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
Distributed Energy Resources – Technical Considerations for the Bulk Power System	)))	Docket No. AD18-10-000

<u>POST-TECHNICAL CONFERENCE COMMENTS OF THE ELECTRIC POWER SUPPLY ASSOCIATION</u>

Pursuant to Rule 211 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (the "Commission"),[1] the Electric Power Supply Association ("EPSA")[2] hereby submits comments in response to the Commission's April 27, 2018 Notices Inviting Post-Technical Conference Comments in the above-captioned matters.[3] These notices were issued after the Commission convened a two-day technical conference on April 10-11, 2018 ("DERs conference"), at which issues in both proceedings were addressed.

While EPSA recognizes that distributed energy resources ("DERs") continue to evolve and make up a larger portion of the nation's electric system, any initiatives or rules to facilitate participation of these emerging resources must first and foremost be

---

[1] 18 C.F.R. §§ 385.211.

[2] Launched over 20 years ago, EPSA is the national trade association representing leading independent power producers and marketers. EPSA members provide reliable and competitively priced electricity from environmentally responsible facilities using a diverse mix of fuels and technologies. Power supplied on a competitive basis collectively accounts for 40 percent of the U.S. installed generating capacity. EPSA seeks to bring the benefits of competition to all power customers. This pleading represents the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue. EPSA intervened in this matter on May 4, 2018.

[3] EPSA is submitting one set of comments in both of the instant proceedings for efficiency and to address general issues raised by the integration of DERs into the competitive wholesale power markets.

designed to serve reliability and efficiency objectives, not simply to facilitate DERs business model objectives. DERs rules must be compatible with, and work in tandem with, the extensive system of conventional resources serving critical reliability needs based on market signals through flexible and on-demand (dispatchable) capabilities. The DERs rules cannot interfere with those of the flexible, traditional resources that make up the backbone of the Bulk Power System ("BPS"), today and for years to come, even in light of the very changes created by the integration of new resources and technologies over time. All resources should be valued based on how well and flexibly they can serve reliability and resilience needs of the system. Therefore, the most critical work of the Commission is the continued improvement to and protection of the competitive wholesale power markets, including the finalization and expeditious implementation of price formation improvements that help ensure the right price signals for all resources, conventional and new, competing in markets. Consequently, EPSA urges the Commission to weigh the importance of potential rule changes to accommodate DERs wholesale market participation in light of the needs and operation of the overall BPS.

I. Background

These proceedings stem from the Commission's February 15, 2018 Order[4] in its proceeding on electric storage participation in markets operated by Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs"). While the Commission issued a final rule on storage participation on February

[4] Order No. 841, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61, 127, Docket Nos. RM16-23-000, AD16-20-000 (February 15, 2018) ("Order No. 841").

15, 2018, the Commission determined that additional information was needed with respect to distributed energy resources. Contemporaneous with the issuance of Order No. 841, the Commission issued a Notice of Technical Conference[5] to continue to explore the proposed distributed energy resource aggregation reforms under Docket No. RM18-9-000. All comments previously filed in response to the storage NOPR in Docket No. RM16-23-000[6] were incorporated by reference into Docket No. RM18-9-000. Pursuant to this notice, the Commission convened a two-day technical conference on April 10-11, 2018, after which the Commission issued a Notice Inviting Post-Technical Conference Comments in Docket No. RM18-9-000 and a second, concurrent Notice Inviting Post-Technical Conference Comments in Docket No. AD18-10-000.

The integration of DERs aggregations into wholesale markets represents an innovative move forward for markets, but efforts to enable their participation on the electric grid cannot upset the pricing and operational efficiencies that support the system's backbone – conventional generation and demand response. As EPSA has noted in previous proceedings, the power sector is entering what will likely be a multi-year, even multi-decade, series of profound changes to the provision and consumption of power as the resource mix includes greater deployment of many new resources and technologies, include DERs. One of the critical implications of these changes is the market impact of new resources with different or new cost structures and revenue

---

5 FERC Notice of Technical Conference, *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators* (Docket No. RM18-0-000) and *Distributed Energy Resources-Technical Considerations for the Bulk Power System* (Docket No. AD18-10-000), (Issued February 15, 2018). https://www.ferc.gov/CalendarFiles/20180215200832-RM18-9-000.pdf.

6 *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Notice of Proposed Rulemaking, 157 FERC ¶ 61,121 (November 17, 2016) ("NOPR").

requirements, as certain resources will have low to zero marginal costs while most conventional resources with significant marginal costs will continue to be needed to meet operational and planning system needs. While this poses challenges under the current competitive market structure, the best and most efficient way to facilitate and accommodate these changes remains reliance on well-designed, transparent, properly regulated competitive wholesale markets. In such markets, energy, ancillary services, and operating reserve price formation policies and practices (both day-ahead and real-time) should result in price signals that reflect actual system conditions and support incentives for all resources to operate in support of system reliability, including investment in additional resources that will sustain and improve operation of the system. Resources that are available for operators to call on and adjust as needed (committable and dispatchable) provide greater reliability value since they can adjust based on system operator directions and real-time market signals to address the reliability needs of the system and adequately serve varying load. Therefore, it is important that market changes to facilitate particular new technologies be undertaken in a manner that does not undermine or take away from other market improvement, reliability, and protection efforts, including energy price formation, that have an extensive material impact today and going forward on the wholesale electric grid by providing market signals to which generation can respond to support reliability and resilience of the system.

The sometimes-inflexible nature of DERs and its higher market penetration over time will make the effectiveness of market price signals all the more critical to ensure DERs participate without jeopardizing reliability and resilience of the power system. Perhaps, even more importantly, an increased effectiveness of market price signals (via energy price formation improvements) is needed to account for the intermittency and uncontrolled variability of DERs output.

II. Comments in Docket No. RM18-9-000

a. The Commission Should Prioritize Single-Node Aggregations

A well-designed, security constrained economic dispatch market model best manages the challenges and risks presented by a diverse system of resources, including the integration of new and emerging technologies, as it is inherently more flexible and adaptable by providing price signals to incent reliable operation and dispatch in a very targeted (nodal) and timely fashion. These market signals also inform all generation on where to locate and invest. Markets additionally have the huge benefit of placing risks primarily on investors rather than on consumers. Therefore, while it is beneficial to ensure that market rules allow for the integration of aggregated DER resources, it is imperative that this work "do no harm" to market operations for all resources. In this instance, allowing DERs to aggregate on a multi-nodal basis will reduce efficiencies and present accountability and performance issues, thereby distorting market outcomes. If not dealt with appropriately, multi-nodal aggregation could mask or exacerbate congestion, lead to suboptimal economic dispatch, and create unnecessary problems with system operators' management of the system, including reliability problems.

As raised by several panelists at the DERs conference, overly broad aggregations, i.e. multi-nodal, can exacerbate transmissions constraints.[7] Dr. Joseph

---

[7] *Participation of Distributed Energy Resource Aggregation in Markets Operated by Regional Transmission Organizations and Independent System Operators* and *Distributed Energy Resources Technical Considerations for the Bulk Power System*, Distributed Energy Resources Technical Conference Transcript, Docket Nos. RM18-9-000 and AD18-10-000. Note that the two transcript

Bowring, Independent Market Monitor ("IMM") for PJM, noted, ""It's not possible to predict congestion, it's not possible to pre-define constraints that exist or don't exist. A zone is way too big for aggregation."[8] For the New York Independent System Operator ("NYISO"), an ISO that has been at the forefront of integrating new technologies like DERs, Michael DeSocio, Senior Manager for Market Design, explained,

> [T]he path that New York has been taking has been focused on a single node aggregation. There's been a lot of discussion with our stakeholders on a multi-node possibility, but when we think about that in New York we get worried about how we're going to deal with managing multiple transmission constraints at the same time and in New York that happens on a minute-by-minute, hour-by-hour basis – New York is highly transmission constrained.[9]

This approach is further explained in the NYISO's white paper outlining its DERs Roadmap, in which the ISO reports,

> To ensure bulk power system reliability, it is important to accurately represent DER impacts at their corresponding interface to the bulk power system, which is typically at a transmission node (substation load bus transformer/PTID) associated with a distribution network. Therefore, we propose at this time, and subject to further study and development in the stakeholder process, to limit the geographical footprint of DER aggregations to only those resources connected to the same bulk transmission node. This geographical limit to DER aggregations will help ensure DER compensation in the wholesale markets reflects the locational and temporal value of the DER aggregation on the bulk power system.[10]

---

documents from Day 1 (April 10) and Day 2 (April 11) are paginated as one source, so are to be cited herein by page number from the "DERs technical conference transcript."

Dr. Joseph Bowring, Independent Market Monitor ("IMM") for PJM Interconnection L.L.C. ("PJM"), "So it's critical I think, to think about how that works in a nodal system and it's not possible to predict congestion. It's not possible to predefine constraints that are exist or don't exist. A zone is way too big for aggregation." Page 14.

Jeff Bladen, Executive Director, Market Services of Midcontinent Independent System Operator, Inc. ("MISO"), "And so as we think about aggregations -- as we think about building aggregation groups, it needs to be more than just how do we security constraint those aggregations for the transmission system, but how are we going to manage the potential constraints that might occur at the distribution level." Page 12.

8 DERs technical conference transcript, p 14.

9 DERs technical conference transcript, p 16.

10 *Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets,* ("NYISO DERs Roadmap"), (January 2017), New York Independent System Operator, Inc. ("NYISO"), p 17. Additionally, "The NYISO believes granular monitoring and control of DER aggregations at the

The NYISO DERs Roadmap also explains why single node aggregation is necessary for price transparency, particularly to incent dispatchable DERs.

> Pricing at the zonal level…dilutes incentives for DER to locate in areas that could provide significant benefits to the grid and the market. To facilitate more economically efficient DER benefits, the NYISO will provide more granular price signals reflecting location specific system conditions. These granular price signals are available to the NYISO, but have not been publicly available. To provide more locationally accurate pricing data to DER, resources that choose to participate in the NYISO's Energy and Ancillary Services markets will be mapped to their appropriate electrical buses and settled at the nodal price associated with the bus. The NYISO's goals are to deliver real-time nodal LBMPs, calculated every five minutes, to reflect more localized system conditions.[11]

In the least, discussion at the DERs conference leads to the conclusion that limiting DERs aggregation to single-node connections may be necessary in certain ISOs/RTOs and should be the foundation for any generic approach considered by the Commission. For instance, while CAISO has allowed DERs aggregations to cross over multiple pricing nodes, the CAISO spokesperson noted that though there are five DERs aggregation contracts in place, there are currently no participants active as of this Spring.[12] Meanwhile, Andrew Levitt, Senior Market Strategist for PJM, shares concerns with the PJM IMM and other ISOs "in terms of DER aggregations at multiple nodes that would span constraints…And this is a concern with respect to market clearing and

---

transmission substation load bus level is needed to effectively and efficiently manage transmission system congestion and reliability. Therefore, the NYISO proposes that dispatchable DER aggregation boundaries to be limited to all DER interconnected to, and having direct impact on, the same transmission substation load bus." Report available here: http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/DER_Roadmap/Distributed_Energy_Resources_Roadmap.pdf

[11] NYISO DERs Roadmap, p 29.

See also, DERs technical conference transcript, Michael DeSocio of NYISO, p 17, "And so as we thought about making sure the values were there for DER and making sure that the price signals incented DER to locate in the right places it occurred to us that nodal made the most sense."

[12] DERs technical conference transcript, p 69.

pricing and settlement and also operational dispatch."[13] It is important to keep in mind that transmission constraints are dynamic and appear on different paths. They change drastically over time as transmission topology and generation mix evolve, thus making it more imperative that aggregation be constrained to single-node. Yet PJM incorrectly also believes that it can develop an approach to aggregation which combines CAISO's broader boundaries by essentially splitting larger aggregations by single node.[14] Such a "hybrid" approach when facing unknown future constraints would be a threat to reliability and future resilience of the grid.

While detailed rules applicable to all RTOs are generally not optimal,[15] a high-level rule limiting aggregation to a single node makes sense because all the ISOs/RTOs rely on a security constrained economic dispatch market model (LMP) to incent dispatchable output from resources to produce extremely reliable outcomes that adhere to transmission constraints. Security constrained economic dispatch is nodal by definition and needs to be so to incent price signals aimed at maintaining grid reliability and security, while achieving optimal market efficiency. For PJM, for instance, Dr. Bowring noted, "[F]or purposes of injection into the grid I would suggest to you that anything larger than a node is going to create issues which are non-resolvable."[16]

Nodal aggregation rather than wider aggregation also ensures that DERs locate and invest in the optimal locations based on market signals. These market signals

---

13 DERs technical conference transcript, p 18.

14 DERs technical conference transcript, pp 15-20.

15 DERs technical conference transcript, pp 36-37, Jeff Bladen of MISO, "I would encourage, based on my earlier comments, or reaffirm, encourage, thinking about this as an opportunity to establish a pathway for innovation across the different regions to think about these challenges that are somewhat unique in each region, identify best practices over the coming years and then use that over time to allow us to adopt what we learned from -- from our colleagues around the country."

16 DERs technical conference transcript, p. 15.

provide visibility into where a resource would be optimally located in order to help control secure transmission flows. Likewise, the RTO dispatch system expects visibility on a nodal basis to indirectly incent proper commitment and dispatch on a nodal basis. In other words, the commitment and dispatch system is designed to direct resource output on a nodal basis. A split between this design and reality by allowing resources to aggregate across multiple nodes tends to put security of the system at risk. It reduces visibility and transparency associated with where resources are actually located.

Many states have RPS goals that presume high penetrations of renewables. For instance, Maryland has a goal of 25% by 2020.[17] Given this high level of future penetration, it is easy to see how a flawed rule allowing aggregation of DERs beyond the single-node would cause major dispatch problems for the RTO. At 25% penetration with wide area aggregation, the RTO dispatch system would lose accurate transparency into the location of DERs and lose up to 25% of the value associated with its market signal, which is designed to create a security constrained dispatch of resources on a nodal basis. Aggregation across multiple nodes of any resources, including DERs, is antithetical to proper price formation. Multi-node aggregation also may work to undue the benefits of the various energy market price formation initiatives recently approved or underway at FERC, such as fast-start pricing in PJM.

b. Adequate Metering Is a Prerequisite for Participation in Wholesale Markets

As DERs can participate in both wholesale and retail markets, the need for appropriate metering on both the wholesale and retail side is essential to DERs

---

17 U.S. Energy Information Administration, *Maryland portfolio standard target to 25% by 2020*, March 24, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30492

integration. Without proper sub-metering of retail (consumption) and wholesale (sale for resale), any service-netting protocols become difficult if not impossible to distinguish, and there is insufficient transparency which undermines the fundamental principle of comparable treatment of competitive wholesale resources, as well as the operational concerns of modeling, dispatch, pricing, and settlement.

Traditional supply resources are required to invest in proper metering to participate in wholesale markets while protecting operations and preserving market signals; the same should be expected of DERs providers if they are to participate in wholesale markets in a manner comparable to conventional generation with comparable compliance obligations and price opportunities. While DERs proponents may contend that some metering investments may be redundant or expensive,[18] advanced metering is essential to wholesale market health, and system efficiency and reliability.[19] Proper metering also helps to ensure that resources are performing when called upon. If ISOs/RTOs do not have sufficient visibility into resources on its system because visibility is "netted away," it may inefficiently procure or dispatch certain resources, or dispatch some resources which it cannot demonstrate have performed as directed and needed by the system operator. The NYISO DERs Roadmap explains,

---

18 DERs technical conference transcript, pp 189-190, Mihir Desu-Manager, Strategen (on behalf of New Hampshire Office of the Consumer Advocate), "I just wanted to respond to one comment that Ted had made about, you know, increasing the amount of competition leading directly to reduce costs. I think, you know, there can be times where that's not the case especially with DER's when if you have large metering and telemetry requirements that especially those costs are borne on ratepayers, you might -- that might not be a sufficient condition because those metering and telemetry costs may, you know, out cost the value that the DER's are providing."

19 DERs technical conference transcript, p 32, Henry Yoshimura, Director of Demand Resource Strategy for ISO New England, "And there are a lot of requirements because those are reliability products. There are a lot of requirements around them. We need telemetry to know the state of the resources. We -- there's more technical requirements, communication -- electronic communication requirements which get somewhat expensive when you're talking about communicating with smaller resources."

> One of the key challenges to participation of DER in NYISO markets is accurately measuring and verifying resource performance in order to compensate resources appropriately. DER participating in the NYISO's Energy and Ancillary Services markets will require well-defined metering configurations as well as processes for calculating baseline load levels from which to measure performance….A policy for meter data and metering requirements will be critical to ensuring the integrity of the market. The ability for the NYISO to measure gross generation and gross native load at DER sites participating in NYISO markets will be necessary to ensure that the market is properly compensating DER for their contribution to system needs.[20]

Beyond market reasons for requiring adequate metering, reliability is jeopardized without visibility to DERs' gross output and gross load, and real-time changes to both. As a severe illustrative example of the reliability issue at stake, suppose that the RTO needs an accurate read in the afternoon winter peak from solar, but only has a net read of load consumption. The RTO would have at best a hazy idea of how much solar generation will become unavailable as the sun goes down over the next couple of hours. This would have reliability impacts, which would occur on a nodal basis.

By insisting upon adequate metering, ISOs/RTOs are able to see when resources perform and hold those that do not perform accountable – all of which ensures and enhances system reliability. Dr. Bowring, PJM's IMM, put this requirement simply,

> If this is going to work with the system and system operators are going to continue to have the ability to control the system, both the distribution levels that have been talked about at the transmission level, then we need to know where these resources are. We need to know what they are. We need to know what they're capable of doing. In fact we need to know what they are doing in real time.[21]

---

[20] NYISO DERs Roadmap, pp 29-30.
[21] DERs technical conference transcript, pp 38-39.

These principles and benefits also extend to system planning. Clyde Loutan, Principal, Renewable Energy Integration with California Independent System Operator ("CAISO"), provided a scenario that shows why planning data collection and the deployment of advanced metering need to be contemporaneously deployed:

> So we pretty much from a planning perspective know the amount of DER, where it's located, the capacity, the technology. Every year we send surveys out to all the load serving entities in California within the ISO's jurisdiction and we collect that data. We develop profiles, you know. Profiles in the sense of we try to develop minute by minute profiles for rooftop PV to determine the impact it has on system operations. We also do forecasts -- day ahead forecasts but we have a third-party provider that provides us with this forecast. We do make adjustments to the load. Just for clarification, when I said the load is pretty much all predictable today -- when you think about 5 years ago a load was pretty much temperature dependent. You know what the temperature is, you know what the load is. But with all the variations and things like you know, as I said in my response, electric vehicles -- everything else that's on the system it makes it a little more difficult. So whereas 5 years ago we know our trajectory with where the load was heading, no[w] you have a range which makes it a little challenging for the operators. So even though we know from our planning perspective what we have in terms of DER, our rooftop PV, from a real time perspective we have no telemetry and this is what makes it difficult.[22]

As Mr. Loutan outlined, even with fairly sophisticated planning data collection practices in place, the lack of telemetry potentially sets CAISO up for operational challenges as additional DERs come onto the system. Accordingly, real-time data provided by advanced metering would better allow ISOs/RTOs to plan and model system capabilities, providing further evidence that its deployment should be required in any Commission policy or regulations regarding DERs wholesale market participation.

Additionally, meters in place specifically for wholesale energy market transactions are essential to ensure comparable treatment of all resources participating in those markets and are vital to delineating the jurisdictional and functional divide

---

[22] DERs technical conference transcript, pp. 243-244.

between retail and wholesale markets. Paul Zummo, Director of Policy Research and Analysis for American Public Power Association, explained,

> If we're going to have entities that are kind of going back and forth between the retail and wholesale markets, I think it necessitates metering beyond even AMI or at least I think you need to go beyond AMI. You need to have communication channels at the AMI. The AMI itself will not be sufficient to sort of distinguish when an entity is acting or a resource is acting in a, you know, retail capacity or a wholesale capacity.[23]

Estimation, sampling, and other inexact methods do not provide the precision necessary for participation in complex, diverse, and expansive ISOs/RTOs. Strong guidance from the Commission and the insistence on advanced metering infrastructure will help to ensure that markets are protected and jurisdictional lines are clearly drawn.

c. Accountability is a Prerequisite for Participation in Wholesale Capacity Markets

By insisting upon adequate metering, ISOs/RTOs are able to see when resources perform and allows them to hold those that do not perform accountable in wholesale energy markets. The need for accountability carries over to centralized wholesale capacity markets, as well. These capacity markets do more than simply ensure resources are available to meet the peak load, they also procure critical call rights to resources that are required to be available and which can be committed when needed. This includes a requirement that they are available to meet daily load and address normal transmission constraints in addition to being available for transmission emergencies and resource adequacy emergencies (when there is not enough total generation to meet all load). Failure to perform during these transmission emergencies or resource adequacy emergencies results in capacity market penalties in PJM and

[23] DERs technical conference transcript, p 155.

elsewhere. This potential penalty ensures resources receiving a capacity market payment take appropriate steps to serve capacity needs during emergencies.

To maintain the resilience of the grid as the resource mix evolves, DERs must face similar capacity obligations and capacity market consequences as traditional resources to the extent that DERs participate in the capacity market. Recognizing that DERs are targeted to make extensive penetrations in many states and that each RTO capacity market is locational by delivery area, DERs will likely make up a sizeable portion of the capacity market resources even at a capacity factor in the 40% range, such as for solar DERs. DERs gross output must be measurable so that market rules can be developed to ensure that distributed resources face the same capacity market penalty rate as traditional resources that receive capacity revenues. Without this rule, ISOs/RTOs with competitive capacity markets could see those markets regress such that resource adequacy and resilience are severely reduced during emergencies or extreme weather events.

d. Tools are Necessary to Protect Against Double Counting or Payment

Another concern that is raised by the ability of DERs to participate in both retail and wholesale markets is the opportunity for services to be double counted or, in fact, receive double payments for the same service. As Commissioner Cheryl LaFleur stated ahead of the technical conference, "Since storage and other distributed resources are technically capable of providing many different services at both the wholesale and retail level, there needs to be a crisp understanding of who pays what to whom for what, which encompasses service definition, accounting, metering, and billing."[24] This

[24] Commissioner Cheryl A. LaFleur Statement, (February 15, 2018), available here: https://www.ferc.gov/media/statements-speeches/lafleur/2018/02-15-18-lafleur-E-1.asp#.WyLS2C7waUk.

concern over storage resources equally applies to DERs, which similarly can participate across jurisdictional divides, and emerged as a widely held concern at the Commission's technical conference.[25] Protecting against this possibility requires clear delineation between the jurisdictional markets, which yet again bodes for specific and detailed metering technology and data.

One method of dealing with this issue in a broad manner was offered by Arkansas Public Service Commission Chairman Ted Thomas, who represented the Organization of MISO States at the DERs technical conference. To address the potential for combining wholesale and retail compensation for the same service, Chairman Thomas proposed that FERC allow states to tell DERs providers to,

> [P]ick one or the other rather than trying to capture the value streams because that's where the double-counting risks and those risks exist that some states are in the process of tackling but others are not. That way you don't have unintended consequences -- it's not an opt-out such that we don't want any DERs to participate in wholesale… To capture all these different value streams is a complex question and let the states decide whether you can participate at the same time in retail and wholesale, have your wholesale the way it is under [FERC Order 841]. To me that -- that is a logical way to do it that protects the states from unintended consequences.[26]

At a minimum, resources should not be allowed to participate in the wholesale market where they are being paid in the retail market for the same MWs serving essentially the same service. For instance, a distributed resource should not be able to participate in a net-metering program at the retail level and get paid for the same MW

---

[25] DERs technical conference transcript:
- Ben D'Antonio, Counsel & Analyst, New England States Committee on Electricity p. 130;
- Christopher Norton, Director of Market Regulatory Affairs, American Municipal Power, p 132;
- FERC Commissioner Robert Powelson, p. 134;
- Marco Padula, Deputy Director, Market Structure, NYISO, p. 153;
- Michael DeSocio, Sr. Manager, Market Design, NYISO, p. 160;
- Simon Baker, Deputy Director, Energy Division, California Public Utility Commission, p. 186.

[26] DERS technical conference Transcript, p. 121.

output in the PJM energy market. Such allowance would undermine price formation in the wholesale market, severely compromising the price signals in the energy market. The compromised LMPs will markedly dilute the price signals given to non-intermittent generation, as well as flexible (dispatchable) generation, thereby reducing the response to market signals and hampering the reliable operation of the grid.

e. DERs Should Participate in Wholesale Markets on a Merchant Only Basis

As discussed above, increased data visibility and collaboration between ISOs/RTOs and utilities is necessary to allow each to efficiently plan and deploy DERs development. Certainly, the utility knows its own system best, and is the connection point for DERs, even those that will or can participate in wholesale markets. That noted, it must also be recognized that utilities are armed with advanced, sophisticated knowledge of their systems and needs. Therefore, to the extent possible under its jurisdiction, the Commission should not allow them to use this information to their advantage and to the detriment of their competitors in developing and owning DERs. Additionally, if this information is provided to all merchant developers on a non-discriminatory basis, there is no reason why DERs built by transmission and distribution utilities would offer any greater benefit than DERs built by private developers. If utilities are allowed to exploit their asymmetric access to information to the detriment of their competitors, even for the short term to speed the deployment of DERs, it will serve to chill merchant investment in this space, which may ultimately slow DERs deployment.

In this vein, the development of distributed resources pursuant to non-competitive State processes and procurement processes threaten to undermine wholesale competitive markets by creating or allowing a subsidized class of resources.

Particularly where Transmission & Distribution utilities may develop and own DERs, concerns over the exercise of vertical market power certainly exist. If not barred from participation in centralized wholesale capacity markets due to T&D level cost-of-service recovery or subsidization, then market power mitigation rules must be developed and in place to protect those markets against distributed resources developed and supported in a discriminatory manner, i.e. not through an open, non-discriminatory competitive procurement process.

III. Comments in Docket No. AD18-10-000

The increased penetration of DERs also presents significant planning and operational technical issues affecting potential reliability issues and likely benefits to the system, highlighted in a FERC staff white paper in a new administrative proceeding related to the instant DERs NOPR proceeding.[27] In that paper, FERC staff identities that, "increasing DERs capacity, if not properly accounted for, could cause reliability concerns for the bulk power system. Further industry discussion is needed to improve and refine the data that is available for DERs that will be incorporated into planning and operating models. Collecting and using the most current and accurate data is key to getting a complete picture of how DERs affect the bulk power system."[28] A concern here is that, in addition to challenging the economics of traditional resources, absent adequate metering and data visibility, ISOs/RTOs may not be able to efficiently procure or dispatch DERs on the system. As the U.S. Department of Energy's Grid

---

[27] FERC Staff Report, *Distributed Energy Resources: Technical Considerations for the Bulk Power System*, (February 2018), ("Staff White Paper"), Docket No. AD18-10-000, available here: http://www.ferc.gov/CalendarFiles/20180215112833-der-report.pdf

[28] Staff White Paper, pp 3-4.

Modernization Laboratory Consortium provides, DERs amounts and locations must be known for reliable and efficient grid operations.[29]

PJM offers an example of why better data, visibility and coordination are essential, as noted in the Staff White Paper. In its *Technical Analysis of Operational Events and Market Impacts During the September 2013 Heat Wave*, PJM explained that it was able to avoid a blackout of the city of Sturgis, MI, due to the discovery of a 6-MW generator within the city limits. However, neither PJM nor the local transmission provider (AEP) had the Sturgis generator specifically modeled in their respective energy management systems.[30] While this was a fortunate discovery in that instance, PJM ultimately concluded they needed to establish and document their approach going forward while working with states and transmission owners to collect information about behind-the-meter generation. Additionally, PJM resolved to work with transmission owners and the states to review existing modeling and telemetry, based on the issues experienced.[31]

This example highlights the need for strong coordination between ISOs/RTOs, states, transmission owners, and other affected stakeholders in ensuring reliable and efficient delivery of power with increased DERs participation. EPSA urges FERC to encourage the strongest level of coordination possible and insist upon metering equipment, data, and visibility practices that facilitate efficiency and transparency.

---

[29] *Impacts of DER on Transmission Systems,* John J. Miller, P.E., Randy Berry, U.S. Department of Energy Grid Modernization Laboratory Consortium, (January 12, 2018), available here: https://eta.lbl.gov/sites/default/files/publications/13._berry_and_miller_impacts_of_ders_on_transmission.pdf

[30] *Technical Analysis of Operational Events and Market Impacts During the September 2013 Heat Wave,* pp. 22-23. Available here: http://www.pjm.com/~/media/library/reports-notices/weather-related/20131223-technical-analysis-of-operational-events-and-market-impacts-during-the-september-2013-heat-wave.ashx

[31] Id. at pp. 23-24.

Additional coordination and data visibility can also assist ISOs/RTOs with forecasting and mitigating the effects of the variable nature of many DERs. For example, a fast-moving storm could bring clouds that quickly blunt the impact of a solar installation in the storm's path. If the ISO/RTO is aware of this installation and has adequate visibility into its performance, not just its nameplate capacity, it can adjust its procurement of other resources accordingly to assure that reliability is maintained.

As the BPS has evolved, traditional generation resources with operational flexibility are increasingly required as the primary support of system operations due to the changing generation resource mix. Conversely, while the BPS continues to demand this service in greater quantities, DERs cannot provide frequency response in the same way that traditional resources can. Failure to account for the lack of these attributes could greatly impact system planning and reliability. As NERC points out in its Distributed Energy Resources Task Force Report,

> [T]he effect of aggregated DER is not fully represented in BPS models and operating tools. This could result in unanticipated power flows and increased demand forecast errors. An unexpected loss of aggregated DER could also cause frequency and voltage instability at sufficient DER penetrations. Variable output from DER can contribute to ramping and system balancing challenges for system operators whom typically do not have control or observability of the DER within the BPS.[32]

[32] North American Electric Reliability Corporation, *Distributed Energy Resources Connection Modeling and Reliability Considerations*, at p. vi., (February 2017), available here: https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

IV. Conclusion

EPSA appreciates the opportunity to comment on these issues and urges the Commission to hold DERs to the same standards of metering, transparency and performance as traditional resources, thereby enabling comparable compensation for resources that participate in the maintenance of a reliable and resilient grid. Any new regulatory framework should be resource-neutral, which will protect markets while helping to ensure the reliability and efficiency of the BPS.

Respectfully submitted,

/s/

Nancy Bagot, Senior Vice President
Bill Zuretti, Director of Regulatory Affairs and Counsel
Electric Power Supply Association
1401 New York Avenue, NW, Suite 950
Washington, DC 20005

June 26, 2018

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the comments via email upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., June 26, 2018.

/s/

____

Bill Zuretti, Director, Regulatory Affairs, and Counsel