UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Advanced Energy Management Alliance v. PJM Interconnection, L.L.C.	)))	Docket No. EL17-36-000
	)	
Old Dominion Electric Cooperative, *et al*. v. PJM Interconnection, L.L.C.	)))	Docket No. EL17-32-000 (not consolidated)

POST-TECHNICAL CONFERENCE COMMENTS OF
ADVANCED ENERGY MANAGEMENT ALLIANCE

Pursuant to the notice issued June 13, 2018 in the above captioned proceeding, the Advanced Energy Management Alliance ("AEMA") respectfully submits the following comments. AEMA appreciates this opportunity to provide the Commission with additional comments[1] regarding seasonal resource participation in PJM Interconnection L.L.C's ("PJM") Reliability Pricing Model ("RPM") capacity construct. AEMA is a trade association under section 501(c)(6) of the federal tax code whose members include national distributed energy resource ("DER"), demand response ("DR"), and advanced energy management service and technology providers, as well as some of the nation's largest consumer resources, who support advanced energy management solutions due to the electricity cost savings those solutions provide to their businesses. This filing represents the opinions of AEMA as an organization rather than those of any individual association members.

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[1] AEMA submitted pre-technical conference comments and AEMA member representatives participated on each of the three panels in the April 24, 2018 technical conference.

I. INTRODUCTION

AEMA's prior filings in these dockets demonstrate that PJM's current RPM rules are unjust, unreasonable, unduly discriminatory, and preferential under Federal Power Act ("FPA") section 206.[2] We will not repeat those here, except as necessary to provide context in relation to AEMA's post-technical conference comments. These comments present AEMA's view of the policy concerns underlying the complaints and options for the Commission to consider in resolving the complaints.

A. RPM is a Reliability Construct Rather than an Efficient and Effective Capacity Market.

The purpose of a capacity market is to ensure that sufficient resources are available to meet demand and preserve reliability at all times. RPM has become burdened with additional purposes to the point where it no longer adequately serves its original intended purpose. During the technical conference, speakers opined that a capacity market should facilitate the energy market, supply peak hour resources, supply baseload resources, send stable long-term investment signals, address the "missing money" problem, and lower energy prices. We disagree. A market cannot serve so many masters.

Doing so has turned RPM into a subsidy mechanism. As planners tweak RPM to achieve their preferred outcomes and market participants litigate the meaning of definitions in an effort to include their resources and exclude competitors, the resulting barriers to entry for some technologies and discriminatory accommodations for others are economically inefficient. This phenomenon was abundantly displayed during the technical conference when, for example, panelists who believe the capacity market should support lower energy prices argued that

[2] 16 U.S.C. § 824e.

emergency-only resources provide "inferior" capacity;[3] panelists representing capital intensive resources argued that low-cost resources that can enter and leave the market easily are undesirable;[4] panelists justified accommodations for their preferred resource's limitations but condemned accommodations for their competition;[5] and so on.

A perfect capacity market would precisely account for every resource's ability to serve load at all times and find the least-cost mix of those that meets reliability standards. This may not be achievable in practice, but how close market designs come to this ideal should guide the Commission. In this light, AEMA's complaint boils down to identifying specific areas where the inefficiencies and discrimination resulting from PJM's RPM rules require action by the Commission under FPA section 206.

B. Capacity Performance Makes Numerous Accommodations for the Limitations of Traditional Generating Resources, while Denying Comparable Treatment to Non-Traditional Capacity Resources.[6]

Defining capacity as a 24 hours-per-day, 365 days-per-year product prioritizes standardized capacity obligations over economically meeting reliability standards. PJM's Capacity Performance rules require resources to have the ability to deliver energy at any time rather than targeting peak conditions. However, RPM fails to consistently impose this "all capacity is always available" requirement. The technical conference proceedings revealed

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3 Transcript of Aug. 24 2018 Technical Conference, Docket Nos. EL17-32-000 and EL17-35-000 ("Technical Conference Transcript") at 103:21-104:11.

4 *Id.* at 191:11-194:2.

5 For example, compare *id.* at 147:15-148:11 (generators must be allowed to take winter maintenance) with 88:21-89:3 (speculation that demand response "fatigue" makes it inferior capacity). *See also* 218:16-20 (generator outages are part-and-parcel of the capacity product) with 166:17-167-21 (renewables are not good capacity because of their operational characteristics).

6 "Non-traditional capacity" generally refers to demand response, energy efficiency, and intermittent generation resources.

multiple cases where traditional generation is excused from performance requirements, while very similar requirements are used to justify excluding other resources:

- Generators can qualify as Capacity Performance resources even when at the time of the auction it is known that the generator will have to take extended outages during the winter peak season, but non-traditional capacity is entirely excluded from the market if it cannot perform during the winter.
- PJM procures extra capacity to allow generators to take planned outages during winter peaks and socializes costs to load, but non-traditional capacity is penalized if called upon when it is unable to operate (*e.g.*, solar at night, demand response when load is already down).
- Common-mode failures of traditional generation (*e.g.*, gas pipeline outages, extreme cold conditions) were offered as a justification for carrying excess reserves during winter months and socializing that cost to load, while common-mode failures of non-traditional capacity (*e.g.*, weather affecting multiple wind or solar plants) were offered as a reason why they are not acceptable capacity resources.
- The risk of wintertime common-mode failures of traditional generation is presented as justification for excluding summer-only resources from the market.

Additional examples of similar accommodations for traditional resources follow below, along with further discussion of the issues outlined above.

Some commenters have characterized seasonal products as "inferior," presumably because their seasonal availability is explicitly acknowledged. But in many respects traditional generators also have seasonal attributes that can be similarly characterized as inferior. These traditional resources often have seasonal limits on availability, but are not required to explicitly state these limits. In many cases these restrictions are accommodated in PJM planning processes and exacerbate the seasonal variation of PJM's capacity needs.

PJM planning incorporates allowances for Planned Outages of generators in winter that excuse performance shortfalls and simultaneously allow full RPM payments during the winter season. This allowance is significant and inconsistent with a "superior" product. While information is scarce on PJM's approaches to planned generator outages, PJM materials supporting an increase in the allowed Planned Outage rate for winter suggest that PJM has historically allowed at least 2.5% of the generation fleet to be on Planned Outages during the peak winter week. This equates to approximately 3,500 MW of supposedly superior annual products that are not available during winter peaks and yet still receive full capacity payments. This point is important because the need for winter capability is used to justify PJM's exclusive annual resources requirement.

Allowances for traditional generators are not limited to the winter. Perversely, resources that PJM recognizes as having year-round capability are in fact not providing year-round service. PJM's planning processes allow for ambient derates of generation totaling 2,500 MW in the *summer*. The Reserve Requirement Study ("RSS") states: "In the 2017 RRS, 2,500 MW of ambient derates in the peak summer period were modeled via planned outage maintenance. This modeling assumption was developed in early 2016 by analyzing Summer Verification Test data from 2013-2015. The impact of this assumption is an increase in the IRM of 1.36%."[7]

These derates do not expressly excuse individual capacity shortfalls, but instead simply increase the amount of overall summer capacity requirements in PJM, necessitating the need for more overall resources. But PJM's discriminatory and inefficient annual Capacity Performance

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[7] PJM, *2017 PJM Reserve Requirement Study*, at 32 (Oct. 12, 2017), *available at* http://pjm.com/-/media/planning/res-adeq/2017-pjm-reserve-requirement-study.ashx.

regime requires that this summer-only need be met with annual resources. It is difficult to reconcile assertions that seasonal resources are inferior with the clear shortcomings of so-called annual resources that are embedded in PJM's planning processes.

This favored treatment effectively increases the seasonal variation in capacity needs. As noted above, PJM's summer load forecasts are nearly 20,000 MW higher than its winter forecasts. But the summer derates mean that PJM must procure an additional 2,500 MW plus associated reserves to meet summer peaks, further increasing the need for resources in the summer. The set-aside for winter planned outages demonstrates that these resources are not needed to meet winter peak demand. These facts suggest that annual resources in PJM are over-compensated, and further demonstrates the seasonal variability of PJM's capacity needs.

We are left with a capacity market that defines its product as having 24/365 availability for the convenience of suppliers rather than to meet the needs of consumers, but then proceeds to freely deviate from the claimed "no excuses" rules to the benefit of particular technologies. AEMA submits that a truly cost-effective, non-discriminatory capacity market will value heterogeneous resources based on an objective measure of their ability to contribute to meeting reliability needs, send appropriate price signals, and consistently put performance risk on suppliers, all at the lowest reasonable cost. The following comments include suggestions that, if implemented, would move RPM in that direction.

II. COMMENTS

A. Seasonal Load Variation and Alternative Market Designs.

Some panelists indicated that the current annual construct and existing aggregation rules result in a barrier to entry. Please comment on whether or not there are barriers to entry and provide any supporting information, such as unmatched MWs of capacity. Could this be fully addressed by improving or modifying aggregation rules? If not, what other changes would be required? What would be the downside of modifying such rules?

1. PJM's Aggregation Approach Does Not Eliminate the Barrier to Entry Posed by PJM's Annual-Only Requirements in Light of PJM's Differing Seasonal Needs.

PJM's current annual-only capacity acquisition construct is, by design, a barrier to entry. Any unaggregated resource that is not available year-round is treated as having zero reliability value, regardless of its actual ability to serve load. Resources excluded from the market by this barrier in the most recent Base Residual Auction ("BRA") include:

- 488.7 MW of summer resources (including demand response, energy efficiency and solar) that were unable to be matched to a winter resource, and
- an unknown amount of summer-only demand response resources that elected not to offer.

Aggregation could only fully address this barrier if there were no seasonal variation in PJM's capacity needs. Otherwise, aggregation artificially constrains participation in the capacity market by resources in the seasons they *are* needed by the availability of other resources in the seasons when they are not needed.

PJM's capacity needs are, in fact, seasonal. Peak demand occurs in the summer with forecast loads nearly 20,000 MW (13%) higher than in winter.[8] As AEMA explained in its preconference comments, PJM's Loss of Load Expectation ("LOLE") is currently near zero in the winter. As a result, additional winter resources provide very little reliability benefit or value.

[8] *See* PJM, *2018 Load Forecast* (PJM's summer forecast is 152,108 MW and winter is 132,357 MW), *available at* http://www.pjm.com/-/media/library/reports-notices/load-forecast/2018-load-forecast-report.ashx?la=en.

Insisting on procuring all capacity resources in rigid twelve-month commitments, whether aggregated or not, ignores the fact that both supply and demand in PJM are seasonal. Although several speakers at the technical conference raised concerns with how PJM models winter capacity needs, none disputed the basic point that PJM's summer capacity needs are higher than winter.[9]

While the 2,500 MW of seasonal summer-only generator derates and 3,500 MW of allowances for seasonal winter outages described above are small relative to PJM's overall capacity requirements of approximately 171,000 MW, these quantities are each comparable to the 3,000 MW of seasonal resources that are essentially excluded from the market by PJM's annual-only Capacity Performance requirement. PJM should allow summer-capable resources to be eligible to meet these portions of PJM's overall capacity requirements.

2. Aggregation Results in Misalignment of Seasonal Resource Compensation with Seasonal Resource Value.

PJM's Capacity Performance rules require all resources participating in RPM to have year-round capability. To meet this requirement through aggregation, the summer-capable resources that contribute the vast majority of the reliability value must share revenue with winter resources that add little reliability value. In the case of auction-based aggregation, PJM has arbitrarily determined that fully half the annual revenue must be shared. This results in summer-capable resources being undercompensated, while winter capable resources are overcompensated.

Under PJM's aggregation and revenue sharing mechanism, there is no relationship between the value provided by the aggregated components and the compensation they receive. This violates fundamental market precepts by failing to compensate a resource for the value that

[9] *See, e.g.,* Technical Conference Transcript at 93:2-9.

it brings. Combining that failure with a mechanism that over-compensates low value resources (winter capable resources in this case) aggravates this market design flaw. This results from PJM's inefficient exclusion of stand-alone seasonal products. While we acknowledge that the most recent BRA cleared increased aggregations of seasonal resources, this outcome does not remedy the discriminatory compensation that results from PJM's fatally flawed aggregation mechanism.

3. Fixes to Aggregation Cannot Remedy its Fundamental Flaws.

Fixes to aggregation are unlikely to overcome the flaws described above. It may be possible to develop a method to better align resource value with resource compensation. This approach would result in summer-capable resources receiving the greater portion of annual RPM revenues because these resources provide greater reliability value. However, PJM's analysis suggests that this approach may leave winter resources with 10% or less of the annual compensation. It is highly unlikely that winter capable resources would be willing to take on the performance risk associated with Capacity Performance for this small revenue stream. Instead, AEMA recommends that PJM resume utilizing its historical mechanism that allowed seasonally capable products to participate directly in the market, subject to constraints consistent with their capability and PJM's reliability needs. Most recently referred to as "Base Capacity," this mechanism demonstrated that it can deliver prices consistent with each resource's contribution to reliability.

4. Higher Clearing Prices and Lower Perceived Risk Have Incrementally Increased Participation by Some Non-Traditional Resources But Alternative Market Designs Can Do Better than Aggregation.

According to the 2021/2022 Reliability Pricing Model (RPM) Base Residual Auction (BRA) report, cleared megawatt quantities of wind, solar, demand response, and energy efficiency resources all increased compared to the 2020/2021RPM BRA and at higher clearing prices throughout the PJM footprint. Please comment on how these results reflect on the efficacy of PJM's seasonal aggregation mechanism and the ability of these resource types to participate in RPM as either annual resources or aggregated resources under existing RPM rules. To the extent you view one or more of the alternative market designs mentioned above as better than the existing RPM rules, please explain how those alternative designs would yield preferable auction outcomes relative to those seen in the 2021/2022 BRA. Please provide evidence and quantitative support where possible.

Wind, solar, demand response (including Price Responsive Demand), and energy efficiency resources clearing in the BRA increased by 5,029.7 MW between the auctions for the 2020/21 and 2021/22 delivery years.[10] This increase breaks down into:

- roughly 2,000 MW from an increase in the total amount of DR and EE offered;
- roughly 1,200 MW from a greater willingness of DR and EE to offer as annual rather than summer-only capacity;
- roughly 1,000 MW simply from more resources clearing due to higher prices for the 2021/22 delivery year;
- about 400 MW from an increase in offered solar; and
- exactly 317.8 MW from aggregation.

During the technical conference, AEMA member representatives noted that the current construct inflates prices above natural levels, possibly resulting in a chronic oversupply of capacity. One effect of oversupply is that Performance Assessment Intervals ("PAIs") will

[10] Calculations and sources for the data in this section are attached as Exhibit A.

become rare. With an over-supply of capacity, operators will rarely have to invoke the emergency procedures that trigger PAIs. In fact, there have been no relevant PAIs since Capacity Performance was approved.[11]

The simplest explanation for the increase in offers from solar resources, demand response offering as annual resources, and the overall increase in offers from demand response resources is market participants adapting to that reality and offering resources with the expectation that there is little chance they will be called upon during winter.[12] This is most starkly illustrated for solar resources: 516 MW of solar resources offered and cleared as annual Capacity Performance resources, despite the fact that 54% of the winter performance intervals are either before or after sunset.[13] Similarly, demand response providers may be more willing to contemplate heroic demand response measures, such as full facility shutdown, or to bear more performance risk if they judge winter capacity events to be extremely unlikely.

Of the 1,416 MW of wind resources that cleared, 710 MW cleared as full year Capacity Performance resources–well below the allowed annual capacity cap of 13% or 1,056 MW, and well below the portion of wind that cleared as annual resources in the prior year. The remaining 706 MW of cleared wind resources cleared as aggregated winter resources.

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[11] On May 29, 2018, a transmission outage caused a 30-minute localized PAI. PJM concluded that "there was no possible generation dispatch that would have mitigated" the issue, and no non-performance charges were assessed to generators. *See* PJM, *Twin Branch/Edison Area Load Shed Event*, at 9 *(*Jul. 5, 2018), *available at* http://www.pjm.com/-/media/committees-groups/committees/oc/20180710/20180710-item-17-twin-branch-area-load-shed-oc.ashx. *See also* PJM, *Balancing Ratio Determination Problem/Opportunity Statement* (Sep. 21, 2017) ("no Performance Assessment Intervals have occurred for the relevant time period (*i.e.*, calendar years 2015, 2016 and 2017) . . . ."), *available at* http://www.pjm.com/-/media/committees-groups/committees/mrc/20170928/20170928-item-05-balancing-ratio-problem-statement.ashx.

[12] Non-traditional capacity resources are generally exempt from must-offer requirements and have significant freedom to determine how much capacity to offer.

[13] Winter Performance Hours are defined as 7:00 to 9:00 A.M. and 6:00 to 8:00 P.M. in January and February. *See* PJM, *RPM 301: Performance in Reliability Pricing Model*, at 27 (Apr. 20, 2017), *available at* https://www.pjm.com/-/media/training/nerc-certifications/markets-exam-materials/rpm/rpm-301-performance-in-reliability-pricing-model.ashx?la=en.

Total aggregated resources cleared increased by 317.6 MW, resulting from this increase in winter-only capacity offered by wind resources. However, this is offset by the 100 MW or so of wind that switched from offering annual to winter-only capacity. Compared to the prior year, wind resources offered relatively more winter capacity than annual capacity, while demand response, energy efficiency, and solar resources offered relatively less summer capacity than annual capacity. These results are consistent with AEMA's concerns that the aggregation model encourages winter resource owners to seek scarcity rents,[14] while summer resource owners balance the risk of taking on winter commitments versus having to sacrifice half or all of their revenue when offering as summer-only resources.

In summary, the increase in non-traditional capacity clearing in the latest BRA is almost entirely due to a combination of ordinary new resource development, higher prices, and market flaws caused by over procurement of winter capacity and incorrect seasonal price signals. The seasonal aggregation mechanism is only responsible for about 217 MW of the 5,029.7 MW increase.

AEMA believes that each of the alternative market structures discussed during the technical conference would produce outcomes preferable to this:

- All three alternatives[15] would facilitate participation in the market by the 488.7 MW that are currently stranded;
- All three alternatives would present a more accurate price signal to summer-capable resources when these resources make the decision between offering as summer-only or taking on winter performance risk; and

[14] *See* AEMA Complaint at 25-27.

[15] Two season, three season, and winter aggregation tickets. *See infra* at 13.

- The three-season and possibly the winter performance ticket alternatives would present a more accurate price signal to resources deciding how to allocate their capacity between annual and winter-only commitments.

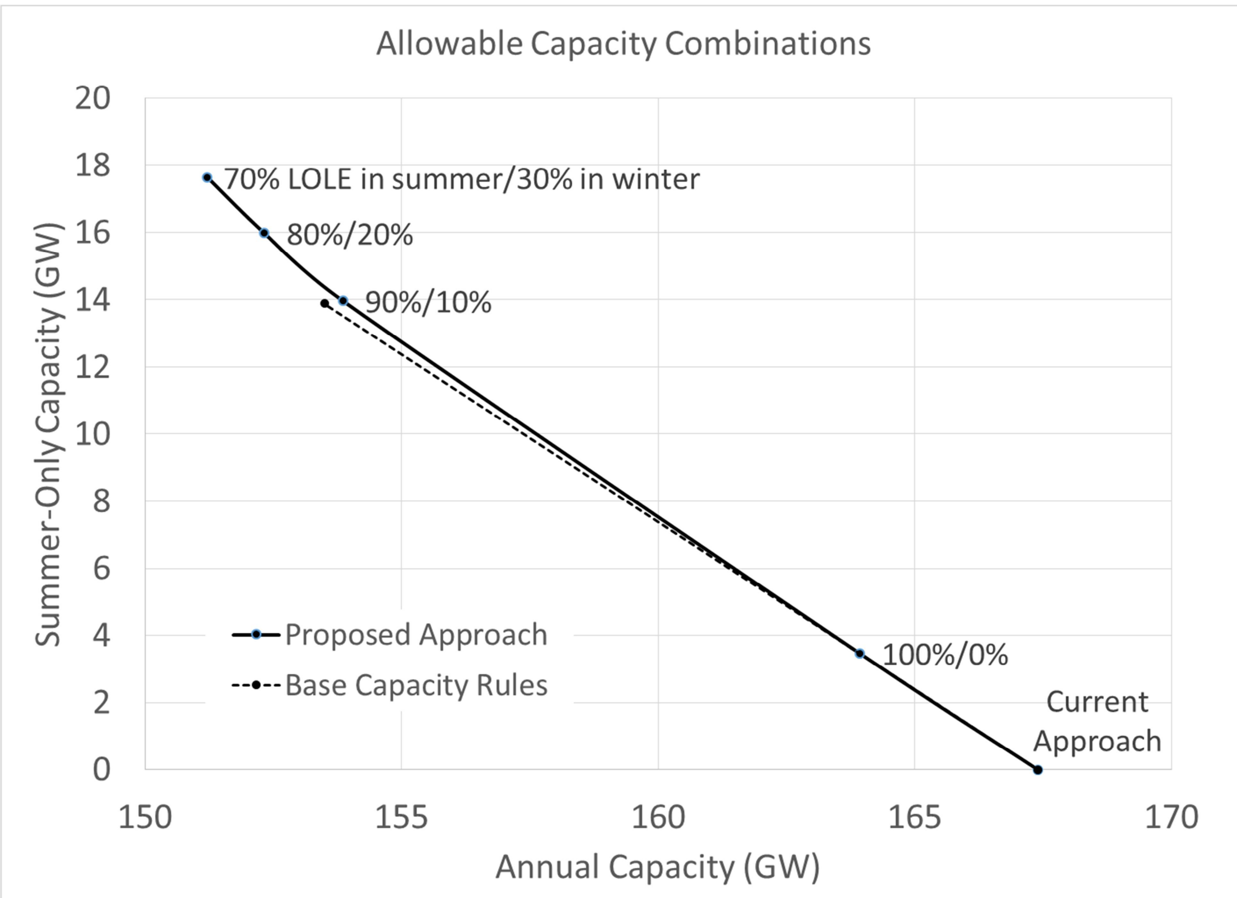
5. A Single Auction and That Simultaneously Optimizes Capacity Procurement Across Two or Three Seasons Would Efficiently Secure Sufficient Capacity to Meet PJM's Reliability Needs.

Under either a two-season or three-season market construct, how would PJM optimize capacity procurement within and across seasons? Would each season have a distinct demand curve and auction that clears independently of other seasons, or would all seasonal auctions be cleared simultaneously to optimize procurement for a delivery year?

Three alternative market designs were discussed during the technical conference:

- *Annual plus summer ("two season").* The market procures sufficient annual capacity to meet reliability needs outside of summer months, plus additional summer-only or annual capacity to meet summer peak needs. Historically, RPM has used this approach. There have been several iterations, the most recent of which was the Base Capacity construct used during the Capacity Performance implementation transition period.
- *Annual plus summer plus winter ("three season").* The market procures annual capacity plus additional capacity in the summer and winter to meet each season's peak.
- *Winter Aggregation Tickets*. Just as today, the market procures purely annual capacity to meet annual peaks, but releases excess winter capacity through an auction. Summer-only resources purchase this excess winter capacity in order to qualify as annual resources.

AEMA does not believe a purely seasonal market with no annual product is appropriate for PJM. Our comments here speak to the "annual plus summer" and "annual plus summer plus winter" models. In both models, AEMA recommends that PJM hold a single auction and optimize capacity procurement across seasons. Although comments during the technical conference indicated that some refinements may be needed,[16] current planning tools appear to be able to determine the combinations of seasonal resource mixes that meet reliability requirements. For example, the chart below presents the results of PJM's winter reliability study[17] as the solid line of the possible combinations of annual and summer-only capacity that provide a 1-in-10 LOLE.[18] A similar approach would produce the set of acceptable combinations of annual, summer-only, and winter-only capacity needed for a three-season market.



[16] *See, e.g.*, Technical Conference Transcript at 72:8-18.

[17] *See* PJM, *Winter Season Resource Adequacy* (Feb. 2, 2018), *available at* http://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180202/20180202-item-06-winter-resource-adequacy-education.ashx.

[18] This is very similar to the "isoquant" concept under discussion in relation to PJM's regulation market, in that it creates a curve establishing equally valuable combinations of heterogeneous resources. *See* PJM, Proposed Tariff Revisions to Implement Regulation Market Enhancements, Docket No. ER18-87-000, at 15-16 (Oct. 17, 2017).

So long as the purpose of a capacity market is to ensure sufficient resources exist to serve load, all points on this line are equivalent. The most cost-efficient capacity mix is simply the least-cost mix that lies on this line. By simultaneously clearing all capacity products in a single auction, the market can optimize the product mix to find this solution.

The clearing price of each capacity product (annual, summer-only, and possibly winter-only) would be the offer price of the last resource cleared for each product. This sends the correct price signal, reflecting both the reliability value and available supply for each resource type.

The Base Capacity rules used during the Capacity Performance transition period closely approximate our proposed solution—the dashed line on the graph shows the capacity mixes allowed when Base Capacity was still in the market. The slight divergence between Base Capacity and our approach reflect that Base Capacity relaxed reliability requirements under a limited set of circumstances[19] and for simplicity assumed a one-to-one tradeoff between annual and summer-only capacity.

Unlike the current aggregation model, these approaches comport with FERC policy that supports paying for value received. As discussed here and in AEMA's prior comments,[20] a well-functioning capacity market will send the correct price signals to seasonal capacity resources. Because PJM is a summer-peaking system with most of the LOLE occurring in the summer months, this will usually mean that summer capacity is nearly as valuable as annual. Base Capacity prices aligned reasonably well with the relative value of seasonal resources versus

[19] When Base Capacity was included, auction results could have resulted in up to an 11% LOLE under a highly contrived set of assumptions. This incremental risk was mostly theoretical and actual auction results yielded an LOLE much less than 10%. *See* WeatherBug Home, *Base Capacity and Reliability* (Jun. 6, 2016), *available at* http://www.pjm.com/-/media/committees-groups/task-forces/scrstf/20160606/20160606-item-04-base-capacity-analysis.ashx.

[20] *See* AEMA Complaint at 26-27. *See also* AEMA *et al.*, Protest, Docket No. ER17-367-000, at 15-16 (Dec. 8, 2016).

annual resources. For example, the Base Capacity prices for the 2018/19 and 2019/20 delivery years were 71% and 80% of the Capacity Performance resource prices, respectively.

6. Transitioning to a Two-Season or Three-Season Market With a Single Auction Would Not Pose Insurmountable Challenges.

What other implementation challenges would be involved in transitioning to a two-season or three-season market construct (aside from a lengthy stakeholder process)?

- *Resource cost recovery and market power mitigation*. Resource owners, and generation owners in particular, need to assure that cleared offers cover annual costs. Similarly, unit-specific offer caps are determined based on annual costs and revenues, and auction parameters are set based on cost-of-new-entry and expected energy and ancillary services revenues. All of these mechanisms assume the existence of an annual market. It is unclear how they would be adapted for exclusively seasonal markets, considering that resources might clear during one season but not the other. This could provide an incentive for resource owners to engage in strategic bidding to assure that their resource clears for the entire year, even though their costs do not vary from summer to winter. These concerns lead AEMA to oppose eliminating the annual capacity product. Each of the alternative market designs discussed above retain an annual product, which would allow current cost development rules to remain in place.
- *Cost allocation*. The current construct uses a single cost allocation approach based on summer peak demand. Separate seasonal auctions would invite a review of cost allocation and potentially significant cost shifting among load zones. For example, any zone can have a different allocation of capacity in winter than in summer. Related to this would be a need to develop more robust analyses of capacity constraints in winter. It is

not clear if such analyses for winter are currently in place. Notably, stakeholders have recently declined to address this issue.

- *How to apply VRR curves*. RPM features a sloped demand curve where capacity exceeding reliability requirements may be procured if prices fall sufficiently low. How to apply these curves in a multi-product market has been a matter of controversy. When PJM originally introduced a seasonal product, capacity beyond the minimum reliability requirement was cleared least-cost first. This resulted in excessive procurement of less expensive summer-only resources.[21] PJM then revised the rules so only annual resources could clear once reliably requirements were met.[22] This excluded seasonal resources from the benefits of the sloped demand curve and resulted in occasional price collapses.[23] Any future multi-product market design should address this issue in a more thoughtful manner, which could potentially consider the expected load carrying capability of the various types of capacity.

- *Demand Resource retail capacity cost allocation*. If costs are allocated differently from summer to winter, then states and utilities will need to consider how these costs are allocated to retail customers. Customers would experience different summer and winter capacity obligations.

- *Different capacity costs between seasons.* Even if capacity is not allocated differently in summer and winter, capacity costs will differ in winter and in summer. This could add

[21] *See* Technical Conference Transcript at 150:11-23. *See also PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,066, at P 4 (Jan. 31, 2011).

[22] *See PJM Interconnection, L.L.C.*, 146 FERC ¶ 61,052, at P 5 (2014).

[23] For example, in the BRA for the 2019/20 delivery year, summer-only products in the PEPCO LDA cleared at $0.01/MW-day, compared with $100.00/MW-day for annual resources. *See* PJM, *2019/20 RPM Base Residual Auction Results,* at 2 (May 24, 2016), *available at* http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2019-2020-base-residual-auction-report.ashx?la=en.

complexities for retail access states because the timing of adding or releasing individual customers could be influenced by such price differentials.

- *Seasonal Load Forecasts*. Developing assumptions for seasonal load forecasts would be necessary. PJM forecasts focus on summer loads and supply capabilities because the system peak is in the summer. Winter forecasts are prepared but not with the same rigor. In particular, the winter capability of resources is not well defined.

B. Peak Shaving and Price Responsive Demand are Not Viable Approaches for Fully and Efficiently Utilizing Demand Response Resources in PJM.

The Commission seeks input on peak shaving as an approach to realize the value of seasonal resources. PJM stakeholders are engaged in two formal processes involving seasonal resource participation. One of these processes involves Price Responsive Demand ("PRD").[24] The other involves summer-only demand response. Neither of these approaches will provide a viable pathway for fully utilizing the available capability of demand response resources. Moreover, the changes proposed for PRD will effectively eliminate this option.

1. Price Responsive Demand Will Not Adequately Accommodate Summer Capable Resources.

Changes to PRD are being considered in PJM's Demand Response Subcommittee. PRD is a program that was established to allow load serving entities ("LSE") to reduce their capacity obligation in RPM by committing to reduce load in response to price triggers. At the time of its introduction, PRD had a number of similarities to Annual Demand Response. These included alignment of performance metrics. PRD performance was measured the same way as supply-side demand response resource performance was measured.

[24] *See* PJM, *Issue Details: Price Responsive Demand Review for Capacity Performance Requirements*, *available at* http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={481B6E7B-6015-4623-966F-EDE6982E0165}.

PRD also had features that made it sufficiently unattractive that it was not utilized at all until opportunities for stand-alone seasonal demand response resource participation were eliminated upon full implementation of Capacity Performance in the BRA for the 2020/21 delivery year conducted in May 2017. These features included directing the benefits of demand response to the LSE without necessarily compensating the customer. This is because PRD is treated as a reduction in capacity obligations for the participating LSE. As a result, any benefit of a reduced capacity obligation to the customer must be monetized by the LSE and passed on to curtailing customers as a credit. Demand response aggregators have demonstrated that direct payments to customers are a much more effective engagement tool than such indirect discounts. Further, LSEs may have difficulty aggregating enough customers to make a PRD offer viable. The mandatory price-responsive nature of providing PRD has proven to be an obstacle as well. These less attractive features are expected to remain largely unchanged.

When PJM implemented Capacity Performance, no substantive changes were made to PRD. In contrast, the measurement approach established for Capacity Performance derived from demand response resources was changed. The pre-Capacity Performance Annual Demand Resource measurement metrics did not include different summer and winter methods. Both the PRD and Annual Demand Resource methodologies measured performance as the difference between peak summer demand and actual demand at the time of dispatch. This approach applied in both summer and winter. With this method, a customer with a heavy air conditioning load might be required to substantially reduce use in the summer, but might need to show little or no load reduction in winter to reach the targeted reduction. This approach aligns well with residential utility programs that curtail air conditioning loads in summer. It also aligns with cost causation principles in that customer capacity charges are based on the customer's peak summer demand.

With implementation of Capacity Performance, demand response resources offered as Capacity Performance resources are required to utilize a separate winter baseline derived from winter peak demand. In an apparent oversight, PJM did not propose to apply this change to PRD. LSEs recognized that this feature of PRD offered seasonal resource opportunities that demand response resources could no longer offer and recently began utilizing PRD. The legacy identical summer and winter measurement approach is the sole apparent reason that the PRD process was finally utilized after years of dormancy. PRD as currently structured allows resources that operate normally at winter loads well below their capacity purchase obligation to still meet their performance obligations. Demand response resources offered as Capacity Performance resources, on the other hand, must curtail from a baseline established by winter load profiles. PRD is structured as a reduction to an LSE's capacity obligation and it is not considered a Capacity Performance resource. However, an LSE that can implement PRD with summer-capable demand resources can realize a value comparable to a Capacity Performance resource. This value can be retained by the LSE or shared with the customer at the LSE's option.

Subsequent to the initial utilization of PRD, PJM recommended that measurement methods be revised to align the performance requirements of PRD with the performance requirements applicable to demand response resources offering as Capacity Performance resources. In the current stakeholder process, PJM proposes to align the PRD winter performance metrics with the approach used for demand resources under Capacity Performance. AEMA believes that such a change will return PRD to dormancy because the apparent measurement advantage of PRD over Capacity Performance resources will be eliminated.

However, AEMA also notes that even an unchanged PRD is of limited utility. In addition to the unattractive features noted above, PRD has characteristics that make it useful mostly for utility mass market programs. These characteristics include, but are not limited to, automated curtailment and obstacles to direct participation by curtailment service providers ("CSP"). This effectively precludes utilization of PRD by commercial and industrial customers with seasonal capability. Further, CSPs that propose to offer summer capability directly through mass market use of smart thermostats and similar devices would face insurmountable barriers due to the need to contract with each customer's energy provider in order to monetize the value of the reduced capacity obligation under PRD. As a result, PRD is of limited value without the proposed change in measurement and is of no discernable value if PJM's changes in measurement are implemented.

The limited applicability of PRD can be roughly quantified. PJM's Demand Response Activity Report[25] indicates that 8,946 MW of demand response was registered for the 2018/19 delivery year. This delivery year allows for summer-only Base Capacity. Of this, 30% of curtailments were derived from air conditioning sources. The report also indicates that 11% of curtailment is derived from residential customers. If it is assumed that all of the 11% residential curtailment is also air conditioning, the remaining 19% of reductions from air conditioning are derived from commercial, industrial and institutional customers—types that are unlikely to be participating in PRD programs. Thus, even if PRD is not modified as PJM proposes, it is likely to enable no more than a third of the seasonal curtailment capacity that has been eliminated by full implementation of PJM's Capacity Performance construct.

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[25] *See* PJM, *2018 Demand Response Operations Market Activity Report,* at 5-6 (Jul. 10, 2018), *available at* http://www.pjm.com/-/media/markets-ops/dsr/2018-demand-response-activity-report.ashx?la=en.

The remaining two-thirds of air conditioning curtailment capacity (1,700 MW) could contribute to hundreds of millions of dollars in cost savings. PJM's analysis for the BRA for the 2018/19 delivery year[26] provides scenarios that simulate the addition or elimination of various quantities of capacity supply. For example, the addition of 3,000 MW of supply (scenario 3) in the RTO Region would reduce the RTO clearing price from $164.77/MW-day to $148.50/MW-day. If this change is prorated for 1,700 MW the resulting price is about $156/MW-day. If this $8.50/MW-day change is applied to the 160,839 MW that cleared, the savings would be approximately $517 million for all customers.

PRD, if unmodified, is at best a partial remedy to enabling summer capable resources to have their value recognized. PRD, if modified, can be expected to revert to its dormant state.

2. Peak Shaving is a Highly Inefficient Approach to Recognizing the Value of Load Curtailment Even If Incorporated Into Load Forecasting.

> *In PJM's June 2017 white paper "Demand Response Strategy", PJM stated "Ideally, PJM would have a truly unrestricted peak-load forecast with a complete understanding of explicit (dispatch and/or managed by PJM) versus implicit (managed by LSE, EDC or end-use customer) DR, allowing more visibility to quantify forecast risk." Please describe the steps PJM is taking to accomplish this goal. Are these steps sufficient to accomplish this goal? Why or why not? How is PJM working to change its load forecasting methodology to achieve this goal?*

It is appropriate to note that PJM raised the point in regard to treatment of demand resources in transmission planning and not in the context of resource adequacy. However, the following discussion regarding the activity of the Summer Only Demand Response Senior Task Force ("SODRSTF") addresses the steps that PJM is taking toward refining the unrestricted peak load forecast.

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[26] *See* PJM, *2018-19 Scenario Analysis* (Dec. 28, 2015), *available at* http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2018-2019-bra-scenario-analysis.ashx?la=en.

In the SODRSTF process, PJM stakeholders are considering how peak shaving activity can be properly valued without actually becoming a PJM capacity product. The primary focus of this effort is to find ways to incorporate peak shaving into load forecasts. There are two important types of peak shaving activity. One type involves utility-sponsored activity targeted at reducing utility capacity obligations and has historically been offered into the capacity market as a Limited or Extended Summer resource. The other involves unilateral customer activity aimed at reducing the customer's own capacity costs. The stakeholders are only considering the former situation because these utility-sponsored peak shaving activities operate on a known and predictable basis.

Stakeholder discussions have focused on a concept that would model known curtailment dispatch criteria to determine the impact on the load forecast. For example, a dispatch that is triggered at 96% of the forecasted annual peak load would have predictable impact on the forecast. The amount of impact depends on the program parameters, and most significantly on the number of allowed dispatches. The details are still being considered so potential solutions cannot be fully evaluated. However, PJM has recently posted analyses that show the relationship between the number of dispatches for a given reduction amount and the corresponding impact on the load forecast.

Conceptually, a single dispatch in a summer would have very little impact on future load forecasts, while a daily dispatch would have a nearly one-to-one impact on the load forecast. The recent analysis indicates that a program that dispatched 6% of zonal load for six hours approximately ten times per year would have an average impact on load forecasts of 80% of the dispatched load.[27] In other words, a 100 MW portfolio of customers could be expected to be

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[27] PJM, *Proposal Updates*, at 13 (Jun. 29, 2018), *available at* http://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180629/20180629-item-03a-pjm-proposal-updates-and-walkthrough.ashx.

dispatched for sixty hours in a summer in order for PJM to reflect an 80 MW reduction in its load forecast. PJM indicates that fewer dispatches would have lesser benefit. For example, five days at six hours per dispatch would produce approximately 32 MW in benefits.

PJM can technically accommodate an analysis for a number of curtailment variations, but it is not clear at this point if there will be a limited number of program criteria that could be used. The difference between the curtailment amount and the forecast reduction is explained by noting that any limitation on the number of curtailments could allow a load that exceeds the postulated trigger level of 96% of forecast load if the number of high load days exceeds the limit on curtailments. This introduces uncertainty in load forecasts that utilize that data point.

The extensive dispatch required to achieve even an 80% curtailment benefit imposes substantial inefficiency on the approach. With demand response resources offering as either Capacity Performance or Base Capacity, a single test hour can achieve a greater benefit for ratepayers than sixty hours of peak shaving. There can be little doubt that there are economic costs for the curtailing load for this much activity or that these costs would discourage participation.

It is worth noting that the size of the dispatch relative to the zone is a consideration also. A smaller percentage of zonal load dispatched would reduce the benefit to participating customers. This is because there is less predictability to a smaller dispatch quantity. AEMA notes that PJM's example of peak shaving 6% of zonal load approximates the total demand response that has been historically delivered. This suggests that even 80% of benefit for sixty hours of dispatch is overstating the benefit of a peak shaving approach because it is unrealistic to expect that 6% of zonal load would be available to participate, given that much of the curtailable load will be participating as Capacity Performance resources. In addition, the customer costs of sixty hours of curtailment may be significant, especially for commercial and industrial customers. This would discourage participation by such customers. Further, mass market customers can be expected to resist programs that predictably curtail air conditioning use on the ten hottest days of the year.

There are other concerns about the practicability of peak shaving as a substitute for seasonal capacity products in RPM. One concern is the program life cycle—how long is the program in service and when might it end. Like PRD, a peak shaving approach is best suited to utility programs. This is because the benefits would accrue to the zone while any incentives would likely be sourced from all customers in a zone *via* a retail rate rider. But such programs often have a limited life. For example, Act 129 in Pennsylvania includes a peak shaving program utilized by industrial, commercial and institutional customers. It is only authorized through the summer of 2020. Thus, a practical peak shaving approach relies on state commissions authorizing compatible programs for indefinite periods. The need for state commissions to approve utility programs limits the usefulness of peak shaving to regions where such programs are approved.

The SODRSTF has undertaken no discussion regarding how peak shaving by customers that are not in utility programs can be captured. PJM has acknowledged that this activity is not captured by load forecasts except over very long periods—twenty years and more. There are challenges in collecting such information because there is no obvious way to address the cost of data collection. Peak shaving customers would need to be identified and, for forecast purposes, their future behavior predicted and incorporated into load forecasts.

In summary, peak shaving as a method to improve utilization of summer capable resources is inefficient and costly. It requires substantially more curtailment activity than demand response acting as Base Capacity and incurs significant customer costs as a result. It is also of limited applicability, with only residential mass market customers likely to participate.

Respectfully submitted,

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Counsel for AEMA

Dated: July 13, 2018

EXHIBIT A

Non-Generation Resources														
	2020/21 BRA				2021/22 BRA Offered				Change in Offered Amount			Change in Cleared Amount		
	Offered	Cleared	% Cleared		Offered	Cleared	% Cleared		MW	Percent		MW	Percent	Source
CP Demand Response	8367.2	7531.5	90%		11094.6	10673.5	96%		2727.4	33%		3142	42%	Reports Table 3C
CP Energy Efficiency	1839.0	1607.4	87%		2649.0	2622.7	99%		810.0	44%		1015.3	63%	Reports Table 3B
CP Solar	119.1	119.1	100%		516.0	516.0	100%		396.9	333%		396.9	333%	2020/21 Report p. 13; 2021/22 Report p.14
CP Wind	504.3	504.3	100%		710.2	710.2	100%		205.9	41%		205.9	41%	2020/21 Report p. 13; 2021/22 Report p.13
Price Responsive Demand	558.0	558.0	100%		510.0	510.0			-48.0	-9%		-48	-9%	2020/21 Report p. 13; 2021/22 Report p. 14
Sesonally Aggregated Resources		397.9				715.5						317.6	80%	Table 3C
Total non-generation capacity	**11387.6**	**10718.2**			**15479.8**	**15747.9**			**4092.2**	**36%**		**5029.7**	**47%**	
Seasonal Resources														
	2020/21 BRA				2021/22 BRA				Change in Offered Amount			Change in Cleared Amount		
	Offered	Cleared			Offered	Cleared			MW	Percent		MW	Percent	Source
Summer Demand Response	1479.5	288.9			792.2	452.3			-687.3	-46%		163.4	57%	Reports Table 3C
Summer Energy Efficiency	403.5	102.8			305.8	209.3			-97.7	-24%		106.5	104%	Reports Table 3C
Summer Solar	6.2	6.2			53.9	53.9			47.7	769%		47.7	769%	2020/21 Report p. 13; 2021/22 Report p.14
Other Summer Generation	178.5	0			52.3	0			-126.2	-71%		0		Total summer generation from Table 2C less cleared summer solar.
Total Summer Capacity	**2067.7**	**397.9**			**1204.2**	**715.5**			-863.5	-42%		317.6	80%	
Winter Wind	383.4	383.4			706.5	706.5			323.1	84%		323.1	84%	2020/21 Report p. 13; 2021/22 Report p.13
Other Winter Genration	102.5	14.3			9	9			-93.5	-91%		-5.3	-37%	Total winter generation from Table 3C less winter wind
Total Winter Capaacity	**485.9**	**397.7**			**715.5**	**715.5**			229.6	47%		317.8	80%	
Total Cleared Aggregated Resources		**397.7**				**715.5**								

All data sourced from PJM Base Residual Auction reports, available at http://www.pjm.com/markets-and-operations/rpm.aspx.

Increase due to Higher Clearing Rates					
	2021/22 BRA Offered	2020/21 Clearing Rate	Amount Cleared at 2020/21 Rates	2021/22 Actually Cleared	Increase due to Higher Clearing Rate
CP Demand Response	11094.6	90%	9986.5	10673.5	687.0
CP Energy Efficiency	2649.0	87%	2315.4	2622.7	307.3
Total Increase					**994.3**
Increase due to swtich from seasonal to annual					
	2020/21 Portion Annual	2021/22 Portion Annual	Increase	2021/22 Total Offered	Effect of Switch to Annual
Demand Response (incl PRD)	86%	94%	8%	12396.8	970.6
Energy Efficiency	82%	90%	8%	2954.8	225.9
Solar	95%	91%	-5%	569.9	-25.7
Net Increase					**1170.7**
Change in Wind Offers					
	2020/21 BRA	2021/22 BRA			
Offered as Annual	504.3	710.2			
Offered as Winter-only	383.4	706.5			
Total offered	**887.7**	**1416.7**			
Annual as % of total	57%	50%			
Winter only as % of total	43%	50%			
Expected annual at 2020/21 Rates		804.8			
less actual annual offered		706.5			
Wind switching from annual to winter only		**98.3**			

	Day	Sunrise	Sunset	PAI Minutes before sunrise	PAI Minutes after sunset			Day	Rise	Set	Sunrise	Sunset	PAI Minutes before sunrise	PAI Minutes after sunset
Jan	01	7:22 AM	4:46 PM	22	120		Feb	01	0709	1720	0.297917	0.722222	9	120
Jan	02	7:23 AM	4:47 PM	23	120		Feb	02	0708	1721	0.297222	0.722917	8	120
Jan	03	7:23 AM	4:48 PM	23	120		Feb	03	0707	1722	0.296528	0.723611	7	120
Jan	04	7:23 AM	4:49 PM	23	120		Feb	04	0706	1723	0.295833	0.724306	6	120
Jan	05	7:23 AM	4:50 PM	23	120		Feb	05	0705	1725	0.295139	0.725694	5	120
Jan	06	7:23 AM	4:51 PM	23	120		Feb	06	0704	1726	0.294444	0.726389	4	120
Jan	07	7:23 AM	4:52 PM	23	120		Feb	07	0703	1727	0.29375	0.727083	3	120
Jan	08	7:22 AM	4:53 PM	22	120		Feb	08	0702	1728	0.293056	0.727778	2	120
Jan	09	7:22 AM	4:54 PM	22	120		Feb	09	0701	1729	0.292361	0.728472	1	120
Jan	10	7:22 AM	4:55 PM	22	120		Feb	10	0659	1731	0.290972	0.729861	0	120
Jan	11	7:22 AM	4:56 PM	22	120		Feb	11	0658	1732	0.290278	0.730556	0	120
Jan	12	7:22 AM	4:57 PM	22	120		Feb	12	0657	1733	0.289583	0.73125	0	120
Jan	13	7:21 AM	4:58 PM	21	120		Feb	13	0656	1734	0.288889	0.731944	0	120
Jan	14	7:21 AM	4:59 PM	21	120		Feb	14	0655	1735	0.288194	0.732639	0	120
Jan	15	7:21 AM	5:00 PM	21	120		Feb	15	0653	1737	0.286806	0.734028	0	120
Jan	16	7:20 AM	5:01 PM	20	120		Feb	16	0652	1738	0.286111	0.734722	0	120
Jan	17	7:20 AM	5:02 PM	20	120		Feb	17	0651	1739	0.285417	0.735417	0	120
Jan	18	7:19 AM	5:03 PM	19	120		Feb	18	0649	1740	0.284028	0.736111	0	120
Jan	19	7:19 AM	5:04 PM	19	120		Feb	19	0648	1741	0.283333	0.736806	0	120
Jan	20	7:18 AM	5:06 PM	18	120		Feb	20	0647	1742	0.282639	0.7375	0	120
Jan	21	7:18 AM	5:07 PM	18	120		Feb	21	0645	1744	0.28125	0.738889	0	120
Jan	22	7:17 AM	5:08 PM	17	120		Feb	22	0644	1745	0.280556	0.739583	0	120
Jan	23	7:16 AM	5:09 PM	16	120		Feb	23	0643	1746	0.279861	0.740278	0	120
Jan	24	7:16 AM	5:10 PM	16	120		Feb	24	0641	1747	0.278472	0.740972	0	120
Jan	25	7:15 AM	5:11 PM	15	120		Feb	25	0640	1748	0.277778	0.741667	0	120
Jan	26	7:14 AM	5:13 PM	14	120		Feb	26	0638	1749	0.276389	0.742361	0	120
Jan	27	7:13 AM	5:14 PM	13	120		Feb	27	0637	1750	0.275694	0.743056	0	120
Jan	28	7:13 AM	5:15 PM	13	120		Feb	28	0635	1751	0.274306	0.74375	0	120
Jan	29	7:12 AM	5:16 PM	12	120									
Jan	30	7:11 AM	5:17 PM	11	120									
Jan	31	7:10 AM	5:19 PM	10	120									
Total				**584**	**3720**								**45**	**3360**
Total PAI minutes (240 min/day * 59 days)						**14160**								
PAI minutes at night						**7709**								
% of PAIs at night						**54%**								

2022 Sunrise and sunset times for Philadelphia from U.S. Naval Observatory, *Sun or Moon Rise/Set Tables for One Year*, available at http://aa.usno.navy.mil/data/docs/RS_OneYear.php.

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 these proceedings 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 at Washington, D.C., this 13th day of July, 2018.

By: *___/s/ Anna Williamson___*
Anna Williamson