UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators	))))))	Docket No. RM18-9-000

POST-TECHNICAL CONFERENCE COMMENTS

Pursuant to Notice Inviting Post Technical Conference Comments issued in this proceeding April 27, 2018, Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM[1] ("Market Monitor"), submits these comments.

I. ECONOMIC DISPATCH, PRICING, AND SETTLEMENT OF DER AGGREGATIONS (PANEL 1)

In the Commission's Notice of Proposed Rulemaking on Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators (NOPR), the Commission proposed to require each RTO/ISO to revise its tariff to remove barriers to the participation of DER aggregations in its markets by, among other measures, establishing locational requirements for DER aggregations that are as geographically broad as technically feasible.[2] The NOPR also

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1 PJM Interconnection, L.L.C. ("PJM") is a Commission-approved Regional Transmission Organization. Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT") or the PJM ("OA").

2 NOPR, FERC Stats. & Regs. ¶ 32,718 at P 139.

addressed the use of distribution factors and bidding parameters for DER aggregations.[3] [4] In consideration of comments received in response to the NOPR, the Commission seeks additional information about how DER aggregations could locate across more than one pricing node. The Commission would also like additional information about bidding parameters or other potential mechanisms needed to represent the physical and operational characteristics of DER aggregations in RTO/ISO markets.

A. The Commission Should Not Adopt DER Aggregation

Aggregation is inconsistent with the fundamental logic of a system based on nodal prices. All the organized wholesale power markets are based on networks of nodes and based on corresponding nodal pricing. Given that many participants believe that distributed resources will play an increasingly important role in wholesale power markets, it is essential that we try to get the rules right from the beginning. If the precedent is established now that DER, alone among generation resources, does not need to be nodal, it will be difficult or impossible to reverse that precedent as DER grows based on that approach. The fact that aggregation may provide some short term business benefits to the providers of DER is not relevant to defining the correct market design to facilitate the long term, effective participation by DER. The benefits of DER derive from the fact that these resources are distributed across the system and not in a single central location. The network of electrical nodes and the associated nodal market are the ideal mechanism for incorporating distributed resources and pricing their output based on their actual electrical

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[3] The Commission proposed to require each RTO/ISO to revise its tariff to include the requirement that DER aggregators (1) provide default distribution factors when they register their DER aggregation and (2) update those distribution factors if necessary when they submit offers to sell or bids to buy into the organized wholesale electric markets. *Id*. at P 143.

[4] The Commission sought comment on whether bidding parameters in addition to those already incorporated into existing participation models may be necessary to adequately characterize the physical or operational characteristics of DER aggregations. *Id*. at P 144.

impacts at each node where they are located. Nodal signals provide the right feedback to distributed resources and provide the right incentives to potential distributed resource entrants. Nodal signals would ensure that the markets would continue to be efficient and competitive.

Transmission constraints can occur anywhere on the system at any time. Aggregation of DER would create unavoidable potential conflicts between distributed resources within an aggregation. If one part of an aggregation helps a constraint and another part hurts a constraint, dispatching the aggregate would not be efficient and would make the dispatchers' job more difficult. The dispatch would be internally inconsistent. If the dispatchers see only the aggregate, the dispatch could result in unintended consequences. This problem is not avoidable with aggregated distributed resources. All resources should be nodal for that reason.

There is no reason to grant DER special privileges based on asserted benefits of being distributed. In fact it is ironic that DER's asserted benefits are based on its distributed nature but that some proponents would reverse those benefits by permitting aggregation.

DER can aggregate for settlement purposes without aggregating for pricing or dispatch purposes. DER could be subject to fully nodal pricing and dispatch and aggregate for settlement purposes via RTO billing. DER can have a portfolio of individual distributed resources that are each nodally priced and dispatched.

DER can also aggregate at the distribution level as long as the entire aggregate was behind an individual wholesale market node. The specific aggregation rules in that case would be defined by the local utility and its commission.

The exact needs for DER to aggregate remain less than clear. Aggregation is not limited for business or financial or settlement purposes. But aggregation should not be permitted for pricing or dispatch purposes.

It is conceivable that DER could take advantage of the differences between nodal pricing of generation and generally zonal pricing of load. If an aggregation of distributed resources could select the node at which they are priced, the aggregator could select the highest price node at which to sell power while the loads which comprise the aggregate could continue to purchase power at the lower zonal rate. To permit such an arrangement would be to permit participants to benefit from rules arbitrage and the mispricing of power supply and demand.

Comments are requested on the following topics and questions that were included in previous supplemental notices:

1. **Acknowledging that some RTOs/ISOs already allow aggregations across multiple pricing nodes, what approaches are available to ensure that the dispatch of a multi-node DER aggregation does not exacerbate a transmission constraint?**

It is not possible to ensure that the dispatch of a multi-node DER aggregation does not exacerbate a transmission constraint in a nodal system subject to security constrained, economic dispatch.

2. **Because transmission constraints change over time, would the ability of a multi-node DER aggregation to participate in an RTO/ISO market need to be revisited as system topology changes?**

Transmission constraints change dynamically and unpredictably. As a result it would not be efficient to permit aggregation across nodes for pricing and dispatch purposes.

3. **Do multi-node DER aggregations present any special considerations for the reliability of the transmission system that do not arise from other market participants? How could these concerns be resolved?**

Yes, multi-node DER aggregations create unique considerations for the reliability of the transmission system. Dispatch of an aggregated DER would create internal conflicts in the dispatch signals with unintended and unforeseeable consequences if the aggregation included resources on both sides of one or more constraints.

4. **What types of modifications would need to be made to the modeling and dispatch software, communications platforms, and automation tools necessary to enable reliable and efficient system dispatch for multi-node DER aggregations? How long would it take for these changes to be implemented?**

The simplest required changes would be to require DER to be subject to fully nodal dispatch and pricing. Aggregation could be handled at the settlement level using existing settlement systems. It is not possible to produce results equivalent to nodal dispatch and pricing short of doing it correctly.

5. **If the Commission requires the RTOs/ISOs to allow multi-node DER aggregations to participate in their markets, how should a DER aggregation located across multiple pricing nodes be settled for the services that it provides? One approach to settling a multi-node DER aggregation could be to pay it the weighted average locational marginal price (LMP) across the nodes at which it is located. What are the advantages and disadvantages of this approach? Are there other approaches that should be considered?**

The individual elements of the aggregation should be priced based on the relevant nodal prices. Settlements can be aggregated as the sum of the MWh at each pricing node.

6. **The NOPR considered the use of "distribution factors" to account for the expected response of DER aggregations from multiple nodes. Are there other characteristics of DER aggregations that may not be accommodated by existing bidding parameters in the RTOs/ISOs? If so, what are they? Would new bidding parameters be necessary? If so, what are they?**

As long as DERs are priced and dispatched locationally, the existing offer parameters should address the characteristics of the resources.

Based on the discussion at the April 10-11 Technical Conference, comments are also requested on the following additional questions:

7. **During the technical conference, some panelists noted that for multi-node aggregations (a) there is a need to accurately represent the capabilities of DER aggregations at each node that they are located, and (b) more accurate representation at each node of a multi-node aggregation begins to make the aggregation look like a single-node resource. Some of the benefits discussed of multi-node aggregation included allowing an aggregation of DERs to provide more reliable services to the market and reducing transaction costs as a market participant, among others. Conversely, there was a discussion of the market operator's need to accurately represent the capabilities of the aggregation at individual nodes. Please comment on the benefits of being able to aggregate across multiple nodes versus the market operator's need to accurately represent the capabilities of the aggregation at individual nodes. If multi-node resources present risks or challenges to the system, what are they? Can they be overcome? How?**

No participant explained how aggregations provide more reliable service to the market. The response of the individual elements of the aggregation are not changed by aggregating them. The fundamental purpose of nodal markets is to aggregate across many nodal resources. That is why it is inconsistent with the nature of nodal markets to aggregate or to preaggregate resources rather than letting the market aggregate the actual responses of all the nodal resources. The transaction costs can be reduced by aggregating at the settlement level based on the nodal details. It is not the responsibility of the system operator or other market participants to provide a special advantage to DER based on the asserted transactions related benefits of aggregation. The argument for aggregation could be logically extended to groups of existing large generating units. But even if existing generators could assert a financial advantage to being permitted to aggregate, that would be the wrong answer because it is inconsistent with using nodal markets to provide the aggregation based on the actual physical and economic realities of the grid.

8. **During the panel discussion, CAISO mentioned that it allows multi-node aggregations within a defined set of nodes that have been deemed to have sufficiently little congestion across the nodes. Other panelists expressed a preference for single node aggregations. Are there methods to identify sets of nodes within which aggregation could be allowed that would balance concerns with multi-node aggregations against the benefits of multi-node aggregations. For instance, are there ways to group nodes associated with load centers that would facilitate aggregation while not threatening reliability and undermining the benefits of nodal pricing?**

It would be reasonable to permit aggregation within distribution systems behind individual wholesale nodes. The local distribution utility would have to determine whether it faces similar issues at the local level.

9. **Would reducing the minimum size requirement for DER aggregations to participate in the RTO/ISO markets (for example, to 100 kW as proposed in the NYISO DER Roadmap) help alleviate some of the concerns about requiring DER aggregations to be located only at a single pricing node? Or, would locating at a single node inhibit the development of DER aggregations regardless of the minimum size requirement?**

The question that should be answered by DER proponents of aggregation is exactly what benefits are associated with aggregation? The answer seems to be that it makes it easier to do business. But that is not an answer that provides a convincing reason to create resources that are dispatched in way inconsistent with the basic rules and logic of nodal markets.

10. **How are the concerns about constraints on the transmission system different for multi-node demand response aggregations versus multi-node DER aggregations?**

The issues are very similar. As the size and significance of DER could well exceed that of DR, this question makes it clear how critical it is to get the rules for DER correct from the beginning. Many of the core rules for DR were set before the potential size of the DR resources was fully appreciated. As the business grew based on those rules it was very difficult and continues to be very difficult to conform the rules for DR to the logic of the nodal markets. It would be a mistake to repeat the mistakes made in DR rule development in DER rule development. The fact that mistakes were made in DR rule development should not be considered a precedent for repeating these mistakes in DER rule development.

11. **During the technical conference, some panelists raised questions regarding potential tradeoffs between establishing rules for DER aggregations now in anticipation of a high DER future, and the potential technology and market efficiency costs of requiring nodal aggregation or other measures to manage the potential effects of DER aggregations before it is necessary. What are these tradeoffs? Do they change over time? Does the penetration of DERs affect how to assess the tradeoffs? Does the penetration of DERs affect the appropriate locational requirements for DER aggregations?**

It is essential to get the DER rules correct from the beginning. DER could have significant and unanticipated consequences for wholesale power markets. It would be a mistake for DER providers and for other market participants to provide a special advantage in the form of aggregation to DER in the name of short term economic advantages to DER only to change those rules in a year or two. DER should be able to compete on its own merits without artificial advantages that undermine the market design of wholesale power markets.

II. DISCUSSION OF OPERATIONAL IMPLICATIONS OF DER AGGREGATION WITH STATE AND LOCAL REGULATORS (PANEL 2)

The IMM may respond in reply comments to these questions.

III. PARTICIPATION OF DERS IN RTO/ISO MARKETS (PANEL 3)

DERs can both sell services into the RTO/ISO markets and participate in retail compensation programs. To ensure that that there is no duplication of compensation for the same service, in the NOPR the Commission proposed that individual DERs participating in one or more retail compensation programs, such as net metering or another RTO/ISO market participation program, will not be eligible to participate in the RTO/ISO markets as part of a DER aggregation.[5] In consideration of comments received in response to the NOPR, the Commission seeks additional information about potential solutions to challenges associated with DER aggregations that provide multiple services, including ways to avoid duplication of compensation for their services in the RTO/ISO markets, potential ways for the RTOs/ISOs to place appropriate restrictions on the services they can provide, and procedures to ensure that DERs are not accounted for in ways that affect efficient outcomes in the RTO/ISO markets.

Comments are requested on the following topics and questions that were included in previous supplemental notices:

1. **In Order No. 719, the Commission stated that "[a]n RTO or ISO may place appropriate restrictions on any customer's participation in an [aggregation of retail customers]-aggregated demand response bid to avoid counting the same demand response resource more than once."[6] How have the RTOs/ISOs effectuated this requirement or otherwise ensured that demand response participating in their markets is not being double counted? What would be the advantages and disadvantages of taking this approach for DER aggregations instead of the approach proposed in the NOPR for preventing double compensation for the same service?**

The FERC NOPR proposes to restrict participation to either the retail or wholesale market.[7] This is a simple and appropriate solution that avoids double counting. As a precedent under existing PJM rules, if a demand resource responds to both a wholesale and retail event at the same time, there are no payments at the wholesale level.

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5 *Id*. at P 134.

6 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281, at P 158 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 (2009), *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

7 *See* FERC NOPR at P 134.

IV. COORDINATION OF DER AGGREGATIONS PARTICIPATING IN RTO/ISO MARKETS (PANEL 6)

In the NOPR, the Commission proposed to require each RTO/ISO to revise its tariff to provide for coordination among itself, a DER aggregator, and the relevant distribution utility or utilities when a DER aggregator registers a new DER aggregation or modifies an existing DER aggregation.[8] The Commission proposed that this coordination would provide the relevant distribution utility or utilities with the opportunity to review the list of individual resources that are located on their distribution system that enroll in a DER aggregation before those resources may participate in RTO/ISO electric markets. In consideration of comments received in response to the NOPR, the Commission seeks additional information on the potential ways for RTOs/ISOs, distribution utilities, retail regulatory authorities, and DER aggregators to coordinate the integration of a DER aggregation into the RTO/ISO markets. In addition, because the use of grid architecture[9] can help identify the relationships among the entities involved in coordinating the integration of DER aggregations, the Commission is also interested in comments about potential architectural designs for the initial coordination processes from the point of view of the RTO/ISO markets.

Comments are requested on the following topics and questions that were included in previous supplemental notices:

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[8] NOPR, FERC Stats. & Regs. ¶ 32,718 at P 154.

[9] As an aid to thinking about the electric power grid, Pacific Northwest National Laboratory and others have coined the term "grid architecture," which they define as the application of network theory and control theory to a conceptual model of the electric power grid that defines its structure, behavior, and essential limits. *See, e.g.*, https://gridarchitecture.pnnl.gov/. Expanding upon this concept, some researchers have begun discussing different types of "grid architecture," which presumably differ in structure, behavior or essential limits from current norms.

1. **If the Commission adopts its proposal to require the RTO/ISO to allow a distribution utility to review the list of individual resources that are located on their distribution system that enroll in a DER aggregation before those resources may participate in RTO/ISO electric markets, is it appropriate for distribution utilities to have a role in determining when the individual DERs may begin participation? Should the RTO/ISO tariff provide the distribution utility with the ability to provide either binding or non-binding input to the RTO/ISO? Should the RTO/ISO provide the distribution utility with a specific period of time in which to consult before DERs may begin participation? Should the Commission require the RTO/ISO to receive explicit consent from the distribution utility before a DER is included in a DER aggregation? Are there other approaches to coordinate with the distribution utility? What are the advantages and disadvantages of these approaches?**

Coordination among RTO/ISOs; distribution utilities and DER providers is critical, as DER will affect both wholesale and retail markets. To the extent possible, the Commission should require and encourage maximum coordination. Ultimately, to be effective, competition in power markets will need to extend from the busbar to the meter. The introduction of DER is an important step in that direction.

2. **Should there be a coordination agreement in place prior to the participation of DER aggregation in RTO/ISO markets? Who should be parties to this coordination agreement? How would the coordination agreement be enforced?**

Coordination among RTO/ISOs; distribution utilities; and DER providers is critical, as DER will affect both wholesale and retail markets. To the extent possible, the Commission should require and encourage maximum coordination.

3. **As more DERs are added to the distribution system, the system may become more variable due to the output of certain variable resources such as wind and solar PV, and the operation of self-scheduled resources such as batteries and electric vehicles. Given this anticipated volatility at the distribution level, would the participation of aggregations of these DERs in the RTO/ISO markets further increase or decrease system variability?**

The potential addition of more DERs makes it clear why DERs should be nodal from the beginning in order to permit system operators visibility and the ability to control the systems and the grid.

V. ONGOING OPERATIONAL COORDINATION (PANEL 7)

In the NOPR, the Commission acknowledged that ongoing coordination between the RTO/ISO, a DER aggregator, and the relevant distribution utility or utilities may be necessary to ensure that the DER aggregator is dispatching individual resources in a DER aggregation consistent with the limitations of the distribution system.[10] The Commission proposed that each RTO/ISO revise its tariff to establish a process for ongoing coordination, including operational coordination, among itself, the DER aggregator, and the distribution utility to maximize the availability of the DER aggregation consistent with the safe and reliable operation of the distribution system. To help effectuate this proposal, the Commission also proposed to require each RTO/ISO to revise its tariff to require the DER aggregator to report to the RTO/ISO any changes to its offered quantity and related distribution factors that result from distribution line faults or outages. The Commission also sought comment on the level of detail necessary in the RTO/ISO tariffs to establish a framework for ongoing coordination between the RTO/ISO, a DER aggregator, and the relevant distribution utility or utilities.

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[10] NOPR, FERC Stats. & Regs. ¶ 32,718 at P 155.

Comments are requested on the following topics and questions that were included in previous supplemental notices:

1. **Should distribution utilities be able to override RTO/ISO decisions regarding day-ahead and real-time dispatch of DER aggregations to resolve local distribution reliability issues? If so, should DER aggregations nonetheless be subject to non-deliverability penalties under such circumstances?**

Yes. Distribution utilities should be able to override RTO/ISO decisions regarding day-ahead and real-time dispatch of DER to resolve local reliability issues. DERs should be subject to performance penalties consistent with the no excuses policy that applies to all resources. This provides an incentive for DERs to choose locations that do not create reliability issues for the local utility.

COMMUNICATIONS

Pursuant to 18 C.F.R. § 385.203(b)(3), the Market Monitor designates the following persons as those to receive all notices and communications with respect to this proceeding:

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CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to this pleading as the Commission resolves the issues raised in this proceeding.

Respectfully submitted,

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Dated: June 26, 2018

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 26th day of June, 2018.

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