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 OF THE ORGANIZATION OF MISO STATES

Pursuant to the Federal Energy Regulatory Commission's ("Commission") Notice Inviting Post-Technical Conference Comments dated April 27, 2018, the Organization of MISO States ("OMS") provides these comments on issues related to distributed energy resource ("DER") aggregations in RTO markets. On April 10 and April 11, 2018, the OMS participated in the Commission's technical conference on panels 2, 4, and 6. The OMS appreciates the opportunity to further address the administrative, jurisdictional, technical hurdles facing DERs participating on the bulk power system.

As explained in the joint statement[1] filed in this docket on June 1st, the OMS and MISO are committed to working collaboratively to develop a long-term proposal for how to reliably and efficiently integrate DERs into the bulk power system. This effort was initiated by the OMS in 2017 as state[2] regulators recognized two important aspects of DERs: (1) the overlapping jurisdictional framework DERs represent within the context of wholesale markets; and (2) the unique position state regulators occupy to facilitate the exchange of information between the RTO, distribution and transmission utilities, and the stakeholder community more broadly. Both of these aspects are especially critical in a multi-state region with predominately vertically-integrated utilities, where the efficient integration of resources located on state-jurisdictional distribution systems into both retail and wholesale markets will be largely determined by effective jurisdictional cooperation.

Panel 1: Economic Dispatch, Pricing, and Settlement of DER Aggregations

Question 8: 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

[1] *Joint Statement of the Organization of MISO States and Midcontinent Independent System Operator, Inc.* (June 1, 2018)

[2] Throughout this document the word "state" should be read to include the Council of the City of New Orleans.

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?

There is a balance between controlling resources down to a precise level and the ability for resources to be spread out. While a multi-nodal aggregation allows more resources to participate in the wholesale market, it runs a higher risk that the RTO or grid operator cannot operate the resources at the precise level needed for operational or reliability reasons. The key to achieving this balance will be transparency. This transparency will eventually need to go beyond the interconnection agreement and process between the distributed energy resource (DER) and the distribution utility and into what is happening real-time on the grid.

Aggregation across multiple nodes within MISO is currently allowed for purposes of capacity accreditation but is only allowed for a very limited set of resource types.[3] For example, MISO's DRR II resource category is not allowed to aggregate beyond a single node. MISO does not currently allow for aggregation across multiple Local Balancing Authorities by any resource type, but this issue is being investigated as part of the MISO Market Roadmap process. LSEs with geographically diverse footprints have requested this ability in order to meet minimum participation limit thresholds and OMS has been supportive of investigating this enhancement. If participation thresholds are lowered, the need for aggregation across LBAs and/or nodes may decrease. The lower threshold would also reduce the size of resources that would make up an aggregation, which inherently lowers the risk those resources could cause to the system.

<u>Panel 2: Discussion of Operational Implications of DER Aggregation with State and Local Regulators</u>

Question 1: What are the potential positive or negative operational impacts (e.g., safety, reliability, and dispatch) that DER participation in the wholesale market could have on facilities regulated by state and local authorities? How should the costs associated with monitoring and addressing such potential impacts on the distribution grid caused by the NOPR proposal be addressed, and fairly allocated? Are existing retail rate structures able to allocate costs to DER aggregations that utilize the distribution systems, and if not, what modifications or coordination are feasible?

DER participation in wholesale markets can create several potential concerns related to the communication between the distribution and transmission system operators as well as proper

[3] Midcontinent Independent System Operator, Open Access Transmission, Energy, and Operating Reserve Markets Tariff, Module E-1, Section 69A.3.5.

allocation of costs associated with integration and monitoring the additional distribution-connected resources. Though these discussions have begun, there are 17 different jurisdictions in the MISO footprint alone. Each of these jurisdictions may contain multiple utilities with a unique evolution of deployment and operational and planning needs that must be taken into account and accommodated. This will require a great deal of coordination among the distribution utilities, RTO/ISOs, and state and local regulators to determine the parameters of safe, reliable, and efficient operation of DER resources.

Distribution operations will probably be initially managed by the utility. This cost should eventually be borne by DER participants with some allowance for the value of optionality provided by accommodating access to DER. For states with DER participating in wholesale markets and DER that receives compensation through retail tariffs, costs need to be monitored and allocated fairly to both. Existing rate structures will probably have to be modified to fairly identify and allocate a portion of distribution costs to DER aggregations. A charge similar to that authorized in Order 841[4] is warranted for use of the distribution system for states that do not have retail DER programs. A fair allocation system is needed for states that will have both retail and wholesale programs.

Question 2: Do state and local authorities have operational concerns with a DER aggregation participating in both wholesale and retail markets? If so, what, if any, coordination protocols between states or local regulators and regional markets would be required to facilitate DER aggregations' participation in both retail and wholesale markets? Could the use of appropriate metering and telemetry address the ability to distinguish between markets and services, and prevent double compensation for the same services? What is the role of state and local regulators in monitoring and regulating the potential for such double compensation? How should regional flexibility be accommodated?

State regulators do have concerns related to DER aggregations participating in both retail and wholesale markets. Depending on the specific metering requirements for wholesale participation, determinations of how metering equipment is paid for and whether or not its data is available for use by a third party will vary from state to state. Ensuring the appropriate hierarchy of control of a DER will be key. The ability to mitigate operational concerns may largely be determined by a state's investment in the visibility and planning of their distribution systems. This fact will require regional flexibility, especially for multi-state RTOs that will have varying levels of distribution system investments, for varying purposes, throughout their footprints.

Operational challenges should be viewed as opportunities for business and regulatory innovation rather than the basis for prohibition of participation in both retail and wholesale programs. For example, consider that MISO and SPP do not have "eastern RTO" capacity markets. A substantial part of compensation for capacity will be based on retail tariffs so a wholesale-only

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[4] 162 FERC ¶ 61,127, Order No. 841: Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, issued February 15, 2018 at P 35, errata issued February 28, 2018 ("Electric Storage Order").

program might result in limited DER participation. Complementary wholesale and retail programs may be necessary to make DER technologies available. In recognition of this fact, states should be permitted to choose whether resources can provide both wholesale and retail services. This concept is addressed further in response to Panel 2, question 6 below. In addition, states will need visibility into any wholesale-only program that changes consumption at the retail level in order to carry out effective, distribution, generation, and transmission system planning.

Question 3: What entities should be included in the coordination processes used to facilitate the participation of DER aggregations in RTO/ISO markets? Should state and local regulatory authorities play an active role in these coordination processes? Is there a need to modify existing RTO/ISO protocols or develop new protocols to accommodate state participation in this coordination? What should be the role of state and local regulators in the NOPR's proposed distribution utility review of DER aggregation registrations?

Coordination with aggregators should occur based on a regulator-defined process, consistent with prevailing state regulation. Some entity will need the authority to shut down DER resources when warranted by system conditions, and state regulators will need to ensure interconnection standards and utility practices properly account for the expected use of DERs. Since RTO's cannot manage the distribution system under the Federal Power Act, state and local regulators may need to develop new protocols (i.e., investigations or rulemakings) to understand and manage the impacts on their jurisdictional distribution system.

Question 4: Does the proposed use of market participation agreements address state and local regulator concerns about the role of distribution utilities in the coordination and registration of DERs in aggregations? Are the proposed provisions in the market participation agreements that require that DER aggregators attest that they are compliant with the tariffs and operation procedures of distribution utilities and state and local regulators sufficient to address such concerns?

Requiring compliance with tariffs and operation procedures applicable to DER interconnection generally and DER aggregations specifically are imperative but concerns remain about the ability to effectively police compliance. Further, participation agreements will need to be crafted to accommodate ever-evolving technology changes or they could become barriers to innovation. Although the ability to address concerns on the front-end of market participation is ideal, an after-the-fact processes by which a regulator or distribution utility can bring forth distribution-system issues related to a DER aggregation may need to be examined as well. The RTO stakeholder process is the appropriate place for these modifications to participation agreements to occur.

In order to comply with participation agreements, new lines of communication between distribution utilities, DER aggregators, and the RTO will need to be developed. The extent to which a distribution utility is capable of enabling this level of communication will largely depend on state-jurisdictional decisions on distribution system investments. These agreements will need to define the responsibilities distribution utilities have in communicating information that may impact a DER aggregations ability to perform at the wholesale level and the frequency that information must be shared. In addition, agreements should outline the conditions by which a distribution utility can interrupt DER operation as well as identifying the responsible party for any financial consequences of said interruption.

The information from these participation agreements would likely be used by retail regulators as part of state proceedings to monitor aggregations and determine how distribution system costs are allocated between different users of the distribution system. The information required to do this effectively may vary by state. The ability to modify participation agreements through the RTO stakeholder processes will be needed to ensure proper flexibility.

Question 5: What are the proper protections and policies to ensure that DER aggregations participating in wholesale markets will not negatively affect efficient outcomes in the distribution system?

Utilities and state regulators need visibility into DER wholesale participants' quantity of capacity, energy, and expected operating characteristics in order to effectively plan distribution system investments. The operator of the distribution system will need to maintain the ability to shut these systems down for reliability reasons, as well as communicate information on topology changes that may impact the ability of an aggregation to participate in the wholesale market.

Question 6: During the technical conference, some panelists noted interest in a limited opt-out provision which would allow states to require DERs to choose participation in either the RTO/ISO market or retail compensation programs, but not both. How would such a limited opt-out be implemented? What are the benefits and drawbacks of such an approach?

Though a limited opt-out was raised during the technical conference, the OMS continues to prefer, and urge the Commission to adopt, the full opt-in/opt-out policy utilized for demand response resources in Order 719[5] for wholesale DER.[6] The fact that DERs are located on and operate from the distribution system, a field in which states have primary jurisdiction and responsibility, requires a different approach than that applied to traditional wholesale products. The opt-out approach will forego the need to create a new, complicated framework for utilities, state and local regulators, and RTOs that there is little understanding of today and, particularly in the MISO footprint, little activity to drive the need for near term action. This approach is also consistent with the fact that the majority of the benefits, value, and impacts of distributed resources occur at the distribution-level. By allowing state and local regulators to opt-out from wholesale participation, at least for a period of time, more development of processes for safe and

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[5] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281, at P 47 (2008) [hereinafter "Order 719"].

[6] The OMS raised analogous concerns in its comments related to Energy Efficiency Resource and Electric Storage Resources See *Protest of The Organization of MISO States*, FERC Docket No. EL17-75, at pp 12 (July 19, 2017); and *Comments of the Organization of MISO States*, Docket Nos. RM16-23-000 and AD16-20-000, pp 1-2 (Feb, 13, 2017) ("OMS Comments").

reliable incorporation of DER on the distribution system can occur naturally, in a non-disruptive manner, before requiring participation at wholesale, while still allowing for the vast majority of benefits from DER to be realized.

Acknowledging that the Commission has declined to provide this clear line of demarcation in recent cases,[7] it is important to put the new rules for emerging technologies in context. Successful implementation of DER aggregation demands a greater level of cooperative federalism than has been necessary in the past. The increasing amounts of distribution-connected resources that could participate in the wholesale market requires a new way of thinking about the line between state and federal jurisdiction since FERC cannot set the retail or distribution rates, establish interconnection standards for the distribution system, or determine the level of investment in distribution-level technologies, and states cannot regulate the wholesale markets or transmission. A new, well-thought-out structure that tries to calm the intertwined jurisdictional melee is necessary. Justice Kagen recognized the imperative that FERC and state and local regulators fill in the gray jurisdictional areas cooperatively or risk barriers to progress in the *EPSA* case.[8] Justice Scalia posted a hypothetical situation in his dissent in which FERC allowed generators to sell directly to retail customers across state lines and set rates for generation, transmission, and retail services to highlight the regulatory gap between state and federal jurisdiction. In response, Justice Kagan stated:

> [O]f course neither FERC nor the States could issue such a rule: If FERC did so, it would interfere with the State's authority over retail sales and rates as well as (most) generation; if a State did so, it would interfere with FERC's power over transmission. Thus, to implement such a scheme, the States would need to do something and FERC to do others. And if the one or the other declined to cooperate, then the full scheme could not proceed.[9]

FERC's questions on the appropriate role of state and local regulators in the NOPR and technical conference materials on DER aggregation, and in Order 841, are well placed. There are many instances in what FERC has proposed that requires both cooperation and, in some instances, oversight by state and local utility regulators in order to be successful. The rules applying to the interconnecting utility must be fashioned in a way that accommodates these resources yet FERC does not have authority to craft or approve them. Many of the OMS members have ongoing proceedings to support greater deployment of DER and are looking at ways to provide opportunities to monetize and compensate them for their value. If rules at the wholesale level are not developed cooperatively with retail counterparts, they are more likely to serve as barriers to deployment than catalysts. This is particularly true in the MISO region where capacity auction

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[7] See Electric Storage Order at P 35 and 161 FERC ¶ 61,245, Order on Petition for Declaratory Order, Issued December 1, 2019 at P 57.

[8] FERC v Elec. Power Supply Ass'n, 136 S. Ct. 760 (2016).

[9] EPSA at 780, n. 10.

prices are unlikely to support new entrants in the wholesale market because resource procurement is mainly accomplished through a retail construct.

In recognition of this need for cooperation, if FERC does not adopt the full opt-out, the OMS urges FERC to propose a truly collaborative framework that will allow DER resources to have the greatest chance of success. Such a framework will include the forum and time necessary to identify and work through the complicated set of considerations and processes that will be required on the distribution system to make DER aggregation fruitful. Components like developing distribution interconnection standards, understanding real-time reliability coordination, establishing technology to provide needed visibility, creating compensation and rate structures, and communication with the RTO are just the tip of the iceberg and will be different for each state. Opt-out light could be an option to explore with a full understanding of all of the details, but in the meantime, a coordinated effort with full collaborative comprehensive review over a longer period of time, will benefit all of those impacted by the new rule.

In addition, the MISO stakeholder community is working through these types of issues related to energy storage through the Order 841 compliance process. There is significant overlap between the storage and DER aggregation implementation issues since most of both types of resources will be located on the distribution system. Therefore, the OMS encourages the Commission to allow time to capture the value of the storage findings (coming in December 2018) before setting deadlines for DER aggregation compliance. Working through these substantial policy changes in different silos will be more difficult and inefficient.

No one has the right answer today to address the considerable jurisdictional issues raised by bringing large amounts of new energy technology onto the distribution system. The key focus is to provide a structure that will bring these assets on the system in a way that recognizes their value while maintaining safety and reliability. Federal and state cooperation will be required to accomplish this goal and the OMS looks forward to working with FERC to establish a framework for success.

<u>Panel 3: Participation of DERs in RTO/ISO Markets</u>

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.[10] *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*

[10] *Id*. at P 134.

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.

1. **Question 2: 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."[11] 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?**

Concurrent retail and wholesale markets will cause confusion. Distribution utilities will need to manage which DERs they must pay through the state-regulated net metering or feed-in tariff, and which DERs are paid through aggregation in the wholesale market. Across thousands of DERs, some double compensation in this scenario is inevitable. Which regulatory authority will need to monitor who is paying who, and have definitive authority and human resources to police double compensation? Some states may decide that the approach provided in FERC Order 719 for DR, full opt-in or full opt-out, is the best way to draw clear jurisdictional and market boundaries.

<u>**Panel 6: Coordination of DER Aggregations Participating in RTO/ISO Markets**</u>

Question 4: What is the best approach for involving retail regulatory authorities in the registration of DER aggregations in the RTO/ISO markets?

See response to question 10 below.

Question 8: Some panelists suggested that the state and RTO/ISO interconnection processes could provide the means to evaluate the ability of a DER to participate in an RTO/ISO market. To the extent that RTOs/ISOs currently have a process that applies to the interconnection of DERs to Commission-jurisdictional transmission and distribution facilities, please explain the process and criteria evaluated, including referencing any relevant tariff or business practice manual provisions.

State-mandated interconnection standards will determine the capabilities and functions of DER connected to state-jurisdictional distribution systems such as the ability to communicate and the default settings for various system conditions. The capabilities enabled by these interconnection standards may place inherent limitations on DER or enable the necessary communication with RTOs to verify resource performance. However, current interconnection standards were not set up

[11] *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).

to establish the viability of a DER to participate in the wholesale market or contemplate the aggregated impact on transmission. These state-established standards were put in place primarily to ensure human safety and reliability of distribution system for resources active under state tariffs. As such, they can include components such as reliability study requirements, rules for operational control to maintain reliability, telemetry and data sharing requirements, insurance/indemnity clauses, and safety rules.

Though state interconnection standards will evolve, those efforts are in the early stages. For example, the recently-approved update to the IEEE 1547 standard is the first version of the standard to specify new DER technical capabilities and reliability requirements, to include communications and interoperability requirements, and to contemplate bulk electric system impacts. States are not required to adopt these updated IEEE standards, but many will likely choose so to do so. Additional considerations by utilities and their regulators will be needed prior to DER participating at the wholesale level. It is also important to consider the range of interconnection standards that resources will adhere to, depending on when they come online. However, the adoption of consistent standards, such as updated IEEE 1547, will benefit individual states and the regional grid by providing visibility of DERs, improved reliability requirements, and m ore efficient operation.

Question 9: During the technical conference, panelists highlighted the importance of coordination procedures and frameworks. Should coordination frameworks for DER aggregation, particularly between RTOs/ISOs and distribution utilities, be required or encouraged to be developed between the appropriate entities?

Yes. Coordination frameworks that allow for a clear communication of the roles and responsibilities of the RTO and distribution utility will be needed to ensure the wide variety of possible use cases for DER on the distribution system are fully understood. State and local regulatory authorities will need to be aware of these coordination efforts, and be able to participate in, and in some cases lead, these efforts based on jurisdictional scope and prevalence of DER penetration and state policy.

Question 10: During the technical conference, some panelists commented on the importance of specifying roles with regard to DER aggregation. What should be the specific roles and responsibilities for distribution utilities, DER aggregators, retail regulators, and RTOs/ISOs associated with the participation of DER aggregators in RTO/ISO markets? Should the Commission specify these roles?

The retail regulator in conjunction with the distribution utility will be in the best position to determine the extent to which DER can reliably participate in wholesale markets while ensuring that all relevant planning and compensation considerations have been accounted for. If roles and responsibilities are defined by the Commission, state jurisdiction to ensure reliability of the distribution system needs to be considered in the overall structure.

Distribution utilities and retail regulators should develop the interconnection agreements and rules that apply to interconnection, operation to ensure reliability, data sharing, and other requirements so that no harm comes to the utility system or its customers. The RTO should ensure compliance with these requirements and work with the utilities to exchange necessary information to maintain reliability of the distribution and transmission systems and to make sure both can operate efficiently. DER aggregators can work with the utilities and RTOs to ensure the appropriate data is available to ensure reliable and efficient planning and operations.

In addition, RTOs need to accommodate varying roles and responsibilities of distribution utilities and aggregators depending on state policy and the capability of the utility. In all cases, DER aggregators should be responsible to ensure compliance with relevant state and local regulations. But state and local regulators may not have the authority to police non-utility entities which could impact the ability to acquire sufficient information to conduct reliability reviews and proper resource planning.

Question 11: During the technical conference, several panelists discussed the need to know the attributes of DERs on their distribution system. Please describe, where applicable, what types of static and dynamic information is currently being provided about aggregated or individual DERs to distribution utilities and to RTOs/ISOs. Is there additional static information about aggregated DERs or the individual DERs in those aggregations that distribution utilities need that would not be made available during the interconnection process? What, if any, dynamic information would the distribution utility need from the RTO/ISO in real time regarding DER aggregations that are participating in the RTO/ISO markets, or the individual DERs in those aggregations? How would the distribution utility use this static or dynamic information?

Please see responses to Panel 4, questions 1 and 2 in the OMS response in Docket AD18-10.

Question 12: 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?

Aggregation of DERs into the RTO market may balance out resources using storage or demand side management in conjunction with variable resources; however, this balance can be achieved through retail processes as well (e.g., time of use rates or demand charges that discourage large jumps in demand). Distribution utilities are required to maintain reliable distribution systems, so addressing volatility as it develops will naturally occur.

The amount of volatility that is introduced, and the ability to manage it, will depend on which technologies make up an aggregation, which may be driven by penalties for lack of performance and/or other system requirements that can't be known until market rules are in place for these resources. Automation vs. manual intervention will also play a role in the amount of variability that is observed. The level of automation required may be set as part of a states interconnection requirement for DERs.

The OMS files these comments because a majority of its members are in support. The Montana Public Service Commission and Manitoba Public Utilities Board did not participate in the vote. The Illinois Commerce Commission does not join these comments.

Respectfully Submitted,

Tanya Paslawski

Tanya Paslawski
Executive Director
Organization of MISO States
E-mail: tanya@misostates.org
Tel: 515-243-0742

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