UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Old Dominion Electric Cooperative, and Direct Energy Business, LLC, on behalf of itself and its affiliate, Direct Energy Business Marketing, LLC and American Municipal Power, Inc.	))))	**Docket No. EL17-32-000**
v. PJM Interconnection, L.L.C.	)))	
Advanced Energy Management Alliance	)	**Docket No. EL17-36-000**
v. PJM Interconnection, L.L.C.	)	
		(Not Consolidated)

PRE-TECHNICAL CONFERENCE COMMENTS
OF THE PJM POWER PROVIDERS GROUP

On February 23, 2018, the Federal Energy Regulatory Commission's ("FERC" or "Commission") issued an Order in this proceeding directing Commission Staff to convene a technical conference and to issue a request for comments on specified issues prior to the technical conference.[1]

On March 16, 2018, Commission Staff issued a Notice of Request for Comments and Technical Conference, setting April 24, 2018 as the date of the technical conference, stating four (4) detailed, technical questions for consideration and inviting interested parties to file pre-technical conference comments on those questions on or before April 4, 2018. On March 28, 2018, Commission Staff granted PJM Interconnection L.L.C.'s request for an additional seven

[1] *Old Dominion Elec. Coop* v. *PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,160 (2018), at p. 23.

days to submit comments in response to the questions on Notice, setting April 11, 2018 as the date for pre-technical conference comments.

The PJM Power Providers Group ("P3")[2] respectfully submits the Pre-Technical Conference Comments of Roy J. Shanker, Ph.D.

Respectfully submitted,

On behalf of the PJM Power Providers Group

/s/Glen Thomas

Glen Thomas
GT Power Group
101 Lindenwood Drive, Suite 225
Malvern, PA 19355
gthomas@gtpowergroup.com
610-768-8080

April 11, 2018

[2] P3 is a non-profit organization dedicated to advancing federal, state and regional policies that promote properly signed and well-functioning electricity markets in the PJM Interconnection, L.L.C. ("PJM") region. Combined, P3 members own over 84,000 MWs of generation assets, produce enough power to supply over 20 million homes and employ over 40,000 people in the PJM region covering 13 states and the District of Columbia. For more information on P3, visit www.p3powergroup.com. The comments contained in this filing represent the position of P3 as an organization, but not necessarily the views of any particular member with respect to any issue.

Pre-Technical Conference Comments of Roy J Shanker Ph.D.

On Behalf of The PJM Power Providers Group (P3)

Docket EL17-32-000; Docket EL17-36-000

April 11, 2018

1. I want to thank the Federal Energy Regulatory Commission (Commission) for inviting me to participate today.

2. My name is Roy J. Shanker. My address is P.O. Box 1480, Pebble Beach, CA. 93953. I have been asked by PJM Power Providers Group (P3) to participate in this technical session.[3] I have previously submitted an affidavit on behalf of P3 in this proceeding on January 25, 2017.[4] I incorporate that affidavit by reference here.

3. I have been closely involved with virtually all aspects of the development of PJM Interconnection, L.L.C. (PJM) as a Regional Transmission Operator (RTO) for over 20 years. Prior to obtaining RTO status, I worked on PJM issues for approximately 20 years. I have been very active in the portion of RTO activities directly related to these dockets, particularly the basic justification, function and design of the capacity market. More extensive comments on my qualifications are contained in my resume which is attached to my affidavit already submitted in these dockets.[5]

4. At the outset, I want to emphasize that most of the issues raised by the Commission's questions have previously been addressed, both in these dockets and previously in the Commission's approval of the PJM Capacity Performance (CP) design. I welcome the opportunity to add to the Commission's understanding of these issues and encourage

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[3] The views expressed in these comments are mine and do not necessarily reflect the views of P3 or any P3 member with respect to any issue.

[4] Protest of the PJM Power Providers Group, Old Dominion Cooperative and Direct Energy Business, L.L.C., on behalf of itself and its affiliate, Direct Energy Business Marketing, L.L.C., and American Municipal Power, Inc. v. PJM Interconnection, L.L.C., Docket No. EL17-32-000 and Advanced Energy Management Alliance v. PJM Interconnection, L.L.C., Docket No. EL17-36-000 (Not Consolidated), ("ODEC/AEMA Complaints"), dated January 25, 2017 ("P3 Protest").

[5] *Id*.

Commission Staff (Staff) to review my previous comments, as well as the Commission's specific prior findings. It is my understanding that because of this history, several parties, including P3 and PJM, have asked for rehearing or clarification of the Commission's February 23rd Order. While I do not address these types of legal considerations, my comments here are intended to supplement the Commission's understanding of my previous comments and how they comport with the Commission's previous findings regarding seasonal products, as well as the analytic specifics of the questions raised for this Technical Conference.

5. The answers to the technical questions presented in the complaint, if viewed in a vacuum, are very likely to be both misunderstood and incomplete. In order to fully appreciate the gravity of the relief sought by the complaints, it is imperative to evaluate that relief against the entire, recently-approved Capacity Performance market design and the overarching goal for capacity markets: finding a market mechanism to assure the opportunity for participants to earn a just and reasonable total return on investments in a market in which reliability is externally mandated. I have referred to this frequently as the "missing money" problem. When viewed in this context, the flaws of the complaint become apparent and provide a proper context for understanding the nature of the specific questions being addressed in the technical conference. These questions raised in the notice of the technical conference reveal only a small, out of context, piece of the total picture that the Commission would need to evaluate if it was even remotely interested in granting the relief sought by the complaint.

I. Background

6. PJM's capacity market was carefully designed to be a complementary market operating in concert with the energy market and intended to supply an opportunity to recover the "missing money," i.e. the difference over time between the recovery of a competitive new peaking entrant from the energy markets and expected total competitive entry costs for such a unit. This market design assures the opportunity for just and reasonable rates in a market in which the level of reliability is mandated (not set by market forces) and the level of offers for the sale of energy is capped with limited connection to scarcity. With mandated levels of adequacy set exogenously to the market, it is conceivable that a "needed" unit might never run at all. Capacity markets are the tool that assure that such a unit would receive an appropriate level of compensation. The opportunity to achieve such recovery over time is consistent with the overall underlying logic of

the estimate of the "missing money" as has been frequently discussed before the Commission. In PJM, the target for this anticipated long run level of payment would be the net cost of new entry for a peaking unit (Net CONE). The market-based rate design has to afford the opportunity (not guarantee) for just and reasonable recovery of costs. PJM's original RPM design and the new Capacity Performance design were explicitly structured to meet this objective, and found just and reasonable by the Commission.[6] (See, for example, the types of long-term market performance models under differing demand curve designs which PJM submitted to the Commission in August 2005 with its original Reliability Pricing Model, which were intended to demonstrate the ability of varying designs to both meet installed reserve margins (IRM) and maintain adequate levels of compensation to support new market entry[7]).

7. As a result, specific technical properties of forecasts and capacity market design are not generic or free floating. Rather these forecasts are directly tethered to the underlying tools and assumptions driving the specific market design to meet the missing money problem. This linkage must be consistent from the first theoretical steps in characterizing the basic objective, to the characterization of the installed capacity requirements and associated Loss of Load Expectation, to practical mechanisms of assuring proper accounting and crediting for supply and load obligations.

8. The market design must also consider/address how this objective of solving the missing money problem relates to the four technical questions raised by the Commission. This analysis must start from understanding the PJM tools and related assumptions used to address both the IRM and the missing money objective. The current PJM market has the PRISM (Probabilistic Reliability Index Study Model) model as the fundamental basis/analytic tool in the probabilistic calculation of the IRM, which in turn drives system-wide adequacy requirements. Thus, understanding the basic PRISM assumptions is key. The model assumes that *annual* generation with *known, independent outage rates* exists, *outages can be scheduled*, there is *infinite transmission* and *load shapes are known*. Implementation approaches built on PRISM that do not respect these building blocks are doomed to failure, particularly under stressed conditions such as the Polar Vortex or the recent cold snap this past winter. Such solutions also are ad hoc in the

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[6] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208. ("Capacity Performance Order")

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

context of trying to match the objective function, the tools used, and the solutions obtained.

9. The Commission was fully aware of this critical link and specifically noted and endorsed the PJM findings regarding the adoption of a homogeneous annual product at a single (though location dependent) clearing price as part of the current CP design. The Commission rejected the notion that such a product design was discriminatory and supported its use to address PJM's specific reliability/adequacy concerns.[8]

10. The Commission's questions appear to seek a way of integrating the admittedly inferior products into the capacity market design, despite the Commission's early findings, as confirmed recently by the U.S. Court of Appeals, D.C. Circuit. In keeping with the need for a capacity market design that meets its intended objective, any new proposal, including a seasonal market, cannot be implemented simply by ad hoc and out of context changes to select sub-topics in the existing structure, and must conform to the fundamental building blocks that go back to the design tool basics (assumptions and mechanics) and the associated missing money objective. The introduction of a seasonal capacity market in PJM is not a simple or surgical change. It is a fundamental redesign and the Commission should not approach the suggestion as anything less.

11. Changes as fundamental as a seasonal market would require a "start over" approach (assuming such an approach is even feasible). If a capacity market with sub-annual resources is really the desired market design (assuming a finding that the Commission approved CP design that has yet to become fully operational and understood, is not just and reasonable), the right solution is to start building such a market from scratch with consistent assumptions and analyses. The Commission would need to determine that PJM's existing market structure is not just and reasonable and then reach a determination on feasibility, appropriate analytic objective and related tools, full analyses and only then potentially an integrated design. Such a holistic, time-consuming task would be best suited for the stakeholder process where notably a majority of

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[8] "PJM is treating all resources identically in this respect. The rehearing requesters are in effect asking for special treatment for certain resources, permitting them to provide a lesser quality of service for the same price. We cannot find unreasonable PJM's conclusion that non-year-round resources do not provide equivalent service as year-round resources. Permitting non-year- round resources to continue participating could result in a loss of reliability during the fall, winter and spring when PJM will not have as many resources to respond to emergencies, such as a polar vortex." CP Rehearing Order, 155 FERC ¶ 61,157 at P 59. Similarly, the DC Circuit explicitly agreed with this FERC finding and concluded that "[t]he year-round capacity commitment is at the core of what PJM expects of capacity resources and the essential attribute of its revised market rules." *AEMA v FERC*, No 16-1234, U.S. Court of Appeals, D.C. Circuit, June 20, 2017, p. 23.

stakeholders have already, after lengthy discussions, rejected the incorporation of seasonal products.[9] In addition, the Commission should consider whether this is the best focus for PJM and stakeholder resources given a number of pressing items being currently considered in PJM including the need for energy market price reform, the ongoing resilience proceeding, significant nuclear retirement announcements, etc.

12. Looking at each of the four questions raised by the notice of technical conference from this perspective emphasizes the problems seasonal products present, even when mechanical LOLE-type computations of interest to the Commission can be approximated. Basic questions regarding total compensation and the correct tools to calculate LOLE (versus the status quo) under such materially different circumstances from the basic PRISM assumptions have simply not been addressed (other than by PJM approximations or sensitivities built on non-congruent tools) and cannot be fully answered by either the complainants or the specific Commission inquiries (absent material conditioning statements regarding the applicability of such results).

II. Answer to Questions

Question 1. According to complainants, PJM indicated in the stakeholder process that a procurement of 80 percent Capacity Performance and 20 percent Base Capacity yields a near-zero loss of load expectation (LOLE) over 42 (non- summer peak) weeks of the year. Do these results provide information about the value of lost load in 10 peak-summer weeks versus the rest of the year? Is placing the majority of loss-of-load risk in 10 peak-summer weeks an appropriate allocation of risk for purposes of meeting the 1-in-10 LOLE target in a cost-effective manner? If yes, please explain why. If not, what would be a better distribution of risk that can still satisfy the 1-in-10 LOLE target?

13. First, the concentration of the LOLE in the summer months is a design objective of the analysis, not some observation on actual reliability occurrences or subjective preference. That is, it is the answer to the analytic question of "how do you minimize necessary annual resources while meeting the target LOLE values?" The values themselves are set exogenously. In a system with annual products, the total amount of capacity to be procured is minimized by concentrating the LOLE during the periods of highest expected demand (e.g. by accepting lower reliability

[9] *See generally*, http://www.pjm.com/committees-and-groups/closed-groups/scrstf.aspx. PJM eventually suspended the efforts of the Seasonal Capacity Resources Senior Task Force due to lack of stakeholder interest or support.

(within the target level) at these times, you minimize requirements at peak). If the LOLE were lowered during peak periods and raised at other times (still targeting the 1 in 10 criterion), additional annual resources would be needed during the summer peak period to satisfy the higher reliability requirement at the time of greatest need (e.g. to make up for demanding higher summer reliability).[10] Arguably this additional need might be calculated for the highest 9 or11 weeks, but this type of evaluation on the likely occurrence of peak loads has been continually reviewed by PJM for decades, and then used for the minimization of installed requirements in meeting the IRM for the designated summer (and then annual) period. As such, there is no notion of "value" per se in any partition, but rather the property of minimization of the installed reserve requirement.

14. The same is true for "allocation of risk." This partitioning of LOLE in PJM's market design is the allocation of risk that minimizes the annual installed capacity requirement. That is its property. In the context of the PJM CP market design this is the most cost-effective allocation of risk over the year. Given the underlying assumptions and CP design, a single annul capacity product provides the best distribution of risk for a capacity market structure like CP that is intended to be responsive to outage/stress/scarcity events at any hour of the year. The Commission concurred with this conclusion.[11]

Question 2. How is the conclusion that PJM's current capacity procurement yields a near- zero LOLE in the winter consistent with PJM's experience in the Polar Vortex? How does the LOLE calculation take into account outage-related factors, for instance, planned maintenance outages are typically scheduled only during non-summer months?

15. The answers to these questions derive both from understanding the full context of PJM's reliability planning and the incidents in which PJM historically failed to match its own assumptions with its implementation.

16. The focus of the reliability requirement and IRM is on peak periods. Also, as pointed out above, the underlying PRISM model assumes *independent* outages (no correlated or common mode outages) among suppliers. As PJM realized and testified to at length, the Polar Vortex

[10] The PRISM tool is attempting to best "fit" outages in the 42-week period.

[11] Capacity Performance Order, pp. 39 - 40.

forced it to recognize a need for a reliability product that would be expected to perform at all hours on an annual basis, facing forced outages independent of the status of other units. Because of the need for maintenance, while the LOLE is concentrated in the peak periods, the off peak seasons are used to "consume" the reduced demand by allowing for necessary maintenance and associated reduction of total available capacity at different times. Ideally, maintenance is spread across the shoulder and winter periods to allow the near zero LOLE during these non-summer periods. This is what PJM's planning process does. The Commission validated this observation as part of the Capacity Performance Order. As part of my original affidavit in these dockets, I also discussed the Winter Weekly Reserve Target (WWRT) and associated characteristics related to the need for the high level of off peak reserves in order to allow both maintenance and adequate reserves.[12]

17. The nature of reserves and the "excess" in the non-summer period that complainants refer to were sensitivities that built off the existing PJM modeling that inherently allowed flexible winter maintenance planning to "make room" for necessary maintenance without sacrificing reliability (summer planned outages were not allowed). For the sensitivity study on removal of winter resources and the associated impacts on LOLE, PJM froze the planned maintenance from their base case for all sensitivities.

18. This need for winter surplus for maintenance has material implications for the type of "adjustments" that complainants proposed to reduce annual resources by over 17,000 MW. The winter reserve calculations reveal the fundamental problem of just "tacking on" ad hoc computational changes. The WWRT reflects the base case where LOLE is limited to .1 days per year, this is prior to allowing any of the inferior seasonal products, which PJM had allowed to increase the LOLE by 10% to 0.11. "Thus, the GEMARS case for the entire delivery year that includes the upcoming winter has an LOLE of 0.1 days/year. Such a case has a certain amount of "optimized" maintenance schedule in the winter (including a small amount during the winter peak) so that total Winter LOLE is practically "zero." As a proxy to simulate additional maintenance in the winter, the winter peaks (in the period December-February) are increased. This increase of the peaks stops when the total LOLE risk in each of the winter months is 0.0001 days/year (a threshold set arbitrarily). Next, the reserves during the winter period are extracted

[12] P3 Protest at pp. 18-26.

from the base case (computed as a percent of each weekly peak). Lastly, the weekly reserve values are averaged. The average corresponds to the Winter Weekly Reserve Target. The Winter Weekly Reserve Target is then applied to each winter week's forecasted peak load. PJM Operations will then attempt to schedule generator maintenance such that the WWRT is maintained each week of the winter."[13] The WWRT is averaged to maintain flexibility throughout the period, when peak occurrences are less predictable.

19. The Commission should be very troubled by any market design proposal that would have shifted the LOLE to the winter and, as a result, reduced annual products by 17,000 MW during the Polar Vortex. My understanding is that this type of winter reserve target constraint is prevalent in most of PJM's current planning analyses, and again was a material factor in the shift to the CP type of adequacy design. I discussed this in more detail in my January 2017 affidavit.[14]

20. Further, implicitly Question 2 emphasizes the risks that occur when parties fail to design market tools/mechanisms that conform to the underlying technical assumptions. Prior to and during the Polar Vortex, PJM's then existing rules did not reasonably enforce the assumption of independent outage states for generators. Fuel and operating outages were highly correlated with temperature, invalidating a key assumption in the PRISM IRM calculation. Had that assumption been addressed by adequate performance requirements (e.g. the penalty exposure resulting in increasing winterization of units and dual fuel supplies) the operational challenges experienced in January of 2014, would likely not have occurred.

21. Due to the flawed capacity market rules in effect in 2014, a second violation of basic assumptions also occurred during the Polar Vortex, that of annual products. Regardless of the design LOLE stress period, there were approximately 12,000 MW of seasonal supply. Had those resources been annual, without the inherent degradation of reliability of the seasonal resources, there would not have been any material reliability event. Though people may comment that approximately 4,000 MW of summer resources voluntarily participated, the reality is that had the approximately 12,000 MW of summer seasonal products been annual, even at a 20% forced outage rate there would have been approximately an additional 5,600 MWs available during the

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[13] *Id*., May 31, 2016 RAAS presentation.

[14] P3 Protest at pp. 12-18.

Polar Vortex.[15] This additional annual capacity, which would have been obligated under the CP market design, would have been approximately 11 times greater than PJM's critical lowest spinning reserves (500 MW) during this event.[16] With the correction of the correlated or common mode outage issues that will occur under CP incentives, there would have been even more capacity available at this critical time. In other words, understanding the basic assumptions and enforcing them explains both the necessity of the annual product definition and its need in maintaining the target LOLE.

Question 3. Complainants argue that it is appropriate to procure more capacity for the summer months than for the non-summer months. What would be the advantages and disadvantages of (a) procuring this capacity by using annual and summer-only capacity products in a single auction, as PJM did in the past, versus (b) creating two distinct auctions, and procuring summer capacity in one auction and non-summer capacity in the other? Are there other viable methods to meet this objective? If so, please describe them.

22. I believe that the above discussion dismisses any validity to the notion of potential benefits under the current market design from adding inferior seasonal products and solving for multiple products. The Commission itself explicitly considered and rejected these notions in recognizing that under the CP design, that addresses both adequacy and operational security, a homogeneous annual product with common obligations and pricing was an appropriate solution. The Commission has also been articulate with respect to the associated implications of the law of one price (e.g. a single price for the common product).[17]

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[15] See generally http://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx . During 2014 the average (not peak) winter daily peak load was expected to be about 106,000 MW, during the Polar Vortex the peak was a record 141,846 MW. Though not explicitly stated, the WWRT would have been approximately 28,000 MW.

[16] *Id*, p. 4. Note the entire event was during emergency notices and would have been designated PAH.

[17] The Commission has also recognized the problems of deviating from a single price for a common product. This has often been referred to as the law of one price. For a single product providing the same service, there should be a common single price. PJM's adequacy requirements and the underlying PRISM model assume a common product, as does the entire CP design. Similarly, there should not be an artificial differentiation in products that are intended to provide the same services.

The Commission has clearly articulated its view on this principle: "In a competitive market, prices do not differ for new and old plants or for efficient and inefficient plants; commodity markets clear at prices based on location and

23. Moreover, allowing seasonal and annual products simultaneously creates a subsidy for the inferior products while degrading reliability. Presumably, such a subsidy is a benefit for those seeking to sell such services.

24. At a more technical level, this type of joint product procurement (two different products supplying related (but not identical) services with different pricing) has not been demonstrated to accurately price either product. The general inference is that the superior product is under-valued and the inferior product over-valued. But no practical metric other than general allusions to LOLE value (not well defined at all for marginal pricing and complicated by allowing seasonal products to degrade reliability) has been identified.

25. Importantly, it has never been demonstrated that the nature of such formulations appropriately sends information regarding the first principle objective, supplying the opportunity to earn the missing money over time. Simply pointing to the fact that PJM historically could "solve" such a dual or triple product auction ***does not*** mean that the prices are meaningful or

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timing of delivery, not the vintage of the production plants used to produce the commodity. Such competitive market mechanisms provide important economic advantages to electricity customers in comparison with cost-of-service regulation. . . This market result benefits customers, because over time it results in an industry with more efficient sellers and lower prices." From Original: *See, e.g.*, *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 at P 141. *See also*, *Commonwealth Edison Co.*, 113 FERC ¶ 61,278 at P 43 (2005) (nondiscriminatory single-clearing price capacity auctions "ha[ve] the benefit of encouraging all sellers to place bids that reflect their actual marginal opportunity costs" and have been "found to produce just and reasonable rates for all the energy and ancillary service markets currently operated by the independent system operators and regional transmission organizations under our jurisdiction."), *order on reh'g*, 115 FERC ¶ 61,133 (2006); *Devon Power LLC*, 110 FERC ¶ 61,315 at P 45 (2005) (paying all "generators the same market- clearing price creates incentives to minimize costs, because a generator's cost reductions are retained by the generator and thus increase its profits" while paying "different amounts to different generators based on the level of compensation needed to keep the generator in operation would create a unit-specific cost-based system and undermine the advantages of a market for capacity."); *New York Indep. Sys. Operator, Inc.*, 110 FERC ¶ 61,244 at P 65 & n.76 ("Efficient pricing requires that suppliers receive the highest market value for their resources, independent of their bids [as] [t]his gives all sellers the proper incentive to offer their resources at the marginal cost of their highest valued use."), *order on reh'g*, 113 FERC ¶ 61,155 (2005); *New York Indep. Sys. Operator*, 103 FERC ¶ 61,201 at P 81 ("[A]ll capacity suppliers, regardless of the age of their resources, are entitled to the same treatment in the ICAP market. . . . The Commission does not see how [more expensive] generators could receive ICAP revenues that were fundamentally different from those paid to other generators. Moreover, those are the types of market signals the Commission would expect to encourage new 44generation additions.")

accurate. PJM has made other computationally feasible adjustments in the past only to later conclude they were in error.[18] Thus the simple demonstration that LOLE can be shifted means nothing in the context of the correct/consistent allocation of LOLE in the context of the overall market design. The fundamentals have to match and be consistently implemented. Attributes of different paradigms cannot be selectively chosen like a buffet.

26. With respect to the second part of the question, holding two separate seasonal auctions, or potentially some other auction structure, I do not believe it can be effectively constructed or implemented. While perhaps theoretically possible, accommodating non-comparable products in a manner suggested by complainants would demand a lot of basic/fundamental modeling and theoretical design work and likely also require new information that is not currently available. For example, a new market construct would have to clearly address the missing money objective. I do not see an obvious way of doing this with multiple non-comparable products and multiple seasons. No one has demonstrated this is possible, and the only analyses of these issues have been conducted by PJM using comparable/uniform annual products. Issues like how maintenance is treated and valued (or not valued) would also need to be addressed (e.g. what are the implications for the periods when a product has no obligations or fails to clear). Similarly, offer obligations would likely need modified conditions. Fundamentals of the Commission-approved Capacity Performance construct would need to be changed to excuse non-performance during certain periods for certain products. Indeed, it is not clear that any CP-like design could accommodate multiple seasons and the associated partitioning of products and of value. Certainly, no solution like this has been offered. In general, this type of task would be a multi-year undertaking by PJM and stakeholders, with uncertain results, to fix something that the Commission has already resolved and deemed to be just and reasonable.

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[18] For example, for several years PJM incorrectly formulated its RPM auction constraints for the inferior sub annual products. I raised this concern (including in testimony before the Commission) that PJM had "reversed" its constraints and put a floor on the superior product and no cap on the inferior products, instead of employing the correct and opposite constraint formulation - a cap on the inferior products and no cap on the superior products). While the auction software "solved" with the incorrect constraints, the answers were wrong for several years, basically presenting the superior products with a vertical demand curve that capped sales and resulting in an over-procurement of inferior products. Pricing (which in my opinion was questionable to start with) was similarly distorted. PJM subsequently admitted to a computational error and modified these constraints, the fact that this formulation "solved" was irrelevant to the underlying fundamental error.

27. But there is no need for this type of task or complexity. Seasonal products have an important role to play in PJM's existing market design. As suggested above, it is very straight forward to simply shift retail demand side programs to be valued as demand modifications (where they can be controlled and validated by the RTO). Similarly, there is no impediment for wholesale demand response to capture capacity value by simply avoiding consumption during peak hours. Supply options that cannot qualify as CP (which ultimately is a matter of risk assessment for the seller) can either aggregate into a less risky annual product, or simply sell energy and receive capacity compensation when they are on-line during performance assessment hours. Indeed, the value that seasonal resources provide to the grid should not be ignored. This value simply needs to be accounted for in a manner that is consistent with the underlying market design, and assumptions. [19]

Question 4. Does PJM's load forecasting methodology reasonably reflect peak shaving efforts by end users?

What is the basis for the current load forecasting methodology and what are its advantages within the context of peak shaving practices?

Are there aspects of the current load forecasting methodology that can be improved and may be incorrect or resulting in unreasonable outcomes within the context of peak shaving practices?

Are there alternative methodologies to reflect peak shaving efforts? If so, what are they and are there obstacles to implementing them?

28. While the details of the current process are better presented by PJM, simply stated, peak shaving when controlled/seen by PJM is addressed by adding back the associated load into the historic data used to develop future year forecasts. This then becomes the basis for PJM's planning. For programs that PJM does not directly "see," there is no such adjustment, however,

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[19] I would note that in 2017, PJM established the Summer Only Demand Response Senior Task Force and charged the group to "1. Review analysis conducted by PJM's Resource Adequacy department which simulates the impact of summer peak shaving resources on the load forecast used in RPM. a. As applicable, recommend alternative assumptions and/or modified analysis procedures. 2. Education and discussion on specific aspects of certain types of Demand Response resources, or specific market rules, which prevent participation in RPM. 3. Explore mechanisms, including the load forecast, to value Demand Response resource flexibility for those resources that may not be able to clear in the capacity market." http://pjm.com/-/media/committees-groups/task-forces/sodrstf/postings/sodrstf-issue-charge.ashx?la=en

over time the load forecast methodology would adjust to recognize these programs if they continued in operation and were effective (See PJM Manual 19). PJM continues to review its forecast procedures to accurately capture this information.

29. This process is not "incorrect or … unreasonable" in the context of PJM's current planning process and the CP adequacy market design. The "add back" appropriately contributes to a zonal capacity obligation, and in turn is then met by adequacy resources deemed necessary by PJM under the existing planning and CP market design. Modifications of the representation of peak shaving not seen by PJM would require a "retooling" of the planning process that establishes reliability targets, schedules maintenance etc.

30. There may be alternative representations possible, but each alternative would have to comport with either the existing or the notional "retooling" of the planning and adequacy process.

31. This concludes my comments.

Respectfully Submitted,

/s/Roy J. Shanker

Roy J. Shanker
P.O. Box 1480
Pebble Beach CA. 93953

CERTIFICATE OF SERVICE

I hereby certify that on this 11th day of April, 2018, I have served the foregoing document on each person designated on the official service list compiled by the Secretary of the Federal Energy Regulatory Commission in this proceeding.

/s/Laura Chappelle

Laura Chappelle
GT Power Group
101 Lindenwood Drive, Suite 225
Malvern, PA 19355
laurac@chappelleconsulting.net
517-281-1515