Distributed Energy Resources Technical Conference

Docket Nos. RM18-9-000 and AD18-10-000
April 10, 2018 and April 11, 2018

Agenda

The purpose of this technical conference is to gather additional information to help the Commission determine what action to take on the distributed energy resource (DER) aggregation reforms proposed in the Commission's Notice of Proposed Rulemaking on Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators (NOPR), and to explore issues related to the potential effects of DERs on the bulk power system. Panels 1 and 3 on the first day focus on specific NOPR proposals that relate to DER participation and compensation. Panel 2 will provide a forum for Commissioners to discuss DER aggregation with a panel of state and local regulators. During the second day of the technical conference, operational issues associated with DER data, modeling, and coordination will be examined. In the interest of time, panelists will not be expected to provide opening statements; instead the panels will proceed directly to a question and answer format.

Tuesday, April 10, 2018

10:15am – 10:30am **Welcoming Remarks**

10:30am – 12:00pm **Panel 1: Economic Dispatch, Pricing, and Settlement of DER Aggregations**

The objective of this panel is to discuss the integration of DER aggregations into the modeling, clearing, dispatch, and settlement mechanisms of RTOs and ISOs as considered in the NOPR. The NOPR 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.[1] The NOPR also addressed the use of distribution factors[2] and bidding parameters[3] for DER aggregations. In consideration of comments received in response to the NOPR, staff seeks additional information about how DER aggregations could locate across more than one pricing node. Staff 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.

Panelists should be prepared to discuss the following topics and questions:

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?
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?
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?
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?
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

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[1] NOPR, FERC Stats. & Regs. ¶ 32,718 at P 139.

[2] 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*. P 143.

[3] 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*. P 144.

at which it is located. What are the advantages and disadvantages of this approach? Are there other approaches that should be considered?

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?

Panelists:

- Jeff Bladen, Executive Director, Market Services, Midcontinent Independent System Operator, Inc.
- Joseph Bowring, President, Monitoring Analytics, Independent Market Monitor for PJM Interconnection, L.L.C.
- Michael DeSocio, Sr. Manager, Market Design, New York Independent System Operator, Inc.
- John Goodin, Manager, Infrastructure and Regulatory Policy, California Independent System Operator
- Andrew Levitt, Senior Market Strategist, PJM Interconnection, L.L.C.
- Henry Yoshimura, Director, Demand Resource Strategy, ISO New England, Inc.

12:00pm – 1:30pm Lunch

1:30pm – 3:00pm Panel 2: Discussion of Operational Implications of DER Aggregation with State and Local Regulators

This panel will provide a forum for Commissioners to discuss the NOPR's DER aggregation proposals with state and local regulators. The discussion will provide an opportunity for state and local regulators to provide their perspectives and concerns about the operational effects that DER participation in the wholesale market could have on facilities they regulate. In particular, Commissioners expect to explore the following questions:

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?

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?
3. What entities should be included in the coordination processes used to facilitate the participation of DER aggregations in Regional Transmission Organization (RTO) and Independent System Operator (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?
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?
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?

Panelists:

- Ben D'Antonio, Counsel & Analyst, New England States Committee on Electricity
- Asim Haque, Chairman, Public Utilities Commission of Ohio
- Tammy Mitchell, Deputy Director, Electricity, New York State Department of Public Service
- Christopher Norton, Director of Market Regulatory Affairs, American Municipal Power
- Willie Phillips, Commissioner, DC Public Service Commission
- Michael Picker, President, California Public Utilities Commission
- Andrew Place, Vice Chairman, Pennsylvania Public Utility Commission

- Ted Thomas, Chairman, Arkansas Public Service Commission; President, Organization of MISO States

3:00pm – 3:15pm **Break**

3:15pm – 4:45pm **Panel 3: Participation of DERs in RTO/ISO Markets**

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.[4] This panel will explore 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.

Panelists should be prepared to discuss the following topics and questions:

1. Given the variety of wholesale and retail services, is it possible to universally characterize a set of wholesale and retail services as the "same service"? If so, how could the Commission prohibit a DER from providing the same service to the wholesale market as it provides in a retail compensation program?
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."[5] 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?

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[4] *Id*. P 134.

[5] *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).

3. What other options besides the NOPR's proposed limits on dual participation exist to address issues associated with the participation of DERs or DER aggregations in one or more retail compensation programs or another wholesale market participation program at the same time as it participates in a wholesale DER aggregation? Is there a way to coordinate DER participation in multiple markets or compensation programs? Is a possible solution having a targeted prohibition, such as the limitation placed on net-metered resources in CAISO?[6] Are there other means?

Panelists:

- Simon Baker, Deputy Director, Energy Division, California Public Utility Commission
- Michael DeSocio, Sr. Manager, Market Design, New York Independent System Operator, Inc.
- Mihir Desu, Manager, Strategen (on behalf of New Hampshire Office of the Consumer Advocate)
- Katie Guerry, Vice President, Regulatory Affairs, EnerNOC, an Enel X Group Company
- Ted Ko, Director of Policy, Stem
- Roy Kuga, Vice President, Grid Integration and Innovation, Pacific Gas and Electric Company
- Marco Padula, Deputy Director, Market Structure, New York State Department of Public Service
- Paul Zummo, Director, Policy Research and Analysis, American Public Power Association

Wednesday, April 11, 2018

9:00am – 10:30am **Panel 4: Collection and Availability of Data on DER Installations**

To plan and operate the bulk power system, it is important for transmission planners, transmission operators, and distribution utilities to collect and share validated data across the transmission-distribution interface. In September 2017, the North American Electric Reliability Corporation (NERC) published a Reliability Guideline on DER modeling (Guideline) that specified the minimum DER information needed by transmission planners and planning coordinators to assist in modeling and conducting

[6] *See* CAISO Tariff, § 4.17.3(d).

assessments.[7] The Guideline references the importance of static data (such as the capacity, technical capabilities, and location of a DER installation) for the entities involved in the planning of the bulk power system. This panel will focus on understanding the need for bulk power system planners and operators to have access to accurate data to plan and operate the bulk power system, explore the types of data that are needed, and assess the current state of DER data collection. The panel will also address regional DER penetration levels and any potential effects of inaccurate long-term DER forecasting. The Commission Staff DER Technical Report, issued on February 15, 2018, provides a common foundation for the topics raised in this panel.

Panelists should be prepared to discuss the following topics and questions:

1. What type of information do bulk power system planners and operators need regarding DER installations within their footprint to plan and operate the bulk power system? Would it be sufficient for distribution utilities to provide aggregate information about the penetration of DERs below certain points on the transmission-distribution interface? If greater granularity is needed, what level of detail would be sufficient? Is validation of the submitted data possible using data available?
2. What, if any, data on DER installations is currently collected, and by whom is it collected? Do procedures and appropriate agreements exist to share this data with affected bulk power system entities (i.e., those entities responsible for the reliable operation of the bulk power system or for modeling and planning for a reliable bulk power system)? Is there variation by entity or region?
3. At various DER penetration levels, what planning and operations impacts do you observe? Do balancing authorities with significant growth in DERs experience the need to address bulk power system reliability and operational considerations at certain DER penetration levels? What are they? Is the MW level of DER penetration the most important factor in whether DERs cause planning and operational impacts, or do certain characteristics of installed DERs affect the system operator's analysis? Is there a threshold that could trigger a need for distribution utilities to share information on DERs with the bulk power system operator, such as the point at which DER penetration causes bulk power system reliability and operational impacts, or some other, lower, level of penetration? How could the answer to these questions vary on a regional basis, and what factors may contribute to this variance?

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[7] *See* NERC Distributed Energy Resource Modeling Reliability Guideline, at 5 (Sept. 2017), available at http://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf.

4. How are long-term projections for DER penetrations developed? Are these projections currently included in related forecasting efforts? Do system operators study the potential effects of future DER growth to assess changing infrastructure and planning needs at different penetration levels?
5. What are the effects on the bulk power system if long-term forecasts of DER growth are inaccurate? Are these effects within current planning horizons? Are changes in the expected growth of DERs incorporated into ongoing planning efforts? Can these uncertainties be treated similarly to other uncertainties in the planning process?
6. How are DERs incorporated into production cost modeling studies? Do current tools allow for assessment of forecasting variations and their effects?
7. Noting that participation in the RTO/ISO markets by DER aggregators may provide more information to the RTOs/ISOs about DERs than would otherwise be available, should any specific information about DER aggregations or the individual DERs in them be required from aggregators to ensure proper planning and operation of the bulk power system?
8. Do the RTOs/ISOs need any directly metered data about the operations of DER aggregations to ensure proper planning and operation of the bulk power system?

Panelists:

- Larry Bekkedahl, Vice President, Transmission and Distribution, Portland General Electric
- Donald Bielak, Manager, Reliability Engineering, PJM Interconnection, L.L.C.
- Jens Boemer, Principal Technical Leader, Transmission Operations and Planning Group, Electric Power Research Institute
- Marcus Hawkins, Director, Member Services and Advocacy, Organization of MISO States
- Clyde Loutan, Principal, Renewable Energy Integration, California Independent System Operator
- Jacob Tetlow, Vice President of Transmission and Distribution Operations, Arizona Public Service
- Ganesh Velummylum, Senior Manager, System Analysis, NERC
- Tam Wagner, Senior Manager, Regulatory Affairs, Independent Electricity System Operator (Ontario)

10:30am – 10:40am Break

10:40am – 12:10pm Panel 5: Incorporating DERs in Modeling, Planning and Operations Studies

Bulk power system planners and operators must select methods to feasibly model DERs at the bulk power system level with sufficient granularity to ensure accurate results. The chosen methodology for grouping DERs at the bulk power system level could affect planners' ability to predict system behavior following events, or to identify a need for different operating procedures under changing system conditions. Further, the operation of DERs can affect both bulk power systems and distribution facilities in unintended ways, suggesting that new tools to model the transmission and distribution interface may be needed. Staff is also aware of ongoing work in this area, for example efforts at NERC, national labs and other groups, to evaluate options for studies in these areas, which could also inform future work. This panel will focus on the incorporation of DERs into different types of planning and operational studies, including options for modeling DERs and the methodology for the inclusion of DERs in larger regional models. The Commission Staff DER Technical Report, issued on February 15, 2018, provides a common foundation for the topics raised in this panel.

Panelists should be prepared to discuss the following topics and questions:

1. What are current and best practices for modeling DERs in different types of planning, operations, and production cost studies? Are options available for modeling the interactions between the transmission and distribution systems?
2. To what extent are capabilities and performance of DERs currently modeled? Do current modeling tools provide features needed to model these capabilities?
3. What methods, such as net load, composite load models, detailed models or others, are currently used in power flow and dynamic models to represent groups of DERs at the bulk power system level? Would more detailed models of DERs at the bulk power system level provide better visibility and enable more accurate assessment of their impacts on system conditions? Does the appropriate method for grouping DERs vary by penetration level?
4. Do current contingency studies include the outage of DER facilities, and if they are considered, how is the contingency size chosen? At what penetration levels or under what system conditions could including DER outages be beneficial? Are DERs accounted for in calculations for Under Frequency Load Shedding and related studies?
5. What methods are used to calculate capacity needed for balancing supply and demand with large amount of solar DER (ramping and frequency control) and determining which resources can provide an appropriate response?

Panelists:

- Shay Bahramirad, Director of Distribution System Planning, Smart Grid and Innovation, Commonwealth Edison Company
- Jens Boemer, Principal Technical Leader, Transmission Operations and Planning Group, Electric Power Research Institute
- Ning Kang, Staff Scientist, Argonne National Laboratory
- Dennis Kramer, Sr. Director, Transmission Policy, Stakeholder Relations and Business Development, Ameren Services Company
- Marija Prica, Assistant Professor, Case Western University
- Binaya Shrestha, Regional Transmission Engineer, California Independent System Operator
- Ganesh Velummylum, Senior Manager, System Analysis, NERC
- Brant Werts, Lead Engineer, DER Technical Standards, Duke Energy Corporation

12:10pm – 1:30pm **Lunch**

1:30pm – 3:00pm **Panel 6: Coordination of DER Aggregations Participating in RTO/ISO Markets**

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. This panel will examine 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

[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.*,

coordinating the integration of DER aggregations, this panel will also examine the potential architectural designs for the initial coordination processes from the point of view of the RTO/ISO markets.

Panelists should be prepared to discuss the following topics and questions:

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?
2. Are new processes and protocols needed to ensure coordination among DER aggregators, distribution utilities, and RTOs/ISOs during registration of a new DER aggregations? How can the Commission ensure that any new processes and protocols occur in a way that provides adequate transparency to the interested parties and also occurs on a timely basis?
3. 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?
4. What is the best approach for involving retail regulatory authorities in the registration of DER aggregations in the RTO/ISO markets?
5. What types of grid architecture could support the integration of DER aggregations into the RTO/ISO markets? Knowing that a variety of grid architectures are being explored in various regions, does it make sense for the Commission to consider specific architectural requirements for RTOs/ISOs for the effective integration and coordination of DER aggregations?

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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.

Panelists

- David Crews, Senior Vice President, Power Supply, East Kentucky Power Cooperative
- Mark Esguerra, Director, Integrated Grid Planning, Pacific Gas and Electric Company
- Daniel Hall, Chairman, Missouri Public Service Commission and Vice-President, Organization of MISO States
- Peter Langbein, Manager, Demand Response Operations, PJM Interconnection, L.L.C
- Audrey Lee, Vice President, Energy Services, Sunrun, Inc.
- David K. Owens, Retired Executive Vice President, Edison Electric Institute
- Maria Robinson, Director of Wholesale Markets, Advanced Energy Economy
- Jeff Taft, Chief Architect, Pacific Northwest National Laboratory

3:00pm – 3:15pm Break

3:15pm – 4:45pm Panel 7: Ongoing Operational Coordination

This panel will focus primarily on the operational considerations associated with both individual DERs and DER aggregations and with the interactions and communications between DERs, DER aggregators, distribution utilities, and transmission operators. 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.

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

Panelists should be prepared to discuss the following topics and questions:

1. What real-time data acquisition and communication technologies are currently in use to provide bulk power system operators with visibility into the distribution system? Are they adequate to convey the information necessary for transmission and distribution operators to assess distribution system conditions in real time? Are new systems or approaches needed? Does DER aggregation require separate or additional capabilities and infrastructure for communication and control?
2. What processes/protocols do distribution utilities, transmission operators, and DERs or DER aggregators use to coordinate with each other? Are these processes/protocols capable of providing needed real-time communications and coordination? What new processes, resources, and efforts will be required to achieve effective real-time coordination?
3. What are the minimum set of specific RTO/ISO operational protocols, performance standards, and market rules that should be adopted now to ensure operational coordination for DER aggregation participating in the RTO/ISO markets? What additional protocols may be important for the future? Should the Commission adopt more prescriptive requirements with respect to coordination than those proposed in the NOPR? If so, what should the Commission require?
4. 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?
5. Is it possible for DERs or DER aggregations participating in the RTO/ISO markets to also be used to improve distribution system operations and reliability? If so, please provide examples of how this could be accomplished.
6. Can real-time dispatch of aggregated DERs address distribution constraints? If not, can tools be developed to accomplish this?
7. Should individual DERs be required to have communications capabilities to comply with control center obligations? What level of communications security should be employed for these communications?
8. How might recent and expected technical advancements be used to enhance the coordination of DER aggregations, for example, integrating Energy Management Systems (EMS) and Distribution Management Systems (DMS) for efficient operational coordination?

Panelists:

- Joseph Ciabattoni, Manager, Markets Coordination, PJM Interconnection, L.L.C.
- Matthew Glasser, Director, Consolidated Edison Company of New York
- Gerald Gray, Program Manager, Information and Communication Technology, Electric Power Research Institute
- Ali Ipakchi, Executive Vice President, Smart Grid and Green Power, Open Access Technology International, Inc.
- Lorenzo Kristov, Independent Consultant
- Brandon Middaugh, Senior Program Manager for Distributed Energy, Microsoft
- Doug Parker, Director, DSO Implementation, Integrated Innovation and Modernization, Southern California Edison Company
- Martin Ryan, Director, Real Time Operations, NRG Energy, Inc.

4:45pm – 5:00pm **Closing Remarks**