UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF
THE AMERICAN PUBLIC POWER ASSOCIATION

Pursuant to the April 27, 2018 Notice Inviting Post-Technical Conference Comments ("April 27 Notice") issued by the Federal Energy Regulatory Commission ("Commission" or "FERC") in the above-captioned docket, the American Public Power Association ("APPA") provides these comments regarding the participation of distributed energy resource ("DER") aggregations in Regional Transmission Organization ("RTO") and Independent System Operator ("ISO") markets.

I. INTRODUCTION

APPA appreciates the opportunity to provide additional comments on DER aggregation in RTO and ISO markets. As APPA explained in its February 13, 2017 comments[1] on the Commission's Notice of Proposed Rulemaking ("NOPR"),[2] APPA generally supports the Commission's effort to remove barriers to DER aggregation in RTO/ISO markets.[3] It is important for the Commission to distinguish, however, between undue barriers to DER

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[1] APPA filed its comments jointly with the National Rural Electric Cooperative Association ("NRECA"). *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket Nos. RM16-23-000 and AD16-20-000, Comments of the American Public Power Association and the National Rural Electric Cooperative Association on Notice of Proposed Rulemaking (Feb. 13, 2017) ("APPA/NRECA NOPR Comments").

[2] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,121 (2016), 81 Fed. Reg. 86,522 (Nov. 30, 2016).

[3] *See* NOPR at P 1 (explaining that the NOPR's proposed reforms aim "to remove barriers to the participation of . . . distributed energy resource aggregations in the organized wholesale electric markets" (footnotes omitted)).

participation in wholesale markets and factors that, although they might have the effect of limiting DER participation in those markets, are grounded in legitimate operational, reliability, and regulatory considerations relating to DER wholesale market participation. The April 10-11, 2018 technical conference in this docket highlighted a number of these considerations, and any final rule must address these issues in a manner that benefits end-use customers, ensures distribution system reliability, security, and safety, and respects jurisdictional boundaries. In particular, the Commission should afford distribution utilities and their state and local regulators a key role in coordinating the participation of aggregated DER in RTO/ISO markets.

In their 2017 comments on the NOPR, APPA and NRECA discussed numerous factors the Commission would need to consider in establishing rules for aggregated DER participation in RTO/ISO markets, including specific examples of the operational impacts on the distribution system that could result from such participation.[4] The technical conference further highlighted challenges associated with aggregated DER participation in the RTO and ISO markets, including: potential adverse impacts on distribution system operations; processes for appropriate coordination between distribution utilities, state and local regulators, RTOs/ISOs, and DERs; modeling difficulties for the distribution system; the mechanics of aggregating numerous small DER assets; increased costs and security and privacy concerns related to upgraded metering and communications infrastructure; more complicated billing and settlement processes; and the complexities of determining whether a DER is being double-compensated for selling the same service into different markets. Many of these challenges would be particularly daunting for small utilities, which constitute the overwhelming majority of public power systems in the United States.

[4] *See* APPA/NRECA NOPR Comments at 26-37.

The technical conference showed, moreover, that RTOs and ISOs, state regulators, distribution utilities, DER providers, and other stakeholders largely are just beginning to grapple with the implications of increased DER penetration in RTO/ISO markets. And although the challenges associated with aggregated DER participation in wholesale markets are fairly evident, the demand for, and potential benefits from, such aggregation programs remain uncertain.

The April 27 Notice raises numerous important questions concerning the participation of aggregated DER in RTO/ISO markets. That so many details remain to be worked out at this stage of the rulemaking strongly indicates that the Commission should adopt a flexible approach to DER aggregation in wholesale markets that accommodates different regional, state, and local circumstances. The Commission should set aside the notion, discussed at the technical conference, that successful DER participation in the wholesale markets would be best achieved by dictating a uniform approach for RTO and ISO DER aggregation programs. Given the volume of questions that remain, the importance of regional differences, and the lack of any consensus best practices, flexibility is of the utmost importance.

The challenges associated with aggregated DER participation in RTO/ISO markets may not be insurmountable, particularly for larger distribution utilities, but it is important that the Commission strike a balance between facilitating DER participation and ensuring safe, secure, and reliable service on distribution systems at rates that are reasonable for all grid users. Accordingly, the Commission should not adopt rules that promote aggregated DER participation in RTO/ISO markets without providing adequate safeguards, including a central role for state and local regulators.

To help ensure that the operational, reliability, and regulatory challenges associated with aggregated DER participation in the RTO/ISO markets are adequately addressed, APPA makes the following specific recommendations:

- The Commission should recognize the right of the relevant electric retail regulatory authority ("RERRA") to determine if distributed energy resources located behind the meter or on the distribution system may participate in RTO/ISO DER aggregation programs, similar to the Commission's Order Nos. 719 and 719-A opt-out/opt-in framework applicable to demand response aggregation in RTO/ISO markets.

- If the Commission does not adopt a RERRA opt-out/opt-in framework applicable to all aggregated DER participation in RTO/ISO markets, the Commission should, at a minimum, adopt an opt-out mechanism for small distribution utilities, as described more fully in the post-technical conference comments being submitted by the Transmission Access Policy Study Group ("TAPS").

- In any final rule facilitating the participation of aggregated DER in RTO/ISO markets, the Commission should be explicit that nothing in the rule preempts or otherwise limits the ability of state and local regulators to adopt rules or tariffs, and to set rates to recover and allocate the costs associated with facilitating wholesale market participation by aggregated DERs.

- The Commission should adhere to the NOPR's proposal not to permit DERs that are participating in a state retail compensation program to participate in the wholesale market as part of a DER aggregation.

- Electric distribution companies, with the supervision of the RERRA, should play a strong role in coordinating any DER participation in an aggregation, including the right to review and approve or deny the participation of individual DER assets in a DER aggregation.

- Distribution utilities should have the right to override RTO/ISO dispatch instructions for DERs located on their distribution systems to resolve or avoid distribution reliability or operational issues.

APPA elaborates on these points in the sections below, which are generally organized by the technical conference panel topics and related questions included in the Commission's April 27 Notice. APPA focuses in particular on the Panel 2 issues regarding state and local regulator concerns about the potential operational effects of aggregated DER participation in wholesale markets, although there is a significant amount of overlap in the issues raised on the different panels.[5]

II. INTEREST OF APPA

APPA is the national service organization representing the interests of the Nation's 2,000 not-for-profit, community-owned electric utilities. Public power utilities are located in every state except Hawaii. They collectively serve over 49 million people and account for 15 percent of all sales of electric energy (kilowatt-hours) to ultimate customers. Public power utilities are load-serving entities, with the primary goal of providing the communities they serve with safe, reliable electric service at the lowest reasonable cost. This orientation aligns the interests of the utilities with the long-term interests of the residents and businesses in their communities.

Public power utilities operate in all of the Commission-approved RTOs and ISOs. Many participate directly in the organized wholesale electric markets of an RTO or ISO, while others are served by a wholesale supplier – sometimes a joint action agency or another public power utility – that participates in these markets. Although public power utilities own almost 10 percent of the nation's electric generating capacity, they purchase nearly 70 percent of the power used to serve their communities.

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[5] The Commission arguably addressed certain aspects of the above recommendations in its Order No. 841, *Electric Storage Participation in Markets Operated by Regional Transmission Organization and Independent System Operators*, Order No. 841, 162 FERC ¶ 61,127 (2018) ("Order No. 841"). APPA and others have requested rehearing of Order No. 841. *See, e.g.*, *Electric Storage Participation in Markets Operated by Regional Transmission Organization and Independent System Operators*, Docket Nos. RM16-23-000 and AD16-20-000, Request for Rehearing of American Municipal Power, Inc., the American Public Power Association, and the National Rural Electric Cooperative Association (March 19, 2018). Among the issues raised in the AMP/APPA/NRECA rehearing request was the extent to which Order No. 841 intended to address issues associated with electric storage resources connected at the distribution level or behind the meter. *See id.* at pp. 15-17.

III. COMMENTS

A. State and Local Regulators Must Play a Key Role in Addressing the Operational and Other Implications of any Proposed DER Aggregation (Panel 2)

As APPA said in its NOPR comments, a key principle that should guide the Commission's decision-making is that rules facilitating DER aggregation must be aimed at providing benefits to end-use customers.[6] Distributed energy resources, to be sure, can provide benefits such as backup energy, enhanced power quality, peak shaving, and avoidance of distribution system upgrades. Facilitating DER aggregation in RTO/ISO markets, however, presents numerous challenges (and potential costs) for distribution utilities and their regulators at a time when the industry is already confronting significant changes, including a rapidly evolving resource mix, growing DER penetration, accelerating growth in electric vehicles ("EVs"), security concerns, and increasingly regional markets. Utilities are also in the process of implementing the recently-revised IEEE Standard 1547-2018, which "provides interconnection and interoperability technical and test specifications and requirements for distributed energy resources."[7] And while the challenges associated with aggregated DER in RTO/ISO markets are plainly evident, demand for DER aggregation in these markets is not as clear, raising concerns that distribution utilities could be required to make substantial investments for wholesale market participants that never materialize. In light of the uncertain benefits and potentially significant costs associated with DER aggregation, the Commission should be flexible in its rules, and it should ensure that state and local regulators have a strong role in evaluating whether it will be beneficial for distributed energy resources interconnected to distribution facilities subject to their

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[6] *See* APPA/NRECA NOPR Comments at 2.

[7] IEEE Std. 1547-2018 at § 1.1.

jurisdiction or behind the meter to participate in RTO/ISO DER aggregation programs.

1. Aggregated DER Participation in RTO/ISO Markets is Likely to Present Numerous Operational, Reliability, and Cost Challenges for Distribution Utilities

Even without rules facilitating aggregated DER participation in RTO/ISO markets, distribution utilities are currently grappling with the impacts of actual and projected growth in DERs on their systems. The operational, safety, and reliability challenges presented by these resources will only increase as DER penetration grows.[8] The growth in DERs is part of a broader set of industry changes that includes growth in renewable resources (a category that encompasses some types of DERs, such as rooftop solar), energy efficiency, and the accelerating adoption of EVs. These and other developments can significantly alter resource mixes and load shapes of distribution utilities, with resulting impacts on rate design, cost recovery, and resource planning.[9] Greater penetration of DERs, particularly if adopted by commercial customers, could make it difficult to accurately forecast load in both the long- and short-term planning horizons. As APPA's Mr. Zummo observed at the technical conference, distribution utilities are confronting "a new paradigm"[10] for rate design, often with little margin for error.[11] These rate design challenges, Mr. Zummo noted, can be particularly acute for small to medium-sized distribution utilities,[12] which make up the overwhelming majority of public power systems in the

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[8] *See* APPA/NRECA NOPR Comments at 26-37.

[9] *See, e.g.*, *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket Nos. RM18-9-000 and AD18-10-000, Transcript ("Tr.") at 117 (April 10, 2018) (Thomas) (noting the challenges associated with integrated resource planning that accounts for traditional resources "plus what might happen in DER which is outside the utility's control and plus what might happen in demand response or efficiency in all of those things . . . ."); Tr. at 266-67 (Tetlow).

[10] Tr. at 155.

[11] Tr. at 156.

[12] Tr. at 156.

United States.[13] The participation of aggregated DER in RTO/ISO markets will make the operational, technological, and administrative challenges faced by distribution utilities in those regions even more complex, particularly if the Commission were to adopt rules allowing DER resources to participate in retail compensation programs *and* as aggregated DER in RTO/ISO markets.

Thus far, the grid has been able to accommodate the rapid growth in residential solar distributed generation. The participation of dispatchable DERs in wholesale markets, however, will present a different and more complex set of challenges, some of which APPA and NRECA identified in their comments on the NOPR.[14] The distribution system generally has not been designed and built to accommodate the two-way flows caused by DERs,[15] and local distribution system design and construction may not as readily allow for rerouting around faults or congestion, as is frequently possible on the transmission grid.[16]

Of particular concern, dispatchable DERs participating in RTO and ISO markets through aggregators will be responding to wholesale price signals and other exigencies of the bulk-power system that may not be readily visible to the interconnected distribution utility, and the resulting power flows may not be aligned with the safe and reliable operation of the distribution system.[17] The influence on DER operation from wholesale market drivers can create uncertainty in day-to-day operations, as well as long-term system planning, even in cases where a distribution utility

[13] According to information maintained by APPA, 1,684 of the approximately 2,000 public power utilities in the United States serve 10,000 customers or less, and 1,352 of these utilities have fewer than 4,000 customers. In terms of megawatt-hour sales, fewer than 50 public power utilities out of 2,000 sell more than 4 million MWh of energy per year.

[14] *See* APPA/NRECA NOPR Comments at 23-37.

[15] *See* Tr. at 96 (Picker); Tr. at 332 (Esguerra).

[16] *See* APPA/NRECA NOPR Comments at 31; Tr. at 96 (Picker).

[17] *See* Tr. at 351-52 (Esguerra).

has incorporated DERs into system operations. A distribution utility basing its assessment of resource needs on a forecast of load and resource availability that is inclusive of the impacts of DERs would face difficulties were the availability of such DERs to change, resulting in an increase in load or decline in available resources, potentially within a short time frame. Aggregators may not be fully aware of each unique circumstance, and the additional layer between the utility and the resource could exacerbate operational challenges, including by adding latency from the decision to dispatch to the time the energy is delivered.

The Commission observed in the NOPR that the potential for smaller DERs to participate in wholesale electric markets was driven, in part, by "advancements in metering, telemetry, and communication technologies."[18] The Commission suggested, however, that aggregated DERs should rely on distribution utility metering requirements.[19] Facilitating the participation of distributed energy resources in organized wholesale electric markets while relying on distribution utility metering could impose significant burdens on distribution utilities, who will be obligated to consider and address the privacy and cybersecurity implications of the metering and communications facilities.[20] DER aggregation programs could add numerous additional access points to a critical system, all of which must be secured.[21]

Facilitating wholesale market participation by aggregated DERs would also impose incremental costs on distribution utilities. DER participation in the RTO/ISO markets will likely require additional or enhanced metering, communications/telemetry infrastructure on the

[18] NOPR at P 15.

[19] *Id.* at P 152.

[20] *See* Tr. at 401-02 (Ipakchi).

[21] *See* APPA/NRECA NOPR Comments at 37.

distribution system, and security requirements, particularly as DER penetration increases.[22] Changing use patterns associated with DER aggregation activity could require increased distribution system planning and maintenance activity. Distribution utilities will be required to devote time and resources to monitoring and, if necessary, responding to system impacts associated with DER aggregation activity. Absorbing these financial and personnel demands could be particularly difficult for small and medium-sized utilities.[23] What's more, there is a risk of a mismatch between costs and benefits, as distribution system users subsidize these new costs, while the benefits of DER participation flow to aggregators and individual DER resources. In this regard, wholesale aggregation programs could undermine the benefits of distribution utilities' existing retail DER programs, effectively imposing costs on retail customers to subsidize wholesale market participation.

2. The Benefits of Aggregated DER Participation in RTO/ISO Markets Remain Uncertain

Balanced against the challenges and the potentially significant costs of accommodating aggregated DER participation in RTO/ISO markets, the evidence is thin to show that there is a great demand for DER aggregation programs or that such programs will bring meaningful benefits to consumers in the RTO/ISO regions. In the NOPR, the Commission cited the California Independent System Operator Corporation's ("CAISO") Distributed Energy Resource Provider ("DERP") program as a model.[24] But as of November 2016, only four entities had signed agreements with CAISO to become DERPs under the program.[25] John Gooding of

[22] *See, e.g.*, Tr. at 155 (Zummo); Tr. at 348-49, 367 (Crews); Tr. at 407 (Ciabattoni); *see also* NOPR at P 126.

[23] *See* Tr. at 132-34 (Norton); Tr. at 155-56, 200 (Zummo).

[24] *See* NOPR at PP 8, 124 (citing *Cal. Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,229 (2016)).

[25] *California Indep. Sys. Operator Corp.*, Docket No. ER16-1085, Informational Report of the California Independent System Operator Corporation at 4 (Nov. 30, 2016).

CAISO stated at the technical conference that "[w]e have five contracts signed under our distribut[ed] energy resource provider agreement and yet we have no participation."[26] Henry Yoshimura of ISO New England, Inc. ("ISO-NE") expressed skepticism that an aggregation approach like the one described in the NOPR would draw participation by DERs in ISO-NE, which are mostly rooftop solar and energy efficiency.[27] Mr. Yoshimura remarked that adopting prescriptive rules might actually be counterproductive in ISO-NE because "the DERs that currently participate in the wholesale market will likely exit the market as they will not be willing or able to comply with the model's requirements."[28] Marcus Hawkins of the Organization of MISO States remarked that "[r]ight now what wholesale market participation will look like within MISO is unclear and it might be impacted by varying state policies throughout the footprint."[29] Technical conference panelists observed that the costs that would need to be incurred to facilitate DER aggregation in RTO/ISO markets (*e.g.*, new metering) could outweigh any benefits.[30] Even Ms. Lee of Sunrun, Inc. remarked that "we don't know" exactly how the DER products will work; stakeholders should "allow the market to come up with competitive solutions to figure out how."[31] Panelists indicated that there are no established best practices in implementing DER aggregation in RTO/ISO markets,[32] and they highlighted the importance of regional differences in designing RTO/ISO programs.[33]

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[26] Tr. at 69 (Goodin).

[27] *See* Tr. at 20-24, 31-32 (Yoshimura); *see also Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket Nos. RM18-9-000 and AD18-10-000, Statement of Henry Yoshimura at 5 (April 9, 2018) ("Yoshimura Statement").

[28] Yoshimura Statement at 6; *see also* Tr. at 22-23 (Yoshimura).

[29] Tr. at 233.

[30] *See* Tr. at 190 (Desu); Tr. at 367 (Crews).

[31] Tr. at 353 (Lee).

[32] *See* Tr. at 12, 47 (Bladen); Tr. at 43 (Yoshimura); Tr. at 283 (Bahramirad).

[33] *See* Tr. at 29, 47 (Bladen); Tr. at 22-23 (Yoshimura); Tr. at 115 (Thomas); Tr. at 130-31 (Mitchell); Tr. at 143

APPA recognizes that it is difficult to predict exactly how DER aggregation programs might develop if and when rules facilitating such programs are established. A lack of significant participation in DER aggregation programs would alleviate to some extent the operational and reliability concerns cited above. There is still a danger, however, that stakeholders, including distribution utilities, could devote significant time and expense to developing and implementing DER aggregation programs and related infrastructure to comply with Commission rules without much DER aggregation developing. Thus, while APPA can understand the suggestions by Commissioner LaFleur and others that adoption of clear, standardized rules might promote DER aggregation development,[34] there are simply too many uncertainties, regional and locational differences, and potential pitfalls to adopt a one-size-fits all, "build it and they will come" approach.[35] Rather, any rules adopted in this proceeding should allow for regional flexibility and discretion in facilitating the participation of aggregated DERs in wholesale markets.

As part of such a flexible approach, the Commission should recognize the authority of state and local regulators to determine whether DERs located on distribution facilities subject to their jurisdiction or behind the meter may participate in DER aggregation programs, as discussed below.

3. The Commission Should Adopt an "Opt-out/Opt-in" Framework for Aggregated DER Participation in RTO/ISO Markets Based on its Regulations for Demand Response Aggregation

The challenges associated with aggregated DER participation in the RTO/ISO markets are not insurmountable, but addressing these issues will require the adoption of adequate

(Picker); Tr. at 175 (DeSocio).

[34] *See, e.g.*, Tr. at 40-41 (Comm'r LaFleur).

[35] *See* Tr. at 35-37, 45-47 (Bladen); Tr. at 154-55 (Zummo); Tr. at 374 (Hall); Tr. at 415-16 (Kristov).

coordination frameworks between the RTOs/ISOs, distribution utilities, and DER aggregators.[36] This coordination would need to encompass state and local regulatory review, distribution utility review of proposed DER registrations, operational protocols, and procedures for addressing the complex settlement issues that wholesale market participation may present.[37]

An appropriate coordination framework must ensure that distribution utilities and state and local authorities are given an opportunity to fulfill their respective obligations to the public, without preemption or interference by prescriptive federal rules or tariffs.[38] Giving state and local regulators a key role in evaluating potential aggregated DER participation in the RTO/ISO markets would be an important safeguard in ensuring that participation in DER aggregation programs does not adversely impact distribution systems and the customers they serve. From the distribution utility's perspective, the RTO/ISO market rules must preserve the utility's legal authority and technical ability to maintain safe and reliable service over its facilities when its distribution system includes aggregated distributed energy resources. RTO/ISO market rules cannot prescribe the rules for protecting distribution operations and facilities. Instead, the RTO/ISO market rules must defer to, and market participation by resources must be subject to, the rules and regulations for local distribution service established under state and local law.

To provide an appropriate role for state and local authorities, any rules that the Commission adopts regarding the participation of aggregated DER in RTO/ISO markets should include a RERRA "opt-out/opt-in" mechanism applicable to wholesale market participation by aggregated DERs on the distribution system or behind a retail meter, similar to the

[36] *See, e.g.*, Tr. at 92-93 (Norton).

[37] *See, e.g.*, Tr. at 349-50, 395-96 (Crews) (describing the potential settlement complications associated with wholesale market participation of distribution cooperatives).

[38] *See* APPA/NRECA NOPR Comments at 25.

Commission's existing regulations for aggregated demand response bids in RTO and ISO markets adopted in Order Nos. 719 and 719-A.[39]

As APPA and NRECA explained in their NOPR comments,[40] a RERRA opt-out/opt-in approach for DER aggregation would appropriately provide a key decision-making role to those who are closest to the issues and who have an obligation to preserve local reliability and reasonable rates.[41] The opt-out/opt-in framework would permit state and local regulators, with input from distribution utilities and other stakeholders, to assess whether DER aggregation should be allowed on the distribution system(s) they regulate, taking into account the potential impacts of DER aggregation on the operation, reliability, security, and cost of the distribution system and its users. Such a holistic assessment of the impacts of DER aggregation on the local distribution system is one that only the RERRA, in conjunction with the distribution utility, is in a position, practically and legally, to perform.[42]

The participation of aggregated DERs in wholesale markets, like aggregated demand response, "is a complex matter that is subject to the confluence of State and Federal

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[39] 18 C.F.R. § 35.28(g)(1)(iii) (2017); *see also Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 at P 54, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009). Under the rules adopted in Order Nos. 719 and 719-A and currently reflected in the Commission's regulations, an ISO/RTO may not accept bids from an aggregator of retail customers that aggregates the demand response of the customers of utilities that distributed more than 4 million MWhs in the previous year, where the RERRA prohibits the demand response of such customers from being bid into the organized markets by an ARC (opt-out). 18 C.F.R. § 35.28(g)(1)(iii) (2017). In the case of customers of utilities that distribute 4 million megawatt hours or less, the ISO/RTO may not accept bids from an ARC unless the RERRA affirmatively permits it (opt-in). *Id.*

[40] APPA/NRECA NOPR Comments at 17-22.

[41] *See* Tr. at 367 (Crews); Tr. at 346 (Hall).

[42] *See* APPA/NRECA NOPR Comments at 31. Notably, IEEE 1547-2018 provides a significant role for the "authority governing interconnection requirements," or "AGIR." The AGIR is defined in the standard as a "cognizant and responsible entity that defines, codifies, communicates, administers, and enforces the policies and procedures for allowing electrical interconnection of DER to the Area EPS. This may be a regulatory agency, public utility commission, municipality, cooperative board of directors, etc." Local entity, or AGIR, control is required to ensure that the specifications and requirements within IEEE 1547-2018 and the National Electrical Safety Code which provide critical distribution system, public, and utility worker protection features remain in compliance, and to avoid desensitizing equipment to abnormal conditions.

jurisdiction."[43] Accommodating the authority of RERRAs in the rules governing DER participation in the wholesale markets would be consistent with the jurisdictional framework under the FPA. Section 201(b) of the FPA reserves for the states regulation of retail service;[44] the Commission may not "specif[y] terms of sale at retail – which is a job for the States alone."[45] Section 201(b) also specifically excludes local distribution facilities from the Commission's jurisdiction.[46] Most DERs that would participate in an aggregation program are likely to be very small. The Commission has recognized that "the vast majority of small generator interconnections will be with state jurisdictional facilities,"[47] and that such interconnections will be governed by state law.[48] State and local authority over the terms and conditions of interconnection to the distribution system would encompass authority to limit the manner in which a DER uses the distribution system.

Programs that allow wholesale market participation by resources interconnected at the distribution level have accommodated these jurisdictional parameters. Participants in CAISO's DERP program, for example, must comply with applicable distribution utility tariffs and

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[43] Order No. 719-A at P 54. *See also, e.g.*, NOPR at P 157 (observing that "the individual resources in these distributed energy resource aggregations will likely fall under the purview of multiple organizations (e.g., the RTO/ISO, state regulatory commissions, relevant distribution utilities, and local regulatory authorities)."

[44] 16 U.S.C. § 824(b)(1).

[45] *FERC v. Elec. Power Supply Ass'n*, 136 S.Ct. 760, 775 (2016) (footnote omitted).

[46] 16 U.S.C. § 824(b)(1).

[47] *See Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 at P 105 (2005), *order on reh'g*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006).

[48] Order No. 2006-A at P 105. The Commission treats certain distribution level interconnections as jurisdictional where the purpose of the interconnection is to make wholesale sales and the distribution facilities to which the resource is interconnecting are already subject to the utility's OATT. *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at PP 803-809 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 at PP 710, 730 (2004), *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd National Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

operating procedures, as well as applicable requirements of the local regulatory authority.[49] Similarly, in response to the Commission's conclusion that it lacked jurisdiction over the terms of interconnection for a number of wind generating plants interconnecting to distribution facilities in the PJM region,[50] PJM developed a Wholesale Market Participation Agreement that provides a process for resources to interconnect to the local distribution system at locations that are not under Commission jurisdiction to access and participate in FERC-jurisdictional electric markets.[51] As Mr. Langbein of PJM explained at the technical conference, the states set the interconnection criteria for such agreements.[52]

Providing RERRAs opt-out/opt-in authority over aggregated DER participation in RTO/ISO markets would accord with the NOPR's proposal that market participation agreements between DER aggregators and RTOs/ISOs include an attestation that the DER aggregation is compliant with distribution utility tariffs and operating procedures "and the rules and regulations of any other relevant regulatory authority."[53] Likewise, an opt-out/opt-in procedure would conform with the requirement in Order No. 841 that, in order to qualify as an electric storage resource ("ESR"), the resource must be "contractually permitted" to inject electric energy back onto the grid, for example, "per the interconnection agreement between an [ESR] that is interconnected on a distribution system or behind-the-meter with a distribution utility to which it is interconnected."[54] Although APPA has requested rehearing of the Commission's

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[49] *See Cal. Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,229 at P 15.

[50] *See PJM Interconnection, L.L.C.*, 114 FERC ¶ 61,191 (2006), *reh'g denied*, 116 FERC ¶ 61,102 (2006).

[51] *See* PJM Manual 14C at § 1.3.

[52] Tr. at 383-84 (Langbein).

[53] NOPR at P 157 (footnote omitted). In their comments on the NOPR, APPA and NRECA argued that a simple attestation by the DER aggregator would not be sufficient to prove such compliance. APPA/NRECA NOPR Comments at 40.

[54] Order No. 841 at P 33.

jurisdictional analysis in Order No. 841,[55] the Commission's adoption of this requirement appears to acknowledge that the distribution utility (and implicitly, the RERRA) may restrict a storage resource located on the distribution system or behind-the-meter from participating in the wholesale markets of an RTO or ISO. As well, the Commission emphasized in Order No. 841 the "ongoing, vital role of the states" regarding ESRs, including responsibility for "retail services and matters related to the distribution system,"[56] and the Commission clarified that nothing in Order No. 841 "is intended to 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."[57] The opt-out/opt-in rule would provide an administratively simple approach to safeguarding state and local authority.

The adoption of an opt-out/opt-in mechanism for aggregated DERs would also accord with the existing regulations for aggregated demand response participation adopted in Order Nos. 719 and 719-A. This is significant because DERs often participate in wholesale markets as demand response resources.[58] The Commission noted in the NOPR, therefore, that aggregated DERs participating in RTO/ISO demand response programs may be subject to the opt-out/opt-in framework adopted in Order Nos. 719 and 719-A.[59] Thus, at least some, and perhaps much, aggregated DER would be subject to the existing opt-out/opt-in regulations, and it would be both practically and legally problematic for the Commission to apply (as it must) its existing opt-

[55] As noted above, the AMP/APPA/NRECA rehearing request raises the issue of the extent to which Order No. 841 intended to address issues associated with electric storage resources connected at the distribution level or behind the meter.

[56] Order No. 841 at P 36.

[57] *Id.*

[58] *See, e.g.*, NOPR at P 106.

[59] *Id.* at P 157 n.238.

out/opt-in regulations to aggregated DERs participating as demand response, but decline to apply a similar rule for DER aggregation proposing to participate in the RTO/ISO markets under some other participation model.[60] The applicability of state authority should not turn on the wholesale participation model selected by the aggregator. Finally, because DERs can inject energy into the grid, unlike demand response, there is arguably an even greater need for preservation of the state and local authority over rules for participation.[61]

There was discussion at the technical conference concerning the establishment of criteria for aggregated DER participation in the RTO/ISO markets, including criteria that might be included in interconnection agreements between a DER and the distribution utility.[62] The Commission should not adopt any specific criteria that a RERRA is obligated to apply in determining whether to permit DER aggregation participation in the RTO/ISO markets. Consistent with state and local jurisdiction over distribution-level interconnections and the terms and conditions of retail service, state and local regulators have the authority to establish the criteria for such interconnections and service, and must be permitted to do so without preemption or interference with federal tariff rules or requirements.[63]

Finally, APPA disagrees with the notion that an opt-out/opt-in requirement for DER

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[60] The Commission must provide an adequate explanation for departing from previous rulings or treating similar situations differently. *See, e.g., County of Los Angeles v. Shalala*, 192 F.3d 1005, 1022 (D.C. Cir. 1999) (explaining that "an agency action is arbitrary when the agency offers insufficient reasons for treating similar situations differently"); *Koch Gateway Pipeline Co. v. FERC*, 136 F.3d 810, 815-16 (D.C. Cir. 1998) (same); *ANR Pipeline Co.*, 71 F.3d 897, 901 (D.C. Cir. 1995) (same); *see also, e.g.*, *Michigan Pub. Power Agency v. FERC*, 405 F.3d 8, 12-13 (D.C. Cir. 2005) (an agency may not depart from its previous rulings without providing an adequate justification); *Greater Boston Television Corp. v. FCC*, 444 F.2d 841, 852 (D.C. Cir. 1970), *cert. denied*, 403 U.S. 923 (1971) (same).

[61] *See, e.g.*, Tr. at 188 (DeSocio) (explaining that it would be challenging to extend NYISO's existing demand response framework to DERs that "are going to participate more as a dispatchable resource just like a traditional generator").

[62] *See, e.g.*, Tr. at 366 (Hall), Tr. at 369 (Robinson), Tr. at 369-70 (Langbein), Tr. at 382-85 (multiple panelists).

[63] *Cf.* Tr. at 382 (Hall), Tr. at 383-84 (Langbein).

aggregation would improperly inhibit innovation and market development.[64] If state and local regulators conclude – based on a detailed assessment of the likely operational, reliability, administrative, and cost impacts – that allowing DER participation in wholesale aggregation programs is likely to benefit (or at least not harm) the local distribution facilities and service they are charged with regulating, it must be assumed they will opt to allow it. Indeed, even in the face of substantial challenges, Chairman Thomas of the Arkansas PSC observed that "there's a critical mass of states in the MISO area that want to figure out how to mix it,"[65] *i.e.*, to participate in both retail and wholesale compensation programs.

4. The Commission Should, at a Minimum, Provide an Opt-In Mechanism for Small Utilities

APPA supports adoption of an opt-out/opt-in rule for aggregated DER participation in RTO/ISO markets that, like the existing regulations for demand response, would apply to both large utilities (opt-out) and small utilities (opt-in).[66] If, however, the Commission declines to adopt such a mechanism, it should, at a minimum, adopt an opt-in mechanism for small distribution utilities, as described more fully in the post-technical conference comments being submitted by TAPS. Under this proposal, RTOs and ISOs would be required to reject wholesale bids from an aggregator of retail customers that aggregates DERs connected to small distribution utilities, unless the small distribution utility expressly permits them.[67] The "opt-in" would be

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[64] *See, e.g.*, Tr. at 138-39 (Comm'r Glick). Commissioner Glick referenced the Illinois Commerce Commission's ("ICC") suggestion that the opt-out/opt-in framework had prevented demand response aggregation from developing in the Midwest. *Id.* The ICC's assertion was included in a footnote in OMS' February 13, 2017 comments on the NOPR. *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket Nos. RM16-23-000 and AD16-20-000, Comments of the Organization of MISO States at 5 n.3 (Feb. 13, 2017).

[65] Tr. at 119 (Thomas).

[66] 18 C.F.R. § 35.28(g)(1)(iii) (2017).

[67] A small utility would be defined the same way as in Order No. 719-A, *i.e.*, utilities "that distribute 4 million megawatt-hours or less in the previous fiscal year." 18 C.F.R. § 35.28(g)(1)(iii); *see also* Order No. 719-A at P 51. The vast majority of public power utilities in the United States fit within this definition.

exercised by distribution utilities, rather than RERRAs, under the TAPS proposal.[68]

The small utility proposal is appropriate given the potential costs and obligations that could be imposed on distribution utilities to guard against adverse impacts from wholesale market participation by dispatchable DERs. As TAPS explains, small utilities typically have few staff and limited financial and technical resources to implement the operational changes and new procedures that may be required to accommodate aggregated DER participation in RTO/ISO markets. These utilities are less likely than larger utilities to coordinate directly with RTOs/ISOs, and they may not have the staff necessary for around-the-clock monitoring for potential adverse impacts of DER aggregator dispatch decisions. The discussion at the technical conference specifically highlighted some of these concerns.[69] Accordingly, if the Commission declines to adopt the RERRA opt-out/opt-in framework for all DER aggregation, the Commission should adopt the small utility opt-in proposal as described by TAPS.

5. The Commission Should Make Clear that State and Local Regulators Retain Authority to Set Rates for the Recovery and Allocation of Costs Associated with Participation of Aggregated DER Participation in RTO/ISO Markets

Regardless of whether the Commission adopts the opt-out/opt-in approach described above, the Commission should specify in any final rule that nothing in the rule preempts or otherwise limits the ability of state and local regulators to adopt rules, tariffs, and to set rates to recover and allocate the costs associated with facilitating wholesale market participation by aggregated DERs.[70]

Accommodating aggregated DERs is likely to impose incremental costs on distribution

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[68] As TAPS notes, the rule could also be structured to provide for the opt-in for small utilities to come from the RERRA (if separate from the distribution utility).

[69] *See* Tr. at 132-33 (Norton); Tr. at 154-55 (Zummo).

[70] *See* APPA/NRECA NOPR Comments at 38.

utilities beyond any expenses that they would incur in connection with DERs that do not participate in the RTO/ISO markets. Such costs could include, but would not necessarily be limited to, upgrades to distribution facilities, enhanced metering and communications infrastructure, computer hardware and software, staffing costs, and legal and regulatory spending. These incremental costs, moreover, will flow to the benefit of the DER aggregation participants, and are unlikely to provide commensurate benefits, if any, to the distribution utility's native retail load customers.

As discussed above, the vast majority of distribution-level interconnections are likely to be subject to state jurisdiction. State and local authorities, therefore, have the authority to set the terms and conditions of such interconnection, including allocation and recovery of the costs associated with monitoring and addressing potential impacts on the distribution grid associated with the interconnection and operation of the DER resource. RERRAs must have the authority to ensure equitable cost recovery and cost allocation for distribution facilities and services used by DERs when participating in RTO/ISO markets to be sure that other customers using the distribution system do not subsidize participation of DER aggregation in those markets.

6. The "Limited Opt-Out" Concept Does Not Adequately Address the Concerns Associated with Participation of Aggregated DER in RTO/ISO Markets

The Commission's April 27 Notice requests comments on the "limited opt-out" concept proposed by Chairman Thomas of the Arkansas PSC, the President of the Organization of MISO States ("OMS").[71] As APPA understands the proposal, the RERRA would have the authority to require that each particular distributed energy resource asset elect to participate in *either* the

[71] *See* Tr. at 119-22.

wholesale RTO/ISO markets *or* retail DER programs, but not both.[72] In other words, there would be no "mixing" of wholesale and retail compensation for any DER asset.[73] The proposal, however, would be "limited" insofar as RERRAs would not have authority to prevent a DER from electing to participate in the RTO/ISO markets.

The limited opt-out proposal is aimed at addressing the complications of DERs participating in *both* wholesale and retail compensation programs. While APPA appreciates the efforts of Chairman Thomas and OMS to suggest a creative solution for those challenges, APPA does not believe that the limited opt-out mechanism is a reasonable substitute for a full opt-out/opt-in approach. Under the limited opt-out proposal, DER assets could still choose to participate in RTO/ISO markets despite a RERRA's objection, and despite any attendant operational challenges and cost exposure that the DERs' wholesale market participation could impose on distribution utilities. A full opt-out/opt-in rule would recognize state and local regulators' authority to assess, on a comprehensive basis, whether aggregated DER participation by resources interconnected to facilities subject to their jurisdiction or behind the meter would benefit end-use customers. The limited opt-out approach, in contrast, would only recognize the RERRA's authority to restrict wholesale market participation if a DER asset opted to participate in a retail DER compensation program.[74]

If, however, the Commission declines to adopt a full opt-out/opt-in approach as endorsed by APPA, implementing a limited opt-out rule would at least allow RERRAs to insulate distribution utilities and their customers from the complications associated with DERs

[72] *See* Tr. at 119-22

[73] Tr. at 119-22.

[74] RERRAs already possess the right to restrict participation in a *retail* DER programs, so there is no practical significance to "allowing" RERRAs to limit such participation under the "limited opt-out" approach when a DER asset opts to participate in the RTO/ISO markets.

participating in both the retail and wholesale markets.[75] Even under a limited opt-out rule, however, distribution utilities and their RERRAs must be able to apply appropriate interconnection requirements and conditions on DERs and retain their authority over cost recovery and cost allocation for distribution facilities and services used by DERs when participating in RTO/ISO markets.

B. The Commission Should Adopt the NOPR's Proposal to Restrict DERs From Participating in Both State Retail Compensation Programs and in Wholesale DER Aggregation (Panel 3)

The NOPR reasonably proposed a bright line rule under which DERs participating in one or more retail compensation programs (or another wholesale program) would be ineligible to participate in the RTO/ISO markets as part of a DER aggregation.[76] Among the issues discussed at the technical conference was whether rules could be fashioned to allow a DER to participate in retail DER programs *and* wholesale DER aggregation programs, so long as resources were not double-compensated for providing the same service in both markets. APPA urges the Commission to adhere to the bright line rule proposed in the NOPR.[77]

The discussion at the technical conference did not suggest any disagreement with the principle that DERs should not be permitted to collect double compensation for providing the same service in both the retail and wholesale markets. But the technical conference also demonstrated the challenges associated with identifying the "same" or "different" services in the retail and wholesale markets. RTO and ISO representatives and other stakeholders that have worked on these questions acknowledged the difficulty of drawing workable distinctions

[75] *See* Tr. at 154-55 (Zummo).

[76] NOPR at P 134.

[77] If the Commission does not adopt the full opt-out/opt-in approach supported by APPA, the Commission could also address the complications associated with DERs participating in both the retail and wholesale markets by adopting the "limited opt-out" described above.

between different services.[78] And while additional metering and communications technology may be *necessary* to facilitate aggregated DER participation in RTO/ISO markets, the complications associated with distinguishing between services suggests that such infrastructure would not be *sufficient* to define different services.

Even proponents of allowing DER participation in both markets had difficulty articulating clear, consistent guiding principles to resolve the double compensation issue. Mr. Ko of Stem, for example, described a complicated conceptual approach focusing on whether the compensation in the wholesale market is for "incremental value" provided in the wholesale market, a question that he said would involve assessing whether "providing of the retail service in some way affects the efficient clearing of the wholesale market."[79]

Ms. Guerry of EnerNoc argued for an approach focused on the "dispatch trigger."[80] She stated that "[a]n example of something that is not the same service would be if a DER is registered at the wholesale level to be available in the event of a reliability event – that customer could also be signed up at the distribution level to be available in the event of reliability."[81] But looking at the dispatch trigger to distinguish between services is problematic. For example, a resource that receives capacity payments in the RTO/ISO markets is committing to make energy available in the wholesale market if called upon, and, allowing that resource also to collect net metering payments for energy provided to the distribution company would be a form of double compensation. In this regard, Mr. Crews of East Kentucky Power Cooperative pointed out that, in PJM, capacity resources are required to offer into the PJM day-ahead energy market as a

[78] *See, e.g.*, Tr. at 119-20 (Thomas); Tr. at 156-59 (Baker), Tr. at 160-61, 173, 174-75 (DeSocio); Tr. at 166 (Kuga).
[79] Tr. at 152.
[80] Tr. at 150-51.
[81] Tr. at 151.

condition of receiving capacity payments.[82] Even more fundamental, such a dual offering is inconsistent with the principle of a reliability resource; if the reliability event occurs within the same time frame at the wholesale and the retail level, the resource can't be available in both markets at once.

To prevent double compensation for DERs, the Commission should adopt the NOPR's proposal under which DERs participating in one or more retail compensation programs (or another wholesale program) would be ineligible to participate in the RTO/ISO markets as part of a DER aggregation.[83]

Further, as discussed in the APPA/NRECA comments on the NOPR, the Commission should require RTOs and ISOs to adopt restrictions on DER assets switching back and forth between wholesale and retail market participation.[84] In particular, APPA and NRECA proposed that, once a DER asset elects to participate in one market or the other, at least a one-year period should elapse before the resource can switch.[85]

Finally, if the Commission declines to adopt a full opt-out/opt-in approach as endorsed by APPA, the Commission should acknowledge that the RERRA can require, as a condition of

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[82] Tr. at 359 (Crews). Other regions also have must-offer requirements for capacity resources or resources used for resource adequacy. *See* CAISO Business Practice Manual for Reliability Requirements, Sections 7.1.2 and 7.1.3 (generally requiring that Scheduling Coordinators for Resource Adequacy Resources must submit them into the market for all hours that the resource is physically available, and remain available to ISO); MISO Resource Adequacy Business Practice Manual Section 4.2.1.3 (requiring that cleared Capacity Resources must submit the full operable capacity of the Resource and make an offer into the Day-Ahead Energy market and the first post-ay Ahead Reliability Assessment Commitment for every hour of every day); PJM Manual 18, Section 5.5 (requiring that all generation resources that have a Reliability Pricing Model commitment must offer into PJM's Day-Ahead Energy Market); ISO-NE Market Rule 1, III.13.6.1.1.1 (requiring that a Generating Capacity Resource with a Capacity Supply Obligation must be offered into both the Day-Ahead Energy Market and the Real-Time Energy Market); SPP Integrated Marketplace Market Protocols, Section 4.2.1 (requiring that Market Participants offer available Resources to the energy markets); NYISO Installed Capacity Manual, Section 4.8 (requiring that for any day for which it supplies Unforced Capacity, each Installed Capacity Supplier must either schedule or bid into the NY ISO Day-Ahead Market or declare to be unavailable).

[83] NOPR at P 134.

[84] *See* APPA/NRECA NOPR Comments at 40-41.

[85] *Id.* at 41.

participating in a retail compensation program, that the DER asset cannot also participate in a DER aggregation in the RTO/ISO markets.

C. The Commission Should Adopt Strong Coordination Requirements Among DERs, RTOs/ISOs and Affected Electric Distribution Utilities (Panel 6)

The operational and reliability challenges presented by aggregated DER participation in RTO/ISO markets requires that distribution utilities, and their state and local regulators, play an instrumental role in coordinating such wholesale market participation. As APPA explained in section III.A above, a key "coordination" mechanism that the Commission should adopt is a rule recognizing the authority of RERRAs to opt-out or opt-in of allowing aggregated DER participation in RTO/ISO markets.

Where aggregated DER participation in RTO/ISO markets proceeds (either because a RERRA has permitted it or because such participation has otherwise been authorized), it is essential that the affected distribution utilities have a central and continuing role in coordinating the participation of particular DER assets in the wholesale markets. To accomplish the objective of "ensur[ing] that the participation of these [DER] resources in the organized wholesale electric markets does not present reliability or safety concerns for the distribution or transmission system,"[86] the coordination requirements in any final rule should be expanded to ensure that affected distribution utilities are not limited to a mere advisory role.[87]

In this regard, a DER aggregator should be required to establish that the DERs participating in the aggregation are authorized to participate under the applicable "tariffs and operating procedures of the distribution utilities and the rules and regulations of any other

[86] NOPR at P 153.

[87] *See* APPA/NRECA NOPR Comments at 43-46.

relevant regulatory authority."[88] Distribution utilities should have the right to receive notice and provide binding input to RTOs/ISOs as to whether particular DERs can participate in an aggregation. Such binding input should take the form of explicit, affirmative consent from the distribution utility for a particular DER resource to participate. While the Commission should allow for flexibility in how RTOs/ISOs propose to ensure this binding input, the rules should be clear that the obligation is on the DER or aggregator to obtain affirmative distribution utility assent to participate in RTO/ISO markets. Further, as discussed in the APPA/NRECA NOPR Comments, distribution utilities should receive notice and the ability to provide binding input with respect to changes to a DER aggregator's registered resources.[89]

The Commission should refrain from adopting specific criteria governing distribution utility evaluation of individual DER participation. Adoption of criteria by the Commission purporting to define and delimit the requirements that a distribution utility could apply in managing the use of its non-FERC-jurisdictional facilities would, at a minimum, present significant jurisdictional questions. In any case, the better course is to allow for flexibility in the criteria to be applied by distribution utilities.

D. Distribution Utilities Must Have the Authority to Override RTO/ISO Dispatch Decisions (Panel 7)

The principal question that APPA wishes specifically to address in connection with Panel 7 is whether distribution utilities should "be able to override RTO/ISO decisions regarding day-ahead and real-time dispatch of DER aggregations to resolve local distribution reliability issues?"[90] This question must be answered in the affirmative. Distribution utilities simply must

[88] NOPR at P 157.

[89] APPA/NRECA NOPR Comments at 44-45.

[90] April 27 Notice at 9.

have the ability at all times to manage the reliable operation of their distribution systems. Further, the transmission system is likely to be able to absorb and adapt to the impact of an overridden DER dispatch signal, whereas a particular DER dispatch may cause a localized reliability problem on the distribution system that may not be easily managed absent the ability of the distribution utility to override the dispatch. The discussion at the technical conference also supports the need for distribution utility override authority.[91] APPA takes no position on whether DER aggregations should be subject to non-deliverability penalties in such a circumstance.

IV. CONCLUSION

APPA appreciates the opportunity to provide these comments on DER aggregation in RTO and ISO markets. APPA generally supports the Commission's effort to remove barriers to DER aggregation in RTO/ISO markets, but it is important for the Commission to distinguish between undue barriers to DER participation in wholesale markets and factors that, although they might have the effect of limiting DER participation in those markets, are grounded in legitimate operational, reliability, and regulatory considerations relating to DER wholesale market participation. In developing any final rule in this proceeding, APPA respectfully requests the Commission to adopt the recommendations of APPA, which are aimed at ensuring that the operational, reliability, and regulatory challenges associated with aggregated DER participation in the RTO/ISO markets are adequately addressed for the benefit of end-use customers.

[Signature block appears on the next page]

[91] *See* Tr. at 435 (Gray); Tr. at 436 (Ipakchi); Tr. at 437 (Kristov); Tr. at 439 (Parker); Tr. at 443 (Ciabattoni).

Respectfully submitted,

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