UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Electric Storage Participation in Markets	)	Docket Nos. RM16-23-000
Operated by Regional Transmission	)	AD16-20-000
Organizations and Independent System Operators	)	

COMMENTS OF ADVANCED ENERGY MANAGEMENT ALLIANCE REGARDING A NOTICE OF PROPOSED RULEMAKING ON ELECTRIC STORAGE PARTICIPATION IN MARKETS

Pursuant to 18 CFR Part 35, Advanced Energy Management Alliance ("AEMA")[1] submits these comments regarding the Federal Energy Regulatory Commission ("Commission" or "FERC") Docket Nos. RM16-23-000; AD16-20-000, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators ("NOPR").[2] On December 20, 2016, the Commission extended the deadline for filing comments in the subject proceeding from January 30, 2017 to February 13, 2017.

AEMA is a trade association under Section 501(c)(6) of the Federal tax code whose members include national distributed energy resource companies and advanced energy management service and technology providers, including demand response ("DR") providers, as well as some of the nation's largest demand response and distributed energy resources. AEMA members support the beneficial incorporation of distributed energy resources ("DER" or "DERs"), including advanced energy management solutions into wholesale markets as a means to achieving electricity cost savings for consumers, to contributing to system reliability, and to ensuring balanced price formation. This filing represents the collective consensus of AEMA as

[1] Advanced Energy Management Alliance website: http://aem-alliance.org.
[2] FERC NOPR https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-1.pdf; *See*, 157 FERC ¶ 61,121 (November 17, 2016).

an organization, although it does not necessarily represent the individual positions of the full diversity of AEMA member companies.

I. BACKGROUND

AEMA appreciates and supports the intent of the Commission through this NOPR to remove barriers to participation of energy storage resources and aggregated DERs in all wholesale markets. AEMA believes that, while the NOPR has the potential to remove barriers and enhance competition in wholesale markets, sections of the NOPR would not only create barriers to DERs that wish to enter wholesale markets, but could also force existing low-cost, existing DERs out of the wholesale market, depending on how the NOPR is interpreted and implemented by the Regional Transmission Organizations/Independent System Operators ("RTO/ISOs"). Moreover, AEMA believes that the NOPR should go further than proposed to eliminate existing barriers to DERs. In these comments, AEMA will highlight these concerns, and more importantly, provide practical solutions to the Commission to address the concerns.

AEMA's comments reflect today's reality that DERs include a variety of technologies, ranging from promising, emerging, and commercially feasible technologies--such as energy storage and smart home management systems--to more established technologies, including curtailment services from commercial and industrial ("C&I") DR customers. Market rules have been written (and extensively litigated), for C&I DR, with over 10,000 megawatts ("MW") of C&I DR participating across RTO/ISOs. As evidenced by the NOPR's objective, and current RTO/ISO participation levels, few rules have been written to accommodate and reduce barriers for newer distributed resource technologies.

It is critical that any final rule aimed at reducing barriers to distributed resources not have the unintended consequence of disturbing settled principles of regulatory law related to DR.

There is a risk that a final rule could jeopardize these extant principles and the hard fought regulatory certainty that is fundamental to the stability of DR participation in wholesale markets. Therefore, the final rule adopted pursuant to this NOPR should be crafted with newer technologies in mind. AEMA urges extreme caution before extending the reach of the final rule to the more "established" C&I curtailment services, where business models have been developed around existing market rules. While AEMA recognizes that market rules evolve, the justification for the NOPR largely does not apply to these established technologies, with exceptions noted herein. If a final rule is broadly applied to established technologies active in markets today, it could have unintended negative market consequences.

Notwithstanding the foregoing paragraph, the NOPR justification certainly applies to newer technologies, including forms of residential DR such as smart home energy management systems as well as energy storage. In fact, the final rule should make equal effort to integrate residential technologies as it does energy storage, because current rules were not developed with these technologies in mind, and both can deliver value to wholesale markets if existing barriers are addressed. AEMA believes that, while enabling aggregation is a positive step, the proposed rule is insufficient to properly address the barriers faced by residential DR technologies.

Therefore, AEMA respectfully requests[3] that the Commission:

1. Exercise extreme caution prior to extending the proposed reforms for DER Aggregators (Section III.B.4) to the existing, well-established, and well-subscribed, C&I DR participation model.
2. Clarify and modify the proposed reforms for DER Aggregators (III.B.4), especially the prohibition on dual participation for the "same services", telemetry, and the reporting

[3] For convenience, a summary of all of AEMA's recommendations concerning the NOPR are included as an Appendix to these Comments.

from distribution utilities to RTO/ISOs of where DER enrollments could create reliability issues.

3. Include within its charge to the RTOs/ISOs, development of participation models appropriate to weather-sensitive loads, especially residential air conditioning load aggregations, which face barriers in existing markets.

AEMA's comments for suggested improvements in a final rule should enable the Commission to meet the stated objective of the NOPR. With a membership that has collectively deployed between 10,000 MW to 20,000 MW of DERs worldwide, including DR,[4] distributed generation, and energy storage, AEMA offers an informed perspective and significant operational expertise with DERs through these comments and recommends solutions regarding the implementation of new market constructs for DERs.

All correspondence or communications concerning these comments should be addressed to the following:

Katherine Hamilton Executive Director Advanced Energy Management Alliance 1200 18th St, NW, Suite 700 Washington, DC 20036 (202) 524-8832 Katherine@aem-alliance,org	Richard A. Drom Daniel Clearfield Eckert Seamans Cherin & Mellott, LLC 1717 Pennsylvania Avenue Washington, D.C. 20006 (202) 659-6645 rdrom@eckertseamans.com dclearfield@eckertseaman.com

II. AEMA COMMENTS

[4] As defined by FERC, demand response is "Changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." AEMA notes that certain behind-the-meter resources can increase their consumption in response to price signals, which is not explicitly captured in the above definition. https://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp.

AEMA's comments focus on: (1) seeking clarification on how the NOPR is intended to apply to existing participation models and resources, and urging the Commission not to undermine existing and functional C&I DR participation models; (2) clarifying whether the definition of DER includes demand response; (3) discussing the proposed reforms that will govern "Participation of Distributed Energy Resource Aggregators in the Organized Wholesale Electric Markets," including highlighting sections of the NOPR that could restrict DER participation and detailing how FERC should alter these sections in a final rulemaking; (4) highlighting proposed reforms in the DER section (III.B.4) that AEMA supports; and (5) identifying existing barriers to DER participation in RTO markets, mainly to residential DR, and explaining why a new participation model is necessary to achieve Commission objectives and more competitive wholesale markets.

A. AEMA Seeks Clarification on the Application of the NOPR to Current DR Participation Models, and Respectfully Urges the Commission Not to Undermine Currently Functional Market Opportunities for C&I DR.

The NOPR states "[w]e also propose to require that each RTO/ISO, to accommodate the participation of distributed energy resource aggregations in the organized wholesale electric markets, establish market rules on (1) eligibility to participate in the organized wholesale electric markets through a distributed energy resource aggregator…"[5] This NOPR section (III.B.4) describes eight different "proposed reforms" for market rule development applicable to DER aggregators. It is unclear, however, what would distinguish a DER Aggregator from a Curtailment Service Provider (or the relevant term that currently describes DR aggregators in each market). RTO/ISOs may view the NOPR as applying to Curtailment Service Providers

[5] NOPR, ¶ 5.

("CSPs") as well, and apply the proposed reforms to all resource owners under the existing DR participation models. Therefore, AEMA seeks clarification from the Commission regarding:

- Which, if any, of the proposed reforms in Section III.B.4 of the NOPR for DER Aggregators would be applicable to CSPs and to the C&I DR participation model?
- What will be the distinction between CSPs and DER Aggregators? AEMA suggests a distinction of using the term CSPs to refer to aggregators of behind-the-meter resources (including DR, storage, advanced energy management, and Distributed Generation) that participate exclusively under the DR participation model, and DER Aggregators referring to aggregators that could include behind-the-meter and/or in front-of the-meter resources and that can participate under any model.

With exceptions noted herein, AEMA respectfully urges the Commission to exercise extreme caution prior to extending the proposed reforms for DER Aggregators (Section III.B.4) to the existing, well-established, and well-subscribed, C&I DR participation model.

In explaining why it was issuing the NOPR, the Commission wrote:

> Further, new resources may have difficulty creating momentum for the market rule changes necessary to facilitate their participation and may thus need to spend considerable time and effort to gain entry to the organized wholesale electric markets. Where rules designed for traditional generation resources are applied to new technologies, where new technologies are required to fit into existing participation models, and where participation models focus on the eligibility of resources to provide services more so than the technical ability of resources to provide services, barriers can emerge to the participation of new technologies in the organized wholesale electric markets. We are therefore issuing this NOPR to address these barriers to the participation of electric storage resources and distributed energy resource aggregations in the organized wholesale electric markets.[6]

While RTO/ISOs may need to improve their market rules to better accommodate all DR, AEMA believes that it is unnecessary to rewrite the rules that govern C&I DR participation

[6] NOPR, ¶ 2.

models as broadly as envisioned in III.B.4. C&I DR is not a "new resource" and, for the most part, has gained entry to wholesale markets as evidenced by the over 10,000 MW currently participating. The proposed reforms go well beyond what is required for the C&I DR participation model. In fact, if the proposed reforms were applied to CSPs in the C&I DR participation model, certain reforms could inadvertently drive existing, low-cost, reliable resources from the market. This could increase costs to consumers and would run directly counter to the intent of the NOPR to make wholesale markets more competitive.

The mirror image of the above reason for not generically extending the DER aggregator model to existing DR models is that certain DR principles are not and should not be applicable to DER aggregators. As one example, FERC Order 719 and its progeny adopted provisions that the "Relevant Electric Retail Regulatory Authority" for retail customers may determine whether a retail customer may participate in wholesale market DR. For one, not all DERs are resources behind retail customer meters, and, as such, the blanket extension of Order 719 to DER would be an unnecessary burden on DERs and interstate commerce generally. Second, to the extent that DERs are selling injections of electric energy in wholesale markets, such activity is governed under the Federal Power Act.[7] For these reasons, and many others, the Commission should refrain from generically extending principles unique to DR to the DER aggregator model.

AEMA believes the Commission should clarify in the final rulemaking that RTO/ISOs are not expected to apply the rules governing DER Aggregator participation to CSPs in the C&I DR participation model. If an RTO/ISO wishes to change its market rules, it is always allowed to do so as part of a 205 filing, but that should be separate from any compliance filing to this rulemaking.

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[7] *EnergyConnect, Inc.*, 130 FERC ¶ 61,031 (2010).

For other newer forms of DER, including residential load management technologies and energy storage for export, the language from the NOPR quoted above is applicable, as existing participation models do not properly accommodate these resources and should be carefully reformed without eliminating current programs or imposing unnecessary new restrictions and barriers.

B. The Commission Should Clarify that the Definition of DER Includes DR or that DR resources Can Choose to Participate in Emerging DER Participation Models Where Such Are a Better Fit.

AEMA assumes that the definition of "Distributed Energy Resources" includes DR given that it is a "sink of power." However, to avoid any unnecessary confusion in the marketplace, and to encourage uniform definitions across RTO/ISOs, AEMA respectfully requests that the Commission clarify that DER does indeed include DR.

For example, the New York Independent System Operator ("NYISO") has determined that DER includes many types of resources; it has expressly included load curtailment (*e.g.*, "end users that may be able to modulate their energy usage strictly through load curtailment measures") as an integral element of DER in New York.[8]

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[8] *See*, NYISO Distributed Energy Resource Roadmap, http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/Distributed_Energy_Resources/DRAFT%20Distributed%20Energy%20Resources%20Roadmap%20-NYISO%208-17.pdf,p. 14. ("The NYISO sees the DER program as expanding opportunities for DER by opening up wholesale electricity markets for combinations of technologies that may not currently participate. Specifically, the DER program would enable five types of resources to participate in the NYISO's Energy, Capacity, and Ancillary Services markets. These resources include (See Appendix A for use cases): * Load-only resources – those end users that may be able to modulate their energy usage strictly through load curtailment measures; * Load with Generation – those end users capable of dispatching behind-the-meter generation resources and/or load curtailment to reduce their demand from the grid; * Load with Storage – those end users capable of calling on behind-the-meter storage resources and/or load curtailment to modulate their demand for energy from the grid; * Load with Generation and Storage – those end users who can call upon a combination of behind- the-meter generation, storage and/or load curtailment to adjust their demand; and * Controllable generation with remote retail load obligations.")

Moreover, excluding DR from the definition of DER could not only create unnecessary confusion in the marketplace, but also inefficiencies. For instance, if an end-use customer is capable of curtailing load and discharging a battery located behind their meter, it would be unclear if the customer's DER aggregator could aggregate both the storage and load curtailment into the same resource if the aggregator wishes to participate in the storage model. It would be inefficient to have the same customer participating as part of two different resources, or through two unnecessarily separate participation models. Indeed, the NOPR clearly recognizes the value created from combining multiple technologies. Footnote 229 of the NOPR states "For example, combining the discharge times of multiple electric storage resources and/or combining them with distributed generation resources could allow aggregated resources to meet minimum run-time requirements that individual electric storage resources may not be able to meet." The same value could be created through combining storage and DR.

Moreover, the NOPR notes that today DERs participate in markets largely through DR participation models, which limits their ability to contribute their full value. AEMA argues below that some residential DR resources require new participation models as well, and should therefore be addressed as DER. At the very least, DR resources should be allowed to operate under new and emerging participation models for DERs where such models are more appropriate to the unique physical and operational characteristics of these resources.

Therefore, to reduce confusion and ensure efficient market outcomes, AEMA respectfully requests that the Commission clarify that advanced energy management, including DR is a form of DER. AEMA acknowledges that in the previous section, we requested that the Commission "exercise extreme caution prior to extending the proposed reforms for DER Aggregators (Section III.B.4) to the existing, well-established, and well-subscribed, C&I DR participation model."

However, including DR as a subset of DER is a definitional issue, not a markets issue, especially, as noted, DER Aggregators can participate under several models, just one of which is DR. This definition of DER would not limit the Commission's ability to have different forms of DER participate under different models and not be exposed to identical rules and, it would allow the RTOs/ISOs to address emerging forms of DR resources, such as large aggregations of connected residential loads.

C. The Commission Should Specifically Modify Certain Proposed Reforms that Will Govern the "Participation of Distributed Energy Resource Aggregators in the Organized Wholesale Electric Markets."

AEMA is concerned that certain proposed reforms will create barriers to new DERs of any kind. And if the Commission were to deny AEMA's request to not apply the NOPR to CSPs participating in the C&I DR participation model, the proposed reforms could force existing DR resources to exit the market. In the following section, AEMA comments on the proposed reforms that should be modified, and provides suggestions for those modifications.

1. Eligibility to Participate in the Organized Wholesale Electric Markets through a Distributed Energy Resource Aggregator.

a. The Commission Should Clarify the Nature of "Same Services".

The proposed reform to "limit the participation of resources in the organized wholesale electric markets through a distributed energy resource aggregator that are receiving compensation for the same services as part of another program" could have a chilling impact on DER participation depending on how the Commission defines "same services." The Commission should recognize, as it did in a recent Order in Docket No. EL16-92-000, that customers and DER aggregators often deliver incremental value through participation in multiple programs, including wholesale and retail programs. This practice has been allowed for years and has incrementally benefited both wholesale and retail markets; a broad ban on wholesale and retail participation would have significant negative market consequences. Therefore, AEMA respectfully urges the Commission to clarify its definition of "same services," and allow (as it has in the past) the same customer to participate in and earn compensation for wholesale programs even if it is already participating in a retail level program, provided that the service being provided at the wholesale level is incremental to the service provided at the retail level. The definition of "same services" should be limited to instances when a DER customer or aggregator receives compensation twice for delivering a single value to the grid, for example, where participation in a wholesale program delivers no incremental value to the grid beyond the participation in a retail level market, tariff or program. A blanket ban of participating in retail and wholesale level programs is not only inconsistent with the purpose of the NOPR, but would force customers to choose between retail and wholesale programs, limit the value aggregated resources could contribute, and render wholesale markets less competitive and increase costs for customers, or even undermine the cost effectiveness or commercial viability of DERs unnecessarily.

Utility load management programs and proposed net metering tariffs in New York provide an illustrative case study to better distinguish "same services" from incremental services. Although the following example is applicable to DR, it could just as easily be applied to all forms of DER more broadly. In New York, a customer may participate in the bulk-level reliability "Special Case Resources" program through the NYISO, and a distribution-level reliability or peak shaving program through Consolidated Edison ("Con Edison"). As correctly recognized by the Commission in its recent order in Docket No. EL16-92-000, the dispatch triggers, performance requirements, and compensation methods are different for each program, and the value streams delivered to the grid are additional, or incremental. The Commission noted: “Further, the payments SCRs receive from the retail-level demand response programs are actually for providing services that are separate and distinct from the payments that SCRs receive for participating in NYISO’s ICAP market. While the wholesale- and the retail-level demand response programs may complement each other*, they serve different purposes, provide different benefits, and compensate distinctly different services* [emphasis added].”[9] If a customer participated in solely the wholesale program, then distribution level benefits such as avoided transmission and distribution infrastructure would not accrue to Con Edison and its customers. This is because Con Edison would not be able to access the resource during a distribution-level contingency, and would therefore need to build enough infrastructure to accommodate load usage from that resource during a contingency. As stated by the New York Public Service Commission (“NYPSC”) in Docket No. EL16-92-000, “the distribution network peak load reductions that these programs achieve benefit all utility customers by deferring investments in new distribution infrastructure, avoiding emissions, reducing peak period, energy prices, and supporting reliable system operation. Con Edison may rely upon these demand and peak load reductions when planning its capital budget, *which it cannot do for Demand Response that participates only in the wholesale market”* [emphasis added].[10] On the other hand, if a customer participated in solely the Con Edison program, the customer would not be providing capacity to the NYISO, and the NYISO would have to procure and pay for another source to provide that capacity. This would increase wholesale costs and remove that DR as a tool for NYISO system operators.

Performing in one program does not mean the customer would necessarily be compensated in the other program. In fact, dispatch for the Con Edison programs only

[9] *New York State Public Service Commission, et al*., 158 FERC ¶ 61,137, at ¶ 33 (2017).
[10] *See*, June 24, 2016 Complaint of the NYPSC, p. 28.

overlapped with dispatch for the NYISO programs in 6% of hours from 2011 to 2015. Since the customer would have to perform in different hours to earn each revenue stream; clearly these are not the "same services." Moreover, the capacity payment for NYISO participation is based off the wholesale capacity clearing price, and the "availability" payment for the Con Edison programs is based off avoided costs for transmission and distribution infrastructure. This is in line with the incremental value delivered to the wholesale and retail levels.

AEMA agrees, however, that there are instances in which the services provided by a customer could be categorized as the "same." For instance, when such resources are dispatched simultaneously, energy compensation should not be duplicated. In other words, if Con Edison pays the customer wholesale Locational Based Marginal Pricing ("LBMP") for all kilowatt-hours ("kWh") delivered during a dispatch, then NYISO should not pay the customer LBMP for performance during any overlapping dispatch window. In fact, the tariff that governs the Con Edison DR program prohibits such a double payment of LBMP during overlapping dispatches. Proposed net metering tariffs in New York provide another example of what could be considered a "same service." For instance, a NYPSC whitepaper from October 27, 2016, proposed to pay net-metered customers the NYISO capacity clearing price based on their performance during the peak hours of the year. The NYPSC would be compensating the customer for reducing the amount of capacity that would need to be procured by the NYISO. It would be inappropriate for this customer to also enroll as a supply-side resource in the NYISO market, and receive compensation twice for providing a single value stream of capacity. The customer could either reduce the capacity requirement or provide capacity as a supplier, but not both. AEMA would consider this to be an instance of the "same service" as only one value stream is being created. In this instance, the Commission should prohibit a customer from enrolling as a supply resource and receiving wholesale compensation if the customer was already receiving capacity compensation through a retail tariff.

Another example of where these services are incremental and not the "same," however, is Pennsylvania's Act 129 DR programs. These programs, operated by Pennsylvania Electric Distribution Companies ("EDCs"), are economic programs dispatched during periods of system peak and are intended to reduce costs for Pennsylvania consumers. Dispatches for Act 129 programs, which occur at 96% of system peak, are likely to occur outside of dispatches for the PJM program, which only occur during grid emergencies. Although Phase III of the programs will not begin until the summer of 2017, history suggests that load can often exceed 96% of peak without resulting in a PJM reliability-based dispatch. Moreover, there could be a PJM dispatch due to generator or transmission outages even if load did not exceed 96% of system peak, as evidenced by the Polar Vortex. Again, if a customer participated in just the PJM program, but not the Act 129 programs, the incremental value of the Act 129 program would not be realized by Pennsylvania consumers. The same is true vice versa: if a customer participated in the Act 129 programs but not PJM, the benefits of wholesale DR participation would be unrealized. It would not serve the Commission's interests to force customers to choose between the Act 129 and PJM programs.

It would be inefficient to have dedicated resources for wholesale and another set of dedicated resources for distribution if one resource can do both; the NOPR should recognize the synergies between the two systems. Recognizing that there are jurisdictional differences between the two types of electrical systems, AEMA accepts that the systems are not divorced operationally. Electrons flow from one system to the other and can affect each other. However, creating artificial operational boundaries can complicate or prevent the most efficient operation of both systems.

AEMA recognizes that the Commission may be concerned that payments from retail programs could distort competitive outcomes in wholesale markets. AEMA's members share this concern in instances when retail compensation is tied only to participation or performance in the wholesale market. That is why AEMA believes that the retail and wholesale programs must create incremental value streams and benefits to consumers and the electric grid in order for consumers to be allowed to participate and be compensated in both. One clear way to tell if the value streams and benefits offered are incremental is to look at the dispatch triggers for each program, the purpose of each program, and how compensation is determined, as it did in the docket quoted above.

The Commission also may believe that participating in wholesale and retail programs could create coordination issues. AEMA supports the need for coordination, but asserts that participation in retail and wholesale programs has the potential to provide system operators with insight that they might not otherwise receive. For instance, if a group of customers were participating in only a retail program, and a retail program for several dozen MWs was dispatched by the utility, the wholesale system operator may have no advance notice of this sizable grid impact. By virtue of allowing customers to participate in both programs, and requiring coordination between DER aggregators and RTO/ISOs and utilities, the aggregator or utility could communicate to the RTO/ISOs ahead of the dispatch, avoiding surprises.

For the reasons discussed above, AEMA respectfully urges the Commission to clarify its definition of "same services," and allow (as it has in the past) the same customer to participate in and earn compensation for wholesale programs, even if it is already participating in a retail level program, provided that the service being provided at the wholesale level is incremental to the service provided at the retail level. The definition of "same services" should be limited to instances when a DER customer or aggregator receives compensation twice for delivering only a single value to the grid.

b. The Minimum Size Requirement should be Set at 100 kW.

In this section, the Commission also seeks comment on its "proposal to require distributed energy resource aggregations to meet the minimum size requirements of the participation model that they use to participate in the organized wholesale electric markets." The Commission provides the example of the storage participation model and notes that if a DER aggregator were to participate through that model, the minimum size requirement for an aggregation would be 100 kW. AEMA supports the minimum size requirement of 100 kW for the storage participation model and the Commission's assertion that:

> While we acknowledge that minimum size requirements may be necessary to ensure that the RTOs/ISOs can effectively model and dispatch the resources participating in their markets, large minimum size requirements create a barrier to the participation of smaller electric storage resources. We preliminarily conclude that requiring that the minimum size requirement not exceed 100 kW balances the benefits of increased competition with the ability of RTO/ISO market clearing software to effectively model and dispatch smaller resources often located on the distribution system.[11]

The well-reasoned justification provided by the Commission in the above quote is broadly applicable and should be allowed for DER Aggregators under all participation models. Regardless of what technology a small customer uses behind the meter, the fixed cost of participation in the wholesale market is comparably high. A customer with storage may be part of an aggregation that is better suited for a different participation model than storage alone. Subjecting the DER aggregator of that customer to a minimum size requirement significantly above the 100 kW minimum size proposed for the storage participation model runs counter to the

[11] NOPR, ¶ 94.

goals of the NOPR. To achieve maximum competition in wholesale markets, AEMA respectfully requests that the Commission direct the RTO/ISOs to have a minimum aggregation requirement of 100 kW for all DER aggregations.

2. Metering and Telemetry System Requirements for Distributed Energy Resource Aggregations Should Not Create Barriers to Participation.

In this section of the NOPR, the Commission repeatedly recognizes the expensive nature of metering & telemetry. AEMA appreciates that the NOPR recognizes that metering telemetry could present a barrier to DER participation.[12] Unfortunately, by proposing that DER aggregators "provide to the RTO/ISO the real-time capability of its resource in a manner similar to the requirements for generators," the Commission could erect a significant barrier to entry. The Commission states, "while telemetry data about a distributed energy resource aggregation as a whole is necessary for the RTO/ISO to efficiently dispatch the aggregation, telemetry data for each individual resource in the aggregation may not be." However, if the DER Aggregator has to provide real-time telemetry data to an RTO/ISO, then it might be interpreted that the customers that comprise that aggregated DER resource will also require real-time telemetry. Otherwise, it is unclear what data the real-time telemetry from the DER Aggregator to the RTO/ISO would be based on. This would be cost prohibitive, as per site costs for telemetry comparable to generation can reach $30,000, excluding all but the largest customers from participation.

Even if individual customers or resources were allowed not to have real-time telemetry, imposing real-time telemetry requirements on DER aggregators comparable to generation, which is typically six seconds or less, would, at best, meaningfully raise the offers of that resource into the market and increase costs to consumers, and would, at worse, be cost-prohibitive for DER aggregators altogether. And once again, this is another example of why it is critical that the

[12] NOPR, ¶ 150, § III.B.4.f.

NOPR not apply to CSPs participating under the existing C&I DR participation model since this would significantly increase the costs of participation for those existing resources and force smaller customers or aggregations from the market.

AEMA believes it is important for the Commission to note that a single generator can spread the cost of six-second data requirements across hundreds of MWs of revenue. For a DER aggregation, the fixed cost could be the same, but the cost would be spread around a small number of MWs, imposing much more of a burden. Also, six-second data is more necessary for generators, as they could either be on or off, and so if a 300 MW generator trips and goes off-line, the RTO/ISO needs to know immediately. The generator's size and centralized nature requires this immediate attention. A DER resource, on the other hand, would be comprised likely of dozens of smaller resources that operate independently, such that, if one battery stops working behind one customer, the overall resource could still be performing at 95% or even 100% and it is less critical for the RTO/ISO to know within six seconds.

AEMA is not opposed to telemetry requirements, but respectfully urges that the Commission implement the following parameters:

a. For DERs that participate exclusively in the capacity market, and not energy and ancillary markets, do not require RTO/ISOs to go beyond current requirements. If an RTO/ISO feels that the current metering and telemetry requirements are inadequate for preserving reliability, the RTO/ISO is able to file tariff changes at any point.

b. For DERs participating in energy and ancillary markets, the Commission should look at telemetry requirements it has previously approved for behind-the-meter resources, and not require RTO/ISOs to go beyond that for DER Aggregators unless RTO/ISOs can make a compelling case that those requirements are insufficient. For instance, in ISO-

New England ("ISO-NE"), capacity resources will have a "must offer" into the energy and ancillary markets beginning in June 2018. These resources will be required to provide five-minute telemetry if they are participating in the energy market or providing 30-minute reserves and one-minute telemetry if they are providing 10-minute reserves. ISO-NE recognized that it was unnecessary to have more granular telemetry requirements for DR, despite six-second requirements for generation. Other ISOs such as California ISO ("CAISO") have more liberal requirements and those should be maintained.

c. Particularly for aggregations of small DER, the Commission should allow virtual telemetry, by the DER, it aggregator, or its scheduling coordinator, with validation via meter data after the fact. This procedure is critically important for large aggregations of smaller loads. Large aggregations of load resources or DERs often rely on statistical performance of their fleets of participating resources, generally monitored by some form of communications-- sometimes near real time--to confirm expected performance and refine forecasted behavior of the resource. The larger and more homogeneous the portfolio of DERs, the more accurate the statistical performance forecast can become over time. For example, the performance of an aggregation of many thermostats, through which an aggregator and its Scheduling Coordinator achieves increased or decreased consumption on command, will generally be confirmed through an internet protocol via common, perhaps multiple, telecom channels, to its own systems dashboard. The aggregator or the Scheduling Coordinator can then provide the market operator a signal, comparable to what the system receives from generators today, communicating the operational status of the load response fleet. As noted above, the frequency of the communication should be appropriate to the service provided. Any DER aggregation can develop the same capability to accurately link its monitored performance to verified meter data statistically. The Scheduling Coordinator for the DER can validate accuracy after the fact with the RTO/ISO. The RTO/ISO can then equitably and appropriately compensate each DER that is either short or long. AEMA accepts that aggregators that are repeatedly or markedly inaccurate may have to be allowed more limited participation or expect performance-based penalties.

3. Coordination between the RTO/ISO, the Distributed Energy Resource Aggregator, and the Distribution Utility Should be Appropriate.

While AEMA understands the need to ensure that DER aggregations do not jeopardize distribution-level reliability, the proposed reforms in this section could serve as a significant barrier to entry for DER customers. AEMA is also concerned with the Commission's justification for this coordination, which is the "purpose of this coordination would be to ensure that all of the individual resources in the distributed energy resource aggregation are technically capable of providing services to the RTO/ISO through the aggregator and are eligible to be part of the aggregation (*i.e.*, are not participating in another retail or wholesale compensation program, as discussed in Section III.B.4.a above)."[13] As detailed in a previous section, the mere participation of a customer in another program should not render the customer ineligible for wholesale participation. A customer participating in a retail program would still be technically capable of providing services to the RTO/ISO, as evidenced by recent history, where single customers have participated and performed in multiple programs in different markets. Dispatches for retail and wholesale programs often do not overlap, and so there is no reason a customer could not participate in one program at one time and another program at a different time. If the dispatches overlapped, then the customer could perform in both programs at the same time, and

[13] NOPR, ¶ 154.

both the retail and wholesale operators could receive the desired performance. If for some reason the retail and wholesale dispatches were back-to-back on the same day, and the customer could not perform in both, the DER Aggregator would backfill that customer's capacity with capacity from another customer. This is why DER Aggregators typically "overbuild" their portfolio.

FERC also proposes to allow distribution utilities to review the registration of individual DERs before they are enrolled in the wholesale market, and report to the RTO/ISO any concerns they have about that customer's enrollment jeopardizing reliability. In order for this not to create an unnecessary barrier to entry, or enable discriminatory treatment, AEMA respectfully urges the Commission to place the following parameters around the reporting from distribution utilities:

a. There should be no requirement for distribution utilities to review the registration for reliability unless the customers are exporting to the grid. Under the existing DR participation model, no RTO/ISO currently requires distribution utility review for reliability purposes before registrations. Tens of thousands of registrations have occurred without ever jeopardizing distribution-level reliability.

b. It is inefficient for all market participants, including distribution utilities, to review every single registration. A more efficient solution would be for distribution utilities to provide to RTO/ISOs specific areas of their network that have limited ability for additional DER registrations. If a DER wished to enroll and export power in that area, then it would trigger a notification requirement to the distribution utility. If the distribution utility did not provide the RTO/ISO with any information, nor did it designate any areas as ones that could not accommodate additional DER registrations, then the distribution utility would not need to review the DER registration in the wholesale market. This would eliminate unnecessary reviews and barriers to entry.

c. To ensure that the reviews from distribution utilities do not unreasonably delay a customer's ability to enroll in the wholesale market, a time limit of not more than 10 days should be placed on the distribution utility to review the registration, even for very large DERs. After that time period, if the distribution utility has not reported back to the RTO/ISO, then the RTO/ISO will approve the registration.

d. To prevent against discriminatory treatment from a distribution utility that may want to own and enroll their own DERs, or that does not want to see DERs enroll in the market and suppress wholesale prices, the Commission needs to implement certain safeguards. Most importantly, if a distribution utility reports to the RTO/ISO that a DER registration will jeopardize distribution level reliability, then the distribution utility or any other DER provider should also be prohibited from registering that customer in the future.

e. Finally, if the RTO/ISO decides to prohibit a DER registration based off information provided by the distribution-level utility, then the customer and their DER aggregator should be allowed to see the information provided by the distribution-level utility, and should be able to appeal to an independent body.

4. Information and Data Requirements for Distributed Energy Resource Aggregations Should Not Create Barriers to Participation.

AEMA agrees with the NOPR that a RTO/ISO needs sufficient information to model, dispatch and settle aggregations[14] and AEMA supports a reasonable registration process. Unfortunately, the NOPR appears to permit RTO/ISOs to require excessive amounts of

[14] *See, e.g.*, NOPR, ¶ 145.

data regarding the *details* of locational information, which could be interpreted to require DER to identify the individual location of residences that participate in DER programs. Instead, the NOPR should be amended to only require the type of locational information required by RTO/ISOs for reliable operations, like Commercial Pricing Nodes ("CPNodes") or zones. Such an amendment to the NOPR should be accompanied by requirement of a process that would permit DERs to easily access locational information (easily meaning even machine-to-machine Application Programming Interfaces ("API") integration capacity to identify which CPNodes or zone a resource belongs to, based on easily available information such as zip code or street address) to enable DERs to participate in the RTO/ISO markets. This automated access would be particularly important for very large aggregations of relatively smaller resources, such as residential resources.

Secondly, the NOPR might allow RTO/ISOs to establish reasonable operating limits of an aggregation, but providing the operating limits of the aggregation's component locations would be both extraneous and burdensome. The NOPR should recognize that RTO/ISOs will dispatch an aggregation of DER, not component parts of that aggregation, unless specific provisions are made for that, and presumably compensated appropriately. As a result, it is only reasonable for RTO/ISOs to ask the operating parameters of the aggregation. It should be the DER aggregator's job to ensure that its locations deliver according to the aggregation's operating parameters.

Similarly, the requirement in the NOPR for DERs to provide one-line diagrams[15] should also not be necessary, especially for aggregations of small loads, particularly if it is for aggregations of essentially homogeneous loads like residential loads, or residential solar or solar and storage. This requirement is certainly unwarranted where there is only load response and no export of power to the system.

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[15] NOPR, ¶ 146.

D. AEMA Strongly Supports Certain Proposed Reforms that Will g\Govern the "Participation of Distributed Energy Resource Aggregators in the Organized Wholesale Electric Markets."

1. Locational Requirements for Distributed Energy Resource Aggregations

AEMA strongly supports the Commission's proposal "to require each RTO/ISO to revise its tariff to establish locational requirements for distributed energy resources to participate in a distributed energy resource aggregation that are as geographically broad as technically feasible." Different RTO/ISOs may understandably have different standards for interpreting this direction from the Commission, but the Commission should clarify that only allowing aggregation to the nodal level, as is proposed by NYISO in their latest DER Roadmap,[16] will not meet the standard in the previous sentence.

As the Commission recognizes, aggregation is critical for enabling participation from individual customers, as the overwhelming majority of customers do not have the resources, technical capability, or desire to participate directly in the market. Aggregation also protects individual customers from out-of-pocket penalties, which is necessary for gaining customer approval for participation. The larger the aggregation of customers, the lower the chances that under performance from an individual customer will have a negative impact on the expected performance of the aggregated resource. This ensures that system operators receive the performance they are expecting.

AEMA anticipates that certain parties may argue, as NYISO does in their Roadmap, that overly broad aggregation could result in dispatches that exacerbate transmission constraints if customers are on the "wrong" side of a constraint. Therefore, they may argue that "technically

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16 http://www.nyiso.com/public/webdocs/media_room/press_releases/2017/Child_DER_Roadmap/Distributed_Energy_Resources_Roadmap.pdf

feasible" actually could be a very limited geographic area. When considering what is "technically feasible", AEMA urges the Commission to consider the following:

i. Resources can be aggregated at a very broad level, and be dispatched more granularly if there are constraints that would be exacerbated by dispatching an entire aggregated resource at a certain point in time, or if performance from a customer would be non-deliverable to other geographic areas of where the aggregated resource is located. In other words, just because constraints could potentially exist, it could still be "technically feasible" to allow for aggregation across a broad area. There may be instances when the entire aggregated resource is not dispatched, but it is unreasonable to have a blanket policy that prohibits broad aggregation in an RTO/ISO solely because a limited area of the RTO/ISO may have constraints.

ii. If broad aggregation is not allowed, the quantity of resources could become overwhelming and unmanageable for RTO/ISOs and DER providers alike. For instance, instead of having to calculate performance and payments for 100 aggregate resources, an RTO/ISO could have to do the same for thousands of smaller resources.

iii. In ISO-NE, all DR with a Capacity Supply Obligation will have a must-offer obligation into the energy & reserves market. Aggregation will be allowed at the dispatch zone level, with 19 dispatch zones currently in ISO-NE. While aggregation is "technically feasible" at an even broader level than the dispatch zone level, the rules in ISO-NE suggest that it is technically feasible to at least aggregate behind the meter resources to that level even for energy and ancillary participation, and that any suggestions of only allowing nodal aggregation are misguided.

iv. A specific example of an overly restrictive policy on aggregation is in Midwest ISO ("MISO"), where aggregation is not allowed across Commercial Pricing nodes ("CPNodes") or Local Balancing Areas to meet the minimum size requirement of 5 MW. This can prevent operationally capable resources, such as air conditioning loads, from participating in providing critical services such as spinning reserves. With a minimum size requirement of 5 MW and minimal ability to aggregate, there are significant barriers to entry for DERs in MISO, and the Commission should direct MISO to fix them immediately. And as mentioned above, the NYISO is contemplating only allowing aggregation to the nodal level, which would present a major barrier to DER Aggregators. While the Commission should give some leeway to the ISOs to determine what is "technically feasible", the bar for "technically feasible needs to exceed the nodal level. In another example, the NYISO is contemplating a DER framework, for which at least the early iteration may require aggregations to be identified with one of 56 nodes.[17] While this might be all that is today "technically feasible" for the ISO due to systems limitations, it would not be technically feasible, much less commercially viable for large aggregations of small resources to comply with such granular boundary conditions.

2. Modifications to the List of Resources in a Distributed Energy Resource Aggregation.

AEMA supports the proposed reforms here made by the Commission concerning the list of resources in a DER Aggregation.[18]

E. Weather-Sensitive Loads, including essentially all residential load resource aggregations, require a new participation model.

[17] *See*, *e.g.*, January 2017 New York PSC DER Roadmap, http://www.nyiso.com/public/webdocs/media_room/press_releases/2017/Child_DER_Roadmap/Distributed_Energy_Resources_Roadmap.pdf.

[18] *NOPR, ¶ 149.*

AEMA encourages the Commission to address barriers for a rapidly emerging residential DR resource enabled by the growth of smart-home energy management technologies and services. While direct load control is not new at the residential level, and its value and reliability is well-proven, the technology is growing more sophisticated and attractive to consumers for a variety of reasons unrelated to energy savings or grid reliability. An irreversible trend in home appliance controls (for health, convenience, safety, control, security as well as economic reasons) is introducing a significant and growing potential resource. While it is weather sensitive, and variable, this resource is increasingly predictable and reliable. The resource value is that it in part provides control of the very demand that drives system peaks, dominantly space heating and cooling. In addition, this resource provides the ability to change the very nature of resource planning, so that markets truly experience demand elasticity, a feature of an ideally competitive economy.

Yet, there is only one market in North America that is truly developed to intentionally capture, and compensate, the value of this resource: the Weather Sensitive Loads component of ERCOT's Emergency Response Service. ISO NE has no market for residential loads to participate at all, nor does Southwest Power Pool ("SPP") or MISO. Residential participation is theoretically but not practically possible in NYISO. California is piloting direct participation of customers in CAISO, though while mandating inclusion of residential loads, makes no provision for their variability. In PJM, the one RTO/ISO that accepts seasonal products, has demonstrated the value and success of this resource, demand response, which is even now under threat of being eliminated from the market.

In reading the present NOPR, AEMA is struck that market participation by emerging building controls face many of the same barriers as energy storage. And, as alluded to briefly above, it seems clear that there is more than mere analogy in common between these resources. When these parties precool a space, they are charging the thermal mass of a building. When a residential energy management platform is asked to reduce system demands during a hot afternoon, the aggregator depends on the discharge of thermal storage to maintain comfort levels for a period. This is not only a limited duration resource, it is also linked to the cycles of the weather (not unlike some renewable resources), making it a truly unique resource, as might properly be addressed by this NOPR. Fortunately, as previously noted, these weather sensitive loads, while variable, are also highly predictable and correlated to peak demand. FERC should specifically require the RTOs/ISOs to develop a residential DR participation model to address the unique characteristics of this burgeoning resource.

In particular, development of appropriate participation models for weather sensitive loads would recognize that they are the very loads that drive peaks, and are therefore valuable as peak resources. Heating and air conditioning systems are not running, or running as much, during mild weather, and so have less load reduction possible. But when the weather reaches extremes, and electric markets reach their peak demand, these resources are the logical resource to turn to. Incorporating them into a wholesale market structure, therefore, would require a number of accommodations, several of which AEMA discusses in its comments responding to sections III.B. 4. In addition, however, AEMA respectfully requests the Commission in its final rulemaking to direct the ISOs to better incorporate weather sensitive loads into wholesale markets through adoption of:

i. Availability and performance metrics that do not penalize these resources for performing as would be expected;

ii. Limited Duration event opportunities;

iii. Baseline methodologies that match adopted availability and performance metrics.

The California Public Utilities Commission, for example, requires the investor owned utilities ("IOUs") in that state to include residential loads in their Demand Response Auction Mechanism ("DRAM") pilot. Load resource aggregators being granted a capacity credit in the DRAM accept a must offer obligation in the CASO wholesale market. CAISO requires that a resource, including residential resource, bid its full net qualifying capacity for all availability assessment hours ("AAH"), for months at a time. This either forces residential aggregators to offer extremely low monthly capacities into DRAM, or bid their peak capacity (and assume that penalties are an acceptable method for payment adjustment for a variable resource), or bid only at the price cap (in hopes of being called only at peak times). This seems less appropriate because it is not explicitly recognizing the character of the resource (*e.g.*, forcing a round peg into a square hole), and either method of adjustment tends to lead to uneconomic outcomes, and therefore may discourage participation.

NYISO is taking a different approach to matching baseline availability and performance requirements in its DER Roadmap initiative. This approach combines a fixed capacity bid with a Must Offer Obligation, but NYISO is considering allowing loads to bid as a "peaking resource." This may well be a sufficient means to recognize the value and character of residential (and even commercial) loads driven largely by air conditioning or heating, albeit indirect. (The NYISO initiative has other shortcomings addressed in locational requirements section above.) PJM had historically allowed summer peaking resources to participate, although they are planning on eliminating this avenue for participation, which, AEMA has noted in several forums, will be deleterious to the participation of weather sensitive loads and to consumers. By being considered within their own separate bid stack, these resources were allowed to reach their own price level appropriately.

Finally, it should be noted that in ERCOT's Emergency Resource Service market, Weather Sensitive Load resources bid the reduction they can provide toward more extreme weather conditions, so that ERCOT has transparency to what capacity is available when it most needs load reduction. Loads are paid for what they actually deliver during tests or emergency events, which can be less than what they have bid. These resources are essentially recognized as peaking resources. There is no penalty for loads that deliver less reduction when the weather conditions are mild, that is, for load resources that act as would be expected. Another way to say this is that ERCOT has adopted a "pay for performance" model, so loads that provide less are paid less, but there is no added penalty for unavailability during mild weather.

The ERCOT weather sensitive loads are required to perform for only three hours. The NYISO proposal will presumably identify a peak period that is reasonable for peaking resources as well. The California AAH window is larger, and again threatens to reduce the potential participation for residential loads.

With regard to baseline approaches, extensive data available in California indicates that traditional baselines used for blocky industrial or large commercial loads are ineffective at predicting residential behavior. A CAISO Baseline Alternatives Working Group ("BAWG") is recommending three options on the basis of studies to the CAISO Energy Storage and DER initiative stakeholders. Random Control Tests were found the most accurate approach to evaluating what large relatively homogeneous populations of resources would have done in the absence of control actions. Utilities are working to make research populations of non-participants available for Propensity Score Matched Control Groups available so that participating load resources don't have to be held back during actual events, only to provide the control group reading. For smaller populations of weather sensitive loads, the BAWG will recommend a weighted X of Y days with a weather adjustment, or a "like weather days" methodology, also with a day-of weather adjustment. Unfortunately, these baseline approach improvements simply help more accurately recognize the variable nature of weather sensitive residential loads, but do not remove the financial disincentives to participate. ERCOT uses all these same approaches for its weather sensitive loads program, which works quite well. In the ERCOT case, as mentioned however, the ISO also pays for performance, and does not ask weather sensitive loads to act like industrial load shed, or traditional generation, in terms of availability or performance. PJM for its historical summer peak capacity products, and its current Base Capacity market, used a fixed-service level baseline, or "drop-to" baseline, that allows a load resource to be credited with its full performance so long as its demand does not rise above a fixed (preset) level when called upon. This recognizes, for example, that during a cool fall afternoon, air conditioning systems may already be down, and are therefore, neither contributing to resource adequacy shortages, nor available for reduction. They are not penalized under this approach for unavailability, when it would logically be expected.

F. To Achieve FERC's Objectives of Removing Barriers to DER, the Commission Should Direct MISO to Undertake Certain Reforms.

AEMA applauds the Commission for its recognition that existing participation models need to be reformed to integrate newer DER resources.[19] Given that the Commission intends for DER Aggregators to be able to continue to participate through existing participation models, it is imperative that the Commission address the major barriers that exist to DER within these

[19] NOPR, ¶ 2.

models. In proposing reforms and directing the RTO/ISOs to develop rules in the eight areas outlined, the Commission clearly recognizes the need to reform those models to accommodate DER Aggregators. However, if the Commission only limits reform to the eight areas in the NOPR, it will not comprehensively "address the barriers" faced by DER aggregations from legacy performance requirements in existing models.

In particular, existing market rules in MISO serve as a barrier to participation from behind-the-meter resources, and will prevent DER aggregators from entering the market. Areas of necessary reform in MISO include:

A. Modeling of the ancillary service for frequency regulation that is not energy neutral.[20]
B. Modeling currently requires that for a resource to clear ancillary service of frequency regulation, it must previously clear the full range of dispatch in energy and then sell back the upper regulation range to the market. This creates a "phantom load" due to forcing the resource to look like a generator and is unnecessary for the modeling.[21]
C. Allow Price Responsive Demand to participate within the market.[22]

These barriers in MISO remain a key focus of stakeholders, as shown in the 2016 roadmap prioritization survey although these were very low priority for MISO[23]. Additionally, the MISO dissolved the long standing Demand Response Working Group in 2016, which had

[20] https://www.misoenergy.org/StakeholderCenter/CommitteesWorkGroupsTaskForces/IssuesTracking/Pages/IssueDetail.aspx?IssueID=103&MISOIssueID=DRWG097.

[21] https://www.misoenergy.org/StakeholderCenter/CommitteesWorkGroupsTaskForces/IssuesTracking/Pages/IssueDetail.aspx?IssueID=101&MISOIssueID=DRWG095.

[22] https://www.misoenergy.org/StakeholderCenter/CommitteesWorkGroupsTaskForces/IssuesTracking/Pages/IssueDetail.aspx?IssueID=96&MISOIssueID=DRWG062.

[23] https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/MSC/2016/20160830/20160830%20MSC%20Item%2005%20Market%20Roadmap%20Draft%20Prioritization%20Proposal%20with%20extended%20Appendix.pdf.

been actively focused on these issues. MISO no longer has a focused group working on promoting access to wholesale markets from behind the meter resources issues in their stakeholder process. To address these longstanding DER barriers in a timely manner, AEMA respectfully requests that the Commission direct MISO to remedy these shortcomings upon compliance in this rulemaking within six months. AEMA's concern is that, just as these issues on DR have not been addressed by the MISO in a timely manner, the Commission must ensure that RTO/ISOs do not delay and stall in timely identification and resolution of DER issues since the DER issues will not be the priority for the majority of traditional RTO/ISO stakeholders.

Moreover, the Commission should require the RTO/ISO organizations to develop focused task teams to identify and resolve common issues that are barriers to DER modeling, dispatch and participation in their region. These task teams should be directed to include representatives from organizations that have active DER resources, so that the host of issues is identified and just and reasonable solutions are developed.

III. CONCLUSION

WHEREFORE, AEMA respectfully requests that the Commission accept the subject comments in this proceeding. In particular, AEMA respectfully requests that the Commission: (1) exercise caution in extending the proposed reforms for DER Aggregators to the existing, well-established, and well-subscribed C&I Demand Response participation model; (2) clarify and modify the proposed reforms for DER Aggregators as described herein (particularly with respect to elimination of the proposed prohibition on dual participation for the "same services", required telemetry and distribution utility reporting requirements); and (3) include within its charge to the RTOs/ISOs, development of participation models appropriate to weather-sensitive loads, especially residential load aggregations, which face barriers in existing markets.

Respectfully submitted,

/s/ Richard A. Drom

Richard A. Drom
Daniel Clearfield
Eckert Seamans Cherin & Mellott, LLC
1717 Pennsylvania Avenue
Washington, D.C. 20006
(202) 659-6645
rdrom@eckertseamans.com
dclearfield@eckertseaman.com

Attorneys for AEMA

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Appendix Summarizing AEMA Recommendations

For convenience, AEMA summarizes the recommendations included in its Comments, as follows:

1) Exercise extreme caution prior to extending the proposed reforms for DER Aggregators (Section III.B.4) to the existing, well-established, and well-subscribed, C&I DR participation model.

2) Clarify and modify the proposed reforms for DER Aggregators (III.B.4), especially the prohibition on dual participation for the "same services", telemetry, and the reporting from distribution utilities to RTO/ISOs of where DER enrollments could create reliability issues.

3) Include within its charge to the RTOs/ISOs, development of participation models appropriate to weather-sensitive loads, especially residential load aggregations, which face barriers in existing markets.

4) Establish a distinction between using the term CSPs to refer to aggregators of exclusively behind-the-meter resources (including DR, storage, and Distributed Generation) that participate exclusively under the DR participation model, and DER Aggregators referring to aggregators that could include behind-the-meter and/or in front-of the- meter resources and that can participate under any model.

5) Clarify that DER does indeed include DR.

6) Clarify its definition of "same services," and allow (as it has in the past) the same customer to participate in and earn compensation for wholesale programs even if it is already participating in a retail level program, provided that the service being

provided at the wholesale level is incremental to the service provided at the retail level.

7) Direct the RTO/ISOs to have a minimum aggregation requirement of 100 kW for all DER aggregations.

8) Implement the following parameters as they relate to telemetry:

   a. For DERs that participate exclusively in the capacity market, and not energy and ancillary markets, do not require RTO/ISOs to go beyond current requirements.

   b. For DERs participating in energy and ancillary markets, the Commission should look at what telemetry requirements it has previously approved for behind-the-meter resources, and not require RTO/ISOs to go beyond that for DER Aggregators unless RTO/ISOs can make a compelling case that those requirements are insufficient.

   c. Particularly for aggregations of small DER, the Commission should allow virtual telemetry, by the DER scheduling coordinator, with validation via meter data after the fact.

9) Place the following parameters around the reporting from distribution utilities in the section "Coordination between the RTO/ISO, the Distributed Energy Resource Aggregator, and the Distribution Utility:"

   a. There should be no requirement for distribution utilities to review the registration for reliability unless the customers are exporting to the grid.

   b. Limit distribution utility review to specific networks or sections of the grid where the distribution utility has indicated there is a limit on the amount of additional DER capacity that can be exported.

c. To ensure that the reviews from distribution utilities do not unreasonably delay a customer's ability to enroll in the wholesale market, a time limit of not more than 10 days should be placed on the distribution utility to review the registration.

d. If a distribution utility reports to the RTO/ISO that a DER registration will jeopardize distribution level reliability, then the distribution utility or any other DER provider should also be prohibited from registering that customer in the future.

e. If the RTO/ISO decides to prohibit a DER registration based off information provided by the distribution-level utility, then the customer and their DER aggregator should be allowed to see the information provided by the distribution-level utility, and should be able to appeal to an independent body.

10) Only require the type of locational information required by RTOs for reliable operations, like CPNodes or zones.

11) Require each RTO/ISO to revise its tariff to establish locational requirements for distributed energy resources to participate in a distributed energy resource aggregation that are as geographically broad as technically feasible.

12) Adopt the proposed reforms in the section "Modifications to the List of Resources in a Distributed Energy Resource Aggregation."

13) Direct the ISOs to better incorporate weather sensitive loads into wholesale markets through adoption of:

a. Availability and performance metrics that do not penalize these resources for performing as would be expected;

b. Limited Duration event opportunities;

c. Baseline methodologies that match adopted availability and performance metrics.

14) Reform MISO's existing market rules that serve as a barrier to participation from behind-the-meter resources, and will prevent DER aggregators from entering the market, by considering changes to the:

a. Modeling of the ancillary service for frequency regulation that is not energy neutral.

b. Modeling requirement that for a resource to clear ancillary service of frequency regulation, it must previously clear the full range of dispatch in energy and then sell back the upper regulation range to the market.

c. Prohibition on allowing Price Responsive Demand to participate within the market.

Certificate of Service

I, Richard A. Drom, hereby certify that on this day I served "Comments of the Advanced Energy Management Alliance Regarding NOPR on Electric Storage Participation in Markets" on all parties in Docket Nos. RM13-23-000; AD16-20-000 via electronic mail.

/s/ Richard A. Drom
Richard A. Drom

February 13, 2017