UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

POST-TECHNICAL CONFERENCE COMMENTS OF THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

June 26, 2018

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Pursuant to the Notice Inviting Post-Technical Conference Comments issued by the Federal Energy Regulatory Commission ("Commission" or "FERC"), the National Rural Electric Cooperative Association ("NRECA") submits these comments addressing issues discussed at the technical conference held April 10-11, 2018, regarding the Commission's proposals concerning the participation of distributed energy resource ("DER") aggregations in Regional Transmission Organization ("RTO") and Independent System Operator ("ISO") markets.

I. INTRODUCTION AND SUMMARY OF COMMENTS

NRECA appreciates the opportunity to provide input to the Commission on the topics discussed at the technical conference. NRECA has participated actively in the Commission's rulemaking efforts. NRECA submitted comments jointly with the American Public Power Association[1] on the Commission's Notice of Proposed Rulemaking,[2] and joined in a request for rehearing[3] of Order No. 841, the Final Rule on electric storage participation in RTO/ISO

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1 Comments of the American Public Power Association and the National Rural Electric Cooperative Association on Notice of Proposed Rulemaking, Docket Nos. RM16-23-000, AD16-20-000 (Feb. 13, 2017).

2 *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,718 (2016) ("NOPR").

3 Request for Rehearing of American Municipal Power, Inc., the American Public Power Association and the National Rural Electric Cooperative Association, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, et al.*, Docket Nos. RM16-23-000, AD16-20-000 (Mar. 19, 2018).

markets.[4] NRECA's comments are focused primarily on the questions raised with respect to Panels 2, 6 and 7 of the technical conference.

NRECA fully supports the development of DERs, and many of its member cooperatives across the country have been successful in using DERs owned either by the cooperatives themselves or by the cooperatives' member-consumers. In some cases, distribution cooperatives manage the DERs themselves, while in other cases, distribution cooperatives are members of generation and transmission ("G&T") cooperatives, which manage the DERs on behalf of their distribution cooperative members.[5] To be sure, DER deployment is presenting cooperatives with new challenges—but also with new opportunities to meet their ultimate objective of providing safe, reliable, sustainable, and affordable electric service to their member-consumers.

The Commission's proposal to require RTOs and ISOs to permit third-party DER aggregators to participate directly in RTO/ISO markets has the potential to pose an entirely distinct, and much larger, constellation of challenges for NRECA's member cooperatives than does the simple deployment of additional DERs on cooperative distribution systems. Third-party DER aggregators participating in the RTO/ISO markets will have incentives to operate the DER in response to wholesale market signals, which can pose operational, reliability, and safety issues for local distribution cooperatives. Moreover, to facilitate third-party DER aggregators participating directly in wholesale markets, nearly every cooperative will have to invest in new equipment and software for metering, communications, and billing. Cooperatives will have to develop new customer privacy and cyber-security measures to accommodate DER aggregators. Additional staffing by cooperatives will be required to participate meaningfully in the RTO/ISO

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4 *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, Final Rule, 162 FERC ¶ 61,127 (2018) (errata notice issued Feb. 28, 2018).

5 *See* Technical Conference Tr. at 412 (explaining how G&T aggregates for distribution cooperatives).

stakeholder processes where the new market rules will be developed; to develop and implement the needed coordination agreements—and perform the ongoing coordination—with the aggregators, the RTO/ISO, and multiple other parties; and to review and address the reliability impacts of DER aggregations. Cooperatives will have to undertake these tasks while they are still in the beginning phases of implementing the new interconnection requirements for DER adopted earlier this year.[6] Cooperatives will also have the expense of developing new rate structures to recover these additional costs and fairly allocate them to DER aggregators and if appropriate, to the cooperatives' members. Beyond these direct costs, cooperatives may incur increased operational costs if (as one would expect) the DER aggregator cherry-picks certain members' DER and essentially removes them from the cooperatives' resource portfolios, or if the DER aggregator reduces the ability of the distribution (or even the G&T) cooperative to control the peak loads that help determine its wholesale power and transmission bills. For some cooperatives, it may make sense for their members to incur these costs and burdens sooner rather than later; but for others—particularly smaller distribution cooperatives in more rural communities—it does not make sense for them to incur these substantial costs now for, what may be at best, an uncertain future benefit.

This is why NRECA has been urging the Commission, in comments on the NOPR and in its request for rehearing of Order No. 841, to modify its proposed requirements for the RTOs and ISOs to ensure that the RTO and ISO market rules respect the decisions by the relevant electric retail regulatory authority ("RERRA") on whether to permit DER aggregations to participate directly in wholesale markets. NRECA reiterates this request and proposes specific regulatory language below.

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[6] IEEE Std 1547™-2018, Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces ("IEEE 1547").

The discussions at the technical conference raised a plethora of issues related to the impacts that DER aggregations participating in RTO/ISO markets could have on distribution systems. To honor the Commission's request for concrete examples in support of comments,[7] NRECA surveyed its member cooperatives, seeking input on the potential impacts that DER aggregations could have on their systems, and sought the technical assistance of an engineering firm to analyze the issues discussed at the technical conference. NRECA appends to its comments as Attachment A the affidavit of Jeffrey M. Triplett, P.E., of Power System Engineering, Inc. ("Triplett Affidavit"), and as Attachment B, the statements of several of its members providing concrete examples of the effects that the Commission's proposal could have on them, if that proposal is not modified as NRECA recommends:

- Adams-Columbia Electric Cooperative, a distribution cooperative in Wisconsin whose distribution facilities are interconnected to a transmission-owning member of the Midcontinent Independent System Operator, Inc. ("MISO");[8]
- Anza Electric Cooperative, Inc. ("Anza"), a very small distribution cooperative located within the California Independent System Operator ("CAISO");[9]
- Dakota Electric Association ("Dakota Electric"), a large distribution cooperative in Minnesota, whose G&T cooperative is a transmission-owning member of MISO;[10]
- New Hampshire Electric Cooperative, Inc. ("NHEC"), a distribution cooperative that participates in ISO New England Inc. ("ISO-NE");[11] and
- Ozark Electric Cooperative, Inc. ("Ozark"), a small distribution cooperative in Missouri.[12]

These statements provide evidence supporting NRECA's core message—that the Commission should modify its NOPR proposal to require RTO and ISO market rules to allow

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7 April 27 Notice Inviting Post-Technical Conference Comments at 1.

8 Statement of Gerry Schmitz, Adams-Columbia Electric Cooperative ("Adams-Columbia Statement").

9 Statement of Kevin Short, Anza Electric Cooperative, Inc. ("Anza Statement").

10 Statement of Craig C. Turner, P.E., Dakota Electric Association ("Dakota Electric Statement").

11 Statement of Brian Callnan, New Hampshire Electric Cooperative, Inc. ("NHEC Statement").

12 Statement of Kenneth M. Raming, P.E., Ozark Electric Cooperative, Inc. ("Ozark Statement").

DER aggregators to offer to sell capacity, energy, and ancillary services into organized wholesale markets *only* (i) for larger systems, if the RERRA does not prohibit it or (ii) for smaller systems, if the RERRA expressly permits it. This opt-out/opt-in condition on the Commission's directive that RTOs and ISOs accept bids by DER aggregators would respect state and local jurisdiction over retail and local distribution service, avoid needless controversy over the extent of the Commission's own authority, and avoid the potential for serious unintended consequences harming distribution utilities and the consumers they serve. RERRAs must be able to determine if and when to allow such DER aggregations in the retail markets and on the distribution systems over which they have authority.

II. COMMENTS

A. The Commission Should Direct RTOs/ISOs To Adopt Procedures That Require RTOs/ISOs To Defer to State and Local Regulatory Authorities.

1. Failing To Give the RERRAs of Distribution Utilities a Say in Whether Third-Party DER Aggregation Should Be Permitted on their Systems Will Harm Consumers.

Although cooperatives come in different sizes, and no two cooperatives are the same, generally speaking, distribution cooperatives are located in rural areas with low population densities and many fewer customers per mile of line than most investor-owned or municipal utilities.[13] They are typically small and some operate with a staff of fewer than 25 people.[14] In order to serve their geographically dispersed membership, distribution cooperatives often have long radial lines to reach their members. Distribution cooperatives typically serve a high

[13] The nation's 833 distribution cooperatives and 62 G&T cooperatives serve 42 million people—about one in eight electric consumers in the nation. Cooperatives own and maintain 42% of the nation's electric distribution lines—some 2.6 million miles. Using the latest data released from the Energy Information Administration (Form EIA-861), NRECA has calculated that cooperatives serve an average of eight consumers per mile of electric line and collect annual revenue of $19,000 per mile of line. All other utilities average 32 customers per mile of line and collect $79,000 per mile. *See* https://www.electric.coop/electric-co-op-facts-figures-march-2018/.

[14] Anza Statement at P 3.

percentage of residential consumer-members, although some also serve farms and other commercial and industrial customers. Some distribution cooperatives obtain their generation and transmission services from investor-owned utilities, but many are all-requirements customers of their G&T cooperatives. On an operational level, distribution system infrastructure is often dynamic compared to the transmission system infrastructure;[15] customers are routinely being added/retired, and distribution equipment is routinely upgraded and replaced. Additionally, distribution utilities have little to no real-time coordination with RTOs/ISOs (including dispatch, outage coordination, congestion management, etc.), and little to no planning coordination with RTOs/ISOs (modeling, forecasting, contingency analysis, financial transmission rights, *etc*.).[16]

Accordingly, the participation of DER aggregations in RTO and ISO markets is unworkable today for nearly all distribution cooperatives and would not benefit their consumers. A multitude of operational and economic impacts could interfere with cooperatives' mission—to ensure their member-consumers receive safe, reliable electricity at affordable rates. Many cooperatives already use DERs as a tool to reduce their electricity costs and have developed DER programs that benefit all their member-consumers. Third-party DER aggregators would not (and should not be expected to) share the same goal; rather, they would strive to maximize their wholesale revenue. There is no assurance that a DER aggregation participating directly in wholesale markets and independently responding to RTO/ISO dispatch signals would benefit the cooperative, and there are good reasons to think it would not. In some cases, DER aggregation is

15 Technical Conference Tr. at 363-64 (distribution feeder configuration changes frequently, many times a day); *see also id.* at 414-15 (abnormal configuration circuit switching is more volatile on distribution).

16 Triplett Affidavit at P 37; *see also* Technical Conference Tr. at 407-08.

unworkable because the cooperative cannot back-feed energy from its distribution system to the transmission grid[17]—all the more reason for the RERRA to have the ability to opt-out/opt-in.

RTOs and ISOs are not in a position to know whether a third-party DER aggregation could operate on a particular distribution cooperative without compromising the safety and reliability of the distribution system or imposing unreasonable costs on the cooperative. Therefore, only the cooperative's board or its state regulator should decide if and when it would be beneficial (and not harmful) to consumers to allow third-party DER aggregations on the distribution system for the purpose of wholesale market participation. The Commission has an obligation to protect electric customers and should stick to the mantra: first, do no harm.

2. Third-Party DER Aggregation May Create Complex Operational Impacts for Distribution Utilities, and the RERRA Should Decide Whether These Impacts Have Been Adequately Addressed.

Without appropriate deference to distribution systems and their governing authorities, the Commission's proposal to require RTOs/ISOs to permit third-party DER aggregation to participate in wholesale markets could create unintended, yet significant, consequences. NRECA discusses some of these issues below.

a. Reverse power flows and voltage stability

Distribution systems were originally designed for radial, one-directional power flows. While some facilities have been upgraded over time to accommodate two-way power flows, particularly to allow back-feeding during contingencies, a significant portion of existing distribution system feeders safely cannot accommodate reverse power flows.[18] Some of NRECA's members have expressed concern that third-party DER aggregation could result in

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[17] Anza Statement at P 11 (due to import capacity limits and interconnecting utility's inability to accept reverse flows "it would be difficult—if not impossible—for an aggregated DG provider to build and export renewables on our system.").

[18] *See* Triplett Affidavit at P 8.

increased reverse power flows on their systems,[19] and they may lack the resources to deal with additional risk of reverse power flow.[20] Reverse flows from the distribution system to the transmission grid may also be prohibited by contract. For example, Anza's contract with the investor-owned utility from whom it purchases transmission service does not permit reverse flow from the cooperative to either the utility or to the ISO.[21]

Implementing systems to protect against reverse power flow can be quite costly.[22] The risk that voltage levels will rise above appropriate industry standards and that voltage will fluctuate and flicker beyond acceptable limits increases with third-party DER aggregation. This can be a particular concern when a distribution utility attempts to curtail DER output to maintain acceptable voltage levels while a third-party DER aggregator is simultaneously responding to market signals telling it to increase output.[23] If third-party DER aggregation is allowed, distribution voltage regulators, which are only one-way flow regulators, will need to be upgraded in order to be able to support the two-way flows needed, at a significant cost to the distribution utility.

b. Risks that third-party DER aggregators could override or modify operational settings.

Distribution utilities typically require DERs to operate at unity power factor.[24] In order to more effectively manage system losses and voltage issues, IEEE 1547 now requires DER

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19 Adams-Columbia Statement at PP 5, 7.

20 Ozark Statement at P 13.

21 Anza Statement at P 5.

22 NHEC Statement at P 15.

23 *See* Triplett Affidavit at P 8.

24 One key aspect of optimizing and maintaining system utilization and efficiency on any distribution system is that of "power factor," a term which refers to the relationship between "real" and "reactive" power. Reactive power is a characteristic of most electrical load and is typically measured in kVAR (kilovolt-amperes reactive), whereas real power and energy are typically measured in kW and kWh, respectively. Motors have inductive (magnetic) characteristics which consume reactive power, known as "lagging" power factor. This requires a

equipment manufacturers to provide means of voltage control through reactive power regulation. Both the method used and the settings are at the discretion of the distribution utility. However, anything other than unity power factor inherently reduces kWh sales of the DER. Because the equipment involved is typically owned by the DER, it could be tempting for a third-party DER aggregator to adjust the DER's reactive power settings to allow more to be sold.[25] Operating the DER in this fashion can also actively change the voltage through changes in reactive power flows on the distribution system, creating a risk of harm to the distribution system equipment and the consumers they serve.[26] While communications and telemetry with the DER may reduce the risk of this going undetected, the temptation has to be acknowledged.

c. Risks that third-party DER aggregators could override or modify protection settings.

Interconnection equipment for DERs will typically be owned by the DER owner or aggregator. NRECA is concerned that critical protection features in compliance with the IEEE 1547 standard could be overridden or modified (intentionally or unintentionally) to allow DER aggregators to continue to operate through certain over-voltage or under-voltage situations in an effort to increase sales.[27] This can compromise the safety of both utility workers and the public by desensitizing equipment to abnormal conditions. NRECA's members have expressed concern

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distribution system to use more capacity than would otherwise be required and contributes to system losses and voltage regulation issues. Capacitors can supply reactive power and are frequently installed at specific points on a circuit to reduce the reactive power load on the distribution system. Real and reactive power can be envisioned as two legs of a triangle with the third leg as the combined effect, referred to as "apparent" power, measured in kVA (kilovolt-amperes). The ratio of real to apparent power is the measurement of power factor; in an ideal system this ratio is 1.0, or "unity power factor."

[25] Adams-Columbia Statement at P 6 (minimizing system losses requires dispatching DERs at other than unity factor, which would be at odds with the financial interests of third-party aggregated DER).

[26] Triplett Affidavit at P 10.

[27] Triplett Affidavit at PP 9-13.

about the ability of certain settings, for example, the settings of protective devices such as inverters, to be adjusted by third-party aggregators.[28]

d. Safety concerns

Safety is a top priority for distribution cooperatives. One safety-related concern that arises with third-party DER aggregation is that the cooperative will not be able to—as it must—maintain its authority for opening DER disconnect devices as needed and in accordance with established interconnection agreements, regardless of whether the DER has been dispatched to provide a market service.[29] While reverse power flow can exist in some areas already, some cooperatives closely manage DER connections and capacity in order to minimize the risk of this occurrence. Such safe work practices allow linemen to keep up with the source and load ends of feeders. NRECA has heard concerns from some members about the safety of distribution linemen if third-party aggregations of DER for the purpose of operating in the wholesale market are allowed on their systems because it will likely increase the risk of reverse power flows. Additionally, third-party DER aggregation may lead to conditions which are more favorable to the formation of unintentional islands, which present safety and power quality risks. This is because there may be more capacity available during periods of light load, making detection and disconnection more challenging.[30] Before third-party DER aggregations can be allowed on distribution systems, distribution cooperatives must have the ability to develop additional protocols to ensure linemen safety.[31]

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28 Ozark Statement at P 15; NHEC Statement at P 16.

29 Triplett Affidavit at P 13; NHEC Statement at P 19 (cooperative should be allowed to curtail or disconnect DER when the safety of its members, staff or the distribution system is in question). *See also* Technical Conference Tr. at 433, 435, 436, 437, 439, 443 (need for distribution utility to override RTO/ISO dispatch for reliability and security of distribution system).

30 Triplett Affidavit at P 8.

31 Ozark Statement at P 11 (linemen would have to use bracket grounding on both sides of the work zone to provide additional protection from DERs).

3. The Proposal for RTOs and ISOs To Use Distribution Utility Meter Data for DER Aggregator Settlements Raises Legitimate Privacy and Safety Concerns for the RERRA.

The Commission proposes to require RTOs/ISOs to rely heavily on meter data obtained through compliance with distribution utility or local regulatory authority metering system requirements for settlement and auditing purposes.[32] Aside from the question of whether that proposal is workable—and it probably is not for most distribution cooperatives—it raises serious concerns with respect to system safety and customer privacy.

Existing distribution cooperative metering systems may not provide the granularity of data (*e.g.*, five minutes) required by RTO/ISO markets for settlement and auditing purposes.[33] Moreover, even if they had this capability, providing such data would consume communication system bandwidth that might be needed for critical outage reporting and restoration efforts, end-of-line voltage feedback into conservation voltage reduction systems, and other utility operations. Such uses must be given the highest priority, meaning that metering data for the purpose of third-party DER aggregators participating in wholesale markets would necessarily be assigned a lower priority. The safety and integrity of the distribution system require nothing less.[34]

The Commission's metering proposal would also require distribution cooperatives to revisit their policies on cybersecurity and privacy. Typically such policies do not permit access to internal systems or the sharing of customer information with other parties.[35] Special interfaces and data repositories with multiple levels of firewalls would need to be created and maintained to

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[32] NOPR at P 152.

[33] Adams-Columbia Statement at P 9.

[34] *See* Triplett Affidavit at P 16.

[35] Ozark Statement at P 14 ("Ozark has existing privacy policies in place today that protects our members' data…..This could be a problem if DER aggregators were to seek information about our members' data.").

facilitate the sharing of any data between the distribution cooperative and DER aggregators.[36] Furthermore, agreements would likely need to be obtained from customers whose data would need to be shared with the RTO/ISO.[37]

B. Third-Party DER Aggregation Would Impose Significant Costs on Distribution Cooperatives—Costs That Should Be Recoverable From Those DER Aggregators.

A litany of new costs would be imposed on cooperatives as a result of the Commission's proposal. These costs include large investments in equipment and software, and the operating expense required to accommodate DER aggregators. Many upfront costs would be incurred without regard to the actual extent and pace of DER penetration, much less the benefits for cooperatives' member-consumers that subsidize the investment and expense. The costs for cooperatives also include the economic losses associated with the impaired ability of the distribution cooperative—and perhaps its G&T cooperative—to hold down its operating costs, which can result from the DER aggregation's independent, wholesale-market-driven operations.

The incremental investment and expense required to accommodate third-party aggregation, as distinguished from integration of DERs by utilities in their load-serving operations, unless entirely assigned directly to the aggregators, would amount to an unjustifiable subsidy of the aggregators by native load ratepayers. These expenses would benefit DERs and their third-party aggregators—not existing utility operations—and therefore should be recovered solely from those third-party DER aggregators or the DERs themselves.[38] Determining how this

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36 Triplett Affidavit at 24; *see also* Technical Conference Tr. at 402.

37 Triplett Affidavit at P 24; Ozark Statement at P 14.

38 While the focus here is on the significant *incremental* costs that DER aggregation would impose on distribution utilities, those utilities also need assurance that they can recover from DERs or their aggregators the reasonable costs (incremental or not) of wheeling DER output over their distribution facilities to reach RTO/ISO markets. *See* Technical Conference Tr. at 348 (discussing potential need for distribution wheeling tariff to wheel energy "from the home up to the transmission level so that it can be sold at [locational marginal price]").

should be accomplished through appropriate distribution rate design is a complex task, which can be even more complicated when the distribution cooperative is a member of a G&T and receives wholesale and/or transmission service from the G&T.

A primary goal of the cooperative model is to serve members at the least cost, consistent with safety and reliability. Installing new, otherwise unneeded equipment where there is limited DER penetration, in the hope that DERs will materialize in numbers sufficient to warrant the expense, could frustrate this goal. Because of the range of factors that would go into the equation, the evaluation of the business case for the upgrade must be performed on a case-by-case basis. For example, the cooperative might apply the 80/20 rule—if it can obtain 80% of the benefits it is trying to achieve for 20% of the costs, then that is the preferred approach, at least until something better is on the horizon.

Among the types of costs, metering systems would have to be upgraded or replaced in order to provide the granularity of data required by wholesale markets. Additional metering might also be required to distinguish between actual DER production and net output after considering consumer load.[39] These and other necessary enhancements could be cost prohibitive for many distribution cooperatives.[40]

Similarly, communication links between RTOs/ISOs, G&T cooperatives and distribution utility systems would likely have to be established or improved. Traditional generation requires two-way communication between the RTO/ISO and generation. RTOs and ISOs do not generally have the means to "see" distribution utilities' DER.[41] While RTOs/ISOs may be able to add such equipment on their end, many distribution cooperatives may face difficulty in

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[39] Triplett Affidavit at P 17.

[40] Triplett Affidavit at PP 17-19, 21, 23.

[41] Technical Conference Tr. at 387, 403, 405, 421 (real-time coordination between the RTO/ISO and distribution does not occur; no protocols for such coordination exist since it has been unnecessary to date).

implementing such systems. The installation and maintenance of communication links by distribution cooperatives to facilitate market participation of third-party DER aggregations would impose an additional significant cost that would have to be recovered by the distribution utility.[42] Some distribution cooperatives do not have supervisory control and data acquisition ("SCADA") systems,[43] which they do not presently need but may become necessary if there is a need to remotely collect data and monitor the distribution system and its equipment.[44] Billing software would need to be modified as well which could be a complex and expensive endeavor.[45]

To give distribution and G&T cooperatives the ability to conduct ongoing operational coordination with RTOs/ISOs and third-party DER aggregators, in many cases, systems and processes that do not exist today will need to be created and maintained. These systems and interfaces could be cost prohibitive for a small distribution cooperative that would otherwise not require them.[46] Additionally, smaller distribution utilities may not even have the staff needed to handle 24-7 communications.[47]

To address these issues, it is vital that coordination agreements among DER aggregators, distribution cooperatives, RTO/ISOs, and other entities are developed; distribution cooperatives (and, where applicable, their G&Ts) must have input into this effort.[48] The development of

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[42] Triplett Affidavit at PP 20-21.

[43] Technical Conference Tr. at 398; *id.* at 402 (SCADA systems not cost-effective for DERs).

[44] NHEC Statement at P 9.

[45] NHEC Statement at PP 9-10.

[46] Triplett Affidavit at P 38.

[47] Ozark Statement at P 8. *See also* Technical Conference Tr. at 132-133 (keeping up with 5-minute settlements could be challenging for smaller distribution utilities); *id.* at 200.

[48] Anza Statement at P 14.

coordination agreements would require legal, management and administrative staff to create the agreements and ongoing administration to keep the agreements current.[49]

All of these new systems would, of course, require distribution utility personnel to manage and maintain them.[50] Distribution utility personnel would also be required to assume the duties associated with reviewing requests from DERs to participate through an aggregator in the wholesale electric markets. This may cause delays in reviewing new interconnection applications, and, in cases with high demand for DER aggregation, the need for additional staff.[51]

Special interfaces and data repositories with multiple levels of firewalls would be necessary in order to facilitate the sharing of any data between the distribution utility and DER aggregators. This would impose setup and long-term maintenance costs that would be prohibitive if only a small number of DER aggregators actually participate in wholesale electric markets. Likewise, the development of new data-sharing agreements would require the expenditure of funds that would otherwise not be necessary.[52]

Finally, in order to ensure that the various costs associated with implementing any third-party DER aggregations are recoverable by the distribution utility, additional billing and tracking systems would need to be developed, creating additional administrative costs.[53]

C. The Industry Is Not Uniformly Ready for Third-Party DER Aggregations; Therefore, the Commission Should Defer to Each RERRA's Timetable for Implementation.

1. Cooperatives Have Been Successfully Integrating DERs.

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49 NHEC Statement at P 14.

50 Triplett Affidavit at P 23.

51 Triplett Affidavit at P 35; NHEC Statement at P 11.

52 Triplett Affidavit at P 24.

53 NHEC Statement at P 12.

Cooperatives have proven time and again that they are willing and able to integrate cooperative-owned and member-owned DER into their distribution and G&T operations. Many cooperatives, even those on the smaller end of the spectrum, have a history of integrating these resources as a key part of the services they provide to their members. NHEC, for example, has more than 900 member-owned Solar photovoltaic (PV) systems ranging from 48 watts to 288 kW totaling 7.5 MW, and 2.0 MW of PV that is owned by NHEC.[54] In 2017, Anza added 1455.5 utility solar watts per customer, and Pickwick Electric Cooperative in Tennessee added 1195.9 watts per customer—ranking them second and fourth, respectively, in the annual utility solar rankings by the Smart Electric Power Alliance.[55]

Cooperatives have also taken a leading role in community solar and related projects. Nearly 200 cooperatives have a community solar program, far exceeding the number of programs run by investor-owned and public-power utilities combined.[56] Garkane Energy Cooperative, for example, incorporated a rooftop solar array into a performance pavilion that it built for a city park in Kanab, Utah, allowing its members to purchase renewable energy from it.[57] To assist cooperatives in solar PV ownership efforts, NRECA initiated its Solar Utility Network Deployment Acceleration project, which provides resources aimed at helping cooperatives at every phase, from initial conceptualization to design, implementation, service

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54 NHEC Statement at P 5. *See also* Anza Statement at PP 6, 9-10; Dakota Electric Statement at P 5; Ozark Statement at P 5.

55 Smart Electric Power Alliance, 2018 Top 10 Winners, available at https://sepapower.org/2018-top-10-winners/.

56 Michael W. Kahn, *Cooperatives Lauded as 'Trailblazers' in Community Solar*, NRECA (May 4, 2018), https://www.electric.coop/cooperatives-lauded-as-trailblazers-in-community-solar/.

57 Derrill E. Holly, *Utah Co-op Gets Creative With Solar Array*, NRECA (April 16, 2018), https://www.electric.coop/utah-co-op-creative-solar-power-array/.

offering and member engagement. This project has resulted in 17 cooperatives installing more than 20 MW of utility-owned solar PV.[58]

Furthermore, many cooperatives are active in the deployment of storage resources. In 2017, Kauai Island Utility Cooperative in Hawaii led the nation in watts of storage per customer,[59] and Pedernales Electric Cooperative received a Department of Energy grant relating to the use of storage to stabilize high penetrations of solar energy into the grid.[60] Dakota Electric's G&T cooperative, Great River Energy, has been able to store a gigawatt of energy each night by controlling the electric resistance water heaters of 65,000 end-use members.[61] In 2016, NRECA helped launch the Community Storage Initiative, which is focused on supporting wide-scale implementation of energy-storage technologies, including the use of residential electric water heaters.[62]

2. States Are in Different Stages of Developing New Policies To Adapt to Higher Levels of Penetration of DERs.

While states have been regulating solar generation for many years, they are currently in the midst of a major transition, as they attempt to determine how to manage the economic and engineering impacts of increased solar penetration into distribution system operations. According to a recent report, in 2017 alone, 45 states plus the District of Columbia considered or

58 *SUNDA Project*, NRECA, https://www.cooperative.com/programs-services/bts/sunda-solar/Pages/default.aspx.

59 Andy Colthorpe, *Hawaii, California lead the way in SEPA's utility energy storage rankings*, Energy Storage News (April 27, 2018) https://www.energy-storage.news/news/hawaii-california-lead-the-way-in-sepas-utility-energy-storage-rankings (citing information from Smart Electric Power Alliance). *See also* Smart Electric Power Alliance, 2018 Top 10 Winners, available at https://sepapower.org/2018-top-10-winners/.

60 Danielle Ola, *AMS and Pedernales Electric Cooperative win US $3.24 million energy storage grant*, Energy Storage News (Feb. 3, 2017) , https://www.energy-storage.news/news/ams-and-pedernales-electric-cooperative-win-us3.24-million-energy-storage-g (citing Advanced Microgrid Solutions as source)

61 NRECA Media Relations, *Electric Co-ops and Natural Resources Defense Council Launch "Community Storage" Initiative; Unveil New Research from The Brattle Group* (Feb. 10, 2016), https://www.electric.coop/on-the-issues/distributed-energy-resources/.

62 Community Storage Initiative, http://www.communitystorageinitiative.com/.

made changes to their solar policies or rate designs.[63] Among the significant actions taken were the replacement of net metering with net billing (*e.g.*, Indiana, New York) and the implementation of a time-varying rates pilot program (New Hampshire).[64] Furthermore, some states are considering distributed solar policy within the larger context of grid modernization proceedings (*e.g.*, Illinois, Maryland).[65]

States are also beginning to explore the economic and engineering impact of integrating a wide range of other resources into distribution system operations – from storage facilities to electric vehicle ("EV") charging stations. New York, for example, initiated "a transition from the historic model of a unidirectional electric system serving inelastic demand, to a dynamic model of a grid that encompasses both sides of the utility meter and relies increasingly on distributed resources and dynamic load management."[66] The Department of Energy's Grid Modernization Laboratory Consortium recently released a report with a snapshot of current state engagement in distribution system planning.[67] It describes activities in states that have adopted some advanced elements of integrated distribution system planning and analysis (California, Hawaii, Massachusetts, Minnesota, and New York) but noted that among the states more broadly, the "[a]pproaches to state engagement in distribution system planning and grid modernization planning vary widely" and "range from a cohesive set of requirements laid out in

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63 *50 States of Solar Q4 2017 Quarterly Review & 2017 Annual Review, Executive Summary*, NC Clean Energy Technology Center, Jan. 2018, at 5, available at https://nccleantech.ncsu.edu/wp-content/uploads/Q4-17_SolarExecSummary_Final.pdf.

64 *Id*. at 9-10.

65 *Id*. at 10.

66 *In the Matter of Distributed System Implementation Plans*, Order on Distributed System Implementation Plan Filings, N.Y. P.S.C. Case No. 16-M-0411, at 1 (March 9, 2017).

67 DOE Grid Modernization Laboratory Consortium, State Engagement in Electric Distribution System Planning (Dec. 2017), available at http://eta-publications.lbl.gov/sites/default/files/state_engagement_in_dsp_final_rev2.pdf.

state statute or PUC orders, to an ad hoc requirement in a general rate case decision for the utility to file an initial long-term distribution system plan or grid modernization plan."[68]

One approach is the CAISO's Distributed Energy Resources Provider ("DERP") mechanism, which the Commission accepted in 2016.[69] Under that mechanism, a DERP that aggregates DERs to participate in CAISO wholesale markets must comply with the applicable distribution utility's tariffs and operating procedures, as well as the requirements of the local regulatory authority, if any. These actions demonstrate that many states, on their own initiative, are taking an affirmative role in encouraging the development of DERs on timetables that are consistent with their own policies and priorities. NRECA encourages the Commission to allow these processes—which have proven robust without the need for overarching federal mandates—to continue at their own pace.

3. The Industry's Revised Standard That Addresses DER Interconnections Just Became Effective After Years of Work and Will Take Additional Time To Implement.

Any Commission rule governing the participation of DER aggregations in wholesale markets must take into account and be consistent with the new version of IEEE 1547, which delineates the interconnection requirements for DER in general. As a national standard, IEEE 1547 defines how DER is to be integrated into distribution systems, which will affect how distribution systems must be designed and operated over the long term.[70] The major update to IEEE 1547 was approved in February 2018, following four years of work by affected stakeholders, including cooperative representatives. The need for the significant reform to the standard was driven by the surge in DER penetration into the grid in recent years, along with

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[68] *Id.* at C-1.

[69] *Calif. Indep. Sys. Operator Corp*., 155 FERC ¶ 61,229 (2016).

[70] *Revision of IEEE Standard 1547 - The Background for Change, Tech Surveillance* (Nov. 2016), at 10, available at https://www.cooperative.com/topics/operations/Documents/tsieeestandard1547pt1backgroundnov2016.pdf. .

changes in DER technology and economics.[71] The update was incredibly complex, resulting in a far-lengthier standard than the version adopted in 2003. Distribution cooperatives are in varying stages of implementing the new standard, with those in high DER-penetration areas farther along. Meanwhile, a companion standard on testing is still in the process of being developed; many distribution cooperatives are in stand-by mode while this process is being completed.

Rather than force third-party DER aggregations onto all distribution utilities located in RTO and ISO market regions, the Commission can ensure it does not disrupt the implementation of this standard and run afoul of its requirements by adopting the opt-out/opt-in proposal NRECA advocates.

4. Addressing the Likely Costs, Benefits, and Risks of Wholesale Market Participation by DER Aggregations on the Nation's Distribution Cooperatives Will Take Time, and the RERRAs Are in the Best Position To Determine the Appropriate Implementation Timetable.

The significant costs and risks posed for cooperatives by immediate third-party aggregation of DERs stand in stark contrast to the benefits of permitting cooperatives to continue to perform the aggregative function themselves and to permit third-party aggregation in a manner and on a schedule appropriate to their circumstances. The cooperative business model allows for solutions that balance policy priorities with local conditions while ensuring safe, reliable, affordable, and sustainable electric service. As demonstrated here, many cooperatives are actively thinking about how to respond to DER growth while the future impact of DER is unclear. The RERRA, which in many cases is the cooperative's board, is best positioned to decide how DER should be deployed.

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[71] *Id.* at 1.

Accommodation of third-party DER aggregators on distribution cooperatives will require investment in system upgrades and communications equipment and software,[72] as well as increased operational expense, to manage what would be, in essence, an entirely new line of business. In addition to the need for new and upgraded equipment, third-party DER aggregation may result in cooperatives needing to upgrade their distribution facilities before they otherwise would, solely to accommodate the DER aggregations. It would force these costs on cooperatives well in advance of the time that their systems as a whole—and therefore their member-consumers—would benefit from them.

In the near term, the incorporation of DERs on distribution cooperatives can be achieved much more efficiently by cooperatives integrating them into their load-serving operations directly, rather than by third-party aggregation, because direct integration does not require the added layer of infrastructure and operation that managing third-party aggregative activities would. To be sure, significant investment and operating expense is already being incurred by cooperatives as they work to accommodate and make the best use of cooperative- and consumer-owned DERs. Reconfiguring and operating a system designed and operated on a one-way basis to move power to load in order to absorb the output of increasing amounts of DERs requires system alterations and the installation and operation of additional communications and control equipment. But cooperatives can tailor the timing and scope of these investments and activities to the actual pace and extent of DER development on their systems. In contrast, taking immediate steps to accommodate third-party DER aggregators would front-load the development process, assuring that significant investments will be made well in advance of the time that would benefit all of the cooperatives' member-consumers, as distinguished from the aggregators.

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72 Ozark Statement at P 7 (additional metering equipment), P 9 (measurement and verification systems), P 10 (additional resources to process interconnections).

A top-down approach to third-party DER aggregation ignores that distribution utilities and RERRAs are in a better position to analyze the extent and timing of investments necessary to accommodate increased DER. IEEE 1547 recognizes this, explaining that under the "performance-based category approach" each relevant authority governing interconnection requirements ("AGIR") will "perform a DER impact assessment *based on anticipated DER deployment for the future*."[73] By contrast, a one-size-fits all approach would impose significant costs on all distribution utilities in advance of the time, if ever, when these costs would be justified. These costs would effectively be stranded if the aggregations never materialize, resulting in a significant waste of investment.

NRECA submits that the better approach is to allow distribution cooperatives to continue to steadily integrate DER—as they have been for a number of years already—rather than use a top-down rule allowing immediate aggregation in all RTO and ISO regions that could result in unnecessary investment for some and major technical problems for others. The timing for all steps of the ramp up and implementation of third-party aggregation and for individual aggregation activities must reflect limited staffing capabilities and competing obligations of distribution utilities.

D. Forcing Third-Party DER Aggregation on Distribution Cooperatives Would Prevent Them From Achieving the Full Benefits of Integration of DERs.

1. Third-Party DER Aggregators May Engage in "Cherry Picking," to the Disadvantage of Distribution Cooperatives.

The Commission's proposal, if not modified to permit opt-out/opt-in, would frustrate the ability of cooperatives to use their own or their members' DER which, as explained above, may be a significant part of many cooperatives' integrated resource portfolios. If those DER

[73] IEEE 1547 § B.3.1 (emphasis added).

resources are available to third-party aggregators, this could severely undermine the cooperative's ability to manage cost and risks for its consumer-members. This can undermine the economics of a cooperative's DER programs, in turn reducing the cooperative's incentives to invest in DER and the infrastructure required to enable it, and effectively removing DER from the cooperative's integrated resource portfolio. It can also undermine reliability by increasing the unpredictability of load on a cooperative's system. These factors were an integral part of the Commission's decision to permit RERRAs to decide whether to allow aggregators to bypass utility demand response programs and bid retail demand response directly into the wholesale markets in Order No. 719.[74]

Aggregators can reasonably be expected to cherry-pick the most lucrative DERs. The most obvious result of such cherry-picking from the distribution system point of view will be the loss of a heretofore significant risk management tool. The utility's own integration efforts will be impeded, and the reduced scale and scope of the integration effort will disadvantage customers "left behind," possibly leaving them with a disproportionately higher portion of future distribution investment.

2. Third-Party DER Aggregation May Impair Distribution Cooperatives' Ability To Manage Costs by Affecting the Peak Load.

Saddling cooperatives with the financial and operational challenges of managing third-party DER aggregators may hinder their own efforts to harmonize the operation of behind-the-meter generation, distribution, transmission and central-station generation resources to serve load in the most reliable, economic fashion possible. A significant issue is that a third-party DER aggregator would be responding to wholesale price signals instead of local distribution

[74] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A., 74 Fed. Reg. 37,776 (July 29, 2009) ("Order No. 719-A"), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

conditions. As a result, the DER aggregator could operate its portfolio in way that could affect the distribution cooperative's peak load.[75] This, in turn, can affect the ability of the distribution cooperative—and potentially its G&T cooperative, if there is one—to effectively manage its costs.[76] For example, the DER aggregator may seek to maximize its DER output at the ISO or RTO coincident peak load,[77] when wholesale prices may be highest. The distribution cooperative would seek to do so at its non-coincident peak load at the substations where it receives wholesale power (either from its G&T or other power supplier). If the distribution cooperative is part of a G&T, and the G&T had control of the DER, it might seek to maximize the DER output at the *G&T's* non-coincident peak load. In any event, a DER aggregator creates uncertainty for both cooperatives and makes it more difficult for them to control their respective peak loads.[78] For distribution cooperatives, this could reduce the benefits that they have been able to achieve through careful planning of DER on their systems. These concerns could be exacerbated if the aggregated DER is a storage facility.[79] Behind-the-meter storage DER could increase the cooperative's peak load at the time of the RTO's peak, and having DER energy storage aggregation participating in wholesale markets adds additional complexity and costs.[80]

As explained by one of NRECA's member cooperatives:

> Allowing third-party aggregators to assume control of the demand management loads or the member-owned generation systems and to offer services independently to the transmission grid, would, simply put, ***destroy***

[75] Triplett Affidavit at P 6.

[76] Dakota Electric Statement at P 5.

[77] Peaks of distribution utilities and ISOs are not always coincident. *See* Technical Conference Tr. at 454.

[78] The cooperatives will need to know the amount of DER aggregator output during the period used by the G&T to bill the distribution cooperative for wholesale power and transmission costs. Many G&Ts have a demand component in their rates. The DER aggregator muddies the price signals used by the cooperatives to manage their costs.

[79] NHEC Statement at P 18.

[80] Triplett Affidavit at P 7; Adams-Columbia Statement at P 11.

> Dakota Electric's ability to control our system peak. Dakota Electric would no longer be able to plan for or rely on these non-wired solutions to reduce the distribution costs for our members. This would result in the need to construct millions of dollars of additional substation and distribution system capacity. This would also result in higher peak loads, which, in turn, would cost our member-customers millions of dollars annually in higher electrical bills.[81]

Similarly, third-party DER aggregation could negatively affect the ability of distribution cooperatives to use conservation voltage reduction ("CVR"), the practice of intentionally lowering the voltage on primary distribution circuits to maintain voltages on the secondary side to be in the lower portion of the acceptable voltage range.[82] Pee Dee Electric Cooperative ("PDEC"), for example, has a history of using CVR to reduce peak demand costs, and has automated its CVR process with converted water heater switches to lower and reset the regulators automatically for peak demand reduction. By reducing its peak demand, CVR saves PDEC's consumer-members costs without the need for load shedding. CVR can be effectuated without costly investment in equipment and can possibly enable the utility to defer adding capacity to its system or eliminate such additions altogether. Third-party DER aggregation could disrupt the benefits of such CVR programs.[83]

E. Small Entities Have a Particular Need To Be Able To Choose To Manage Integration Themselves.

By its nature, the proposed rule will have a direct impact on distribution utilities, a large number of which meet the definition of "small entity" under Regulatory Flexibility Act.[84] These small entities will find it particularly difficult to comply with a national aggregation standard that imposes significant costs on them.

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81 Dakota Electric Statement at P 7 (emphasis in original).

82 Rob Ardis and Robert Uluski, *CVR Is Here to Stay*, T&D World Magazine (Aug. 26, 2015), available at http://www.tdworld.com/grid-opt-smart-grid/cvr-here-stay.

83 *See also* Adams-Columbia Statement at P 12.

84 5 U.S.C. § 601(6).

Many distribution utilities do not have the scale to make the investments required to enable third-party DER aggregation on their systems. The considerable amount of funding required to potentially benefit a small number of customers imposes too large of a burden. Small utilities face competing capital requirements, limited staffing to deal with the added complexity, and insufficient resources to perform system studies to make determinations regarding hosting capability and other issues. Moreover, given their size, they have limited—if any—ability to participate effectively in RTO/ISO stakeholder processes to protect the interests of their other customers in the development of market rules and coordination agreements.

It is therefore beyond dispute that a rule imposing DER aggregation requirements on small distribution utilities would, under the Regulatory Flexibility Act, "have a significant economic impact on a substantial number of small entities."[85] Contrary to the certification in the NOPR,[86] such a rule would impose financial burdens well beyond the six RTOs/ISOs. Accordingly, as part of its final rule, the Commission must publish a final regulatory flexibility analysis.[87] The analysis must include, among other things, an estimate of the number of small entities to which the rule will apply (or an explanation of why no such estimate is available) and a description of the projected reporting, recordkeeping and other compliance requirements of the rule.[88] Most importantly, the analysis must include:

> a description of the steps the agency has taken to minimize the significant economic impact on small entities consistent with the stated objectives of applicable statutes, including a statement of the factual, policy, and legal reasons for selecting the alternative adopted in the final rule and why each one of the

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85 5 U.S.C. § 605(b).

86 NOPR at P 165.

87 5 U.S.C. § 605(b).

88 5 U.S.C. §§ 603(b)(3), (4).

other significant alternatives to the rule considered by the agency which affect the impact on small entities was rejected.[89]

The Commission can satisfy these requirements—or perhaps even obviate the need to conduct a final regulatory flexibility analysis—by a adopting in its final rule an opt-in structure for smaller distribution utilities.

F. NRECA's Proposed RERRA Language Would Continue the Commission's Use of "Cooperative Federalism" To Respect Traditional State and Local Jurisdiction Over Retail and Local Distribution Service.

NRECA urges the Commission to include in the final rule in this proceeding an opt-out/opt-in structure similar to that implemented for demand response in Order Nos. 719 and 719-A. Specifically, NRECA recommends that the following language be added as subsection (iii) to the regulatory text to be set forth in 18 C.F.R. § 35.28(g)(10):

> (iii) An independent system operator or regional transmission organization must not allow bids from an aggregator of distributed energy resources on utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such distributed energy resources to be bid into organized markets by an aggregator of distributed energy resources, or from an aggregator of distributed energy resources on utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such distributed energy resources to be bid into organized markets by an aggregator of distributed energy resources.

This additional language, which tracks the opt-out/opt-in structure for demand response set forth in 18 C.F.R. § 35.28(g)(1)(iii), would serve multiple purposes. First, the RERRA is the entity that regulates retail electric service for customers, such as a state public utility commission, the city council for a municipal utility, or the governing board of a cooperative utility.[90] As such, the RERRA is the entity that is authorized by state or local law, and is

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[89] 5 U.S.C. §§ 604(a)(6) .

[90] *See* Order No. 719 at P 158 ("The term 'relevant electric retail regulatory authority' means the entity that establishes the retail electric prices and any retail competition policies for customers, such as the city council for a municipal utility, the governing board of a cooperative utility, or the state public utility commission.").

inarguably best positioned, to determine the extent to which DER may use the local distribution system to participate in aggregations, consistent with the safety and reliability of the distribution system and consistent with retail-level programs to promote and manage the DER owned by retail customers and the DER owned by the cooperative.[91] Second, this language would continue the Commission's adherence to the principle of "cooperative federalism" endorsed by the Supreme Court.[92] Third, the "opt-in" language would reduce the compliance burden on smaller entities, consistent with the Commission's action in Order No. 719-A.

Fourth, the provision would be consistent with IEEE 1547. That standard affords significant discretion to the relevant AGIR, which, in the case of most distribution cooperatives, is the cooperative's board.[93] Among other things, IEEE 1547 makes clear that the applicability of certain requirements and specifications is to be determined by the AGIR,[94] that the degree of AGIR involvement will "vary in scope of application and level of enforcement across jurisdictional boundaries,"[95] and that "it remains in the responsibility of an AGIR to quantify impactful DER penetration levels."[96]

G. The Commission Should Address the Impacts On Distribution Utilities in Fashioning the Final Rule.

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91 A so-called "opt-out lite," as discussed during Panel 2 of the technical conference and posed in the additional question 6 in the Notice Inviting Post-Technical Conference Comments, which would enable the RERRA to forbid or permit simultaneous participation in wholesale and retail markets by DER, would be inadequate for this purpose. It would not give the RERRA control over the timetable for DER aggregation on distribution utilities under its jurisdiction. It would only allow the RERRA to defer the additional burden on distribution utilities of devising the metering and communications to protect against double compensation and related misconduct.

92 *FERC v. Electric Power Supply Ass'n*, 136 S. Ct. 760, 780 (2016).

93 IEEE 1547 states that the AGIR "may be a regulatory agency, public utility commission, municipality, cooperative board of directors, etc." § 3.1. Some distributed cooperatives are regulated by state public utility commissions.

94 IEEE 1547 §§ 1.4, 4.1.

95 *Id*. § 3.1.

96 *Id*. §§ 1.4 n.12, B.2 n.134.

NRECA urges the Commission to include certain fundamental protections for distribution utilities in any final rule in this proceeding:

- **A seat at the table for RTO/ISO discussions:** Given the substantial impacts that third-party DER aggregations could have on distribution utilities, they must be able to participate in the development of any relevant market rules and coordination agreements. In light of the resource-intensive nature of such processes, funding of participation in the process for small distribution entities that lack capacity otherwise to participate should be through RTO/ISO tariffs (*e.g.*, similar to the funding mechanism for consumer advocates in PJM).[97]

- **DER aggregation registrations:** NRECA concurs with statements made in Panel 6 that it is insufficient for the distribution utility to have the right to review a list of DERs in a proposed aggregation and report to the RTO/ISO on whether the resources are eligible to participate.[98] The distribution utility needs information about the attributes of the DERs, their locations on the distribution grid, and the proposed aggregation. The distribution utility's consent to the aggregation is a necessary prerequisite before the aggregation may operate. Moreover, an interconnection agreement with the DER is necessary but not sufficient.[99] To determine whether the DER may be operated in an aggregation, the distribution utility needs to be able to conduct an integration study that considers grid topology. A reasonable timetable for this study must be provided, as is the case with generation interconnection studies.[100]

- **Coordination agreements:** As the discussion in Panels 6 and 7 made clear, coordination agreements among the DER, aggregator, distribution utility, RTO/ISO, and other affected parties (including G&T cooperatives and third-party transmission providers) are essential to enable DER aggregation to be operated safely and to protect distribution utilities and their customers.[101] The Commission should ensure that before DER aggregations are permitted to proceed, adequate coordination agreements are in place that would facilitate the two-way (and more) information sharing and operational coordination that will need to occur.[102] These coordination agreements must give the distribution utility the ability to override RTO/ISO decisions regarding day-ahead and real-time dispatch of DER aggregations that threaten the safety and reliability of the local distribution system. The distribution utility should not face any financial consequences from the DER aggregator or the RTO/ISO for these necessary actions.[103]

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97 *PJM Interconnection, L.L.C.*, 154 FERC ¶ 61,147 (2016), *reh'g denied*, 157 FERC ¶ 61,229 (2016).

98 Technical Conference Tr. at 339-40, 345-346.

99 Technical Conference Tr. at 350-51, 355.

100 *See* Triplett Affidavit at PP 34-36.

101 Technical Conference Tr. *e.g.*, at 350-52, 355 (interconnection agreements alone are not enough); *id.* at 413 (identifying parties needed to coordinate)

102 Technical Conference Tr. at 380 (coordination needed because RTO/ISO does not have functional control of distribution system).

103 *See* Triplett Affidavit at P 40.

- **DER participation in retail and wholesale markets:** NRECA supports the NOPR's proposal that simultaneous participation in wholesale and retail markets not be allowed at the outset. The discussions at the technical conference indicate that the metering, telemetry, and communications to police this market activity do not exist and will take some time to develop. This decision could be revisited in the future. But a structural protection is preferable to behavioral rules at this early juncture.

- **Privacy-related agreements:** Distribution utilities need time to develop any needed changes to or new privacy agreements that would facilitate sharing necessary metering data without violating their privacy obligations to their consumers/members.

- **Cybersecurity and other security protections:** Similarly, distribution utilities need to ensure that their operational, IT and other safety protocols are modified as needed to address the impacts of third-party DER aggregation.

- **Interconnection procedures and compliance with IEEE 1547:** Distribution utilities need sufficient time for review and modification of their interconnection policies, process and procedures to ensure that third-party DER participation in RTO/ISO markets will not create any safety, reliability or power quality concerns on their systems, and that implementation will conform to the requirements of the IEEE standards.

- **Cost recovery:** Although potentially controversial and complex, cost recovery and cost allocation mechanisms need to be in place to ensure that distribution utilities are kept financially whole and that the DER aggregators that cause the need for costs to be incurred pay for such costs. Among the issues to be addressed is how to handle cost in the case of DER retirements.

- **Hold harmless rules (to be included in coordination agreements):** Distribution utilities should not be held liable to consumers, aggregators, or RTOs/ISOs for events outside of their control, including unscheduled outages. Distribution cooperatives need to be able to take their systems down for maintenance without being liable to the DERs or the DER aggregator, and to the extent that distribution outages interfere with the ability of DERs to earn wholesale market compensation, the distribution utility should not be liable for these types of losses.

III. CONCLUSION

NRECA respectfully requests that the Commission consider these comments along with the affidavit and its member statements appended hereto and adopt NRECA's recommendations in the final rule.

Respectfully submitted,

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June 26, 2018

Attachment A

Affidavit of
Jeffrey M. Triplett, P.E.,
Power System Engineering, Inc.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

AFFIDAVIT OF JEFFREY M. TRIPLETT, P.E. ON BEHALF OF
THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

I. Introduction

1. My name is Jeffrey M. Triplett. My business address is 2327-A State Route 821, Marietta, OH 45750. I am the Vice President, Power Delivery Planning and Design, at Power System Engineering, Inc. (PSE). I provide expertise in the areas of system planning, system protection, power quality investigations, and distributed energy resource (DER) interconnections. Prior to joining PSE, I worked as the Engineering Manager for two Ohio distribution cooperatives, and as a Power Delivery Engineer for a generation and transmission (G&T) cooperative. I received my BS in Electrical Engineering from Ohio University and am a registered Professional Engineer in multiple states.

2. PSE was established in 1974 to serve the engineering and technology needs of electric cooperatives. Over time, PSE evolved to become a full-service consulting firm for all electric utilities. PSE's clients include municipal utilities, distribution cooperatives, generation and transmission cooperatives, investor-owned utilities, public utility districts, governmental agencies, and industry associations across the U.S. and Canada.

3. The professionals at PSE include engineers, technicians, economists, and financial analysts. PSE has extensive experience in all facets of the utility industry through several

diversified practice areas. We provide services in the areas of power delivery planning and design, distributed energy resources, industrial engineering, utility automation and communication, and economics, rates, and business planning. We are employee-owned and independent. PSE presently has approximately 90 employees located throughout our seven offices in Madison, WI (headquarters), Minneapolis, MN, Prinsburg, MN, Marietta, OH, Sioux Falls, SD, Lexington, KY and Topeka, KS.

4. I prepared this affidavit with the assistance of several other individuals at PSE:

- **Douglas F. Joens, P.E.** *(Manager, Transmission and Distribution Studies, Minneapolis, MN)*
  Mr. Joens earned a BS degree in Electrical Engineering from Iowa State University at Ames, Iowa with an emphasis in power systems. He is experienced with transmission and distribution system protection and planning studies, relay and automation controller programming, commissioning and testing, substation controls, and industrial facility system studies. He is a licensed Professional Engineer in four states.

- **Thomas J. Butz, P.E.** *(Senior Consultant, Minneapolis, MN)*
  Mr. Butz earned a BS degree in Electrical Engineering (emphasis in power systems) from the University of North Dakota at Grand Forks, North Dakota. He is responsible for transmission planning, power supply planning, integrated resource planning, demand-side management evaluations, and supply resource evaluation.

  Experience also includes wholesale purchase power evaluations, RTO/ISO pricing analysis, RTO/ISO congestion analysis, and electric utility strategic planning. In addition, Tom was involved in helping to design and implement a wholesale joint generation dispatch model on two separate occasions for utilities in the Midwest before the April 1, 2005 start date of the MISO LMP market. Tom has also been working with two RTO market participants in making the transition for a distribution co-op from an all-requirements power supply of one market participant to another market participant. He is a licensed Professional Engineer in Minnesota.

- **Peter A. Koegel, P.E.** *(Manager, Transmission Studies, Minneapolis, MN)*
  Mr. Koegel has over 18 years of power utility experience, including generator interconnection studies, transmission planning studies, transfer capability studies, steady-state modeling and analysis, economic planning studies, probabilistic assessment studies, and under frequency load shedding studies. Mr. Koegel also has experience with regional OATT administration, FERC Order 1000

implementation, NERC reliability standards compliance, and generation reserve sharing pools. He is a licensed Professional Engineer in Arkansas, Minnesota, and North Dakota.

- **Richard J. Macke** *(Vice President, Economics, Rates, and Business Planning, Minneapolis, MN)*
  Mr. Macke leads the Economics, Rates, and Business Planning practice area at PSE where he serves on both the Board of Directors and the Executive Committee. He and his staff provide services to utilities and the utility industry in areas concerning business strategy, cost of service studies, rate design studies, demand-side management programs, resource planning, performance benchmarking, mergers and acquisitions, regulatory support, and expert testimony. He is frequently called upon to speak to utility management, directors, commissioners, and industry associations on a broad range of topics related to utility economics, finance, rates, and business strategy. He holds an MBA from the Carlson School of Management at the University of Minnesota and has over 21 years of experience consulting with electric utilities.

- **Curtis A. Lyons** *(Transmission Planning Coordinator, Minneapolis, MN)*
  Mr. Lyons has over 40 years of experience in the technical, financial, IT, and administrative fields. He has significant experience in the RTO/ISO Generation Interconnection study processes, RTO/ISO tariffs, and performing technical analysis.

My views expressed in this affidavit are based on 20 years of personal experience working with distribution and generation & transmission (G&T) utilities, many small as defined by the industry. The team at PSE that assisted me in preparing these comments has a wealth of experience working in areas related to DER interconnections, utility operations, transmission/distribution planning, power supply planning, metering and communications technologies and systems, RTO/SO transmission and market tariffs, and in general all facets related to the technical, economic and market transactions associated with delivering electrical power and energy from generation to the end-use consumers. In addition, I interviewed a number of NRECA member systems on topics associated with this affidavit which helped to provide a broader perspective to the views expressed in this affidavit.

II. Summary

5. NRECA asked me to provide my analysis of the likely impacts on distribution cooperatives of the Notice of Proposed Rulemaking (NOPR) published by the Federal Energy Regulatory Commission (FERC), which proposes to require Regional Transmission Organizations (RTOs) and Independent System Operator (ISOs) that administer wholesale electric markets to allow aggregations of Distributed Energy Resources (DER) to participate in those markets.[1] The NOPR presents technical and economic challenges from a distribution utility's perspective that need to be considered and addressed before DER can successfully aggregate and participate in wholesale electric markets. The technical challenges come at a volatile time for the industry considering that the technical standard for interconnecting DER to utility systems (IEEE Std 1547™-2018, *Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces*) (IEEE-1547-2018) has just recently been significantly revised.[2] IEEE 1547-2018 is very new and the industry has just started to work through incorporating this new standard. It will take time for implementation to occur and adding DER aggregation and participation into wholesale electric markets while this implementation is being done will complicate matters and increases the likelihood of unintended consequences being experienced.

[1] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,718 (2016) (NOPR).

[2] IEEE 1547-2018 is the cornerstone standard in a series of standards relating to DER interconnections. In response to IEEE 1547-2018 being revised, other significant standards in this series, in particular IEEE 1547.1 *IEEE Standard for Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces*, are also presently being revised. Until the relevant standards in the series are all updated consistent with IEEE 1547-2018, the industry will be heavily engaged in conforming to IEEE 1547-2018.

III. Technical and Operational Considerations

6. DER participating in wholesale electric markets on an aggregated basis, and independent from utility coordination and direction (note that this is an important distinction as DER aggregated by a utility and operated in a coordinated fashion by the utility presents far less technical and operational challenges), may have a financial incentive to change their behavior and operate differently than DER not participating in these markets. In particular, DER may be dispatched to maximize value in the RTO/ISO wholesale electric markets without taking into account conditions on the distribution system. This can be even more of an issue when the wholesale electric markets are being served by many DER installations through a DER aggregator. The times when these wholesale electric market services are needed may not necessarily be aligned with the distribution utility system needs, particularly for rural distribution utilities. For example, RTO/ISO loads typically peak earlier in the day than rural distribution utility loads that are predominately residential in nature, thus creating greater capacity and energy needs at different times on the Bulk Electric System (BES) than on the distribution system. This peak mismatch could increase the costs for distribution utilities, which are simply trying to minimize their peak loads to keep costs down for their consumers, when DER aggregators respond to wholesale electric market needs independent from distribution utility coordination and direction.

7. The provision of ancillary services in wholesale markets creates the potential for an even larger disconnect between wholesale electric market needs and distribution system needs, because these services, such as spinning reserves, supplemental reserves and regulation, may have no correlation at all with distribution system load. Instead, these needs may be based solely on conditions related to the BES and generation availability. In the case of energy storage,

this disconnect could be exacerbated if storage is discharging in response to a wholesale electric market need or dispatch signal during a time when the distribution system has no need for its output, and subsequently charging during a time when the distribution system load is higher, and charging is therefore less desirable.

8. Technical and operational concerns exist when aggregated DER is asked to respond to wholesale electric market needs/signals, especially during lighter loading distribution time periods. The issues highlighted here will be worsened with DER aggregation, if not properly coordinated with the distribution utility, due to larger amounts of DER responding at the same time all across a distribution utility's service territory.

- **Reverse power flow risk increases.** Distribution systems were originally designed for radial, one-direction power flows. Some facilities have been upgraded over time to accommodate two-way power flows, particularly to allow backfeeding areas of the system during contingencies; however, not all facilities have a need for this capability, and a significant portion of existing distribution system feeders cannot accommodate reverse power flows. Voltage regulators and protective devices are the distribution assets most at risk for experiencing unintended consequences during times of reverse power flows. For example, voltage regulators that cannot accommodate reverse power flows can raise or lower the voltage to unacceptable levels when reverse power flows are experienced, and protective devices can mis-operate and cause unnecessary outages when reverse power flows above their capability or programmed thresholds are experienced.

- **Voltage stability issues increase.** The risks of voltage rising to levels above the ANSI C84.1 *Standard for Electric Power Systems and Equipment Voltage Ratings*, and of experiencing unacceptable levels of voltage fluctuations/flicker increases with greater amounts of DER output as compared to load. These are two of the leading limitations confronted by higher penetrations of DER. Curtailing DER output during lower distribution loading periods is one strategy used by distribution utilities to allow greater levels of DER interconnection on a feeder. However, if distribution utilities attempt to curtail DER output in order to maintain acceptable distribution system voltage levels at the same time a DER aggregator is responding to wholesale electric market signals, this could have the effect of frustrating the distribution utility's efforts and could, ironically, lead to overall lower levels of DER penetrations being realized.

- **Increased operations of distribution equipment.** Voltage fluctuations caused by DER variability and intermittency cause more frequent operations of distribution voltage regulating equipment, which increases maintenance costs and shortens the life of such equipment.

- **Increased risk of unintentional islanding.** Islanding is a condition where a portion of a utility system is electrically separated from the normal utility source and energized solely by DER. Unintentional islands are a serious safety concern and can also have negative consequences to the power quality being experienced by other consumers served in the island. For an island to be sustained, generation and load must be reasonably matched such that the voltage and frequency do not deviate outside of established trip parameters. IEEE 1547-2018 notes that in regards to meeting the unintentional islanding provisions, "reliance solely on under/over voltage and frequency trip is not considered sufficient to detect and *cease to energize* and trip."[3] Therefore, other means of detecting an island may need to be employed. One such strategy employed by inverter manufacturers is to include "active" anti-islanding provisions that attempt to force frequency outside trip parameters when operating as an island. These methods are implemented in different manners by each inverter manufacturer and have not been proven to be effective when many different inverter models are operating together across the utility system. Greater DER output during lower loading times increases the probability of DER being able to carry the entire distribution load and therefore the risk of being able to sustain an unintentional island even with active anti-islanding features included with certain inverter models.

9. DER operational and protection settings required to ensure safe and reliable operation of the distribution utility consistent with IEEE 1547-2018 may restrict how much DER output can be provided to wholesale electric markets. This may create a situation where DER owners/operators intentionally or unintentionally change these parameters to maximize return from participating in wholesale electric markets.

10. For example, the distribution utility typically requires the DER to operate at unity power factor – a condition where no reactive power (VARs) are being supplied or absorbed by

[3] IEEE Standards Coordinating Committee 21, "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces." IEEE Std 1547™-2018: 65.

the DER. This is generally beneficial to the DER as well, in that operating at unity power factor allows for maximum energy production. Adjusting the power factor of the DER to absorb VARs can help to lower voltage and allow more DER to be accommodated in areas where DER output is high compared to load. Operating the DER in this fashion can actively change the voltage through changes in reactive power flows on the distribution system, which cannot be allowed without the approval of, and coordination with, the distribution utility.[4] Any changes to the DER power factor settings and reactive power flow have to be coordinated with the distribution utility so as not to adversely affect utility voltage regulation schemes and the voltages experienced by other consumers. Distribution utilities will typically work with DER to consider active voltage regulation control strategies such as those included in IEEE 1547-2018 when appropriate. However, if distribution utilities were forced into having to do so as a result of FERC's proposal for DER aggregations, there would be a risk of harm to their distribution systems and the consumers they serve. DER owners/operators cannot be allowed to modify the operating settings defined in their Interconnection Agreement with the distribution utility to participate in, or maximize benefit from participating in, wholesale electric markets without regard for the needs of the distribution system on which they are relying.

11. In addition, DER have specific protection settings, such as over/under voltage and frequency, that are required to be programmed in compliance with the IEEE 1547-2018 standard, and which are critical to the safe and reliable operation of the distribution system. During times of high generation and low load causing over-voltages on the distribution system, at some point the DER will trip off-line due to the over-voltages being experienced. A concern exists that

[4] IEEE Standards Coordinating Committee 21, "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces." IEEE Std 1547™-2018: 38.

these critical protection features could be overridden or modified (intentionally or unintentionally) to allow the DER to continue to operate through these over-voltage situations so as to allow the DER to contribute into the wholesale electric market. There is also a concern that the distribution utility could be criticized or even held liable due to DER tripping off-line and not being able to provide services they were dispatched to provide. Anecdotal evidence exists of situations where inverter protection settings were changed at some point after the initial installation was tested, commissioned and approved by the distribution utility, likely to counter tripping off-line during times of high voltage. Aggregated DER participating in wholesale electric markets may be dispatched to provide output during times when the distribution utility load is low and higher voltage levels exist, thus increasing the risk of unauthorized changes to DER protection settings to counter this.

12. Based on my experience with distribution utilities and my discussion with a number of NRECA's distribution cooperative members, I believe that distribution utilities have significant concerns related to RTOs/ISOs providing aggregated DER access to the wholesale electric markets using their distribution facilities. Improper implementation of these DER aggregations could undermine distribution utility safety, reliability, power quality and economics, and could prevent the distribution utilities from fulfilling their responsibility to maintain these fundamentals for their facilities and consumers. State and local regulatory authorities, industry working groups that produce technical standards, industry associations, special interest groups and utilities have worked together and have come a very long way to work out methods and procedures to safely and reliably interconnect DER to distribution utility systems – the result being the newly adopted IEEE 1547-2018 standard. The economic

incentives posed by participation of aggregated DER in the wholesale electric markets should not be allowed to trump these efforts.

13. Safety is a top priority for distribution utilities. One simple yet very important example of a safety concern related to DER is the distribution system operator's need to maintain its authority for opening DER disconnect devices as needed and in accordance with established Interconnection Agreements, regardless of whether the DER has been dispatched to provide a market service. IEEE 1547-2018 is an excellent example of an industry standard that recognizes the complexity and potential issues from integrating DER and grants the utility final approval authority in many critical areas such as in the case of active voltage regulation discussed earlier.

IV. Data, Systems, Communications

14. The FERC NOPR indicates "With respect to metering, we recognize that distributed energy resources may be subject to metering system requirements established by the distribution utility or local regulatory authority. Therefore, we propose that each RTO/ISO should rely on meter data obtained through compliance with these distribution utility or local regulatory authority metering system requirements whenever possible for settlement and auditing purposes, only applying additional metering system requirements for distributed energy resource aggregations when this data is insufficient."[5] On the surface, this sounds reasonable; however, there are serious concerns related to the ability of DER entities and distribution utilities to comply with this proposal. If FERC directs RTOs/ISOs to permit DER aggregation in wholesale markets, this will require adequate systems to be developed so that DER aggregators, RTOs/ISOs and distribution systems have the means to properly interact with one another, as is the case with the provisions imposed on any market participant.

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[5] NOPR at P 152.

15. Although DER aggregators may meet a defined minimum size requirement to participate in wholesale capacity, energy and ancillary markets, there are defined requirements for RTO/ISO wholesale market participation that also need to be met, that can be broadly categorized as follows:

- Metering & Communications
- Cyber Security & Privacy
- Real-Time & Market Operations
- Market Settlements

A. Metering & Communications

16. Existing distribution utility metering systems may not provide the granularity of data (*e.g.*, 5 minutes) required by the wholesale electric markets for settlement and auditing purposes. The capability of providing the real-time 3-5 second visibility required to participate in real-time markets is rarely in place within the vast majority of existing distribution utility metering systems. Advanced Metering Infrastructure (AMI) systems are designed with certain specifications and uses in mind. The AMI equipment, and in particular the communications media and paths used to get data back from the meter to the utility, have limitations and cannot pass unlimited amounts of data. Providing real-time or even 5-minute data would consume bandwidth that might be needed for critical outage reporting and restoration efforts, end-of-line voltage feedback into conservation voltage reduction (CVR) systems, and other distribution utility operations. Data being provided through the distribution utility AMI system must be prioritized, and metering data for the purpose of DER aggregators participating in wholesale electric markets (both real time and other) would necessarily need to be assigned a lower priority

to keep the AMI priorities focused on duties related to preserving the safety and integrity of the distribution system.

17. Another potential issue with the distribution utility providing metering data for DER participating in wholesale electric markets is that in many cases the utility is not currently metering the actual DER output. In situations where the DER is being net metered, only the net load or generation output after all local consumer load is met by the generation output is metered. It is unclear if the actual DER output, or its net output after considering consumer load, is what would be counted in the wholesale electric markets it might participate in. These rules may vary by RTO/ISO; for example, under the California ISO (CAISO) DER implementation regime, each DER participating in a DER Aggregation is to be directly metered,[6] and may not also participate in a retail net energy metering program that does not expressly permit wholesale market participation.[7] Additional metering (aka a "production meter") installed on the consumer's side of the point of interconnection would be required to meter DER output if that is required by the RTO/ISO. This expenditure would need to be at the DER's expense if the distribution utility does not require production metering data for its load-serving purposes.

18. SCADA and AMI systems being installed at the present time will typically provide higher levels of data scan rates and available metering data then older systems, but most have not been designed to be capable of supporting market operations. Upgrading existing metering systems and related communications media to provide additional functionality they were not originally designed to provide could be cost prohibitive for many distribution utilities.

[6] *CAISO Open Access Transmission Tariff* (Effective as of May 15, 2018), Appendix B.21 *Distributed Energy Resource Provider Agreement (DERPA)*, section 4.17.5.2 Metering and Telemetry.

[7] *Id.*, 4.17.3 *Requirements for Distributed Energy Resource Aggregations*, item (d).

It may be more cost effective for the RTO/ISO to install their own metering and communications than for the distribution utility to do so and then provide the RTO/ISO access to that data.

19. Distribution utility systems used to process and store information and metering data differ greatly depending on the needs of the distribution utility and how it can most economically serve its consumers. Customer Information Systems (CIS) alone are typically sufficient for most small distribution utilities. Meter Data Management (MDM) systems and the latest generation AMI systems provide additional functionality and would be needed to provide the data likely required by the RTO/ISO to participate in wholesale electric markets. Obtaining and maintaining these types of systems would impose additional costs that many small distribution utilities cannot justify for their normal operations. These systems may be cost-prohibitive, and if they are only needed for a handful of DER aggregations participating in wholesale electric markets, they are systems the distribution utilities would not otherwise undertake.

20. Communication links between the RTO/ISO, the distribution utility, and the DER would likely require secure data communication systems, software, and protocols to allow these systems to share the information required for DER participation in wholesale electric markets. Current rules don't allow public internet as a means of communicating such data between market participants and the RTO/ISO; it is unclear what additional communications would be required to allow DER aggregations' wholesale electric market participation.

21. Traditional generation requires two-way communication where the RTO/ISO sends dispatch signals to the generation, and the market participant sends the MW, MVAR, breaker status, etc. of system elements to the RTO/ISO. If this level of communication is required for aggregated DER participation in wholesale electric markets, many existing

distribution utility systems would likely not be adequate. The installation and maintenance of any communications links and systems by distribution utilities to facilitate DER market participation would be another added cost that would need to be recovered by the distribution utility.

22. Providing and physically securing the facilities, equipment, and software required to gather data and securely exchange it between the distribution utility, the DER, and the RTO/ISO via secured and redundant communication circuits will require a significant infrastructure investment. In addition, this may place additional burdens on distribution utilities, by requiring them to comply with North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) requirements that they would not otherwise be subject to. For example, control centers that are capable of providing a means of communicating information to the RTO/ISO are a medium- or high-level risk as defined in the NERC CIP-002.5.1a standard.[8] Would distribution utility facilities now fall under the same type of NERC CIP requirements? The ramifications of these additional requirements could be overwhelming for a small distribution utility.

23. The aforementioned systems would also require distribution utility personnel to manage and maintain them. Small distribution utilities often operate with minimal staffing levels; adding sophisticated systems like these would likely require additional staff that would otherwise not be needed, and for which they lack the financial means to support through their existing customer base.

[8] North American Electric Reliability Corporation. "*Reliability Standards for the Bulk Electric Systems of North America*" CIP-002-5.1a Cyber Security – BES Cyber System Categorization – 2018: 157.

B. Cyber Security and Privacy

24. Cyber security and privacy policies established by distribution utilities typically do not allow them to share consumer information and access to internal systems with other parties. Special interfaces and data repositories with multiple levels of firewalls would need to be created and maintained to facilitate the sharing of any data between the distribution utility and any other entities, including DER aggregators. These interfaces and systems would involve costs to set them up and then maintain them over time that may be very prohibitive if only needed for a handful of DER aggregators participating in wholesale electric markets. The content of any data shared would by necessity be very limited and could not include any sensitive consumer information. Agreements would likely need to be put in place with the consumers whose data would need to be shared with the RTO/ISO to give the distribution utility permission to do so. Developing such agreements would also be a cost that the distribution utilities would not otherwise need to incur, and could be time- and resource-intensive.

C. Real-Time & Market Operations

25. Historically, RTOs/ISOs have attempted to utilize their existing processes, procedures, and protocols to the extent possible when adding new services. It is anticipated that the information and data requirements for DER aggregating and participating in wholesale electric markets would need to be comparable to the current requirements of other market participants, as DER aggregators would be participating in the same market operations and settlement processes. Examples of expected information and data requirements include:

- 3-5 second operational data to participate in real-time services;
- MDM systems and 5-minute data requirements for market settlements;
- Day-ahead load/generation forecast and market data requirements; and
- 7-day ahead forecast for operational data requirements.

26. The CAISO market rules approved by FERC in June 2016 allow aggregations of DERs to participate in the CAISO day-ahead, real-time and ancillary services markets as participating generators. What is being done at the CAISO may serve as an indicator of the data and information requirements that would be imposed by other RTOs/ISOs responding to a FERC mandate to allow DER aggregation and wholesale electric market participation. These DERs are included in a DER aggregation, which has to become a certified Scheduling Coordinator (SC) or retain the services of a certified SC to act on their behalf in order to participate in the CAISO market. SCs are required to submit Actual Settlement Quality Meter Data or Estimated Settlement Quality Meter Data for the DER aggregations they represent for each Settlement Period in an Operating Day to the CAISO. Each DER participating in a DER aggregation is to be directly metered.

27. RTO/ISO Energy Markets typically include day-ahead and real-time markets. The day-ahead market schedules the energy production before the operating day, and requires a load forecast and resource offering, typically by 3 p.m. in the day previous to the market clearing. The real-time market balances the demand to serve load, within transmission limitations, while observing reliability criteria. Operational requirements for the real-time market are more stringent, where markets typically clear in 5-minute intervals and are monitored on a real-time basis in 3-5 second intervals. Generator dispatch is a key component to energy market operation. RTOs/ISOs require visibility of generation and load, including aggregated DER that is participating in wholesale electric markets, in order to reliably operate the wholesale electric markets.

28. Ancillary Services maintain the reliability of the BES. These services are produced and consumed in near real-time, and include regulation, operating reserves (made up of

spinning, non-spinning, and supplemental reserves), black start, and reactive power. Some RTOs/ISOs have created an ancillary service market where regulation and reserves are the primary commodities. Regulation provides market-based compensation to resources that have the ability to adjust output or consumption in response to an automated signal. Regulation maintains the real-time balance of generation and load. In order to effectively participate in ancillary service markets, DER Aggregators will likely need to aggregate energy storage devices with DER to be able to regulate frequency and changes in scheduled vs. actual generation schedules or be able to ramp quickly to respond to an operating reserve activation.

29. Capacity markets are typically designed to determine resource adequacy in longer timeframes (annual, seasonal or monthly), and are dependent on the documented levels of proven production. The variability of DER output complicates matters and introduces much uncertainty that they'll be available when needed. Market rules need to properly reflect the capacity value of DER taking into account factors such as forced outage rates and any variability of output.

30. If the expanded DER aggregation and market participation moves market pricing into the distribution system, the inclusion of DER into the RTO/ISO least-cost security constrained economic energy dispatch will require a significant increase in the model complexity in order to define the interaction of load and resource elements. DERs are more likely to be successfully included by seeking to show the impact at the associated Elementary Pricing Node, and being able to provide a time synchronized certified metering value for settlements. Expanding marginal pricing to distribution utilities would be an onerous requirement that would impose a significant burden on those distribution systems that would be unlikely to provide any benefits to the systems or their ratepayers.

D. Market Settlements

31. Once the markets have closed and the Energy, Capacity and Ancillary services have been provided by all resources, there is a process in RTO/ISO wholesale markets where parties are invoiced. This is commonly referred to as market settlements. Market participants are compensated for resources provided and pay for services received. Typically, entities gather all the known information on billing units and pricing provided by the RTO/ISO and estimated statements are generated and referred to as shadow settlements. It is a fairly complicated process, and typically requires specialized software and databases. Smaller market participants have ways of receiving the information that don't involve a full shadow settlement but the review process is fairly intensive in terms of the human resources required. There is an opportunity to raise questions on charges or credits being made, and parties are continually making requests to the RTO/ISO. There are timeframes of settlements being published for a particular day of operations, and typically are provided one week later (S7), two weeks later (S14), etc.

32. The key to being able to evaluate settlement statements is the metered load data, and this will also be true for aggregated DER settlements. Identifying the aggregated DER products (energy, demand, ancillary services) that are being settled in the wholesale market vs. what items are being compensated in the retail market, if these services are indeed allowed to be provided in both markets, is also likely to be a key piece of information. Additional items of interest for aggregated DER would be the assessment of what wholesale node is being used for settlement, and how much of the energy is being pushed to the wholesale node, vs. how much of the energy is being netted out with local load. Identifying the wholesale node is also likely to be a key element in settlements. As explained above, meter data of this kind is unavailable on

most distribution systems, and the investment and operating expense required to develop it would outweigh any benefit to distribution customers.

33. It is important that, to the extent that smaller DER aggregator market participants were to delegate real-time and market operations functions and settlement functions (like some smaller wholesale load-serving customers have elected to do in RTOs), they must still be responsible for the communication and metering infrastructure that would allow DER to participate in the wholesale market. The distribution utilities must not be expected to finance this effort which is wholly to benefit the DER aggregators.

V. Distribution Utility Review of DER Registering for Wholesale Electric Market Participation

34. Distribution utilities have existing interconnection policies, processes and procedures to allow DER to interconnect and operate in parallel with the distribution utility systems. If FERC proceeds with its proposal, additional criteria would need to be added to the existing review/screening/study processes to determine if DER aggregations participating in wholesale electric markets would create any safety, reliability or power quality concerns on the distribution utility system. And an additional layer of agreements, procedures and criteria would need to be developed for aggregators of DER. RTOs/ISOs have no experience in the area of distribution level DER impacts and should not be allowed to define these standards alone. To make sure that the criteria are responsive to distribution utilities' needs, these additional criteria would need to be defined by the industry, based on industry standards and best practices, and then their adequacy would need to be, at a minimum, confirmed by distribution utilities; however, the preferred approach would be for distribution utilities or the relevant regulatory authority to have substantial input into the criteria.

35. Personnel at distribution utilities (possibly those currently reviewing interconnection requests) would also be required to assume the duties associated with reviewing requests from DER to participate through an aggregator in the wholesale electric markets. This may cause delays in reviewing new interconnection applications and in cases with high demand/interest in DER aggregation, the need to add additional staff. The costs associated with distribution utility personnel fulfilling these duties would need to be recovered by the distribution utility, and would be appropriate to be assigned directly to the DER aggregator.

36. Distribution utilities need to have the final approval for a DER installation participating through an aggregator in the RTO/ISO wholesale electric markets, as such an installation raises significant safety, reliability and power quality risks on their systems, above and beyond those impacts on their systems raised by individual DERs. It is important that distribution utilities have recourse to address these documented concerns. The CAISO has addressed this by requiring that a DER provider must obtain concurrence from the applicable utility distribution company or metered sub system that there are no concerns about the DER comprising a DER aggregation before they are allowed to begin the ISO New Resource Implementation process.[9]

VI. <u>Ongoing Operational Coordination</u>

37. Real-time data exchanges and operational or planning coordination with RTOs/ISOs typically occurs as a market participant, or as a Transmission Owner. Real-time coordination includes generator and demand side management (DSM) dispatch, outage coordination, congestion management, and regulation among others. Planning coordination

[9] *CAISO Open Access Transmission Tariff* (Effective as of May 15, 2018), Appendix B.21 *Distributed Energy Resource Provider Agreement (DERPA)*, section *4.17.4 Identification of Distributed Energy Resources*.

includes modeling, forecasting, contingency analysis, regional planning activities, and interconnection requests, among others. Distribution utilities are typically not market participants or a Transmission Owner in an RTO/ISO. In the case of distribution cooperatives, most are either members of a G&T cooperative or receive their power from another provider. These power supply providers are responsible for coordinating with RTOs/ISOs. Distribution cooperatives are most likely to coordinate with the G&T supplier in planning activities and interconnection requests, and not in regular market operations.

38. To allow distribution utilities the ability to conduct ongoing operational coordination with RTOs/ISOs and DER aggregators, systems and processes that do not exist today will need to be created and maintained. These systems and interfaces will need to meet RTO/ISO requirements to allow the distribution utility to provide real-time feedback to the RTO/ISO and DER aggregator. These systems and interfaces could be cost prohibitive for a small distribution utility that would otherwise not require these, especially when considering they may only benefit a handful of DER aggregators participating in wholesale electric markets.

39. The systems mentioned would also require distribution utility personnel to manage and maintain these systems. Small distribution utilities often operate with minimal staffing and adding sophisticated systems like these that would need to be monitored on a real-time basis would require adding personnel that would otherwise not be needed. This could be a significant burden on the daily operations at a small distribution utility. DER aggregators should not be allowed to take on the role of handling operational communications between the distribution utility and the RTO/ISO, because a conflict of interest would exist. As discussed previously, the utility, either directly or through a related entity such as a G&T power supplier, knows how best to safely and reliably integrate DER into its operations and should be the center

of operational coordination for aggregated DER utilizing its facilities to participate in wholesale electric markets.

40. The DER agreement(s) need to make it very clear that distribution utilities will not be held responsible for distribution system outages and other constraints on the distribution system that may prevent or limit the aggregated DER's ability to provide wholesale electric market services, including ones that DER aggregators and RTO/ISO cannot be made aware of in advance (*i.e.*, unplanned outages). Many outages and constraints are out of the control of the distribution utility. On an operational level, distribution system infrastructure is very dynamic compared to the transmission systems infrastructure. Services to consumers are routinely being added/retired, and equipment such as fuses, transformers, arresters, etc, are regularly added/retired or modified. Awareness of these changing conditions and their impact on aggregated DER participating in wholesale electric markets is a very real concern.

41. Distribution utilities vary in size and complexity; a "one size fits all" approach to DER aggregation and market participation would be problematic. Technology, systems and capabilities vary widely among distribution utilities based on geography, size, consumer needs and economics. Small distribution utilities likely do not have the systems and staff in place to handle the significant challenges that DER aggregation and participation in wholesale electric markets could impose.

42. Smaller utilities located within the geographic area of an RTO/ISO often elect to not be a market participant due to the need to justify the cost/benefit of the related higher level operations and planning requirements. The related data requirements, both in terms of accuracy and scan rates, have also typically been avoided by the smaller entities. In addition, the fundamental data and settlement activities that must occur in a centralized market suggest that a

critical size is needed for market participants to justify the resources required in order to be a market participant.

VII. Market Participation Agreements

43. The FERC NOPR is vague on this topic and leaves it open-ended for the RTO/ISO to figure out. I believe it is of utmost importance that these agreements should not broadly require system changes with associated costs being borne by the distribution utility and its ratepayers or exclude technical and operational provisions that are critical to distribution utilities. If distribution utilities are going to be parties to these agreements or affected by their terms, then they should have a say in what these agreements look like. In the case of distribution cooperatives that are part of a G&T cooperative, it is likely that the G&T would need to be a party to these agreements as well, and would have additional needs specific to their circumstances to be addressed. Defining all the activities and systems required to make DER aggregation and market participation work should be a priority before drafting the agreements so that important concepts and utility concerns are identified and can be addressed in the agreements. Significant resources and costs are expected to be required to develop these initial agreements that, again, must be borne by the DER aggregators and market participants that are causing these costs to be incurred.

VIII. Economics

44. As noted above, the ramification of DER aggregation and market participation includes significant uncertainty, concern and risk related to technical, operational, coordination, communication infrastructure, and security challenges. Substantial incremental costs will be incurred to deploy infrastructure, understand impacts/requirements, and add staff. There may also be future costs on the grid to accommodate DER aggregations that are not being deployed with local grid impacts in mind. Small, rural distribution utilities already face challenges when it

comes to financing plant replacements and expansions to provide safe and reliable distribution service to rural communicates and customers. Layering on additional costs and increasing competition for limited resources could be very unduly burdensome. It may require the utilities to defer higher priority projects to instead pursue financial support of projects required from DER aggregation and market participation.

45. I believe there is a great deal of uncertainty about the magnitude of these costs, and as I understand the NOPR, little information about who would be responsible for what, and how these costs would be collected. Distribution utilities and their customers should not have to incur costs that won't benefit them, but it is unclear how the utility would go about establishing a mechanism to recover these costs from only DER aggregating and participating in wholesale electric markets, and to do so in a way that isn't cost prohibitive to early adopters. I believe there will continue to be uncertainty on a going-forward basis, too. The availability of DER aggregations to participate in wholesale or retail markets will cause ongoing challenges when it comes to both providing economically efficient price signals, ensuring proper cost allocation and equitable rates.

46. DER compensation may come from providing energy, capacity, and/or ancillary services. Clear policies would need to be developed around defining whether DER is providing these services to the wholesale <u>or</u> retail market. It would be necessary for DER to select, for some period, whether it will be providing services to either the wholesale market or at retail. If this is not required, it is possible that a DER would "double-dip" and receive benefit at both the wholesale and retail levels on the same "product." This would be an uneconomic outcome as it would drive additional costs into the markets and cause financial harm to non-DER customers. For example, it would be uneconomical for a DER aggregation to receive compensation for

energy production by the distribution utility (*e.g.*, via net metering) and receive compensation for that same energy from the wholesale market. Requiring the DER to select either wholesale or retail is necessary.

47. The DER's decision of whether to participate in the wholesale market or retail should be based on clear and complete information. Utility rates and incentives must properly communicate this information. If not, DER development, operation, and dispatch will be suboptimal. Not only that, but substantial and perpetual cost-shifting can occur that puts a burden on all other customers. The challenge is that existing rate structures are not capable of providing this type of information – and it may be difficult to adjust or develop a structure that would. For example, aggregated DER that operates or is dispatched for purposes of wholesale market services can have a dramatically different profile and resulting cost/benefit from individual DER that serve retail purposes. Rates therefore would need to either be made much more complex, or many more rate options would need to be developed. It has already proven to be challenging to establish rate structures that balance price signals and cost recovery for DER that operates within retail markets. Establishing, maintaining and communicating more, or more complicated, structures to accommodate the economic proposition of aggregated DER responding to wholesale markets will add a significant challenge. Undoubtedly, additional burdens will be placed on utility systems, staff, and customers. If this is not dealt with and clearly prescribed from the start, there is a risk of significant, perpetual cost-shifting burden on non-DER customers and on DER not participating in the wholesale markets.

48. FERC needs to make sure these issues are fully resolved and that distribution utilities don't end up harmed in any program it decides to implement regarding DER aggregation participation in wholesale electric markets.

49. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

I, Jeffrey M. Triplett, being first duly sworn, certify that the Affidavit on Behalf of the National Rural Electric Cooperative Association was prepared by me or under my supervision; and that the statements and facts set forth therein are true and correct to the best of my knowledge, information, and belief.

Jeffrey M. Triplett

Subscribed and sworn before me, a Notary Public in and for the State of Ohio

this 25th day of June, 2018.

Notary Public (OFFICIAL SEAL)

My Commission Expires:
8-18-2019

NOTARIAL SEAL STATE OF OHIO

REBECCA A WOODBY
Notary Public, State of Ohio
My Commission Expires 8-18-2019

ATTACHMENT B:

Statement of Gerry Schmitz, Adams-Columbia Electric Cooperative

Statement of Kevin Short, Anza Electric Cooperative, Inc.

Statement of Craig C. Turner, P.E., Dakota Electric Association

Statement of Brian Callnan, New Hampshire Electric Cooperative, Inc.

Statement of Kenneth M. Raming, P.E., Ozark Electric Cooperative, Inc.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

Statement of Gerry Schmitz
Adams-Columbia Electric Cooperative

1. My name is Gerry Schmitz. I am the Senior Electrical Engineer at Adams-Columbia Electric Cooperative (Adams-Columbia), located in central Wisconsin. I have served in that position since 2012 and perform system and reliability planning. My business address is 401 East Lake St., Friendship, Wisconsin.

2. Adams-Columbia Electric Cooperative is a rural electric distribution cooperative serving approximately 36,000 member/owners in parts of 12 central Wisconsin counties spread out over approximately 2,500 square miles. Approximately half of our member/owners are residential and farms; we also have a significant number of non-residential seasonal members and serve some irrigation districts. We have 94 full-time employees and 5,785 miles of line in service. Adams-Columbia is the largest rural electric cooperative in Wisconsin.

3. Adams-Columbia's distribution facilities are interconnected to American Transmission Company, LLC (ATC), a transmission owning member of the Midcontinent Independent System Operator, Inc. (MISO). Adams-Columbia purchases its power from Alliant Energy.

4. The purpose of this statement is to provide information on Adams-Columbia's

experience with distributed energy resources, and on the expected impact on Adams-Columbia of FERC's proposal to require regional transmission organizations (RTOs) and independent system operators (ISOs) to permit aggregations of DERs to participate in RTO/ISO markets.

5. I have concerns that aggregation of DER and operating them for the wholesale market could exacerbate issues we have with DERs. We have already seen local voltage rise "islands" and experienced voltage regulation issues with current reversing on single-phase lines due to DERs. Greater penetration and concentrations of DERs will mean greater amounts of resources will need to be implemented to locate, monitor and then find solutions to correct the problems.

6. Another issue is that I expect DERs will want to run at unity power factor to maximize their sales of kWh. Minimizing our system losses would require the ability to dispatch the DER at other than unity power factor. Our financial best interest will be at odds with the financial best interest of the third-party DER aggregator, which could create some difficulties. We have a lot of underground lines, and most of the year a leading power factor. If we were able to dispatch DER, we would want them to operate at lagging power factor to help mitigate voltage rise issues. However, most inverters interconnected with our system today don't have the capability to operate at other than unity power factor, which is a big concern for us.

7. Our system has experienced reverse power flow at a regulator near a wind turbine. In the end we were forced to extend 3 phase and break up load that was being successfully managed by a regulator. The regulator simply wasn't built to handle the intermittent nature of wind generation. I'm concerned that situations like this could happen more frequently with third-party aggregation of DERs operating in MISO.

8. To make sure that third-party DERs are interconnected safely to our system we

would need to perform interconnection studies in coordination with MISO and ATC for transmission related costs, as well as distribution system interconnection studies. All of these studies and related system upgrades will create costs, and we need a way to make sure that all of these costs will be paid by the third-party DER aggregators. We have the responsibility to maintain voltage and power quality requirements, and we need to be able to directly assign the costs to identify and rectify nonconforming DERs.

9. Another issue that we don't have communications or AMI systems to support 5-minute telemetry and metering. To upgrade the AMI system to have that capability we will need approximately 3 years and $8 million. We would run meter reading, OMS, and SCADA over the AMI communications network, so the $8 million would cover some of these issues too. We also would need communications to American Transmission Company and MISO, at an unknown cost. We also would need to establish a means for settlements with MISO.

10. Providing third-party access to our distribution automation, SCADA, and/or billing system creates massive concerns for member identity theft and rogue system operations. My assessment is that it is an unacceptable risk. We would need to reach out to MISO and ATC for assistance but would not want to have to pay for systems that are needed only to serve third-party DER aggregators.

11. Another issue is that behind-the-meter (BTM) storage could increase our peak and costs. We would need a way to charge the BTM storage member a coincident power purchase demand charge and distribution demand charge to cover our costs.

12. We also have conservation voltage reduction (CVR), which drops our system voltage as much as possible. We would like DER to offset load as much as possible to reduce power flows and help with voltage profile. Third-party DER aggregation could create problems

for us because our CVR equipment can't react fast enough to cover instability from intermittent DER output; there is no stability mechanism unless there is energy storage or ride-through performance in the DER equipment.

13. Given all of these concerns, I hope that FERC does not require third-party DER aggregations on our system unless and until we decide we can handle them. As it is now, we would have staffing issues; we would need additional in-house staffing in particular for the communications with MISO and the DER aggregator.

VERIFICATION

I, Gerry Schmitz, state under penalty of perjury that the foregoing is true and correct.

Executed on 6-22-18.

DATE

Gerald W. Schmitz

Signature

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

Statement of Kevin Short
Anza Electric Cooperative, Inc.

1. My name is Kevin Short. I am the General Manager of Anza Electric Cooperative, Inc. (Anza), located in Southern California's Riverside County. I have been General Manager since 2012, and I have previous experience as an electrical contractor specializing in solar electric systems since 1989. My business address is P.O. Box 391909, Anza, CA 92539.

2. The purpose of this statement is to provide information on Anza's experience with distributed energy resources, and on the expected impact on Anza of FERC's proposal to require regional transmission organizations (RTOs) and independent system operators (ISOs) to permit aggregations of DERs to participate in RTO/ISO markets.

3. One of only three electric distribution cooperatives in the Golden State, Anza serves 5,000 meters across a 550 square mile rural area. Anza owns and services a little over 700 miles of distribution lines in Southwest Riverside County. Anza is a small cooperative, with only 23 employees. Located in the mountainous area of southern California at an elevation of 4,000', we experience extremes in weather ranging from 100˚ summer days to low temperatures in the teens and snow fall in the winter months.

4. Anza is located in the California Independent System Operator (CAISO) and is interconnected with the distribution system of Southern California Edison Company (SCE) at 34 kilovolts. Our energy and capacity are supplied via an all requirements contract with our Generation and Transmission (G&T) provider, Arizona Electric Power Cooperative, Inc. (AEPCO), located in Benson, AZ. Power is delivered via the CAISO tariff and distribution service contracts with SCE. Our G&T purchases energy for us within the CAISO, but we have no direct interaction with CAISO.

5. Our contract import capacity from our single radial feed with SCE is 14 MW. Our load varies with the season, typically peaking in summer with air conditioning driving demand. Due to load growth, we have contracted to increase this to 19 MW by spring 2019. The SCE contract provides for one-way service from CAISO to Anza; it does not provide for reverse flow from Anza to SCE or the CAISO. Due to solar projects on the distribution line to Anza, SCE is unable to accept reverse energy flows from Anza.

6. In 2014, we exceeded the California Net Energy Metering (NEM) requirement of 5% of our historic peak demand. At that point, our elected Board of Directors—our rate making authority—determined that continuing NEM under the existing tariff would result in further cost shifting to non-participating members. We instead developed a successor Distributed Generation (DG) tariff which allowed for a further 5% of peak demand capacity, while increasing interconnection costs and modifying rate structure to reduce cost shifting. The interconnected NEM and DG solar capacity is currently approximately 1 MW AC capacity behind the meter.

7. In late 2016, the Anza Board of Directors approved the installation of an Electric Vehicle (EV) Charging station, open to the public. The station is the first in the region, serving more than 700 square miles previously unserved by EV infrastructure. This project was funded

through the California Pollution Control Financing Authority's California Capital Access Program. Anza's loan was the very first successful loan in this state program.

8. Our member-owned DG is all solar capacity. Behind-the-meter solar capacity on our system is about 1 MW AC. At the distribution circuit level, we are up against the technical restraints of equipment, with certain items, such as voltage regulators, unable to allow reverse flow. Thus, we are limited in the ability to allow more DG in some areas of our distribution system.

9. In 2017, we commissioned phase 1 of our SunAnza solar farm project, which is interconnected at our main substation to provide feed to our whole system. This is a 2 MW AC capacity array, ownership of which is held by a for profit subsidiary of AEPCO. Combined contribution of all our renewable resources amounts to about 30% of our energy requirements. Demand reduction is limited to daylight hours, which does not help in peak reduction, as our system demand typically peaks between 6 and 9 p.m.

10. We are currently exploring the second phase of SunAnza, which is intended to include energy storage capability. This will include approximately 1.4 MW of solar feeding a 2 MW, 4 MWh battery system, intended to assist in peak demand reduction, voltage and frequency stabilization, and micro-grid islanding.

11. Due to our import capacity limits, as well as SCE's inability to accept reverse flow on their circuit that feeds us, it would be difficult—if not impossible—for an aggregated DG provider to build and export renewables on our system. This has hampered efforts by one or more of the Native American Tribes that we serve to build and operate renewable sources on their reservations.

12. In 2011 we investigated the options of constructing a second transmission line to

our territory. In the multiple scenarios reviewed, most suffered fatal flaws due to cost or technical infeasibility. The one option that was considered involved a 16-mile interconnection with an SCE substation located many miles from the existing point of service, and fed from a different source. Unfortunately, this option was rejected due to the high cost; the line was priced at more than our entire system's net value.

13. In summary, Anza faces multiple challenges to enabling Distributed Energy Resources (DER) within our service territory. We are under constant pressure from state and federal agencies to increase the adoption of such resources, but lack the funding and technical capabilities to easily comply. Clear direction and coordination from the disparate regulatory bodies is a necessary first step of any action that we could take as a distribution utility to enable DER deployments at the retail level.

14. Anza is committed to providing safe, reliable, and affordable service to its members. In conjunction with our G&T cooperative supplier, we have developed and are planning to develop DER resources on our distribution system to meet particular local needs. The opportunities for aggregated DER on our distribution system to participate in CAISO markets are severely limited. Any such aggregated DER participation would require coordination of planning and operations not only between the aggregator, Anza, and the CAISO, but also with SCE. It would be very important for Anza to have input into any coordination agreements, although given our limited staff and resources, we would need to rely on our G&T to develop any such agreements. I expect these agreements could take a while to negotiate because there are many complex issues that need to be worked out, but these issues need to be resolved up front.

VERIFICATION

I, Kevin Short, state under penalty of perjury that the foregoing is true and correct.

Executed on 25 June 2018.

DATE

Signature

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

<u>Statement of Craig C. Turner, P.E.</u>
<u>Dakota Electric Association</u>

1. My name is Craig C. Turner, P.E. I am the Director of Engineering Services at Dakota Electric Association, in Farmington Minnesota (Dakota Electric). I have served in that role since 2015. My responsibilities include coordinating technical projects which include advanced metering infrastructure (AMI), meter data management (MDM), demand reduction, system-wide fiber communication system and a pager communication system. I manage our engineering section which provides distribution engineering for Dakota Electric, including substation design, protection relaying, SCADA implementation & design, distribution studies (load flow, sectionalizing), equipment specifications, construction standards, technical standards, member generation interconnection, power quality investigation (EMF & stray voltage), and technical training for field crews. Prior to my current position I was the Engineering Services Manager at Dakota Electric for 17 years. My business address is 4300 220th Street West, Farmington, Minnesota 55024.

2. The purpose of this statement is to provide information on Dakota Electric's experience with load management and distributed energy resources (DER) programs and to tell FERC about the harmful effects we expect from FERC's proposal to require regional

transmission organizations (RTOs) and independent system operators (ISOs) to permit aggregations of DERs to participate in RTO/ISO markets.

3. Dakota Electric is a member-owned, not-for-profit electric distribution cooperative founded by local farmers in 1937. Dakota Electric's utility services are regulated by the Minnesota Public Utilities Commission. Dakota Electric is the only regulated electric distribution cooperative in Minnesota. Dakota Electric's utility services reach more than 106,000 members, making Dakota Electric the second largest electric cooperative in Minnesota and among the 25 largest electric distribution cooperatives in the nation. We have approximately 200 full- and part-time employees. Dakota Electric purchases wholesale electricity from Great River Energy (GRE), a generation and transmission (G&T) cooperative in Maple Grove Minnesota. Dakota Electric's utility services are distributed to homes, farms and businesses in parts of Dakota, Goodhue, Scott and Rice counties; nearly 58 percent of our revenues come from residential and farm members.

4. Dakota Electric members voluntarily purchase more than 8.7 million kWh of renewable energy annually through the Wellspring Renewable Energy program. Dakota Electric provides Wellspring energy to its members through GRE, our wholesale power supplier.

5. Dakota Electric has built up significant load management capabilities in conjunction with our members participation in controlling end-uses and installing on-site generation. More than 50% of Dakota Electric's members participate in one or more of our demand management or member-owned generation programs. Dakota Electric's system peak demand is about 450 MW, but with the loss of the ability to control and utilize our DER systems would be substantially higher. During our control periods, we have the ability to shed between 20-25% of our peak demand – a significant achievement. That allow us to decrease our demand

on the transmission system by 75-125 MWs.

6. In working with our members, we have integrated these controlled loads and member-owned generation systems with our distribution planning process. This has resulted in lower cost, non-wired solutions, which reduce our peak distribution system capacity needs. This provides savings for our members of millions of dollars annually. Within these programs, our members have created campus micro-grids. With these campus generation systems, our members are able to reduce their energy demands during peak load periods, and they can also improve their reliability by isolating their portion of the Dakota Electric distribution system during storms.

7. Allowing third-party aggregators to assume control of the demand management loads or the member-owned generation systems and to offer services independently to the transmission grid, would, simply put, ***destroy*** Dakota Electric's ability to control our system peak. Dakota Electric would no longer be able to plan for or rely on these non-wired solutions to reduce the distribution costs for our members. This would result in the need to construct millions of dollars of additional substation and distribution system capacity. This would also result in higher peak loads, which, in turn, would cost our member millions of dollars annually in higher electrical bills.

8. Dakota Electric is presently in the process of replacing all of our load control receivers with new devices which have fast two-way communication. We are looking forward to being able to enhance our options and services to our members, by being able to sell services to the transmission system with or through our G&T. We believe the local distribution utility is in the best position to coordinate the operation of systems interconnected with the distribution system and make the daily and sometimes hourly decisions between, costs, reliability and

opportunities which these new technologies can provide. Allowing third-party aggregators to "cherry pick" the best loads and to undermine the ability for the local distribution operator to control their system would be costly and cause significant additional costs and extreme disruption to Dakota Electric.

VERIFICATION

I, Craig Turner P.E., state under penalty of perjury that the foregoing is true and correct.

Executed on 6/21/18.

DATE

Signature

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

<u>Statement of Brian Callnan,</u>
<u>New Hampshire Electric Cooperative, Inc.</u>

1. My name is Brian Callnan. I am Director of Power Resources at New Hampshire Electric Cooperative, Inc. (NHEC). I have served in this role since 2017. My business address is 579 Tenney Mountain Highway, Plymouth, NH 03264.

2. The purpose of this statement is to provide information on NHEC's experience with distributed energy resources, and the expected impacts NHEC may have in providing reliable cost effective service to its members given FERC's proposal to require regional transmission organizations (RTOs) and independent system operators (ISOs) to permit aggregations of DERs to participate in RTO/ISO markets.

3. NHEC is a member-owned not-for-profit distribution cooperative providing over 85,000 retail electric services to members in 115 communities located in nine of the ten counties in New Hampshire. NHEC has over 200 employees disbursed over ten district offices in the state with its headquarter residing in Plymouth, NH. NHEC owns and maintains over 5,500 miles of energized distribution lines. NHEC's operating revenues in 2017 were $140 million with a peak load of 180 MW's delivered to its members over 5,500 miles of distribution lines owned and maintained by NHEC.

4. As a Load Serving Entity (LSE) NHEC is an active market participant in the wholesale markets operated by the Independent System Operator of New England (ISO-NE). NHEC participates daily in the regions energy markets, capacity markets, ancillary services markets, receives Regional Network Service and helps to fund various other operational markets as a LSE. NHEC is operates in a state with a Renewable Portfolio Standard and in a state that is part of the nine state Regional Greenhouse Gas Initiative (RGGI). NHEC operates in a deregulated state with retail competitive energy suppliers and its Board of Directors sets the retail tariffs needed to recover operating expenses. NHEC allows its members to connect to its distribution system with net-metered generators, predominately Solar Photovoltaic facilities. NHEC coordinates with ISO-NE when generators wishing to connect to its distribution system will impact the regional Bulk Electric System and with neighboring utilities when generation may impact their distribution system. NHEC is an active participant in the ISO-NE stakeholder process and is engaged in the creation and modification market rules that affect the region and its membership.

5. NHEC has more than 900 member-owned Solar Photovoltaic systems ranging from 48 watts to 288 kW totaling 7.5 MW and 2.0 MWs of PV that is owned by NHEC. Additionally, NHEC has approximately 100 kW of member-owned wind and 500 kW of member-owned hydro. In 2017, NHEC constructed New Hampshire's largest solar array, a 2 MW project in Moultonborough, using $5 million in low interest funds from New Clean Renewable Energy Bonds issued by the U.S. Department of Treasury and loaned to NHEC by the National Rural Utilities Cooperative Finance Corporation. The output from this facility will be used to reduce the amount of energy and capacity NHEC would otherwise need to buy from

the New England regional power grid. These facilities are not currently remotely dispatched nor are they able to be remotely dispatched by ISO-NE or NHEC.

6. NHEC aims to make the process for members to connect DER to the distribution system as easy and fair as possible while not negatively impacting members who do not wish to connect DER to the distribution system. Member owned DER on the NHEC distribution system helps to reduce the wholesale market energy, capacity, regional transmission and local transmission that NHEC needs to purchase to meet the needs of its members. In order to help maximize the value for its members NHEC offers to purchase the renewable attributes of the PV facilities by qualifying and purchasing the Renewable Energy Credits produced. Not all members take this option as some market their benefits to other purchasers. All system interconnections are studied as to their impact on the distribution system and members with generation proposals that require distribution system upgrades are notified of the need and cost of the upgrade before interconnection. NHEC does not perform the necessary upgrades to the distribution system unless they are funded by the member or developer wishing to interconnect the generator to the distribution system.

7. NHEC does not currently schedule or dispatch any DER, although it is possible in the future that our terms and conditions of service will need to include the ability to curtail DER production should it be necessary for the efficient use of the distribution system or in the best interest of our members.

8. NHEC has some concerns about FERC's proposals. If DER aggregation by third parties is allowed onto the distribution system without the knowledge of our distribution system engineers, we could be introducing significant member service reliability concerns. Capacity limits of individual distribution lines and equipment could be exceeded increasing the likelihood

of an outage on that part of the system. A public, continually updated hosting capacity might help alleviate this concern. NHEC estimates that this could be a significant expense and would require additional administrative burden to maintain.

9. NHEC anticipates that expansion of DER on parts of its distribution system will require upgrades to the system that would not have been needed if the DER were not interconnected. With increased DER (including DER aggregation), NHEC expects increased costs to account for the DER and its impact on the system, for example, costs associated with increasing the flexibility requirements of the SCADA system, the robustness of the communications system, the capacity of our information systems and the versatility of member direct communications software such as billing. DER aggregation is expected to increase complexity similar to what we have seen with Group Net Metering for retail billing. Group Net Metering requires the utility in some New England states to manage the benefit of production to the offsetting of load, which could include hundreds of members. The administration of this complexity is compounded by the interpretation of current and state laws and the uncertainty of changes to those state laws.

10. If DER is aggregated by a third-party rather than the co-op, NHEC is concerned our costs could be even higher. As an example, the state of New Hampshire requires the unbundling of rates, and retail choice for energy and capacity providers. This requires additional administrative costs associated with informing our membership of options, assigning specific annual costs associated with a member's use to third-party suppliers, supporting information requests from third-party suppliers and having the ability to support billing of non-co-op rates for third-party suppliers that wish to use the NHEC billing system. While this is not an exhaustive

list of expected cost increases, it is likely that costs similar to these would increase should third-party aggregators of DER be required.

11. Another type of costs that would likely increase with third-party DER aggregation are costs associated with the processing of DER interconnections; NHEC expects that DER aggregations would greatly expand the time and resources needed to process these. It is expected that this would increase the need for distribution utility personnel resources.

12. Additionally, NHEC would need to develop, modify or purchase a system to track and charge the entities that caused any additional costs to NHEC in order to minimize spreading those costs to members that did not cause them. It is expected this would also require additional administration overhead and may prove difficult to unbundle from overall member charges.

13. Another possible impact is that third-party DER aggregation could complicate our efforts to manage and reduce system losses, as more data collection and analysis would be required. Managing the load needs of the cooperative is one of the main requirements to consistently deliver reliable stably cost energy services to our members and an increase in the complexity of forecasting those future needs makes that requirement more difficult.

14. Another anticipated impact is the cost that we will have to incur to participate in the development of coordination agreements among NHEC, third-party DER aggregators, and ISO-NE. Any coordination agreements would require legal, management and administrative staff to create the agreements and ongoing administrative staff to keep the agreements current.

15. I believe that aggregation of DER for the purpose of operating in the wholesale market could have some operational impacts on NHEC, as well. Although NHEC's system is almost fully engineered to handle "2-way flows," DER aggregations have the potential for "backfeeding." Backfeeding onto our transmission provider could create additional issues

technically and perhaps contractually, especially because NHEC's distribution system does not have the native load required to absorb the output of these facilities. This could then strand the real power flow to our distribution system, which may require curtailment of the DER facilities (which could cause prospective interconnecting DER facilities financing difficulties). The conditions under which NHEC can backfeed onto its transmission service provider at wholesale delivery points would require, at a minimum, coordination with the transmission provider, likely predicated upon a full system study for the interconnecting facility, which is executed under the full discretion of the transmission provider, and which would likely include expensive protection packages such as a direct transfer trip scheme, reverse power flow, etc.

16. Another concern that NHEC has is that with third-party DER aggregation, the settings of protective devices, such as inverters, could be changed – possibly radically and with need for complex systems and communications technology to account for rapid changes in real-time DER output and load. We already face challenges trying to make sure our members' inverters operate in parallel with the NHEC distribution system.

17. Another concern is that aggregation of DER for wholesale market purposes could limit the expansion of DER on the distribution system, since many of the benefits from the avoidance of wholesale market charges would be removed. NHEC expects there may be additional costs associated with needing to react to a separate wholesale signal for scheduling or dispatch of DER, but has not quantified such costs.

18. DER storage is expected to further complicate the accurate forecasting of system needs on the distribution system, amplifying the concerns listed above, As a market participant in ISO-NE, NHEC attempts to control its costs by bidding into the energy markets the day before it needs the energy (DA-Market). Should there be significant variances in the amount of energy

forecasted due to the operation of a DER aggregator with storage it is possible NHEC could see increased energy costs as a result. This uncertainty also has the possibility of impacting the capacity and transmission costs that NHEC is required to pay

19. There are some other concerns and questions NHEC has, including:

- NHEC should be allowed to curtail or disconnect DER when the safety of its members, staff or the distribution system is in question. This seems to be a critical design to any rule or market.
- How would NHEC allow third-party aggregators access to our distribution system and still maintain our cybersecurity policies?
- Could any of this subject NHEC to additional NERC requirements? What happens if current state laws/efforts/mandates contradict or don't align well with FERC's requirements?

20. This concludes my statement and thank you for the opportunity to comment.

VERIFICATION

I, Brian Callnan, state under penalty of perjury that the foregoing is true and correct.

Executed on 6/26/2018.

DATE

Signature

NRECA/NHEC

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

<u>Statement of Kenneth M. Raming, P.E.</u>
<u>Ozark Electric Cooperative, Inc.</u>

1. My name is Kenneth M. Raming, P.E. and I am the Division Manager of Engineering at Ozark Electric Cooperative, Inc. (Ozark). I have served in this role since 2002 and was the Consulting Engineer for Ozark from 1988 to 2001. My business address is 2007 James River Ct., Nixa, MO 65714.

2. The purpose of this statement is to provide information on Ozark's experience with distributed energy resources, and on the expected impact on Ozark if FERC were to permit third-party aggregations of DERs on our system for the purpose of those DERS participating in neighboring RTO/ISO markets.

3. Ozark is a member-owned, not-for-profit distribution cooperative providing retail electric service to over 33,500 members in southwest Missouri. Ozark owns and maintains 4,765 miles of 7.62/13.2 KV distribution lines. Ozark's operating revenues in 2017 were $55.7 M and its expenses were $54 M. Ozark staff currently numbers 89 full time employees. After July 27, 2018, there will be only two (2) electrical engineers on staff with myself as the only Professional Engineer.

4. Ozark is a member of and full-requirements power customer of KAMO Electric Cooperative, Inc. (KAMO Power). KAMO Power is a generation and transmission (G&T) cooperative located in Vinita, OK.

5. Ozark currently has 150 photovoltaic (PV) rooftop systems on its system, with the average rooftop system at 9.1 kW. These PV DERs are all member-owned and each new one now requires a power flow study to check the impact of the proposed DER. We have utilized the export limiting capabilities of the inverters on the DER to maintain a level voltage profile and mitigate the effects of the reverse power flow on our system. I use Milsoft Windmil to model each DER under light loading conditions on our system with full DER generation.

6. I believe that our existing SCADA system handles the DER on our system today. We are fully deployed with OSII SCADA in our substations and have a few downline devices connected as well. I believe our SCADA system could handle higher penetrations of DER, but would require additional communication infrastructure to do so.

7. However, if third-party DER aggregation was allowed on our system, I would be concerned about the additional communication equipment that would be needed. Currently, we have Aclara Powerline Carrier Advanced Metering Infrastructure (PLC AMI), and we are in the process of upgrading to our meters to Landis & Gyr Focus AX meters. These are set up for 15-minute demand intervals. Currently, we read hourly data, 8 hours of data three times a day. We have a Meter Data Management (MDM) system that all the AMI data flows into. If five-minute metering were needed to accommodate DER aggregations, we would need additional investment in our metering equipment to be able to provide that. We would not want to have to charge our members for this because this is something that wouldn't benefit them, and we would need a way to charge the DER aggregators. Also, if we were to update our metering to facilitate DER

aggregations in wholesale markets, we would need to make sure that our metering priorities are first and foremost on preserving the safety and integrity of our distribution system.

8. Ozark is not a member of an RTO; nor is our G&T, KAMO. If we were, I do not know how our existing cooperative staff would have time to review ongoing day-ahead or real-time dispatching of third-party DER connected to our system to make sure there are no concerns. We have a small staff and we are only staffed during normal business hours. Ozark does not currently schedule or dispatch any DER now period, let alone in an RTO market. We rely on KAMO for dispatching; we are not set up for this type of real-time activity. Our AMI & SCADA communications goes through KAMO first, then to Ozark. If we needed to build and maintain additional communications systems for third-party DER aggregators, it would require extensive work, which would be nearly impossible—we have only two IT staff.

9. Additionally, dispatch of DER for participation in the wholesale market would require us to have some sort of measurement and verification system in place. To handle this, we would have to have our National Information Solutions Cooperative (NISC) software upgraded, which would be an additional cost to us.

10. Possible additional concerns are the resources available to study and process interconnection requests. Currently, I am the only person to review and approve Net Metering Applications. Due to my current work load and staff limitations, Ozark would not be able to handle a higher volume with DER aggregations.

11. Separately, I have very real concerns about for the safety on our system if aggregations of DER for the purpose of operating in the wholesale market, rather than for local concerns, are allowed on our system. The system we have designed and operated and for years is a radial system with a known source and load direction. Third-party DER aggregations could

make this more complicated. This is a huge safety concern for us and our linemen and it will significantly affect how our linemen work. Our linemen will use bracket grounding on both sides of the work zone as outlined in our Safety Manual to provide additional protection from DERs. We would, however, likely need to develop additional safety protocols to ensure linemen safety.

12. It is very important that whatever rule FERC issues that cooperatives like Ozark be able to manage the DER interconnections on our system so that we can protect the safety of our system and our personnel.

13. I also have concerns about the operational effect on our systems that could occur with third-party DER aggregations. In particular, Ozark has concerns about reverse power flow. For example, we have an 8 kW PV installation in place, and then a second 8 kW PV system applied for interconnection near same location. The load flow analysis showed the combined kW would push our system into reverse power flow. A solution that can be used to prevent reverse power flow/high voltage is to limit the amount that can be exported from the second inverter (this is set up within the inverter itself). In this case, the limit was set to 3 kW, to keep the system from experiencing reverse power flows. Since our interconnection process provides access on a first-come, first-serve basis, the first PV still has ability to export 8 kW as communicated with the original installation and application. Ozark has the ability to see through its MDM system what the hourly reads are and watch the ones that are exported, to determine if an established threshold is being exceeded. Because of our staffing limitations, we would not be able to go out and do an audit/review after the fact.

14. Ozark has existing privacy policies in place today that protects our members' data. If, for example, we had a request by a solar developer to access a member's kWh usage to

evaluate/size systems, Ozark will not provide that data to the solar company. Instead, we would advise the member and let the member send that information. This could be a problem if DER aggregators were to seek information about our members' data. If Ozark needed to set up additional interfaces, firewalls etc. we would not have the resources to do so. Additionally, Ozark would need to have agreements in place with its members to share such data.

15. Another concern I have is that the new IEEE 1547-2018 standard gives too much control of our grid to people who have little knowledge about how DER works. The adjustability settings are worrisome and changeable by individuals at any point in time. This concern would be made worse by having third-party aggregation of DER on our system. Ozark needs the ability to determine the appropriate settings during the DER interconnection process and establish these settings in the DER interconnection agreement and in an agreement with the DER aggregator. Ozark also needs the ability to enforce the agreed settings during the operation of the DER to prevent them from being changed by the DER operator without our knowledge or authorization.

VERIFICATION

I, Kenneth M. Raming,P.E. state under penalty of perjury that the foregoing is true and correct.

Executed on 6/25/18.

DATE

Signature