reduction in the clearing price,²² the Commission concludes that it can no longer assume substantive differences among the types of resources participating in the PJM capacity construct with the benefit of “out-of-market support.”²³ June 29 Order at P 155. In spite of this conclusion, the Commission fails to define the appropriate scope of out-of-market support that it determines should be mitigated. June 29 Order at P 165. The Commission merely suggests that an Actionable Subsidy should be any resource with a state-sponsored subsidy with few exceptions. June 29 Order at P 159. Rather, the Order requests that parties address the appropriate scope of out-of-market support to be mitigated by the expanded MOPR through this paper hearing process. Order at P 165, note 294.

²² See Request for Rehearing of American Public Power Association, American Municipal Power, Inc., and Public Power Association of New Jersey, Docket Nos. EL16-49-001, EL18-178-001, ER18-1314-002 (July 30, 2018).

²³ In the last substantive order on MOPR, the Commission stated that “after clearing in the market at the offer floor price, ‘there is no reasonable basis for continuing to apply the MOPR,’ given the market’s demonstration of its need for the resource.” See *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090 at P 211 (2013) (quoting April 2011 Order, 135 FERC ¶ 61,022 at P 175).

In response to the Commission's invitation, AMP contends that Public Power entities with capacity resources, including bilateral contracts or generating assets, for the purpose of self-supply do not receive material subsidies that the Commission may or should mitigate by application of the MOPR. The Commission should adopt this exclusion from the definition of an Actionable Subsidy for several reasons: (1) Public Power does not receive state-sponsored subsidies; (2) Public Power is fundamentally different from investor-owned utilities ("IOUs") and independent power producers ("IPPs") that are receiving state-sponsored subsidies; and (3) the Public Power business model precludes the opportunity to economically benefit from artificially lowering the clearing price through use of state subsidies, the policies from which the Commission is attempting to protect the market.

1. Public Power does not receive state-sponsored subsidies.

The PJM Tariff defines Relevant Electric Retail Regulatory Authority (or "RERRA") as "an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity." PJM Tariff, Section I. Common Service Provisions, OATT Definitions – R-S. Thus, PJM recognizes, as the Commission has, that decisions regarding how to meet capacity needs are not limited to states: such decisions for Public Power customers are made at the local level. In most states within the PJM footprint, the public utility commissions, or "PUCs", have little to no regulatory authority over Public Power entities. For that reason, the PUCs or state regulatory authorities also do not have the authority to require Public Power entities either to pay charges authorized to be

recovered from the customers of IOUs or to authorize Public Power entities to recover costs from customers of IOUs. Given the lack of state authority over Public Power resource selection and cost recovery, the states are also not offering subsidies to specific generating resources owned by Public Power. In other words, Public Power does not receive the state “subsidies” that raised concerns of the Commission.

2. Public Power is fundamentally different from IOUs and IPPs.

In addition to the fact that Public Power is a unique RERRA from the state and does not receive state subsidies, Public Power entities are also fundamentally different from the IOUs and IPPs that are receiving subsidies from the states.

Public Power utilities are deeply rooted in the history of the United States. They are an expression of the American ideal of local people working together to meet local needs. Like schools, parks, libraries, police, and fire protection, Public Power utilities are part of local government. They are governed locally and operated to provide an essential public service at a reasonable price. They were formed in the early days of the electricity industry when smaller communities were not attractive to private electricity companies. When the private sector failed to meet their needs, these communities took matters into their own hands, which led to the establishment of public power utilities.²⁴ The basis of authority for municipal utilities stems from the right of municipalities to “exercise all powers of local self-government and to adopt and enforce within their limits such local police, sanitary and other similar regulations, as are not in conflict with general laws.” See, for

²⁴ The first public power utility was born on the evening of March 31, 1880, in the farm community of Wabash, Indiana. See, *“Public Power: A Rich History, A Bright Future”*, available at: <https://www.publicpower.org/blog/public-power-rich-history-bright-future>.

example, Section 3, Article XVIII of the Ohio Constitution, also known as the home rule amendment.

For decades, Public Power and IOUs co-existed in their respective regulatory spheres, planning for and managing the needs of their respective customers. Both IOUs and Public Power utilities were required by their respective regulators (whether it was the state PUCs or city councils) to “satisfy the regulator’s standards for performance at ‘lowest feasible cost,’ to use ‘all available cost savings opportunities’; and to pursue its customers’ legitimate interests free of conflicting business objectives. In return, the regulator must establish compensation that is commensurate with the utility’s performance.”²⁵ However, with the dawn of deregulation, although the regulatory compact between local governmental regulators and Public Power utilities remained unchanged, it was significantly modified for state PUCs and IOUs in an attempt to eliminate monopolies and to substitute competition for regulation to achieve the “lowest feasible cost” of providing capacity.

While Public Power strongly supported competitive markets, Public Power did not take the same approach as the states to achieve a competitive end because Public Power, by definition, is incentivized to achieve the lowest cost results for their citizen owners/operators. The states, on the other hand, had to protect the interests of IOU customers given that IOUs were no longer guaranteed a return on and of their investments in generating resources through regulation. In order to protect customers and allow IOUs to meet their corporate objectives through competition, the states required

²⁵ See, “*What ‘Regulatory Compact’*”, Scott Hempling, available at: <http://www.scotthemplinglaw.com/essays/what-regulatory-compact> (internal citations omitted).

the IOUs to functionally separate to guard against the IOUs exercising market power to benefit their generation resources at the expense of customers. This change resulted in the generation-owning IOUs being unleashed from the obligation to serve customers.²⁶ Rather, the primary corporate purpose of IOUs after deregulation is to benefit shareholders who are separate and distinct from their customers. Public Power, on the other hand, remains vertically integrated and retains the obligation to serve Public Power load (who are the citizen owners/operators of Public Power), through a combination of generation development, bilateral contracts, and purchases through the auction process.

This retention of the obligation to serve load is significant because, with the exception of cooperatives, rate-regulated investor-owned utilities and LSEs that are created by and intended to serve large end-use customers, no other market participants in PJM have both an obligation to serve and capacity resources required to meet those obligations. Consequently, unlike IOUs and IPPs, which comprise the majority of generators in PJM's thirteen state footprint where deregulation has obligated most investor-owned utilities to divest generation, Public Power entities continue to plan for and meet the resource adequacy needs of their customer-owners. The generation-owning IOUs and IPPs simply do not have the same cost-based obligation to serve load; rather, they rely on the "market" to ensure just and reasonable rate outcomes. This makes Public Power fundamentally different from the IOUs and IPPs. The IOUs and IPPs offer their capacity into the PJM capacity construct, which they have a must-offer obligation to do, and rationally have the incentive to achieve the highest possible price for their capacity. Public Power, on the other hand, has both generation to offer and

²⁶ In most deregulated states, it is the distribution utility that does not own generating resources that retains the obligation to serve.

citizen owner-load to serve by purchasing capacity not otherwise secured through generation development or bilateral contracts from the PJM capacity construct. Thus, Public Power has to balance two distinct interests in ways the IOUs and IPPs no longer have: generation and load. In other words, Public Power's citizen-owner load directly pays for the generation developed, contracts entered into *and* capacity purchased from the PJM capacity construct as part of the retained "regulatory compact." This is also fundamentally different from IOUs and IPPs because if they receive out-of-market support, they do not have an obligation to correspondingly reduce the retail rates that customers pay. For this reason, the Commission should not lump the payments made by Public Power load in with payments received by stand-alone generation resources.

3. The Public Power business model precludes the opportunity to economically benefit from artificially lowering the clearing price.

As the Commission is well aware, the self-supply business models of Public Power Entities operate under longstanding business models recognized by the Commission and that precede PJM's resource adequacy construct by multiple decades.

Public Power entities have long used a business model that accords with their status as components of municipal governments with local control and ownership. Specifically, the Public Power LSE business model is premised on securing a reliable supply of power for each utility's citizen-owners at a reasonable and stable cost. An essential element in meeting that objective is to include in the utility's power supply portfolio an appropriate component of *long-term* supply. Generally speaking, Public Power Entities do not base their supply arrangements on short-term market developments, but rather seek to "lock in" a significant part of their cost structure through

ownership of assets or long-term contracts.²⁷

In the context of meeting resource adequacy requirements, municipal LSEs have sought to stabilize this part of their overall cost structure by avoiding, to the extent possible, the price volatility that has been an unfortunate hallmark of RPM.²⁸ It is for this precise reason, among others, that a number of municipal LSEs in PJM have pursued long-term capacity supply arrangements in the form of asset ownership.

Specifically, in order to secure long-term capacity supply arrangements in the form of asset ownership at the lowest possible cost, municipal LSEs utilize tax exempt and tax advantaged financing, such as Build America Bonds (collectively “tax advantaged obligations”). For example, a municipal LSE may use a combination of interim and permanent bonds and other obligations intended to provide the lowest cost financing that does not expose the municipal LSE to undue interest rate risk. Included in the mix of bonds and obligations may be those that are eligible to receive direct and indirect federal tax exemptions or credits that provide a lower cost to the municipal LSEs, of financing the long-term capacity supply assets that are critical to public power entities. This access is especially critical when financing high capital cost projects or generation. However, in order to maintain the critically important tax exempt and tax advantaged status, municipal LSEs must meet and maintain several mandatory conditions.²⁹

²⁷ In fact, the desire of municipal utilities to utilize such long-term arrangements was one of the driving forces behind the adoption of 16 U.S.C. §824q(b)(4), which directs the Commission to use its authority in a manner that enables LSEs to secure firm transmission rights (or equivalent rights) on a long-term basis for long-term power supply arrangements to meet their needs.

²⁸ See *The Brattle Group, Fourth Review of PJM’s Variable Resource Requirement Curve* at 59 (April 19, 2018), available at: <http://www.pjm.com/-/media/library/reports-notice/special-reports/2018/20180420-pjm-2018-variable-resource-requirement-curve-study.ashx?la=en>.

²⁹ The Internal Revenue Code of 1986, as amended, the Treasury Regulations (including final, temporary and proposed regulations) promulgated thereunder and the rulings with respect thereto, set forth

For example, neither the municipal LSE nor any participants in a project financed with tax-advantaged obligations may use the project for anything other than the governmental purposes of such municipal LSE or project participant. Additionally, so long as any tax-advantaged obligations are outstanding with respect to a project, neither the municipal LSE nor any project participant may use their interest in the project for any activities that constitute a “private use.” Private use means any activity that constitutes a trade or business that is carried on by persons or entities other than state or local governmental entities (“nongovernmental persons”). Any activity carried on by a person other than a natural person is treated as a trade or business. In most cases, private use will occur if a nongovernmental person has a “special legal entitlement” to use the power associated with the project under an arrangement with the municipal LSE or any project participant. Such a special legal entitlement would include ownership or actual or beneficial use pursuant to a lease, management or incentive payment contract, output contract, research agreement or similar arrangement. Private use may be also established solely on the basis of a special economic benefit to one or more nongovernmental persons.

Additionally, neither the municipal LSE nor any project participant may enter into any output contract that results in private use with respect to the project or any share in the project. Generally, an output contract is one under which the municipal LSE or any project participant agrees to sell electricity to a nongovernmental person and, thus,

conditions that must be satisfied on a continuous basis in order for tax-advantaged obligations to retain their tax status and impose limitations on the use of the property financed with the proceeds of the tax-advantaged obligations as long as the tax-advantaged obligations are outstanding and on the use and investment of proceeds of the tax-advantaged obligations and certain other moneys relating to the tax-advantaged obligations. If the municipal LSEs or one or more participants in a project financed with tax-advantaged obligations fail to comply with the requirements, the tax status of obligations issued by the municipal LSEs could be jeopardized and result in the loss of the related Federal subsidy.

transfers the benefits of the tax advantaged financed property and the burdens of paying the debt service on the tax-advantaged obligations to a nongovernmental person.

In other words, the federal tax requirements on tax-advantaged obligations that are critical to the longstanding business models of public power entities serve as effective barriers against such entities building generation as merchant generation, market manipulation, or anything other than legitimate self-supply.

For each of the reasons discussed above, Public Power does not receive the type of state support for specific generation resources that the Commission has identified as raising concerns of unacceptable out-of-market subsidies. Accordingly, the Commission should not include Public Power in the definition of an Actionable Subsidy.

C. If FERC defines Actionable Subsidy to include Public Power, Public Power should be exempt from the MOPR.

The MOPR has its origins in a 2006 Settlement Agreement dealing with establishing PJM's RPM administrative resource adequacy construct.³⁰ As originally crafted in that 2006 settlement, the MOPR applied to a limited set of new or uprated combined-cycle and combustion turbine resources because, in theory, these resources could be developed on a timeframe and at a size that could allow the exercise of buyer-side market power.³¹ The entire legal and policy underpinning of the MOPR is the concept that a net buyer of capacity could have an incentive to exercise buyer-side market

³⁰ See *PJM Interconnection, L.L.C.*, 153 FERC ¶ 61,066 at P 2 (2015) ("PJM first established the MOPR in 2006, as part of its capacity auction protocols, to address the concern that load may have buyer-side market power, i.e., an incentive to suppress market clearing prices by offering supply at less than a competitive level.").

³¹ See, Affidavit of Robert B. Stoddard filed in Support of the Settlement Agreement in Docket No. EL05-148 on Oct. 19, 2005 at 5.

power and drive prices to unreasonably low levels.³²

The original settlement that created RPM also included a guaranteed clearing for Public Power entities.³³ In regards to inclusion of the MOPR, the Commission acknowledged that "the purpose and function of the MOPR is not to unreasonably impede the efforts of resources choosing to procure or build capacity under long-standing business models."³⁴ In fact, PJM and the Commission have established that legitimate self-supply – self-supply that is offered into RPM without any intent to economically benefit from artificially lowering clearing prices – has never been the target of the MOPR revisions. Instead, the legitimate self-supply of Public Power LSEs who procure capacity outside of the RPM auctions became collateral damage in the campaign to change the MOPR.

It was also never the intention of RPM for all capacity to be procured in the auctions (hence the name, Base *Residual* Auction or “BRA”). LSEs must have the ability to achieve greater price certainty and control over resource decisions through long-term procurement of capacity than what the one year, three years forward clearing price can offer. PJM continued to recognize these principles in supporting a PJM-proposed settlement that included a self-supply MOPR exemption in 2012.³⁵ PJM noted that

³² See *PJM Interconnection L.L.C.*, 117 FERC ¶ 61,331 (2006).

³³ The Tariff previously required that in applying the MOPR to an LDA, PJM must accept (1) first, all self-supply Sell Offers in their entirety; (2) second, all Sell Offers of zero, prorating to the extent necessary; and (3) third, all remaining Sell Offers in order of the lowest price. PJM Tariff Attachment DD, Section 5.14(h)(4). *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006).

³⁴ *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006).

³⁵ *PJM Interconnection, L.L.C.*, Docket No. ER13-535, Revisions to the PJM Tariff re: 2012 Stakeholder Proposed MOPR Revisions at 18 (December 7, 2012).

“[p]ursuit by these types of LSEs of the types of bilateral contracts and other power supply arrangements on which they have relied for years generally should not raise concerns of possible price suppression, absent additional facts, such as excess net-short or excess net-long positions, or anomalous or unusual costs or revenues.”³⁶ Further, PJM argued that expressly identifying in the Tariff these long-standing business models “(which the current effective Tariff language fairly is read to have assumed) will help avoid over-mitigation and unintended consequences from MOPR for these LSEs.”³⁷

Moreover, the Commission agreed that with suitable net-short and net-long thresholds, a Public Power self-supply exemption from MOPR is reasonable:

We find that, as a general matter, providing exemptions for resources properly designated as self-supply when they meet suitable net-short and net-long thresholds is reasonable. The concern giving rise to the MOPR is that buyers can reduce their total capacity cost by financing uncompetitive entry, because the cost of financing the entrant is offset by the overall cost reduction achieved by lowering the price of capacity for the remainder of the capacity purchased. While such a strategy may lower capacity costs in the short-run, over the long-run this strategy will prove more costly as it encourages early retirement and discourages new, at-risk investment. However, if a self-supply entity meets a sufficiently large proportion of its capacity needs through its own generation investment, it has little or no incentive to suppress capacity market prices. If the amount of non-self-supplied resources procured from RPM is sufficiently small, uneconomic entry would reduce the cost of procuring this portion by less than the amount spent on the uneconomic entry.³⁸

The Commission upheld its initial finding on rehearing:

NRG argues that the self-supply exemption will result in a large number of new power plants being built by vertically-integrated utilities and public power entities, the effects of which will suppress

³⁶ See Ott MOPR Affidavit at 2-11.

³⁷ *PJM Interconnection L.L.C.*, Docket No. ER13-535, Revisions to the PJM Tariff re: 2012 Stakeholder Proposed MOPR Revisions at 18 (December 7, 2012).

³⁸ *PJM Interconnection, L.L.C.*, 143 FERC ¶61,090 at P 108 (May 3, 2013) (“MOPR Settlement Order”).

market clearing prices. We disagree. With properly-calibrated net thresholds, PJM's self-supply exemption will not operate in a manner that encourages uneconomic entry and thus will not artificially suppress market clearing prices. PJM's analysis of offers submitted into its Base Residual Auction (BRA), moreover, reasonably identifies the threshold level at which a self-supply entity would not have the incentive to seek uneconomic entry.³⁹

The 2012 MOPR settlement was vacated by the circuit court on appeal, not on the basis that the Commission's holdings approving the self-supply exemption from MOPR were unreasonable or unsupported but rather because the court found the Commission had exceeded its authority under FPA section 205 in its compliance directive for PJM to make, what the court found to be, non-minor changes to PJM's December 2012 Filing.⁴⁰ Accordingly, it would be a reversal of numerous precedential orders spanning years to include Public Power in an expanded MOPR without exemption.

The Commission must ensure that any MOPR, particularly the newly proposed expanded MOPR, is tethered by a foundation in fact and reason and not simply an allegation that states' increasing support for specific resources may have a price suppressing effect. The Commission must bear in mind that the proposed remedy to this unsupported concern is to mitigate bids *upward* and *raise prices*. This remedy runs afoul of the Commission's longstanding balancing of the competing concerns, particularly by inclusion of Public Power.

1. Public Power self-supply should be exempt from any MOPR.

While the Commission noted in the Order (at P 69) that the Commission "may, and has, accepted PJM Tariff changes limiting PJM's MOPR exemptions, even where those

³⁹ *PJM Interconnection, L.L.C.*, 153 FERC ¶ 61,066 at P 52 (October 15, 2015) ("MOPR Settlement Rehearing Order").

⁴⁰ *NRG Power Marketing, LLC v. FERC*, 862 F.3d 108 (D.C. Cir. 2017) ("NRG").

revisions may have required load to ‘pay twice’ for capacity resources that a state requires its constituents to support through out-of-market payments”, that is simply not analogous for Public Power Entities. The Commission also correctly noted that the FPA does not forbid preferences, advantages, and prejudices *per se*; only “undue” preferences, advantages and prejudices.⁴¹ The Commission further elaborated that the determination as to whether a Commission-regulated rate or practice that provides different treatment to different classes of entities is unduly discriminatory “is fact-based, and turns on whether the relevant classes of entities are similarly situated.”⁴² “To say that entities are similarly situated does not mean that there are no differences between them; rather, it means that there are no differences that are material to the inquiry at hand.”⁴³ Public Power self-supply is sufficiently different from other generating resources that it warrants an exemption from MOPR even if the Commission includes Public Power in the definition of Actionable Subsidy.

In the context of meeting resource adequacy requirements, Public Power entities have sought to stabilize this part of their overall cost structure by avoiding, to the extent possible, the price volatility that has been an unfortunate hallmark of RPM.⁴⁴ It is for this

⁴¹ Order at P 101 (citing 16 U.S.C. § 824d(b)).

⁴² *Id.*

⁴³ See *N.Y. Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,124, at P 10 & n.30 (2018) (*NYISO*) (citing *Iberdrola Renewables, Inc. v. Bonneville Power Admin.*, 137 FERC ¶ 61,185, at P 62 (2011), *reh’g denied*, 141 FERC ¶ 61,233 (2012)). See also *Black Oak Energy, LLC v. FERC*, 725 F.3d 230, 239 (D.C. Cir. 2013) (“We accept disparate treatment between ratepayers only if FERC “offer[s] a valid reason for the disparity.”) (citing *Elcon*, 747 F.2d at 1515); *Ark. Elec. Energy Consumers v. FERC*, 290 F.3d at 367 (“A rate is not unduly preferential or unreasonably discriminatory if the utility can justify the disparate effect.”).

⁴⁴ See *The Brattle Group, Second Performance Assessment of PJM Reliability Pricing Model* (August 26, 2011) at V. The Brattle Report states that “[c]apacity prices have been volatile and uncertain, which increases the risks and therefore the costs faced by suppliers.” That same price volatility and uncertainty also increases the risks and costs faced by LSEs. See also, *The Brattle Group, Fourth Review of PJM’s Variable Resource Requirement Curve* at 59 (April 19, 2018), available at: <http://www.pjm.com/>

precise reason, among others, that a number of Public Power LSEs in PJM have pursued long-term capacity supply arrangements in the form of asset ownership. These arrangements serve their intended purpose, however, only if the sponsoring Public Power LSE is assured that it will be able, over the long term, to use its resource to meet all or a portion of its PJM capacity obligation. Absent this assurance, a Public Power entity that had taken steps to stabilize its costs instead would face the prospect of simultaneously paying for the resource it secured on its own while also purchasing capacity from PJM to meet its resource adequacy goals.

It was the elimination of guaranteed clearing for self-supply in 2011 that fundamentally modified the MOPR in a manner that adversely impacts Public Power LSEs' ability to meet their obligations under longstanding business models. Specifically, elimination of guaranteed clearing for self-supply created uncertainty that adversely impacted long-term arrangements, price volatility and reliability.⁴⁵

In 2012, PJM proposed a package of revisions to the RPM rules and the MOPR that included a more formalized Self-Supply Exemption supported by an independent analysis of the RPM market design by the Brattle Group as well as a thorough analysis by Andrew L. Ott.⁴⁶ In reviewing the elimination of guaranteed clearing for self-supply in the 2011 MOPR revisions, the Brattle Group concluded that subjecting self-supply to the

/media/library/reports-notices/special-reports/2018/20180420-pjm-2018-variable-resource-requirement-curve-study.ashx?la=en. The Brattle Report states that the "consequence of these relatively large deviations in cleared supply, combined with PJM's current and past VRR curves, is that RPM has produced relatively volatile price outcomes." That same price volatility and uncertainty also increases the risks and costs faced by LSEs.

⁴⁵ See Request for Rehearing and Clarification of the PJM Load Group, filed in Docket Nos. EL11-20, *et al.*, on May 12, 2011.

⁴⁶ *Ott MOPR Affidavit*.

MOPR would inadvertently interfere with self-supply offers from generating resources that are competitive and do not involve manipulation. “We are particularly concerned that the MOPR will lead to over-mitigation that will undermine bilateral markets and RPM participation by entities, such as public power companies, that meet their customers’ needs primarily through long-term contracts or other self-supply options.”⁴⁷

Over-mitigation would be particularly problematic for resources developed as Public Power self-supply or through bilateral contracts. In addition to the factors described above, self-supply and bilateral resources will rationally offer into RPM as a price taker (i.e., offer at or near zero) if the development of the resource has already been committed. Such a project’s development is not contingent on the auction outcome, but the project must clear to count toward the resource requirement or contractual obligations of the Public Power entity as a buyer. Mitigating offers from such a generating unit is problematic because it might prevent the resource from clearing, the prospect of which could create a prohibitive risk for the resource owner, the LSE, or both.

As noted above and as recognized by the Commission,⁴⁸ this is distinctly different from an IOU or IPP who develops generation resources for profit through the competitive market as opposed to serving load and then seeks to subsidize those generation resources when the auction clearing price is not sufficiently high. Rather, self-supply of new resources or existing resources in the case of a Public Power entity is the result of integrated resource planning to ensure that the resource procurement is in the best

⁴⁷ See *The Brattle Group, Second Performance Assessment of PJM Reliability Pricing Model* (August 26, 2011) at 149.

⁴⁸ The Commission stated, “The incentives for uneconomic entry in restructured states differ because, in those market structures, LSEs rely largely on the market to meet their capacity obligations.” MOPR Settlement Order at P 111.

interests of citizen owners/customers. These generation resource plans are developed by Public Power entities, whose goals are to provide economic and stable long-term rates for their members. Public Power entities clear all of their resources in RPM, purchase all of the load obligations from RPM, and, effectively, are net purchasers or sellers for the difference between their load obligation and their total cleared resources. The inability to receive full capacity credit in RPM for all of their resources unreasonably harms Public Power self-supply entities and their ratepayers. Accordingly, Public Power self-supply, if included in the definition of “Actionable Subsidy”, should be exempt from application of the MOPR.

2. Even if Public Power could manipulate the market to economically benefit from artificially lowering clearing prices, adequate protections can be included.

Although AMP does not concede that Public Power has the ability or inclination to artificially lower clearing prices, to further allay any such concerns, the Commission could impose the measures that it has previously found to mitigate any risk that market rules incentivize Public Power entities to attempt to economically benefit from artificially lowering clearing prices. Specifically, those include both the qualitative and quantitative measures described below.

- 1) Net-Short Criteria. To qualify for the Public Power self-supply exemption, a Public Power self-supply LSE may be net-short, meaning that its owned and contracted capacity is less than its capacity obligation. However, a Public Power LSE may not be net-short on capacity and still receive the Public Power self-supply exception if it is more than 1000 MW short for a single-state public power entity or across three specified Local Deliverability Areas (“LDAs”) or 1800 MW short at the RTO level for a multi-state Public Power entity.

PJM argued, and the Commission accepted that these net-short thresholds are reasonable. Notably, the thresholds are small enough to prevent such entities from

economically benefiting from a strategy of using a new resource to artificially lower price for their net-short position.

- 2) **Net-Long Criteria.** Similarly, the Commission could require the Public Power exemption to include maximum levels at which a Public Power LSE can be net-long on capacity and still qualify for the Public Power self-supply exemption. This provision reflects the concern, however unreasonable,⁴⁹ that an LSE may have such a relatively large amount of excess capacity that it may seek to “dump” capacity on the RPM auction, pushing down capacity prices in the process. The Public Power self-supply exemption could incorporate the following set of thresholds, varying by the size of the LSE’s capacity obligation, for this purpose:

Estimated Capacity Obligation	
Less than 500	75 MW
Greater than or equal to 500 and less than 5,000	15% of LSE’s Estimated Capacity Obligation
Greater than or equal to 5,000 and less than 15,000	750 MW
Greater than or equal to 15,000 and less than 25,000	1,000 MW
Greater than or equal to 25,000	4% of LSE’s Estimated Capacity Obligation capped at 1300 MWs

PJM argued, and the Commission agreed, that these levels are reasonable because they serve to limit a Public Power self-supply entity from substantially overbuilding while recognizing that the addition of a large resource that may be efficiently sized to accommodate the LSE’s long-term needs may put the LSE in a net-long position at the beginning of the resource’s life. To avoid an undue penalty, if the new resource causes the LSE to exceed the net-long threshold, then the LSE will be subject to the MOPR floor price only for the increment of capacity that exceeds the threshold.

⁴⁹ Public Power is incapable of developing capacity in excess of its reasonable needs, with the exception of some small amount that may result from the “lumpiness” inherent in generation resources.

- 3) Officer Certification. Additionally, the Commission could require Public Power entities seeking the Public Power self-supply exemption to submit a sworn, notarized certification of one of its duly authorized officers certifying that the information submitted to PJM and the IMM in support of its exemption request is true and correct, that the generation resource that is the subject of the exemption request will be part of its owned and contracted capacity, that the LSE has disclosed all material facts, and that the market seller satisfies the criteria for the exemption. PJM argued that a requirement for the LSE to obtain such a certification from an officer of the company will provide greater incentive for thorough review of information to ensure accuracy prior to submittal to PJM and the IMM, which also promotes greater confidence in relying on the facts presented by the LSE to support its exemption request, and thereby facilitate the exemption process.

The Commission could direct PJM to specify in the Tariff that in order to qualify for the Public Power self-supply exemption, the Public Power entity must also meet these qualitative criteria:

- 1) Belong to a defined Public Power Self-Supply LSE, which is limited to: cooperative, municipal utilities, joint action agencies. The definition of Self-Supply LSE makes it clear that each of these is an LSE which operates under long-standing business models.
- 2) Not include any cost or revenue advantages that are irregular or anomalous, that do not reflect arms-length transactions, or that are not in the ordinary course of the Self-Supply LSE's business unless the LSE demonstrates that the costs or revenues are consistent with the overall objectives of the self-supply exemption. Costs may include: economic development incentives from a town or county to locate in that town or county, revenues attributable to inclusion of the costs of the project (planned consistent with the LSE's most recent resource plan), and cost or revenue advantages associated with the LSE's long-standing business model, such as tax preferences.
- 3) Not include any "payment upon clearing" arrangements whereby the LSE receives payments or subsidies that are specifically tied to the LSE clearing its project in an RPM auction, or to the construction of its project.

These measures, consistent with those the Commission has formerly held to be just and reasonable, ensure that a Public Power self-supply MOPR exemption is not a blanket exemption. Whereas the long-standing business models of Public Power should

alleviate concern over the incentive and capability of these entities' ability to exercise buyer side market power to unduly influence the capacity market, the individual net-short limits, the specific prohibition of out-of-market revenues contrary to an established business model, and the prohibition of revenues tied to clearing provide additional safeguards against anti-competitive behavior.

While AMP believes that the information and analysis provided by PJM to support the 2012 MOPR Settlement, coupled with the information provided herein, is more than sufficient to demonstrate that a Public Power MOPR exemption is just and reasonable, AMP provides the additional information in the affidavit of Christopher J. Norton, attached hereto as Exhibit A, to demonstrate that AMP has neither the incentive nor the ability to economically benefit from artificially lowering market prices. Specifically, as Mr. Norton concludes, using PJM's analysis from the MOPR settlement proposal, AMP's total unforced capacity or "UCAP" obligation is well below the net-short required to gain an economic advantage.

Accordingly, even if this unprecedented type of market intervention could be justified, for the reasons stated herein and in the attached affidavit of Mr. Norton, the expanded MOPR should not be utilized to penalize Public Power resources that do not receive state support and are not similarly situated to those investor-owned resources that do. Thus, if the Commission includes Public Power in the definition of "Actionable Subsidy", which it should not, the Commission should exempt Public Power from the MOPR subject to the limitations described herein.

D. FRR-RS Alternative.

AMP has long expressed fundamental concerns with features of RPM, and mandatory administrative capacity constructs in general. AMP has been particularly critical of the MOPR component of these constructs, and its detrimental effect on new public power self-supply resources and new resources developed to achieve state policy goals. AMP agrees, therefore, that the time is ripe to revisit RPM in a comprehensive manner. Indeed, in its protest in this proceeding, AMP urged the Commission to reject PJM's proposals, arguing that PJM should seek to reform its resource adequacy construct to encourage more stable forms of procurement via bilateral contracting and ownership of resources by states, utilities and large customers.⁵⁰ AMP argued that PJM stakeholders should be encouraged to develop true market reforms that would create a viable residual capacity market without mandatory capacity market restrictions.⁵¹ Respondents assume that the Commission's attempt at such comprehensive reform is the FRR-SR Alternative. While the FRR-RS Alternative could potentially offer a workable improvement to some of the significant concerns for Public Power that have been raised, the uncertainty of what the FRR-RS Alternative option may ultimately look like is too high for Respondents to conclude that the FRR-RS Alternative option works to satisfy any of those concerns. Nonetheless, and in response to the Commission's request, Respondents offer their recommendations for the FRR-RS Alternative option, whereby

⁵⁰ *PJM Interconnection, L.L.C.*, Docket No. ER18-1314-000, Comments of American Municipal Power, Inc. on PJM interconnection L.L.C.'s Capacity Repricing or in the Alternative MOPR-Ex Proposal at 14 (May 7, 2018).

⁵¹ See AMP's proposal for achieving the goal of creating a viable residual capacity market without mandatory capacity market restrictions and while accommodating state preferences attached hereto as Exhibit B.

individual resources and an associated portion of load, would not participate in the PJM resource adequacy construct.

Respondents are hopeful that the Commission agrees that Public Power self-supply should not be included as an Actionable Subsidy or, at least, should be properly be exempted from the expanded MOPR contemplated by the Commission.⁵² Nonetheless, if that is not the case and Public Power is considered an “Actionable Subsidy”, Public Power should have the choice to elect the FRR-RS Alternative.

Respondents believe that the MOPR should apply only to new natural gas resources consistent with the theory of mitigating buyer side monopsony market power. However, if the MOPR is expanded as suggested in the June 29 Order, than any resource or any portion thereof, including potentially Public Power resources, subject to the expanded MOPR should be eligible to elect the FRR-RS Alternative. However, whether resources are carved out of the capacity construct or remain in, they should be subject to the same capacity performance requirements including non-performance charges and the ability to earn bonus payments.

Election of carve-out status must be made no later than 120 days prior to the commencement of the BRA. Rules and practices governing the submission of offers by joint owners of individual generating units shall remain unchanged and, therefore, a carve-out election by one joint owner shall not affect RPM participation by the other owner.

The Commission stated that, depending on how load is selected for the new FRR-RS Alternative, this new option should “help confine the cost of a particular state policy

⁵² See *id.* at June 29 Order at P 167 (requesting comment on whether “an exemption [should] be included for self-supplied resources used to meet loads of public power entities”).

decision to consumers within the state that made that policy decision, whereas the status quo requires consumers in some PJM states to subsidize the policy decisions of other PJM states.” June 29 Order at 162. As the Commission’s goal is to ensure that subsidies are paid for by the load of the RERRA that made the policy decision, the FRR-RS Alternative design should be structured such that only load subject to the jurisdiction of an RERRA (through retail rate authority) shall pay for the costs associated with such subsidy.⁵³ In other words, in order to confine the cost of a particular state policy decision to consumers within the state that made that policy decision and to avoid requiring Public Power customers to subsidize the customers of IOUs within a state, the Commission should use the RERRA, rather than the state, as the regulatory authority responsible for determining who, within its jurisdiction should be responsible for the cost associated with Actionable Subsidies. To do otherwise would result in undue discrimination and unjust and unreasonable rates. For example, if Ohio passes ZEC legislation that subsidizes nuclear resources owned by FirstEnergy’s generation-owning affiliates, municipal customers in Bowling Green who are not subject to the PUCO’s rate authority should not be required to contribute to such subsidy through a FRR-RS Alternative. Rather, the PUCO will need to undertake an effort to determine how retail load under the PUCO’s rate authority (which excludes Public Power), will be attributed to resources being subsidized.

⁵³ The Commission acknowledges that although it has relied on competitive processes and markets to produce just and reasonable wholesale power rates, the states “undeniably have the power simply to reregulate.” Order at 153. As noted above, Public Power supports competition in electricity markets. However, the Commission should remember that today’s centralized capacity constructs are not “markets” in the classical sense. (If they were, RTOs would not be able to dictate what level of reliability, at what cost, is “optimal.”) Rather than endorsing market design elements that limit LSE optionality, the Commission should promote constructs that effectuate consumers’ resource preferences to meet established reliability requirements free from artificial restrictions and restraints.

In the event that the Commission finds that Public Power has actionable subsidies but is permitted to use the FRR-RS Alternative, for some generating resources, it is easy to match the impacted load because there is a direct contractual relationship whereby the load has a right to its share of the resource's output or specific bilateral contract. See, for example, selected provisions of the AMP Fremont Energy Campus Power Sales Contract, attached hereto as Exhibit C. But Public Power, in most instances is a net purchaser of energy and capacity ("net-short") and will remain so intentionally in order to maintain a diverse resource portfolio and manage changes in load. See Exhibit B, Affidavit of Christopher J. Norton. Accordingly, only a portion of the retail load will be matched with specific generating resources. The balance of capacity to meet Public Power load's needs comes from PJM's RPM auction. There is no subsidy or other value that can be attributed to a price that Public Power load pays for capacity because Public Power relies on the auction to acquire the balance of capacity required after accounting for customer-owned generation resources and bilateral contracts. Consequently, Public Power should be permitted to utilize the capacity construct for balancing the residual needs (or excess) to serve its load obligations.

Finally, once a resource has been carved out, it ought not to be permitted to participate in the capacity auction for any subsequent period until the resource re-enters the market successfully under the mitigation rules.

IV. CONCLUSION

WHEREFORE, for the foregoing reasons, Respondents request that the Commission:

- (1) Continue to reject repricing and expanded MOPR market design proposals and direct the PJM stakeholders to create a viable residual capacity market without mandatory capacity market restrictions that accommodates state and local preferences.
- (2) Determine that Public Power resources are not subsidized and, thus, define “Actionable Subsidy” as “any payments, concessions, rebates, or incentives other than Market Revenue” but not those payments, concessions, rebates, subsidies or incentives that are “consistent with and part of a public power business model.”
- (3) To the extent that the Commission deems Public Power resources as receiving actionable subsidies (which it should not), the Commission should find that Public Power self-supply is properly exempted from the expanded MOPR.

- (4) Should the Commission find that Public Power resources do receive actionable subsidies (which it should not) and should not be exempt from the MOPR (from which they should be exempt), Public Power should be permitted to utilize the FRR-RS Alternative and the FRR-RS Alternative rules should properly recognize local jurisdictional authority as separate and distinct from state regulatory authority.

Respectfully submitted,

AMERICAN MUNICIPAL POWER, INC.

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CERTIFICATE OF SERVICE

I hereby certify that I have on this date caused a copy of the foregoing document to be served on each person included on the official service list maintained for this proceeding by the Commission's Secretary, by electronic mail or such other means as a party may have requested, in accordance with Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010.

Dated this the 2nd day of October, 2018.

/s/ Lisa G. McAlister
Lisa G. McAlister

Exhibit A

AFFIDAVIT OF CHRISTOPHER J. NORTON

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Calpine Corporation, *et al.*

Docket Nos. EL16-49-000

v.

PJM Interconnection, L.L.C.

ER18-1314-000

PJM Interconnection, L.L.C.

ER18-1314-001

PJM Interconnection, L.L.C.

EL18-178-000
(Consolidated)

AFFIDAVIT OF CHRISTOPHER J. NORTON

I. QUALIFICATIONS AND PURPOSE

1. My name is Christopher J. Norton. My business address is 1111 Schrock Road, Columbus, Ohio 43229. I am the Director of Market Regulatory Affairs at American Municipal Power, Inc. ("AMP"). I received a Bachelor of Science in Physics degree from the Ohio State University in 1992. I have worked in the electric utility industry for just over 20 years. I started work at AMP in 1998 as a Power Dispatcher, purchasing and scheduling power in real-time. From there I moved to day-ahead scheduling and then to my current position. I am now responsible for monitoring, analyzing, and working with others at AMP to prepare AMP's responses to proposed FERC Open Access Transmission Tariff and other market rule changes.

2. I have prepared this affidavit on behalf of AMP, which is a nonprofit Ohio corporation organized in 1971. The members of AMP are all political subdivisions of their respective domicile states that own and operate municipal electric utility systems, some of which also operate electric generating and transmission facilities. AMP's primary purpose is to assist its member communities in meeting their electric and energy needs. AMP is a full or partial requirements supplier for most, but not all, of its 135 members.

3. The purpose of my testimony is to address the question of whether AMP, a public power entity, is capable of and motivated to build new generating capacity or "dump" excess generating capacity in order to affect market prices to gain an economic advantage. I have been asked to provide the information in this affidavit in response to claims made in the dockets that have been consolidated along with Docket No. EL18-

178, that the Minimum Offer Price Rule (“MOPR”) should be applied to public power entities, like AMP, to protect the market from artificial price reduction actions by municipal utilities taking advantage of opportunities to “exploit loopholes in the RTO structure that supports their ‘historic business Models’ while at the same time rewarding them with the many benefits of RTO participation” as erroneously suggested by Dr. Roy Shanker. See, *CPV Power Holdings, L.P., Calpine Corporation and Eastern Generation, LLC v. PJM Interconnection, L.L.C.*, Docket No. EL18-169, Shanker Affidavit at P 35 (May 31, 2018).

II. BACKGROUND

4. In Docket No. ER13-535, PJM responded to a FERC deficiency letter regarding PJM’s proposed settlement package that included an exemption for public power entities subject to limitations, including the net-short/net-long criteria. PJM provided information on how it derived its then-proposed net-short and net-long MOPR exemption provision through an Affidavit provided by Andrew L. Ott submitted on March 4, 2013. PJM used the May 2012 RPM auction information to calculate the impact of certain amounts of entry on the auction clearing prices. PJM then compared the impacts to the cost of generation to determine how many MWs net-short an entity would need to be to economically benefit from lowering the capacity price by building and committing a generation unit that was not economic. PJM examined entry at below cost of a 150 MW unit and 600 MW unit.

5. PJM determined that for the unconstrained RTO region, such a strategy would become profitable between 19,350 MW to 19,850 MW for entry of a 150 MW unit and between 14,400 MW and 14,900 MW for entry of a 600 MW unit. .

6. PJM also examined the question on a more granular level by reviewing the net-short levels necessary to achieve an economic benefit in specific Local Delivery Areas (“LDAs”). In his affidavit Mr. Ott provided information on the MAAC LDA, EMAAC LDA, SWMAAC LDA, and ATSI LDA. In the MAAC LDA, an LSE would need to be between 7,350 MW and 7,850 MW net-short to find uneconomic entry of a 150 MW unit profitable. For a 600 MW unit, the threshold falls to between 3,900 MW to 4,400 MW.

III. ANALYSIS

7. AMP has no incentive or ability to exercise buyer market power to economically benefit from artificially lowering market prices through the addition of new generation or maintenance of existing generation. It would not make sense for AMP to build or maintain generation to lower the cost for others. As discussed in AMP’s comments, AMP’s members are municipal electric utilities. They are not legally allowed to build generation for the purpose of speculation. AMP’s members are required to demonstrate that generation they build, or that AMP builds on their behalf, can be used and useful to meet their load either immediately or in the foreseeable future.

8. As for AMP’s ability to build and maintain generation to artificially lower the RPM price, AMP does not have enough load to take advantage of such a strategy.

9. AMP members served through AMP held PJM accounts have a UCAP obligation of about 1,875 MW (rounded to the nearest MW) for the 2018/2019 Planning Year. However, this does not represent the load of all AMP members in PJM. Some members, like Cleveland Public Power and Berlin, Maryland have their own PJM accounts so their capacity is not in AMP's account and is not reflected in the UCAP estimate. Conversely, for the 2018/2019 Planning Year, AMP has 1,290 MW of UCAP (rounded to the nearest MW). This means that AMP is net-short on capacity.

10. As with many loads, the UCAP obligation assigned to AMP's members changes from year-to-year based on the members' loads at the time of the PJM 5 Coincident Peaks. Additionally, AMP experiences, from time-to-time, changes in load based on members changing power suppliers. AMP is a project-based organization as opposed to a traditional, all-in, one-rate joint action agency. This means that AMP's members may take service through AMP or from other power suppliers. This leads to variations in AMP's UCAP obligation from year to year. Based on past changes, AMP could see its load vary by about 300 MW UCAP in a given year.

11. For the 2018/2019 Planning Year, AMP's capacity position is a net-short of 585 MW UCAP. As discussed above, this net-short could change based on member power supplier decisions for any given year.

12. Using PJM's analysis described above, it is clear that AMP's total RTO UCAP obligation is 1,875 MW, well below the net-short level identified as required to gain an economic advantage. Examining the other LDAs shows similar results, that AMP's UCAP obligation is below the threshold that would allow such a strategy to be profitable. AMP has members in AEP, APS, ATSI, Dayton, DEOK, DPL, MAIT, and PPL. All of these thresholds are greater than AMP's UCAP obligation for the relevant LDA. Similarly, for AMP's members in ATSI, PJM determined, "Accordingly, offering a 150 MW or 600 MW resource below its cost would not be profitable at any net short level."

13. While the net-short/net-long criteria will permit AMP to operate under its traditional business model, it also substantially limits the risk that a multistate public power entity could exercise buyer side market power to unduly influence the capacity market for economic gain. For AMP specifically, although AMP is significantly net-short and is required to purchase from the market, AMP could not exercise buyer side market power by building a power plant or continuing to maintain a power plant to lower the market price such that the decrease in the market prices as applied to the load AMP served from the market more than offsets the above market costs paid for a generation unit. With the multistate limit at 1,800 MW, which is a significant portion of AMP's UCAP obligation, if AMP were to own or otherwise have under contract 1,800 MW of generation, AMP would be very close to supplying 100% of its own capacity requirement, which is less than what would be required to depress the market to a sufficient degree for AMP to take advantage of the depressed market prices.

14. This concludes my affidavit.

**UNITED STATES OF AMERICA
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PJM Interconnection, L.L.C.

EL18-178-000

(Consolidated)

Affidavit

I, Christopher J. Norton, do hereby swear and affirm under penalty of law that the statements in the foregoing affidavit are true to the best of my knowledge, information and belief.

Executed this 2nd day of October, 2018.



Christopher J. Norton

Exhibit B

AMP PROPOSAL FOR CAPACITY CONSTRUCT

Executive Summary

American Municipal Power, Inc.'s

Proposal to the Capacity Construct/Public Power Senior Task Force

Executive Summary

I. Introduction

The genesis of the AMP proposal was in part due to AMP's strong belief that any "solution" developed in response to state public policy initiatives should be developed with the input of PJM stakeholders. AMP, and other PJM stakeholders were concerned about PJM's direction and offered a problem statement and issue charge to bring the debate into the PJM stakeholder process.

Many stakeholders were reluctant to take up this effort. Over a six month period, AMP representatives appeared five separate times before the PJM Markets and Reliability Committee ("MRC") and facilitated the discussion as the stakeholders sought to define the problem and limit the universe of solutions.

This background is important to understand as AMP wants it be crystal clear that AMP did not necessarily perceive a problem but instead reacted to PJM's comment at the August 2016 Grid 20/20 meeting that they would not be seeking stakeholder input on their "capacity re-pricing" proposal. The "capacity re-pricing" proposal is fraught with market design errors and having a robust stakeholder process with input from a diverse set of Members from all of the PJM sectors could lead to a better solution than that developed unilaterally by PJM.

II. AMP's Perspective

AMP's concern over PJM's administrative resource adequacy construct is well documented. The proposed actions of FirstEnergy and AEP, with approval by the Public

Utility Commission of Ohio, to recover “out of market” payments from retail customers paid to their unregulated generation affiliates in an effort to keep what were described as uneconomic capacity resources, the advent of ZECs, and the general angst over states having the right and authority to make public policy decisions appears to AMP as yet another symptom of the overall inadequacy of RPM to withstand any type of exogenous actions that threaten “the market.” The Department of Energy’s Notice of Proposed Rulemaking is another symptom of growing dissatisfaction with wholesale market results. PJM has inadvertently fueled this perception via its 27 major design changes to RPM since 2010, some rushed through, to preserve reliability. From AMP’s perspective and experience, any resource action that does not fit into the administratively determined construct is deemed a “threat” by PJM and the rules must be adjusted to protect the “market” (e.g., MOPR). Indeed MOPR has evolved from its stated purpose (mitigate buyer-side market power) to a preferred mechanism to maintain prices administratively determined to be the “right price.”

AMP supports competitive markets. But RPM is not a market and, in our opinion is moving further away from market principles and is creating barriers to truly competitive results. While it is necessary to have some administrative construct for capacity, it need not be a barrier to consumer preferences as expressed through state and local public policies. A simpler capacity construct as proposed by AMP, along with a focused look at energy market price formation to ensure we are identifying all intrinsic value from existing units, is required.

AMP notes that the original RPM construct served to provide states an opportunity “...to resolve a projected capacity shortfall in the Delivery Year affecting that state as

determined pursuant to a state evidentiary proceeding...”. The capacity construct needs to return to being a residual construct and not a primary source of revenue for supply.

With this perspective, AMP observes the following regarding state public policy decisions:

-) States clearly have the right and authority to develop public policy so long as payment of funds are not conditioned on capacity clearing the auction. There are many reasons that states may grant subsidies, but the subsidies that are the focus of this stakeholder process are those that are intended to support an otherwise uneconomic merchant generator that results in an artificially low offer into the capacity construct. We need to decide what action, if any, PJM should take in response to state public policy initiatives.
 - o The current structure of RPM is of itself a barrier to states implementing public policy decisions;
 - o PJM’s “market” is too narrow and ignores the wider, organic market around it;
 - o RPM rules have become too complex (this is also a barrier to state public policy decisions);
 - o A resource adequacy construct with an administratively determined price will always be overly sensitive to external influences;
 - o PJM’s administratively determined price is too high and results in an oversupply of new resources when a true market would indicate there is not a need for new entry (prices are low when supply is high) and signal retirements; and,
 - o The rules keep changing, at a minimum every four years (i.e., quadrennial review) and in reality much more frequently than that with 27 major rule changes to RPM since 2010.
-) Resolution of the “state subsidy issue” requires not only AMP’s proposed modifications to the resource adequacy construct but also significant changes to energy price formation to provide accurate price signals based on system operational needs.

III. What is an actionable subsidy?

Before we can decide what to do in response to a subsidy, we first need to define an actionable subsidy. For the purposes of AMP's proposal we define a subsidy that would require some action (*i.e.*, "actionable") as:

Actionable Subsidies include any payments, concessions, rebates, or incentives other than Market Revenue where Market Revenue is defined as revenue that is received under a tariff administered by PJM or other RTO or ISO and regulated by the Commission but shall not include payments (including payments in lieu of taxes), concessions, rebates, subsidies or incentives:

- A. that are consistent with and part of a public power business model made to a municipal utility, a cooperative utility, a joint action agency or any instrumentality of the state;
- B. designed to incent participation in a program, contract or other arrangement that promotes general industrial development in an area;
- C. are from a county or other local governmental authority using eligibility or selection criteria designed to incent the siting of facilities in that county or locality rather than another county or locality;
- D. are from the federal government and are available to generators without regard to the geographic location of the generation (e.g., production tax credits, investment tax credits, and similar tax advantages);
- E. that are supported through any contracts obtained in any state-sponsored or state-mandated procurement processes that are deemed to be Competitive and Non-Discriminatory as described in under the requirements for a procurement process to be deemed "Competitive and Non-Discriminatory" as specified in Attachment DD, Section 5.14 h) (7) ii), which requires that the process must:
 - i. allow both new and existing resources to satisfy the requirements of the procurement;
 - ii. the requirements of the procurement are fully objective and transparent;
 - iii. the procurement terms do not restrict the type of capacity resources that may participate in and satisfy the requirements of the procurement;
 - iv. the procurement terms do not include selection criteria that could give preference to new resources; and,

- v. the procurement terms do not use indirect means to discriminate against existing capacity, such as geographic constraints inconsistent with LDA import capabilities, unit technology or unit fuel requirements or unit heat- rate requirements, identity or nature of seller requirements, or requirements for new construction.
- F. that are unknowable or unquantifiable; or
- G. that are in exchange for a tradeable credit that both: 1) represents the environmental attributes of one megawatt hour of energy produced from a renewable energy resource as defined by a state or federal law; and 2) is not contingent on the price of energy or capacity.

IV. AMP's Proposal

A. Accommodation

AMP's proposal seeks to accommodate state policy decisions in the sense that there must be a place for these decisions in the *entire* market. AMP doesn't believe a price driven, administrative construct should reprice state decisions to maintain an artificially high price in the RPM auction. Accommodation is not modification of what has been offered. The entire market, not just the administrative residual construct, should drive the price.

B. Bilateral Contracts

The current construct allows for bilateral contracting. However, it is AMP's experience that this option is detrimentally limited by the three year forward administratively determined price available from the base residual auction and PJM's consistent attempts to artificially prop up the auction prices in the near term at the expense of a properly developed long-term price signal that is truly reflective of what investors look to for guidance. In short, AMP's view is that suppliers are reluctant to tie up resources in an oversupply situation for the long term so long as there is the possibility of more revenue as regulatory intervention continues to inflate the auction results.

AMP proposes to address this deficiency by moving to a one year versus three year forward auction, referred to as the Annual Residual Auction or “ARA” in AMP’s proposal. Shortening this timeframe will enable the broader market forces to come into play for resource entry and exit decisions. It also provides the opportunity to eliminate MOPR for new entry as natural gas resources would need more than a year to develop its facility.

C. How State Actions Fit In

States would be free to offer subsidies for specific units or technologies. Several paths would be available to resource owners that are eligible for actionable subsidies: 1) the resource owner could decline the actionable subsidy and either enter into a bilateral contract or participate in the ARA; or 2) the resource owner could accept the actionable subsidy in lieu of seeking additional capacity revenue – essentially opting out of the ARA. The resource can choose only one of these options, which are described in greater detail below.

D. Annual Residual Auction (ARA)

The ARA would retain the same design as PJM’s current Base Residual Auction (“BRA”), but would only be one year forward as opposed to three. Additionally, it would be comprised of those suppliers and load that did not enter into long term bilateral arrangements, load serving entities that did not choose to self-supply, or capacity resources without an actionable subsidy.

This approach would make the auction truly residual (which is what the BRA was touted as when PJM first implemented RPM in 2006). The entire and true market would drive prices and outcomes as opposed to forcing everything through the centralized auction.

The auction will occur annually, one-year ahead of time and will follow all of the rules within today's BRA such as, but not limited to:

1. Utilizing the VRR Curve
2. Utilizing existing rules for RPM bids
3. Abiding by the approved Capacity Performance rules
4. Abiding by the approved RPM rules
5. Maintaining PJM development of auction planning parameters which includes, among other things, the calculated installed reserve margin required to maintain reliability.

Additionally, moving the timing for the ARA to one year forward will allow PJM to utilize a better, and ideally more accurate, forecast of projected demand levels than is in place today. It is undebatable that the three-year forward nature of the BRA has produced an over-procurement of capacity due to load forecast error. Moving the auction closer to the start of the delivery year will help to minimize over-procurement of capacity due to load forecast error.

E. Annual Incremental Auction (AIA)

As a result of moving the timing of the ARA to one-year forward, RPM would no longer require three Incremental Auctions as we have today. Only one incremental auction would be required. AMP proposes modifying the incremental auction calendar such that the timing would be the same as the Third Incremental Auction (i.e., three months forward) that is conducted today. This auction would simply be called the Annual Incremental Auction.

F. PJM's Role

Five months before the ARA, PJM would verify the resource and load obligations for resources that accepted an actionable state subsidy and long-term bilateral contracts between resources and LSEs. PJM would also determine each LSE's peak load obligation based on the previous year's contribution to the 5 coincident peaks.

PJM would continue to calculate its installed reserve margin (“IRM”) and Forecast Pool Requirement (“FPR”). Load associated with resources accepting a subsidy and not participating in the ARA would be adjusted down to reflect the FPR. LSEs’ load would be adjusted to include their peak load obligation plus FPR. The demand curve in the ARA would utilize IRM as its inflection points as done today and load utilizing the ARA would procure an amount of resources determined by the ARA clearing mechanism (possibly IRM plus 2-5%).

G. Resource Owner Options

For resource owners with no actionable subsidies, they may either enter into a bilateral contract or participate in the ARA.

For resource owners who accept an actionable subsidy, the generator is excused from participating in the ARA along with a corresponding, but reduced, amount of load accounting for the IRM. Specifically, the amount of load participating in the ARA would be reduced, on a pro-rata basis, across its footprint accounting for any internal constraints (*i.e.*, Locational Deliverability Areas). The generator would also not be eligible to enter into a bilateral contract with an LSE as the subsidy is equivalent to a bilateral contract with the state that awarded the actionable subsidy.

In order to enable and implement any actionable subsidy, the state would be required to authorize a non-bypassable retail charge that requires the regulated distribution utilities to collect the cost of the actionable subsidy from all jurisdictional retail customers, that may be filed at FERC and included as part of the PJM RAA to obtain cost recovery, as well as any credit mechanism required to allocate the actionable subsidy to the appropriate resource owner.

These options respect the rights of the states to enact public policies they deem to be in the best interests of their jurisdictional retail customers but within the limits of *Hughes v. Talen*. Should a state wish to subsidize a particular resource, it should design the subsidy as a substitute for the resource owner's capacity revenue. States would thus be able to achieve their desired resource adequacy outcomes unencumbered by the residual capacity construct rules.

These options also respect the rights and business models of both competitive generators and competitive retail electric service ("CRES") providers in retail choice states. The competitive generators have the option to seek out subsidized capacity payments that fully compensate them if they are not getting what they need from RPM. The nearer term capacity commitment (not more than one year forward as opposed to three years forward) should give CRES providers adequate time to know their capacity obligations.

H. Curtailment Service Providers

AMP's proposal has evolved over the course of the PJM stakeholder discussion. We have carefully listened to the comments raised and concerns expressed by various stakeholder groups and have modified our proposal to address these concerns whenever possible.

One area AMP is still evaluating is the impact its proposal may have on curtailment service providers ("CSPs"). We recognize there may be significant barriers to implementing load side demand response in some states. AMP expects that supply side DR will still be able to participate in the ARA and AIA. AMP will continue to discuss this issue with the CSPs to determine if transitional measures could be employed to mitigate

potential impacts to this market segment until such time as retail barriers to demand response can be addressed.

Exhibit C

SELECTED PORTIONS OF THE AMP AFEC POWER SALES CONTRACT

4835-0728-1525, v. 6

**POWER SALES CONTRACT
REGARDING THE
AMERICAN MUNICIPAL POWER
FREMONT ENERGY CENTER**

Between

AMERICAN MUNICIPAL POWER, INC.

And

**EACH OF THE PARTICIPANTS LISTED ON THE
ATTACHED SCHEDULE OF PARTICIPANTS
INCLUDING THE**

CITY OF ORRVILLE, OHIO

Dated as of June 15, 2011

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1 **SECTION 3. Sale and Purchase.** (A) AMP hereby agrees to sell to each Participant, and each
2 Participant agrees to buy from AMP, such Participant's PSCR Share (in %) of the Power Sales Contract
3 Resources, such PSCR Share being shown in Appendix A, adjacent to such Participant's name, subject to
4 increase as provided in Section 18, and further subject to *pro rata* reduction or increase, but in no event
5 greater than authorized by such Participant's Utility Governing Body, if the AMP Entitlement in MW to
6 the Base Capacity of the AMP Fremont Energy Center is different than the Base Capacity in MW shown
7 in Appendix A. AMP's obligations to furnish Power Sales Contract Resources shall be principally those
8 set forth in Section 4, in addition to those set out in other provisions of this Contract. The Participants'
9 obligations to take or pay for their respective PSCR Shares of Power Sales Contract Resources shall be
10 principally those set forth in Section 5 and the Rate Schedule (Appendix B), in addition to those set out in
11 other provisions of this Contract.

12 (B) Subject to the absolute payment obligations of the Participants set forth in Section 5(I),
13 AMP shall borrow, and, unless otherwise authorized by a Super Majority of the Participants Committee,
14 capitalize from the proceeds of such borrowing, all or a portion of the amounts otherwise payable by the
15 Participants in respect of AMP's Revenue Requirements prior to the Commercial Operation Date of the
16 AMP Fremont Energy Center and for a reasonable time thereafter.

17 (C) If at any time any Participant has capacity and/or energy in excess of its needs, it may
18 request that AMP sell and make available or deliver any or all of said Participant's PSCR Share of
19 capacity and/or energy available hereunder, and AMP shall use commercially reasonable efforts in
20 consultation with such Participant to attempt to sell such surplus for such Participant at not less than a
21 minimum price approved by the Participant, first, *pro rata* to any other Participants that shall have
22 previously indicated a willingness to AMP, pursuant to Section 4(G) hereof, to purchase any such surplus,
23 second, *pro rata*, to any Members (that are not Participants) that shall have previously indicated a

1 willingness to AMP to purchase any such surplus, and, third, to any other entity, on such terms and for
2 such period as AMP deems appropriate and as AMP deems not adverse to the tax or regulatory status or
3 other interests of AMP or the Participants or any Bonds. All net revenues (revenues received less any
4 expenses incurred in connection with the sale) received by AMP from any such sales shall be credited
5 against the Revenue Requirements allocable to such Participant on such Participant's next invoice
6 rendered pursuant to Section 5 hereof, provided that nothing contained herein shall relieve such
7 Participant from any obligation hereunder, unless and to the extent AMP shall receive net revenues for
8 such sales.

9 (D) Should AMP's Board of Trustees deem it advisable, in order to minimize certain risks and
10 taxes, the Participants specifically acknowledge and authorize AMP to create subsidiary or affiliated
11 entities to own all or certain of the facilities or other assets constituting the Project, including without
12 limitation natural gas reserves, provided that:

13 (i) AMP shall retain control and not less than majority ownership of all such entities
14 and shall remain responsible to the Participants for all obligations to the Participants hereunder.

15 (ii) AMP shall have received opinions of counsel and a Consulting Engineer to the
16 effect that the arrangements regarding such entities should not materially adversely affect the
17 rights of, or increase the costs to, the Participants hereunder and are not inconsistent with any
18 Trust Indenture.

19 (iii) All such arrangements are approved by the Participants Committee.

20 (E) Should the AMP Board of Trustees determine, in its sole discretion, that AMP should
21 exercise its ability as set forth in subsection A of Section 34 to "subscribe" for up to twenty percent (20%)

1 of Base Capacity it may sell or provide sales of capacity and energy therefrom, provided that AMP shall
2 have received opinions of counsel and a Consulting Engineer to the effect that the arrangements regarding
3 such entities should not materially adversely affect the rights of, or increase the costs to, the Participants
4 hereunder, are not inconsistent with any Trust Indenture and will not adversely effect AMP's tax or
5 regulatory status.

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APPENDICES

TO

AMP FREMONT ENERGY CENTER

POWER SALES CONTRACT

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APPENDIX A

**SCHEDULE OF PARTICIPANTS AND PSCR SHARES
(Preliminary – To Be Finalized in Accordance with Section 34)**

SCHEDULE OF PARTICIPANTS AND SHARES

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MUNICIPAL	SERVICE GROUP	PSCR SHARE (kW)	PSCR SHARE %
Amherst	NEASG	6245	
Arcadia	NCASG	344	
Arcanum	WASG	1157	
Beach City	NEASG	578	
Bedford	VASG	20068	
Berlin	PASG	1739	
Blakely	PASG	2903	
Bloomdale	NCASG	511	
Bowling Green	NWASG	8926	
Bradner	NWASG	232	
Brewster	NEASG	3568	
Bryan	NCASG	12058	
Carey	NCASG	4745	
Catawissa	PASG	398	
Celina	WASG	13019	
Cleveland	NASG	82688	
Clyde	NCASG	15503	
Coldwater	MASG	8547	
Columbiana	NEASG	4748	
Columbus	CASG	75469	
Custar	NWASG	187	
Cuyahoga Falls	NEASG	26256	
Cygnets	NCASG	357	
Danville	VASG	68612	
Deshler	NCASG	1236	
Dover	NCASG	19625	
Duncannon	PASG	605	
East Conemaugh	PASG	562	
Edgerton	NWASG	1424	
Eldorado	WASG	370	
Ellwood City	PASG	5230	
Elmore	NWASG	831	
Ephrata	PASG	13445	
Front Royal	VASG	19172	
Galion	NEASG	4723	
Genoa	NWASG	1049	
Girard	PASG	3241	
Glouster	CASG	1188	
Goldsboro	PASG	685	
Grafton	NEASG	1549	
Greenwich	NCASG	1246	
Grove City	PASG	1800	

(Footnote will indicate AMPGS Participants.)

SCHEDULE OF PARTICIPANTS AND SHARES

MUNICIPAL	SERVICE GROUP	PSCR SHARE (kW)	PSCR SHARE %
Haskins	NWASG	707	
Hatfield	PASG	1141	
Hillsdale	MASG	3606	
Holiday City	NWASG	1384	
Hooversville	PASG	340	
Hubbard	NEASG	4467	
Hudson	NEASG	11250	
Jackson	CASG	9218	
Jackson Center	WASG	941	
Kutztown	PASG	3754	
Lakeview	WASG	808	
Lansdale	PASG	6689	
Lebanon	SWASG	34447	
Lehighton	PASG	2180	
Lewisberry	PASG	249	
Lodi	NEASG	2000	
Lucas	NEASG	227	
Marshall	MASG	968	
Martinsville	VASG	11114	
Mendon	WASG	413	
Middletown	PASG	6902	
Mifflinburg	PASG	2178	
Milan	NEASG	759	
Minster	WASG	6718	
Monroeville	NEASG	2231	
Montpelier	NWASG	3124	
Napoleon	NWASG	7549	
New Bremen	WASG	2378	
New Knoxville	NCASG	979	
New Martinsville	OASG	4302	
New Wilmington	PASG	1902	
Newton Falls	NEASG	2364	
Niles	NEASG	16364	
Oak Harbor	NWASG	1361	
Oberlin	NEASG	2678	
Ohio City	NCASG	474	
Orrville	NCASG	20828	
Painesville	NASG	5188	
Pemberville	NWASG	277	
Perkasie	PASG	3210	
Philippi	OASG	3605	
Pioneer	NWASG	1647	
Piqua	WASG	9023	

SCHEDULE OF PARTICIPANTS AND SHARES

MUNICIPAL	SERVICE GROUP	PSCR SHARE (kW)	PSCR SHARE %
Plymouth	NCASG	1092	
Princeton	OASG	1124	
Prospect	NEASG	879	
Quakertown	PASG	3570	
Republic	NCASG	220	
Richlands	VASG	6837	
Royalton	PASG	423	
Saint Clair	PASG	1024	
Schuylkill Haven	PASG	1964	
Seville	NEASG	6268	
Shelby	NEASG	7625	
Shiloh	NCASG	295	
Smethport	PASG	1274	
South Vienna	NEASG	342	
St. Clairsville	NCASG	5018	
St. Marys	NCASG	14513	
Summerhill	PASG	274	
Sycamore	NCASG	392	
Tipp City	WASG	8834	
Union City	MASG	772	
Versailles	WASG	4123	
Wadsworth	NEASG	14678	
Wampum	PASG	486	
Wapakoneta	NCASG	13075	
Watsonstown	PASG	717	
Waynesfield	WASG	468	
Weatherly	PASG	1000	
Wellington	NEASG	3570	
Westerville	CASG	57035	
Wharton	PASG	311	
Williamstown	OASG	4674	
Woodsfield	NCASG	2127	
Woodville	NWASG	800	
Yellow Springs	WASG	1648	
Zelienople	PASG	3276	
Total kW / %		809,511	100%
Total Participants			

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