UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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| 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 TRANSMISSION ACCESS POLICY STUDY GROUP**

The Transmission Access Policy Study Group ("TAPS") appreciates the opportunity to respond to the Commission's April 27, 2018 Notice Inviting Post-Technical Conference Comments regarding the participation of distributed energy resources ("DER") aggregations in Regional Transmission Organization and Independent System Operator ("RTO") markets.[1] As TAPS has previously stated, we see the potential value that DER participation in RTO markets can provide to customers and support the Commission's desire to eliminate unnecessary barriers to such participation. As the operators of distribution systems, however, TAPS members (or, in the case of TAPS members who are municipal joint action agencies ("JAAs"), their distribution utility members) are also aware of the challenges presented by DER participation in wholesale markets, particularly for small distribution utilities. These challenges, described in

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[1] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Notice Inviting Post-Technical Conference Comments (Apr. 27, 2018), eLibrary No. 20180427-3016 ("Notice"). The technical conference was held April 10-11, 2018. Transcript of Technical Conference, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket Nos. RM18-9-000, AD18-10-000 (Apr. 10, 2018), eLibrary No. 20180502-4007 ("Tr. Vol. 1"); Transcript of Technical Conference, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket Nos. RM18-9-000, AD18-10-000 (Apr. 11, 2018), eLibrary No. 20180502-4008 ("Tr. Vol. 2").

Part I.B below, depend on individual circumstances, as well the particular DERs and distribution utilities in question, and thus do not lend themselves to one-size-fits-all solutions. To ensure that participation of DER aggregations in RTO markets would not adversely affect the distribution system, distribution utilities would need to, among other things, develop real-time metering and 24/7 monitoring capabilities, more complicated modeling, new systems for communications with RTOs, and complex settlement arrangements. They might also be required to comply with very substantial new North American Electric Reliability Corporation ("NERC") obligations.

Drawing from TAPS members' experiences with DERs, TAPS offers these comments to provide a real-world perspective on the ways in which the dispatch and operation of DER aggregations can adversely affect distribution systems and to provide recommendations for how the Commission could remove unnecessary barriers to DER participation in RTO markets while minimizing adverse distribution system impacts and respecting jurisdictional boundaries. TAPS requests that any final rule:

- Recognize that regions, states, and distribution utilities are at different stages in terms of DER penetration, and accommodate the flexibility needed to develop systems that make sense in distinct contexts (*see* Parts I.A and I.B);

- Establish mechanisms to defer decisions to those with the best understanding of the relevant distribution systems, including an "opt-in/opt-out" mechanism modeled on Order No. 719-A or, at minimum, an express opt-in requirement for small distribution utilities (*see* Part I.C);

- Confirm that the Commission is not seeking to disturb the existing authority of relevant electric retail regulatory authorities ("RERRA") to set rates to recover and allocate costs, and that the Commission is not seeking to exempt DERs from the obligation to adhere to applicable distribution utility tariffs and RERRA requirements regarding delivery service over distribution systems (*see* Part I.D);

- Direct RTOs to work with distribution utilities to develop settlement processes for DER aggregations that avoid imposing undue burdens and costs on those distribution utilities with DERs in their footprint that participate in wholesale markets (*see* Part I.E);

- Confirm that RERRAs can require, as a condition of eligibility to participate in a retail compensation program, that the DERs enrolled in such a program cannot also participate in wholesale DER aggregations (*see* Part II);

- Provide for binding distribution utility review and approval of individual DERs seeking to enroll in wholesale DER aggregations (*see* Part III); and

- Ensure the ability of distribution utilities to protect local reliability by allowing them to override DER dispatch instructions, or require disconnection of DERs included in aggregations, without financial disincentives (*see* Part IV).

## INTEREST OF TAPS

TAPS is an association of transmission-dependent utilities in more than 35 states, promoting open and non-discriminatory transmission access.[2] Representing load-serving entities ("LSEs") entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS has supported the Commission's initiative to form truly independent RTOs to provide non-discriminatory transmission access and foster robust competition, to enable them to meet their load reliably and affordably. Thus, TAPS supports the development and implementation of new and advanced technologies, including DERs, that will increase reliability and access to more economic power supplies, provided that those technologies reduce cost to the ultimate ratepayer. Because TAPS members (or the distribution utilities that are members of TAPS members) operate distribution systems, they are directly affected by the development of DERs and the Commission's examination of the participation of DER aggregations in RTO markets.

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## I. POST-TECHNICAL CONFERENCE QUESTIONS REGARDING DISCUSSION OF OPERATIONAL IMPLICATIONS OF DER AGGREGATION WITH STATE AND LOCAL REGULATORS (PANEL 2)

### *A. Any Final Rule Should Provide the Flexibility to Accommodate Regional Variation and Innovation*

TAPS members and the distribution utilities they serve have firsthand experience with DERs. Some are preparing their distribution systems for increased prevalence of DERs;[3] some are developing their own distributed generation and storage;[4] and some are

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[3] Wholesale supplier AMP prepares utilities for possible boom in distributed resources, Jeannine Anderson, *Wholesale Supplier AMP Prepares Utilities for Possible Boom in Distributed Resources*, Public Power Daily (Jan. 27, 2017), https://www.publicpower.org/periodical/article/wholesale-supplier-amp-prepares-utilities-possible-boom-distributed-resources.

[4] For example, TAPS member Missouri River Energy Services ("MRES") has installed a 1 MW solar project in its member Pierre, South Dakota; and TAPS member WPPI Energy buys the output of a distribution-connected biogas generation facility located in its member community Richland Center. In addition, several distribution utility members of MRES and WPPI Energy have either already developed or are considering community solar projects connected at the distribution level.

TAPS member City Utilities of Springfield, MO, in partnership with NorthStar Battery, has put in service a battery storage system that will provide an additional 1 MWh of electric energy to its distribution grid, earning it a spot in the Smart Electric Power Alliance's Top 10 ranking of Utility Energy Storage Rankings for Annual Watts-Per-Customer. Paul Ciampoli, *City Utilities of Springfield, MO., Dedicates Energy Storage Project*, Public Power Daily (Nov. 3, 2017), https://www.publicpower.org/periodical/article/city-utilities-springfield-mo-dedicates-energy-storage-project; *2018 Top 10 Winners*, Smart Electric Power Alliance (last visited June 25, 2018), https://sepapower.org/2018-top-10-winners/.

attempting to accommodate retail customer-owned DERs.[5] TAPS supports the Commission's effort to think proactively about the challenges of DER aggregation.

Regions, states, and distribution utilities, however, are at very different stages with respect to DER penetration;[6] and the April 10-11, 2018 technical conference made clear that there is no single set of "best practices" that can be identified and implemented nationwide.[7] DER technologies are still evolving. Even the RTOs most committed to

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[5] For example, a large retail customer of the City of Naperville, a distribution utility member of TAPS member Illinois Municipal Electric Agency, is installing a 250 kW battery/600 kW solar facility. Naperville has worked with the customer to authorize load reductions from use of the device to be bid as demand response into PJM's frequency response market.

[6] Tr. Vol. 1, 104:7-8 (Haque) ("the state of Ohio has very low DER penetration."); *id.* at 133:3-9 (Norton) (noting that "small local communities . . .you're not seeing any [DERs] and then you have other communities, especially around some of the colleges where you see lots of [DER] penetration."); Tr. Vol. 2, 220:7-11 (Tetlow) (Arizona Public Service Company has about 80,000 residential customers with rooftop solar panels, representing about a 7% residential penetration rate); *id.* at 233:1-4 (Hawkins) (the lower level of DER penetration in Midcontinent Independent System Operator compared to California); *id.* at 236:24-25 (Bielak) ("California [Independent System Operator ('CAISO')] has a much larger penetration of DER than PJM."); *id.* at 318:21-319:2 (Bahramirad) (the "low penetration of the distributed energy resources" on the Commonwealth Edison Company system); *id.* at 367:1-3 (Crews) ("California has a much higher [DER] penetration than say, Kentucky").

[7] *See, e.g.*, Tr. Vol. 1, 141:6-144:1 (Picker):

> … [A]t this point we have a range of technologies that haven't been experienced, being used in ways that people didn't anticipate and providing values that are very hard to predict. And we're just trying to make sure that it works.
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> So if in fact, what the intent is of the Commission is to actually remove barriers for people to approach that, God bless you. . . . I do think that it's going to be hard to come up with that magic one size fits all.
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> Someday the grid, at least in portions of California, will be plug and play. You can walk in, plug in your DER, it will be recognized. Whatever algorithms you're using to actually sell services to customers or to the [Independent System Operator ('ISO')] or to the utilities will be recognized and managed and then settled just in the way that people manage to do this and the [Market Redesign and Technology Upgrade] and the wholesale markets.
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> We have a long ways to go and if you want to jump in and help us that's great, but I would recommend that you let us beat our head against those brick walls.

*See also id.* at 43:2-4 (Yoshimura) ("[T]here really isn't consensus in the industry as to how distributed energy resources ought to be operated if at all."); *id.* at 47:7-11 (Bladen) ("I think where we are right now is we don't know yet what best practices are going to look like. We don't know yet what the dominant DER technologies are going to be and that what you have in front of you is a number of companies that are invested in identifying best practices."); *id.* at 130:25-131:5 (Mitchell) "[W]e recognize that desire [for uniformity], you know, for simplicity, to avoid seams in the future. However, I think you've heard today that there are existing regional differences. There are also differences in where we are in the development fostering third-party aggregators for non-demand response DERs have had little experience with them in the energy and ancillary services markets.[8] It is also still unclear which wholesale products DER aggregators can, and are likely to, compete to provide.[9]

In attempting to eliminate unnecessary barriers to DERs, the Commission must be careful to avoid inadvertently creating costly and premature rigidity. RTOs and state and local regulators need time and flexibility to develop systems that make sense for their regions, recognizing that regions are in different stages and have different degrees of vertical integration. And especially in regions that currently have few DERs, RTOs and their stakeholders should be given the opportunity to learn from the experience of other regions, rather than forced to lock into costly regulatory structures that could quickly become obsolete as technologies, RTO markets, and retail regulation change. To be reasonable and serve the intended purpose of reducing unnecessary barriers to DERs, flexibility and accommodation of regional variation must be a key feature of any final rule.

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of the framework for the integration [of] DER resources."); Tr. Vol. 2, 283:10-13 (Bahramirad) ("As far as I know there is not an industry recognized best practices for [modeling DERs] so far and currently there is no DER model for interaction between distribution and transmission.").

[8] In California, there are seven "DER providers"; but TAPS is not aware of any that have begun operating in the energy or ancillary services markets. *Distributed Energy Resource Provider Market Participants*, California ISO, http://www.caiso.com/Documents/ListofDistributedEnergyResourceProviderMarketParticipants.pdf; Tr. Vol. 1, 69:1-14 (Goodin) ("[CAISO] established the DER aggregation model back in 2016. We have five contracts signed under our distributing energy resource provider agreement and yet we have no participation.").

[9] Tr. Vol. 1, 31:21-32:22 (Yoshimura) (DER providers may have little interest in participating in ancillary service markets, which represent only a small share of total market revenue and which have rigorous technical requirements for participation).

### *B. The Dispatch and Operation of DER Aggregations Can Adversely Affect Distribution System Reliability and Operations*

1. At the Distribution Level, DERs Are Not "Plug-and-Play"

While the Commission seeks to identify simple DER penetration thresholds below which DER installation and operations will pose no bulk power system problems,[10] the experience of TAPS members is that at the distribution level, DERs present complicated issues that do not lend themselves to a cookie-cutter approach. As the Commission correctly recognizes, most distribution systems are designed and operated for unidirectional flow, not bi-directional flows.[11] On such systems, power on distribution feeders is assumed to always flow away from the substation. Voltage is set at the substation; it decreases with distance from the substation; and voltage regulation equipment is installed along distribution feeders to boost the voltage level when it drops too low.

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[10] *See, e.g.*, Notice Inviting Post-Technical Conference Comments 2, *Distributed Energy – Technical Considerations for the Bulk Power System*, Docket No. AD18-10-000 (Apr. 27, 2018), eLibrary No. 20180427-3017.

[11] For instance, in Order No. 888, the Commission established seven factors for identifying local distribution facilities, which include "[l]ocal distribution facilities are primarily radial in character" and "[p]ower flows into local distribution systems; it rarely, if ever, flows out." *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,539 at 21,620 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 at 31,771 (1996), *clarified*, 76 FERC ¶ 61,009 (1996), *modified*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64,688 (Dec. 9, 1997), 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002). In Order No. 2006, the Commission explained that although "'[d]istribution' is a vague term, [it is] usually used to refer to non-networked, often lower-voltage facilities, that carry power in one direction." *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, 70 Fed. Reg. 34,190 at 34,191 (June 13, 2005), FERC Stats. & Regs. ¶ 31,180, P 6 (2005), *order on reh'g*, Order No. 2006-A, 70 Fed. Reg. 71,760 (Nov. 30, 2005), FERC Stats. & Regs. ¶ 31,196 (2005), *clarified*, Order No. 2006-B, 71 Fed. Reg. 42,587 (July 27, 2006), FERC Stats. & Regs. ¶ 31,221 (2006), *corrected*, 71 Fed. Reg. 53,965 (Sept. 13, 2006). *See also* Tr. Vol. 2, 375:12-14 (Owens) ("for the most part [a distribution system is] a radial network.").

If, instead, there are multiple sources of generation along the length of a feeder and power flows in the opposite direction, the distribution utility loses some control over voltage in localized areas, which can compromise power quality, overload utility equipment, and cause outages. In addition, distributed storage resources can damage distribution systems even without reversing power flows by drawing power at system peak, increasing loads beyond the design limits of feeders and other utility equipment.

The distribution system modifications necessary to accommodate DERs depend on a variety of technical factors, including the length of the feeder where the DER is located, the DER's specific location along the feeder, and the size and location of other loads and resources. To simplify interconnection and minimize potential impacts on circuits used to serve retail customers, many distribution utilities that have installed their own distributed resources have chosen to connect them directly to substations. However, for location-constrained resources—e.g., landfill gas—that is not always physically possible. In addition, the experience of TAPS members is that third-parties seeking to construct standalone DERs may seek out the cheapest land, which often corresponds to locations far from substations and where the distribution system is at its weakest.

Interconnecting and operating DERs on feeders that also serve retail load pose a greater challenge for distribution utilities. Rapidly fluctuating DER output, for example, can challenge the ability of load tap changers to maintain power quality and minimize voltage deviations. And as one TAPS member experienced, when such DERs inject electricity into the load side of a lightly loaded feeder, voltage regulators configured for standard, unidirectional flows may respond by further boosting the already higher load-side voltage, creating a feedback loop that can increase voltage on that segment of the feeder to levels that damage retail customer equipment.

Distribution utilities with DERs on their systems have thus far been able to address these issues by making upgrades, reconfiguring distribution circuits, changing the settings on programmable voltage control equipment, and replacing voltage control equipment that cannot be adequately reprogrammed. For DERs that have the capability to inject significant amounts of electricity into the distribution system and for utility-scale distributed storage resources, host distribution utilities have also required the installation of generation breakers that enable DER operations to be interrupted when they threaten the distribution system.[12] These are bespoke arrangements, however, and will become increasingly complex if the number and size of DERs increases and DER owners seek greater operational flexibility. Moreover, a DER's decision to participate in an RTO market may pose additional operational challenges to the distribution system, even where the DER in question had complied with local interconnection procedures when it was first developed. For example, a member of TAPS member Illinois Municipal Electric Association had an existing distribution-connected generator that had not been participating in the PJM markets. When the distribution utility attempted to configure the generator to sell energy into the PJM markets, however, it discovered that significant distribution system upgrades would be needed to provide the required firm delivery path from the generator to the RTO.

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[12] For example, the Power and Light Department of the City of Independence, Missouri, purchases the output of a community solar facility connected to its distribution system. The Power Purchase Agreement for the facility includes a provision that gives the City the right to immediately disconnect and lock-out the facility from Independence's electrical system under certain circumstances.

### 2. DERs That Are Dispatchable by Third Parties Pose Additional Challenges for Distribution Utilities

The Commission has proposed to address all DERs—broadly defined to include both loads and resources, and encompassing all technologies—together in a single proceeding. However, the type of the DER and how it will be operated have a significant effect on its impact on distribution system planning and operations. Integrating modern residential solar installations with up-to-date inverters and without storage, for example, tends to pose less of a challenge. A significant increase in such DERs requires changes to distribution system planning and studies—e.g., a shift from modeling focused on system peak, to more detailed 8,760-hour modeling that considers the range of potential solar generation and the changing balance of loads and resources on individual feeders—but the output from such non-dispatchable solar DERs tends to correlate with distribution peak, and where it does not (e.g., in California, where distributed solar output drops off as the evening peak is starting during the winter), it is relatively predictable and does not cause distribution line flows to reverse.

In contrast, dispatchable DERs that can either inject power into the distribution system or increase the amount of electricity they draw beyond normal retail consumption levels pose a significantly greater challenge—particularly if those DERs are dispatched to take advantage of wholesale price signals that are unrelated to distribution system operations. It is much more difficult to analyze and plan for the impacts of such DERs. For example, they could inject power at times when the wholesale market is at peak, but the distribution circuit where they are located is lightly loaded, increasing the likelihood that flows on the distribution circuit will reverse. Or, as the Commission Staff noted in their February 2018 Report on Distributed Energy Resources,[13] storage DERs providing wholesale Regulation Service when distribution circuits are already at peak load may be directed to charge, potentially overloading distribution equipment.

Abrupt, wholesale-market-driven changes in DER dispatch will complicate, and have the potential to destabilize, distribution system operations, especially when multiple DERs within the same area are dispatched in concert under the direction of aggregators. The Commission is already familiar with the potential adverse impacts from many units, each comparatively small, if they change operations identically and simultaneously. The Staff Report describes Europe's experience when the severity of a 2006 disruption to the bulk power system was increased by a significant number of DERs tripping offline, which exacerbated the supply-demand imbalance and, by increasing the frequency deviation, led to further outages.[14] CAISO's recent grid resilience filing describes solar inverter dropout events in 2016 when large blocks of utility-scale solar photovoltaic generation erroneously tripped after the Southern California Edison transmission system experienced line faults during the Blue Cut Fire.[15] In both cases, technical changes to prevent recurrence of such events were recommended.

From the perspective of distribution utilities, multiple dispatchable DERs changing their operations in response to wholesale market price signals could have the same type of disruptive impact, albeit on a more localized basis. Therefore, dispatchable

[13] Staff Report 40, *Distributed Energy Resources: Technical Considerations for the Bulk Power System*, Docket No. AD18-10-000 (Feb. 2018), https://www.ferc.gov/legal/staff-reports/2018/der-report.pdf ("Staff Report").

[14] Staff Report at 15-17.

[15] Comments of the CAISO 108-111, *Grid Resiliency in Regional Transmission Org. & Indep. Sys. Operators*, Docket No. AD18-7-000 (Mar. 9, 2018), eLibrary No. 20180309-5193.

DERs (other than demand response resources) controlled by third-party aggregators responding to external RTO price signals require that distribution systems pursue some combination of two potentially very costly options, neither of which will be simple to implement: (1) engineering the distribution system to withstand all possible RTO and third-party aggregator dispatch decisions, under every possible system condition; or (2) developing the ability to constantly monitor DER aggregator operations and distribution system conditions, and establish protocols for intervention to assure that the distribution system is not overwhelmed by RTO and aggregator decisions.

Option 1—upgrading the distribution system to withstand potential RTO and DER aggregator dispatch decisions—can be part of the solution. But even for distribution utilities with robust generation interconnection processes that include rigorous modeling and studies, it may be impossible to anticipate and fully evaluate every possible combination of loads, resources, and distribution system configuration to determine in advance whether potential RTO and DER aggregator dispatch decisions might have adverse impacts—let alone identify and install upgrades to address those impacts.

Retail loads and customers are constantly changing, and distribution utilities are expected to connect new retail customers in a matter of days, not the months or years typical for wholesale interconnections. Nor are DERs static. Retail customers add, modify, and occasionally shutter them; new stand-alone distribution-connected DERs are sited and developed. Indeed, in the case of electric vehicle batteries, the locations and functions of a large number of DERs may change multiple times over the course of a single day.

In addition, although many distribution systems are primarily designed as radial systems, distribution utilities routinely reconfigure circuits, so that the specific radial path serving any particular location may periodically change.[16] In some instances, this reconfiguration is temporary (e.g., to bypass damaged equipment or perform maintenance);[17] at other times, the reconfiguration is more permanent (e.g., to address changing system loads or new development). Distribution systems are specifically designed to enable such reconfigurations, which are crucial to responding to changing customer needs and to rapidly restoring service after outages; some larger utilities have automated such switching, so that changes can be made remotely and almost instantaneously.

Given the range of different resources, loads, and system configurations that would need to be considered in order to bullet-proof distribution systems from the effects of RTO and DER aggregator dispatch decisions, relying exclusively on Option 1 will likely be unworkable and extremely costly.

Option 2, however, has its own set of problems. Relying on monitoring and intervention to prevent adverse impacts from RTO and DER aggregator dispatch decisions will also be costly in terms of money, technical staff, and other resources. For example, real-time metering and visibility of DERs will be needed; but currently many distribution utilities—especially small utilities—have, and only need, limited real-time

[16] Tr. Vol. 2, 332:21-25 (Esguerra) ("The distribution grid experience[s] much more exposure to outages and switching configurations."); *id.* at 363:16-22 (Taft) ("[D]istribution systems are actually fairly dynamic in terms of configuration. . . . [T]he feeders are radials but in fact in a lot of places they're interconnected in such a way that they act as radials but that radial configuration can be changed on a fairly short timeframe [and] will change a lot in some cases.").

[17] For example, City Utilities of Springfield, Missouri, was forced to reconfigure six circuits—a substantial part of its distribution system—in order to maintain service to retail customers while isolating and repairing equipment damaged by a wild animal.

visibility of their distribution system. And even if the necessary metering and communications systems were in place, distribution utilities often lack 24/7 staff to monitor metering and distribution system conditions in real-time.

Further, new multi-party coordination systems and protocols will be needed so that distribution utilities can take action if DER aggregator dispatch decisions would have adverse impacts on retail service. Distribution utilities, for example, will need timely information on planned dispatch from DER aggregators or the RTO; and if the utility determines that dispatch would create problems, there must be a realistic timeline and systems for preventing it and for alerting the DER aggregator, the RTO, and perhaps the DER owner. Particularly since many distribution utilities currently have no direct relationship with their RTO,[18] the task of creating and implementing the necessary systems and protocols will be significant.

DER aggregation is also likely to complicate settlements and LSE resource decisions. Wholesale market transactions by DERs will presumably require a gross-up or decrement of the load metered at the host distribution utility's RTO delivery points. Based on the experience of TAPS members, even relatively straightforward DER arrangements can require costly and time-consuming RTO settlement processes; just validating that DERs have been appropriately backed out of the distribution utility's RTO delivery point meter readings can be complicated. When dozens or hundreds of DERs scattered across multiple RTO delivery points are involved, DER-related settlements could easily become a full-time job for multiple employees. And where the distribution

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[18] Many municipal systems and distribution cooperatives, for example, do not interact directly with their RTOs. Instead, they rely on JAAs and generation and transmission cooperatives ("G&Ts"), of which they are members, to handle those relationships.

utility is *not* the LSE, the settlements process will be even more complicated, because the gross-up or decrement in metered load must be appropriately allocated among the various LSEs within the distribution utility's footprint, based on the location of the specific DERs dispatched by the aggregator, which the DER aggregator may choose to alter from dispatch interval to dispatch interval.

These complicated settlement processes are necessary because DER aggregation creates a new disconnect between real-time meter readings and LSE costs. Competitive markets are founded on the principle that price provides a crucial signal to guide market participant behavior. In RTOs where there is significant participation by DER aggregators in wholesale markets, however, LSEs will no longer be able to rely on locational marginal prices and actual RTO meter readings to make decisions on resource planning, demand bids, and day-ahead and real-time decisions to deploy LSE-controlled DERs. DER-aggregator-adjusted load—not the real-time meter readings at RTO delivery points—will be the relevant number for those purposes; and while real-time metering of DERs within distribution utility footprints would theoretically make it possible for LSEs to calculate the DER-aggregator-related offsets in near real-time, that process will be more complicated, prone to error, and less reliable, undermining LSEs' ability to plan.

Finally, the operation of DER aggregators within a distribution utility's footprint could dramatically increase the utility's NERC obligations. The obligation to register with NERC as a Distribution Provider ("DP"), Transmission Owner ("TO"), or Transmission Operator ("TOP"), and comply with applicable NERC reliability standards, depends in part on whether a utility owns and operates (in the case of TO/TOP) or is directly connected to (in the case of DP) NERC-defined Bulk Electric System transmission facilities.[19] Whether a particular transmission line greater than 100 kV is part of the Bulk Electric System, in turn, depends in part on the total "non-retail generation" connected to the line.[20] While it is far from clear that the term "non-retail generation" was intended to capture the case of a retail customer electing to bid its behind-the-meter generation into the wholesale market,[21] it is possible that a DER (or aggregation of DERs) switching from retail compensation to wholesale market participation could subject the host distribution utility to NERC registration. Registration as a TO/TOP, which entails compliance with several hundred requirements enforced by penalties of up to $1 million per violation per day, would impose enormous burdens on a small utility.

### *C. Any Final Rule on Eligibility for DER Aggregation Should Include Mechanisms to Defer to the Decisions of Those Most Familiar with the Relevant Distribution Systems*

Both the discussion at the technical conference and the experience of TAPS members underscore that the challenges of DER participation in wholesale markets are heavily dependent on local circumstances. Entities with knowledge and understanding of the specific factors shaping these challenges are the ones in the best position to make decisions regarding the participation of DER aggregation in the wholesale markets.

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[19] NERC Rules of Procedure, App. 5B, Statement of Compliance Registry Criteria § I (Oct. 31, 2016), https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/Appendix_5B_RegistrationCriteria_20161031.pdf.

[20] *Id*. § I, Exclusions E1(c) & E3(a).

[21] In approving the Bulk Electric System definition, the Commission expressly declined requests that it clarify "non-retail generation." *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 78 Fed. Reg. 804 at 834 (Jan. 4, 2013), 141 FERC ¶ 61,236, P 215 (2012), *clarified on reh'g*, Order No. 773-A, 78 Fed. Reg. 29,210 at 29,228 (May 17, 2013), 143 FERC ¶ 61,053, P 116 (2013), *compliance deadline extended*, 143 FERC ¶ 61,231 (2013), *clarified*, 144 FERC ¶ 61,174 (2013), *review denied sub nom. New York v. FERC*, 783 F.3d 946 (2d Cir. 2015).

### 1. The Commission Should Include a RERRA Opt-In/Opt-Out Mechanism for DER Aggregation

As TAPS explained in its request for rehearing of Order No. 841,[22] a RERRA opt-in/opt-out mechanism patterned on Order No. 719-A[23] is the best way to eliminate unnecessary barriers to DER participation in wholesale markets while also appropriately deferring to those responsible for service to retail customers and the distribution system to which DERs interconnect. Such a mechanism would appropriately recognize that the Commission's jurisdiction beyond the interstate transmission grid is limited and nuanced,[24] and that the Commission must work cooperatively with state and local regulators to address the challenges posed by DER participation in wholesale markets.

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[22] Request for Rehearing of TAPS 3-12, *Elec. Storage Participation in Markets Operated by Regional Transmission Operator & Indep. Sys. Operators*, Docket Nos. RM 16-23-000, AD16-20-000 (Mar. 19, 2018), eLibrary No. 20180319-5128 ("TAPS Storage Request for Rehearing").

[23] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719-A, 74 Fed. Reg. 37,776 at 37,783 (July 29, 2009), FERC Stats. & Regs. ¶ 31,292, P 51 (2009), *on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009). 18 C.F.R. § 35.28(g)(1)(iii).

[24] The Commission has held that even when a wholesale transaction is occurring over a "dual use" facility, the Commission "may *not* regulate the 'local distribution' facility itself, which remains state-jurisdictional." *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003-C, 70 Fed. Reg. 37,661 at 37,667 (June 30, 2005), FERC Stats. & Regs. ¶ 31,190, P 53 (2005), *aff'd sub nom. NARUC v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007) (emphasis added). *See also Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 68 Fed. Reg. 49,846 at 49,917 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146, P 804 n.129 (2003), *modified*, 68 Fed. Reg. 69,599 (Dec. 15, 2003), *clarified*, 69 Fed. Reg. 2135 (Jan. 14, 2004), 106 FERC ¶ 61,009 (2004), *order on reh'g*, Order No. 2003-A, 69 Fed. Reg. 15,932 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160 (2004), *order on reh'g*, Order No. 2003-B, 70 Fed. Reg. 265 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,171(2004), *order on reh'g*, Order No. 2003-C; *Detroit Edison Co. v. FERC*, 334 F.3d 48, 51 (D.C. Cir. 2003); *DTE Energy Co. v. FERC*, 394 F.3d 954, 962 (D.C. Cir. 2005). And while the Commission has previously reached into the distribution systems of public utilities in narrow circumstances where the purpose of the interconnection is for wholesale sales and the distribution facilities at issue are already subject to the public utility's OATT, facilities behind the retail meter are plainly beyond the scope of facilities "included in a public utility's Commission-filed OATT." Order No. 2003-A, PP 710, 730. *See also* Order No. 2006, P 481.

Prior Commission orders have also recognized the substantial interest of distribution utilities and state and local regulators regarding whether distribution-connected and behind-the-retail meter resources may participate in RTO markets. The Commission has acknowledged that the vast majority of distribution-level interconnections are subject to the jurisdiction of the RERRA, not the Commission. In Order No. 2006-A, the Commission explained that it was not affecting state rules for the interconnection of generators with state jurisdictional facilities, noting that "*We expect that the vast majority of small generator interconnections will be with state jurisdictional facilities. The Commission encourages development of*

A RERRA opt-in/opt-out would allow state and local regulators to determine whether and when DERs should be permitted to transact in wholesale markets based on distribution-utility-specific facts and conditions. And it would be simple to administer. In contrast to leaving RERRA policies to be implemented through ad hoc decisions or inaction on a case-by-case basis for individual DERs at each interconnection point, an opt-in/opt-out is a straightforward mechanism that enables RTOs to efficiently implement RERRA decisions about distribution-connected and behind-the-retail-meter DERs in a systematic and orderly way. It would provide greater certainty to DER developers and aggregators, enabling RTOs to provide a swift, one-stop eligibility answer for DER aggregators seeking to enroll new DERs, while respecting RERRA jurisdiction over distribution systems. And it could help avoid the need to consider disruptive market re-runs that may otherwise be appropriate (or alternative enforcement mechanisms), if an RTO has accepted supply offers or demand bids from distribution-connected or behind-the-retail-meter DERs that are barred from making such sales or purchases under state law. Further, from the perspective of distribution utilities, it would give them space to focus on planning and priorities, rather than simply reacting.

Adopting this opt-in/opt-out mechanism for DERs would also be consistent with the RERRA opt-in/opt-out that the Commission has already established for demand response resources. In the Notice of Proposed Rulemaking, the Commission proposed a definition for DERs that appears to include demand response resources.[25] Moreover, a

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*state interconnection programs, and interconnections with state jurisdictional facilities continue to be governed by state law*." Order No. 2006-A, P 105 (emphasis added).

[25] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 81 Fed. Reg. 86,522 (proposed Nov. 30, 2015), FERC Stats. & Regs. ¶ 32,718, P 104 (2016) ("NOPR") ("[I]n this NOPR, we define distributed energy resources as a source or

significant number of demand response resources are actually small, behind-the-retail-meter generators that partially offset the load of the retail customer.[26] A final rule for DER aggregation that is not equally deferential to state and local regulators would create a confusing and untenable situation in which the owners of such demand response resources can bypass RERRA authority, RTO tariff requirements, and the Commission's "net benefits" test for demand response resource compensation and cost allocation simply by participating as "DERs" instead.

### 2. At Minimum, the Commission Should Establish an Express Opt-In Requirement for Small Distribution Utilities

Although the most appropriate way to address these concerns is to adopt a generally applicable RERRA opt-in/opt-out provision consistent with Order No. 719-A, the Commission should at minimum establish an express opt-in requirement for small distribution utilities. Specifically, RTOs should be required to reject wholesale bids from an aggregator of DERs connected to small distribution utilities,[27] unless the small

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sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter.").

[26] Peter Cappers et al., *Future Opportunities and Challenges with Using Demand Response as a Resource in Distribution System Operation and Planning Activities* at 2 n.1, Lawrence Berkeley National Laboratory, (Jan. 2016), http://emp.lbl.gov/sites/all/files/lbnl-1003951.pdf ("Behind-the-meter dispatchable generation (e.g., backup diesel generators) has historically been used to enable demand response."). *See Demand Response Supporters v. New York Indep. Syst. Operator, Inc.*, 155 FERC ¶ 61,151, P 14 (2016) (noting that "the Commission has approved provisions that allow demand response facilitated by behind-the-meter generation to provide demand response in other regional transmission organizations and independent system operators" and affirming "the Commission's previous finding that the terms of the [New York ISO's Day-Ahead Demand Response Program] are unduly discriminatory because they exclude from participation demand response facilitated by behind-the-meter generation").

[27] We propose that the Commission use the same threshold that it established in the demand response context, where small utilities are those "that distributed 4 million megawatt-hours or less in the previous fiscal year." 18 C.F.R. § 35.28(g)(1)(iii). This threshold was initially based on the Small Business Size Standards component of the North American Industry Classification system, and the Commission has continued to use this threshold after the United States Small Business Administration changed the basis for measuring business size from MWh to number of employees in 2014. As the Commission explained in Order No. 719-A, 4 million MWh is the same threshold Congress established in EPAct 2005 when amending the exclusions in section 201(f) of the Federal Power Act ("FPA") to include small electric

distribution utility expressly permits them. This requirement is appropriate given the high cost and complexity of new coordination and communications systems needed to avoid adverse impacts on a small distribution system from wholesale market participation by non-demand-response DERs.

As discussed in Part I.B above, distribution utilities will need to undertake significant changes to their systems and operations to allow DERs within their footprints, particularly those that are dispatchable, to participate in RTO markets without causing adverse impacts on the distribution system. These changes include new approaches to distribution system planning and studies, 24/7 monitoring, multi-party coordination systems, complicated settlement processes, and new potential NERC obligations. In addition, to enable DER aggregators to participate in wholesale markets, distribution utilities will need to develop procedures to, among other things: (1) review and evaluate DER aggregation enrollment lists and changes to those lists; (2) coordinate distribution system reconfigurations and reevaluate DER aggregation lists upon reconfigurations, outages, and other changes to the distribution system; (3) review DER aggregator dispatch decisions; and (4) intervene to prevent DER aggregator actions that would adversely affect the distribution system.

The burdens associated with these operational changes and new procedures are especially significant for small utilities, which typically have limited financial and technical resources and staff. While larger utilities may be able to modify existing processes to also support DER participation in wholesale markets, most small utilities

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cooperatives and when excepting small utilities from compliance with rules or orders imposed under section 211A of the FPA. Order No. 719-A, P 51.

will need to develop entirely new administrative and technical systems. Many small municipal systems and distribution cooperatives do not currently directly interact with the RTO (as these communications are handled through their JAA or G&T), and establishing new coordination and communications systems needed to accommodate DER participation in wholesale markets without adverse impact would be complicated and costly. Small distribution utilities are also less likely to engage in, or have the staff necessary for, the 24/7 monitoring necessary to prevent adverse impacts of DER aggregator dispatch decisions. And, as discussed above, if the participation in wholesale markets of DERs within a small utility's footprint required that utility to register with NERC, the new burden would be enormous.

Some small utilities may elect to invest in these changes to accommodate the participation of DERs in their footprint in the wholesale markets, in light of the specific costs and benefits to their particular system. But, this decision should be in the hands of those small utilities, which have the best understanding of their distribution systems and local interest.

This proposed express opt-in requirement for small utilities would be exercised by distribution utilities, rather than RERRAs, because of the detailed distribution engineering considerations that would be a key driver of these decisions.[28] In addition, this approach is consistent with the Commission's treatment of electric storage resources in Order No. 841. Although the Final Rule for electric storage resources does not go far

[28] If the Commission were to decide that it is more appropriate to require the express opt-in for small utilities to come from the RERRA, however, that approach could also work.

enough (and TAPS has a pending rehearing on the issue),[29] the Commission correctly ruled that in order for distribution-connected and behind-the-meter storage resources to participate in RTO markets, the distributed resource must have a contractual right to inject power into the distribution system,[30] and the distribution utility must be able and willing to meter to separate wholesale from retail transactions.[31]

### *D. In Any Rule, the Commission Should Confirm That It Is Not Seeking to Disturb Existing RERRA Authority over Cost Recovery and Allocation and Delivery Service over Distribution Systems*

As discussed above, there are considerable costs to accommodating DER participation in wholesale markets. Significant new investments and ongoing expenses may be needed to ensure that DER aggregation does not adversely affect service to retail load—the purpose for which distribution systems were designed and constructed, and upon which retail customers depend. There is also a substantial risk of a mismatch between those who receive the benefits of such investments and those who bear the costs, since the bulk of the benefits may flow only to aggregators and certain DERs. The

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[29] As TAPS explained in its request for rehearing, the Commission erred in rejecting a RERRA opt-in/opt-out patterned on Order No. 719-A for storage resources connected to distribution facilities or behind the retail meter. The failure to include such a mechanism is inconsistent with: (1) the approach taken by the Commission in the context of demand response resources, which the Supreme Court upheld (*FERC v. Elec. Power Supply Ass'n*, 136 S.Ct. 760 (2016)); (2) other correct holdings in Order No. 841 that recognize the authority of the distribution utility; and (3) limits on the Commission's jurisdiction. TAPS Storage Request for Rehearing at 3-12.

[30] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 83 Fed. Reg. 9580 at 9586, 9587 (Mar. 6, 2018), FERC Stats. & Regs. ¶ 31,398, PP 29, 33 (2018).

[31] Order No. 841, P 326 ("To the extent that the host distribution utility is unable— due to a lack of the necessary metering infrastructure and accounting practices—or unwilling to net out any energy purchases associated with a resource using the participation model for electric storage resources' wholesale charging activities from the host customer's retail bill, the RTO[] would be prevented from charging that resource using the participation model for electric storage resources electric wholesale rates for the charging energy for which it is already paying retail rates.").

Commission should be deferential to RERRAs and tread lightly with respect to the recovery and allocation of such costs.

The Commission should not impose requirements that would force other retail customers to subsidize the costs associated with addressing and monitoring impacts on the distribution grid of DER participation in wholesale markets. When discussing the minimum size requirement for storage resources in Order No. 841, the Commission noted that this requirement "does not change the ability of distribution utilities *to allocate any costs that they incur in operating and maintaining their respective power systems*."[32] Any action taken regarding DER aggregation should similarly acknowledge RERRAs' authority to set rates to recover and allocate costs and confirm that the Commission is not seeking to disturb this authority.

Likewise, any final rule should also confirm that it does not exempt DERs seeking to participate in wholesale markets from the obligation to adhere to applicable distribution utility tariffs and requirements of RERRAs with respect to delivery service over the distribution utility's system.[33]

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[32] Order No. 841, P 269 (emphasis added).

[33] This is consistent with past Commission action on DER aggregation. CAISO's 2016 proposed tariff revisions to facilitate participation of DER aggregations into its energy and ancillary services markets included a requirement "that DER Providers must comply with applicable utility distribution company tariffs and operating procedures incorporated into those tariffs and applicable requirements of the local regulatory authority." *Cal. Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,229, P 15 (2016). The Commission noted the importance of this requirement when it approved these revisions. *Id.* PP 42, 62. *See also* Tr. Vol. 2, 383:2-384:20 (Langbein); PJM Manual 14C, Generation and Transmission Interconnection Facility Construction § 1.3 (June 22, 2017), http://www.pjm.com/-/media/documents/manuals/m14c.ashx ("The [Wholesale Market Participation Agreement between PJM, the resource, and any affected Transmission Owner(s)] does not define the obligations of the Wholesale Market Participant regarding the cost responsibility for any required upgrades to the distribution system, but can contain required Local Upgrades or Network Upgrades to the Transmission System. Any impacts to the Transmission System would result in an accompanying [Interconnection Construction Service Agreements]. . . . Construction responsibility should be defined in an interconnection agreement (IA) between the Wholesale Market Participant and any affected distribution facility owners. PJM is not a party to the IA.").

In Order No. 841, the Commission correctly recognized that states retain their responsibilities for "matters related to the distribution system, including design, operations, power quality, reliability, and system costs."[34] And the Commission expressly clarified that the Final Rule for electric storage resources does not "affect or implicate the responsibilities of distribution utilities to maintain the safety and the reliability of the distribution system or their use of electric storage resources on their systems."[35] These responsibilities are no less critical for DERs in general as they are for electric storage resources, and any final rule issued in this proceeding should similarly make clear that it does not disturb RERRAs' authority regarding cost recovery and allocation and delivery service over the distribution system.

### *E. Settlement Processes for DERs Participating in Wholesale Markets Should Not Unduly Burden Distribution Utilities*

As described in Part I.B.2, DER aggregations will likely increase the complexity of RTO settlement processes.[36] Although some changes may be unavoidable, distribution utilities should not be saddled with unduly burdensome settlement arrangements. The Commission should direct RTOs to work with distribution utilities to develop reasonable settlement processes for DER aggregations that avoid imposing undue burdens and costs on those distribution utilities that host DERs participating in wholesale markets.

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[34] Order No. 841, P 36.

[35] *Id.*

[36] *See also* Tr. Vol. 1, 132:22-133:2 (Norton) ("[A]t least within some of the RTOs we're going to be under 5 minute settlements. That could present a very significant challenge for small utility personnel to . . . keep up with that."); *id.* at 171:23-24 (Kuga) ("[T]here are a lot of issues in terms of settlements . . . that are being worked out.").

## II. POST-TECHNICAL CONFERENCE QUESTIONS REGARDING PARTICIPATION OF DERS IN RTO/ISO MARKETS (PANEL 3)

The Commission's Notice (at 5) seeks "additional information about potential solutions to the challenges associated with DER aggregations that provide multiple services, including ways to avoid duplication of compensation for their services in the [RTO] markets." Allowing double-recovery—from a retail compensation program, as well as RTO wholesale markets—improperly increases consumer costs and sends the wrong price signal to DERs. To prevent duplication of compensation, the NOPR (at P 134) appropriately included a proposal to require DERs to choose between either retail compensation programs or RTO wholesale markets. RTOs with organized markets view electricity very differently from most retail regulators and have deconstructed electric service into many separately identified and traded products. Given the complexity of attempting to map RTO wholesale products against the products covered by a retail compensation program, the best approach is to require DERs to choose one or the other. Although the Commission appears to have taken a different approach in Order No. 841, stating that storage resources need not choose between either wholesale markets or retail compensation programs,[37] TAPS agrees with the NOPR's original proposal and has sought rehearing of Order No. 841 with respect to that issue.[38]

Regardless, the Commission should at minimum confirm in this proceeding that RERRAs can require, as a condition of eligibility to participate in a retail compensation program, that the DERs enrolled in the program cannot also participate in wholesale DER aggregations. Opportunistic moves between retail compensation programs and wholesale

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[37] Order No. 841, P 325.

[38] TAPS Storage Request for Rehearing at 12-18.

markets to take advantage of higher wholesale market prices in certain hours would fundamentally undermine the rate design of most retail compensation programs, unfairly shifting costs between the DER and other retail customers. While a RERRA could conceivably design a retail compensation program that is compatible with the DER periodically transacting in the wholesale market, the decision to attempt to develop and adopt such a retail compensation program (or determine whether an existing retail compensation program is compatible with periodic wholesale transactions) must be the RERRA's to make.

In addition, to the extent that the Commission does not adopt the NOPR's blanket requirement that DERs participating in one or more retail compensation programs will not be eligible to participate in RTO markets as part of a DER aggregation, it must still ensure that RTO tariffs are just and reasonable and do not result in dual compensation with respect to specific electricity products and types of DERs. For example, with respect to distributed storage resources, the Commission is obligated under the Federal Power Act to ensure: (1) that energy purchased from wholesale markets is resold, rather than used by end-use customers, and (2) that energy purchased at retail is not resold into wholesale markets.[39] The ability to arbitrage between wholesale markets and retail compensation programs creates significant incentives for unlawful transactions and opportunities for market manipulation by distributed storage resources. As TAPS explained in its request for rehearing of the Order No. 841 (at 13-15), for such DERs to make lawful purchases and sales, it is necessary, but extremely difficult, to separate

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[39] 16 U.S.C. § 824(b)(1) (limiting the Commission's jurisdiction to "the sale of electric energy at wholesale in interstate commerce").

wholesale transactions from retail use. Therefore, to protect the integrity of wholesale markets, respect the FPA's jurisdictional limits, and assure that RTO tariffs are just and reasonable, the Commission should require RTOs to bar distributed storage resources from transacting in both wholesale markets and retail programs.

Similar restrictions on participation by other types of DERs in both wholesale markets and retail compensation programs, based on the specific market design of individual RTOs, may also be appropriate. In the compliance filings required by any final rule, RTOs should therefore be directed to consider the potential for dual compensation and establish protocols for addressing it in the context of the RTO's particular market design. Addressing concerns regarding dual compensation is not just a matter of respecting RERRAs' decisions regarding the terms and conditions of retail service, it is also necessary for the Commission to fulfill its obligations under the FPA.

## III. POST-TECHNICAL CONFERENCE QUESTIONS REGARDING COORDINATION OF DER AGGREGATIONS PARTICIPATING IN RTO/ISO MARKETS (PANEL 6)

In its Notice (at 6), the Commission "seeks additional information on the potential ways for RTOs[], distribution utilities, retail regulatory authorities, and DER aggregators to coordinate the integration of a DER aggregation into the RTO[] markets." TAPS supports the NOPR's proposal to provide distribution utilities "with the opportunity to review the list of individual resources that are located on their distribution system that enroll in a distributed energy resource aggregation before those resources may participate in the organized wholesale electric markets through the aggregation."[40] Based on the experience of TAPS members, the specifics of how DERs are aggregated and dispatched

[40] NOPR, P 154.

can have significant distribution system impacts. One TAPS member, for example, has a number of small, distributed, diesel-fired generators that provide back-up service and are aggregated to meet the RTO's minimum participation level for a demand response resource. In creating those aggregations, the distribution utility tries to cluster the generators by location, so that local system needs and weakness can be targeted, effects on the distribution system can be anticipated, and adverse impacts are minimized should the RTO dispatch the aggregation. If DER aggregations are created without regard to these factors—which are specific to each distribution utility—it is much more difficult for the utility to predict and address their adverse impacts.

Distribution utilities must therefore have authority to determine whether individual DERs in their footprint may enroll in a DER aggregation. As the entities closest to the affected distribution systems, distribution utilities are best positioned to evaluate and sign off on the enrollment of individual DERs in aggregations. Thus, to the extent not already implicit in any opt-in/opt-out requirement included in any final rule (as TAPS recommends above), the Commission should expressly provide for binding distribution utility review of DER aggregation lists through processes that provide the utility with adequate time.

The binding distribution utility review provision should also allow the utility to reopen the approval of individual DERs' enrollment in a DER aggregation, if the distribution system is reconfigured. As described above in Part I.B.2, distribution systems are routinely reconfigured on both temporary and permanent bases, and the enrollment of a particular DER in a wholesale aggregation may cause system issues under some configurations but not others.

Further, small distribution utilities that participate in a JAA or G&T should be permitted to delegate this resource-specific review function to the relevant JAA or G&T. This option would allow small utilities to more efficiently complete their review of DER enrollment lists while still ensuring that individual DERs' participation in an aggregation does not compromise the distribution system.

## IV. RESPONSE TO POST-TECHNICAL CONFERENCE QUESTIONS REGARDING ONGOING OPERATIONAL COORDINATION (PANEL 7)

In its Notice (at 9), the Commission asked whether "distribution utilities [should] be able to override RTO[] decisions regarding day-ahead and real-time dispatch of DER aggregations to resolve local distribution reliability issues?" The answer is, "Yes." Local distribution utilities must have the authority to override dispatch instructions from DER aggregators, or require disconnection of DERs included in DER aggregations, if their dispatch undermines local distribution reliability.[41] This authority is necessary to ensure that the participation of DER aggregation in the wholesale markets does not come at the expense of degraded service to retail loads. In addition, there should be no financial disincentive to distribution utility actions to protect reliability.

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[41] The *pro forma* generator interconnection agreements established in Order Nos. 2003 and 2006 provide Transmission Providers with the authority to take action regarding interconnected generators to protect transmission system reliability. Order No. 2003, Article 13.5.1 ("Transmission Provider may take whatever actions or inactions with regard to the Transmission System or the Transmission Provider's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Transmission System or the Transmission Provider's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service."); Order No. 2006, Article 3.4.1 ("Under Emergency Conditions, the Transmission Provider may immediately suspend interconnection service and temporarily disconnect the Small Generating Facility."). Just as Transmission Providers are enabled to protect reliability in the context of Commission-jurisdictional generator interconnections, distribution utilities must similarly be empowered to protect distribution system reliability and quality of retail service with respect to DER aggregator dispatch instructions.

## CONCLUSION

The Commission should consider these comments, as well as TAPS' original DER-related comments in Docket No. RM16-23-000, as it continues to explore the proposed reforms regarding the participation of DER aggregations in RTO markets.

Respectfully submitted,

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