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Distributed Energy Resource Aggregation Participation in Organized Markets

Federal Energy Regulatory Commission Order 2222 Summary, Current State-of-the-Art, and Further Research Needs

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Technical Update, February 2021

EPRI Project Manager

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This is an EPRI Technical Update report. A Technical Update report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

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ABSTRACT

In September 2020, the Federal Energy Regulatory Commission (FERC) issued Order No. 2222, which requires each FERC jurisdictional regional transmission organization and independent system operator (RTO and ISO) to revise its tariff to facilitate the participation of distributed energy resources (DER) aggregations in the wholesale energy, ancillary services, and capacity markets. This report summarizes the principal decisions FERC took in Order No. 2222 and history of the decision process. The report also provides a comprehensive update on the state of the art on the participation of DER aggregations across the United States' RTOs/ISOs and elaborates on a few international experiences. Notably, the report also summarizes and compares the existing DER aggregate participation models that were previously filed and approved by FERC for two of the ISOs: California ISO and New York ISO. The report concludes by identifying the open questions and needs across several key areas explored in FERC Order No. 2222 that may need further research in order for RTOs/ISOs to implement the rules of the order reliably and efficiently, especially in cases of higher levels of DER integration.

Keywords

Distributed energy resource aggregations
Distributed energy resources (DER)
Distribution operations and planning
Electricity market design
Electricity market operations
FERC Order No. 2222
Metering and telemetry
Transmission and distribution coordination
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PRIMARY AUDIENCE: ISOs and RTOs, Distribution Utilities

SECONDARY AUDIENCE: Transmission Utilities, Aggregators, Market Participants

KEY RESEARCH QUESTION

FERC Order No. 2222 introduces several challenges for ISOs/RTOs and Distribution Utilities, regarding the efficient and reliable integration of distributed energy resources participated in wholesale markets through aggregators.

RESEARCH OVERVIEW

This report summarizes FERC Order No. 2222 on DER participation in organized electricity markets, capturing the initial proposed rulings from 2016, comments made from industry stakeholders on various questions from the proposed rulings, and the final directives of the order in September 2020. A summary of where each of the U.S. ISOs currently are regarding DER participation in their markets is provided, with detailed review of the two regions that have already had approved rules from FERC. Finally, a summary of key questions is provided across the key areas relevant to the Order, linking to the research that is needed to address implementation and operation with increasing levels of DERs participating in organized markets through aggregators.

KEY FINDINGS

- The FERC Order made several directives in key areas such as participation models, double counting of services, locational and size limitations, bidding requirements, telemetry, and metering requirements, as well as coordination requirements across the important entities.
- In most parts of the Order, FERC was flexible and did not require a prescriptive way in which the ISOs/RTOs must address the different components. Instead, FERC required the ISOs/RTOs to address the issue by working with key stakeholders, describe how they will address it in their compliance filing, and then FERC will make a decision on whether they have addressed it adequately.
- All FERC Jurisdictional ISOs/RTOs have commenced stakeholder discussions and initiatives regarding DER participation through aggregators and the order. Other regions including ERCOT, IESO, and Europe have also made progress and are showing designs that are unique but related to the directives of the order.

The New York ISO and California ISO have made the most progress in their DER Aggregation market designs, with rules already approved by FERC. There are many similarities in the designs of the two markets with both already having addressed many of the directives of Order No. 2222. However, there are also unique differences such as the locational requirements of aggregations and dual participation rules.

- There are several key questions that the team believes require greater consideration for integrating larger amounts of DERs through aggregations reliably and cost-effectively that are related to the directives of the order. These include topics relevant to participation model design, locational feasibility, dual use and retail rate evolution, coordination frameworks, communication technology, cyber security and data privacy, and distribution utility roles.

WHY THIS MATTERS

Over 70% of the U.S. is operated by organized markets that must comply with the order. The rest of the country and the rest of the world will be viewing the implementation of the components to the order to see if it is advantageous to follow the designs placed here to ensure reliability and cost effectively integrate DERs that participate in organized wholesale markets and provide bulk system grid services. Understanding the key challenges and the potential research will help the industry prioritize the future stakeholder discussions, research areas, and regional studies to close these gaps.

HOW TO APPLY RESULTS

Readers are encouraged to review Section 2 to familiarize themselves with the most important pieces of the FERC Order No. 2222 including the key decisions. Readers are encouraged to read Section 3 to understand the current state-of-the-art for DER market participation in the U.S. organized electricity markets as well as a few key international markets. Readers are finally encouraged to review Section 4 to understand the key open questions and where the research in this space is heading.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- The FERC Order No. 2222 Phase 1: Collaborative Forum, Gap Assessment, and Implementation Roadmap Supplemental project is underway, and this is the first deliverable of that project. The goal was to familiarize members with the order and the research questions. The next step is for deeper dives in some of the key research questions across the six workstreams of the project: 1) wholesale market operations and design, 2) distribution system operation and planning, 3) transmission system operation and planning, 4) transmission distribution and aggregator coordination, 5) information communication and cyber security, and 6) customer technology and retail rates. Finally, the project will issue a roadmap for implementation summarizing the key discussions of the group and explore opportunities for further research and study.
- The research group is continuing collaboration with several other organizations, including the EPRI TSO/DSO Working Group, the Energy Systems Integration Group, Advanced Energy Economy, and the various ISO/RTO Stakeholder groups.

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PROGRAMS: Program 39 Grid Operations, Program 174 DER Integration, Program 200 Distribution Operations and Planning, Program 173 Bulk Renewable and DER Integration, Program 161 Information and Communication, Program 170 Customer Technologies, Program 182 Customer Insights.

ACRONYMS AND ABBREVIATIONS

Acronym	Definition (Specific region)
AEE	Advanced Energy Economy
AEM	Advanced Energy Management
AMI	Advanced Metering Infrastructure
APPA	American Public Power Association
AGC	Automatic Generation Control
AS	Ancillary Service
ATRR	Alternative Technology Regulation Resource (ISO-NE, represents a power resource using storage-based or other unconventional technologies to provide frequency regulation services)
BPCG	Bid Production Cost Guarantee (NYISO, Guarantee payment or uplift)
BPM	Business Practice Manuals
BRP	Balance Responsible Party
BTM	Behind-the-Meter
CAISO	California Independent System Operator
CHP	Combined Heat and Power
CPUC	California Public Utilities Commission
CSF	Continuous Storage Facility (ISO-NE, represents the participation model for electric storage resources)
DAM	Day-Ahead Market
DARD	Dispatchable Asset Related Demand (ISO-NE, represents the demand that can be modified based on the physical load's ability to respond to remote dispatch instructions from the ISO)
DDERA	Dispatchable Distributed Energy Resource Aggregation (ISO-NE)
DDP	Desired Dispatch Point
DERs	Distributed Energy Resources
DERA(s)	Distributed Energy Resource Aggregation(s)
DERMS	DER Management Systems
DERP(s)	Distributed Energy Resource Provider(s) (CAISO, represents a DER Aggregator)
DERTF	Distributed Energy Resources Task Force (MISO)
DG	Distributed Generation
DGR	Distribution Generation Resource (ERCOT)
DIR	Dispatchable Intermittent Resource (MISO)
DIRS	DER and Inverter-based Resources Subcommittee (PJM)
DNO	Distribution Network Operator
DR	Demand Response
DRR	Demand Response Resource (MISO)
DSO(s)	Distribution System Operator(s)
DSR	Demand Side Resource (NYISO)
DTU	Demand Turn Up (Great Britain)
DU	Distribution Utility
EEI	Edison Electric Institute
EMS	Energy Management System

ENA	Energy Networks Association
ESDER	Energy Storage and Distributed Energy Resources (CAISO, Stakeholder Initiative)
ESRs	Electric Storage Resources
EVs	Electric Vehicles
FCM	Forward Capacity Market (ISO-NE, represents its long-term wholesale electricity market that ensures resource adequacy, locally and system-wide)
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GOPACS	Grid Operators Platform for Congestion Solutions (The Netherlands)
ICAP	Installed Capacity (NYISO, represents its capacity market)
IRC	ISO-RTO Council
ISO	Independent System Operator
ISO-NE	ISO New England
LAP	Load Aggregation Point (CAISO)
LBMP	Location Based Marginal Price (NYISO, represents LMPs)
LMP	Locational Marginal Price
MISO	Midcontinent Independent System Operator
MOO	Must-Offer Obligation
NEM	Net Energy Metering
NESCOE	New England States Committee on Electricity
NGR	Non-Generator Resource (CAISO, represents its participation model for ESRs)
NOPR	Notice of Proposed Rulemaking
NRECA	National Rural Electric Cooperative Association
NWA	Non-Wires Alternative
NYCA	New York Control Area
NYISO	New York Independent System Operator
NYTO(s)	New York Transmission Owner(s)
OMS	Organization of MISO States
ONP	Open Networks Project (Great Britain)
PG&E	Pacific Gas & Electric
PJM	PJM Interconnection
POI	Point of Interconnection
PURPA	Public Utility Regulatory Policies Act
RA	Resource Adequacy
RERRAs	Relevant Electric Retail Regulatory Authorities
RT	Real-time
RTM	Real-Time Market
RTO	Regional Transmission Organization
RQM	Revenue Quality Metering
SC	Scheduling Coordinator (CAISO, represent a market participant)
SCR	Special Case Resource (NYISO)
SER	Storage Energy Resource (MISO)
SoCal Edison	Southern California Edison Company

SODERA	Settlement Only DERA (ISO-NE)
SODG	Settlement Only DG (ERCOT)
SOR	Settlement Only Resource (ISO-NE)
SPP	Southwest Power Pool
STOR	Short-Term Operating Reserve (Great Britain)
STR	Short-Term Reserve (MISO)
TAPS	Transmission Access Policy Study Group
TMOR	Thirty-Minute Operating Reserve (ISO-NE)
TO	Transmission Owner
TSO	Transmission System Operator
UDC	Utility Distribution Company (CAISO, represents a DU)
UKPN	UK Power Networks
WDAT	Wholesale Distribution Access Tariff (California)

CONTENTS

LIST OF TABLES

1
INTRODUCTION

History of Order No. 2222

FERC Order No. 2222 has a long history that began with inquiries regarding the participation of electric storage resources (ESRs) into electricity markets, with the possibility of those ESRs being located on the distribution system. The Federal Energy Regulatory Commission (FERC) opened an inquiry on ESRs in November 2015, but the comments received from the commenters on the docket were also related to Distributed Energy Resources (DERs) and their participation in the RTO/ISO markets. In November 2016, FERC issued a Notice of Proposed Ruling (NOPR) [1] on ESRs and DER Aggregations (DERAs) and received 109 comments from various stakeholders. Comments were submitted by EPRI and were mostly focused on ESRs, but also a few responses regarding questions on multi-node aggregations of DERs. FERC issued Order No. 841 in February 2018, which only followed through on a final ruling for ESRs, as it decided not to make final rulings on DERAs due to lack of information [2]. Some parties filed for clarification or rehearing on some elements of Order No. 841, primarily concerned with whether ESRs located on the distribution system can participate in wholesale markets or whether states could allow for an opt-out, and in May 2019, Order No. 841-A on rehearing and clarification confirmed FERC jurisdiction [4]

In a new separate DERA docket opened at the time FERC issued Order No. 841, FERC held a technical conference in April 2018, focusing on several different aspects of DERAs including locational requirements, regulatory concerns, compensation for multiple services, coordination of DERAs, and ongoing operational coordination [3]. Many organizations including EPRI submitted comments on several of these aspects. In September 2019, FERC requested information regarding policies and procedures affecting interconnection of DERs from the ISOs/RTOs.

FERC issued Order No. 2222 on September 17, 2020 [5] to facilitate the participation of DERAs in the capacity, energy and ancillary service markets operated by ISOs/RTOs, specifically to address barriers to DER participation related to ISO/RTO minimum size and performance requirements, thereby enhancing competition and producing just and reasonable rates. The order requires ISOs/RTOs to file tariff modifications to comply with the order by July 19, 2021. Notably, two RTOs/ISOs had already filed with FERC designs regarding DERA participation, and FERC had accepted those designs before the order was issued. The California Independent System Operator (CAISO) filed tariff revisions back in March 2016 and received FERC acceptance in June 2016 [6]. The New York Independent System Operator (NYISO) filed tariff modifications in June 2019 followed by FERC approval of those changes in January 2020 [7]. Both these ISOs may still need to propose tariff changes to comply with Order No. 2222. In addition, ISO New England (ISO-NE) currently allows DERAs to participate in wholesale markets as demand response resources or Settlement Only Resources [8].

We note that in general, the rules adopted in FERC Order No. 2222 are those proposed in the NOPR [1] but with specific modifications which were made as a result of the comments received to the NOPR, the feedback to the FERC technical conference in April 2018 [3], the responses to a post-technical conference notice, and the replies RTO/ISOs provided to the FERC's September 2019 data requests regarding the policies and procedures impacting the interconnection of DERs.

Next, we briefly review the key decisions FERC took in Order No. 2222. For a more detailed discussion of the decisions along with the key comments FERC received, the reader is encouraged to refer to Chapter 2.

Overview of FERC Order No. 2222

As stated in Order No. 2222 [5], FERC required each RTO/ISO to revise its tariff to address the following aspects:

- Allow DERAs to participate in energy, ancillary services, and capacity markets in the respective RTO/ISO and establish DER Aggregator as a market participant.
- DER Aggregators must be permitted to register DERAs under one or more participation models that fit their physical and operational characteristics.
- Establish minimum size requirement for a DERA that must not be above 100 kW.
- Establish locational requirements for DERAs.
- Establish requirements related to bidding parameters and (transmission) distribution factors for DERA.
- Establish information and data requirements for DERAs.
- Establish metering and telemetry requirements for DER Aggregators.
- Address coordination between RTO/ISO, the DER Aggregator, the Distribution Utility (DU), and the Relevant Electric Retail Regulatory Authorities (RERRAs).
- Create rules on adjustments to the list of DERs in a DERA.
- Establish market participation agreements for DER Aggregators.

Terminology Review

In this Section, we review the different terminology that is used throughout the report for clarity and to provide additional context.

Ancillary Services (AS): The FERC created a standard definition for ancillary services due to transmission open access in Order No. 888. Accordingly, FERC defines ancillary services as "those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with good utility practice."

Distributed Energy Resource (DER): As per Order No. 2222, the FERC defines DER as "any resource located on the distribution system, any subsystem thereof or behind a customer meter." This includes resources that are in front or behind the customer meter, ESRs, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage, electric vehicle, and their supply equipment as long as such a resource is located on the distribution system, any subsystem thereof or behind a customer meter. FERC also allowed RTOs/ISOs to propose their own definition of a DER for FERC evaluation as long as the scope and applicability of the proposed definitions are consistent with all aspects of Order No. 2222 including its definition of DER.

DER Aggregation (DERA): An aggregation of one or more distributed energy resources.

DER Aggregator: As per Order No. 2222, the FERC defines a DER Aggregator as "the entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy and/or ancillary service markets of the regional transmission organizations and/or independent system operators."

Distribution Factors (DFs): For a multi-node DERA, Distribution Factors are numbers between 0 and 1 that sum to 1 and specify the portion of a DERA's installed capacity or offered quantity at each constituent node on the bulk power system. Distribution Factors that specify a DERA's installed capacity are typically specified when the DERA is registered as a market resource and may be updated as needed when individual DERs are added to or removed from a DERA. Distribution Factors that specify a DERA's offered quantity of energy or AS may be biddable values that reflect current capability of the DERA and/or distribution system conditions at the time the offer is submitted. As such the Distribution Factors are incorporated into the RTO's economic dispatch algorithms to indicate the portion of the DERA response that is anticipated from each pricing node for a multi-node aggregation. Another application of distribution factor is Load Distribution Factors that are typically used by ISOs/RTOs to distribute the overall system Load that is determined from Load forecast to individual pricing nodes. DFs are not to be confused with shift factors or power transfer distribution factors or line outage distribution factors.

Distribution System Operator (DSO): In this report and in associated EPRI research, this term refers to a distribution utility that has greater responsibilities for operating its system and, usually, implemented new functional capabilities to manage larger amounts of DERs on its system.

Distribution Utility (DU): Distribution Utility is an electric utility company that owns, operates, and manages a distribution system (or distribution facilities) that connects the transmission system to the retail electricity customers. A DU can potentially be a municipal utility, a state utility, an investor-owned vertically integrated utility, a cooperative utility, or an investor-owned default service provider.

Independent System Operator and Regional Transmission Organization (RTO/ISO): The entity that operates the bulk power system in organized electricity market regions and administers and operates the wholesale electricity market in that region. The RTO/ISO is also responsible for long-term planning within its region for generation and transmission assets to ensure adequate levels of reliability.

Relevant Electric Retail Regulatory Authorities (RERRAs): As an example, PJM's Tariff defines a Relevant Electric Retail Regulatory Authority as "an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity."

Load Serving Entity (LSE): A market participant in an RTO/ISO that serves load, either as a wholesale consumer or as an energy retailer.

Locational Marginal Price (LMP): LMP is defined as the cost for the operator to deliver one additional or one less MWh of energy (or a small increment or a small decrement) to a bus/node in the system and is the price used to settle energy in ISO energy markets. LMPs consist of three components: the marginal cost of energy, marginal congestion cost, and the marginal cost of losses. The marginal cost of energy is a single value for the system, whereas the marginal costs of congestion and losses vary by node.

Net Energy Metering (NEM): Net Energy Metering[1] is a billing and metering arrangement that permits utility customers that own on-site distributed generation to be compensated (may vary based on location dependent on the prevailing state and local policies, e.g., full retail rate, less than retail rate, zero) for any energy that is exported to the grid (on a per kWh basis). With NEM, the utility customer pays for the *net energy* that the customer consumes from the grid, i.e., the utility customer's charge for energy imported and credits for energy exported are netted against one another at the end of the billing cycle.

Participation Model: As stated in FERC Order No. 841 for stand-alone ESRs, "the RTOs/ISOs generally have a set of tariff provisions that apply to all market participants. In addition, the RTOs/ISOs create tariff provisions for specific types of resources when those resources have unique physical and operational characteristics or other attributes that warrant distinctive treatment from other market participants." These distinct tariff provisions or market rules that are created for a specific type of resource to recognize its physical and operational characteristics appropriately and correspondingly facilitate its participation in the RTO/ISO markets are what FERC refers to as a participation model.

Transmission Owner (TO): The entity that owns and maintains transmission facilities[2].

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[1] NREL, Net Metering. [Online]. Available: https://www.nrel.gov/state-local-tribal/basics-net-metering.html

[2] NERC, Glossary of Terms used in NERC Reliability Standards. Jan. 4, 2021. [Online]. Available: https://www.nerc.com/files/glossary_of_terms.pdf

2
FERC ORDER NO. 2222

Jurisdiction

FERC Jurisdiction

In the NOPR, FERC stated that it has jurisdiction under Section 206 of the Federal Power Act (FPA) to propose and make rulings regarding the participation of DERAs in the RTO/ISO markets.

Commentary

While a lot of commenters accepted FERC legal authority, several others doubted FERC jurisdiction and urged FERC to clarify.

FERC Decisions

In response, FERC referred to sections 201, 205 and 206 of the FPA to argue its legal authority in making rules and regulations regarding the participation of DERAs in the RTO/ISO markets. FERC's argument is two-fold: First, it contends that the sales of energy by a DERA in the RTO/ISO markets are wholesale sales and therefore is under FERC legal authority. Second, it asserts that the U.S. Supreme Court ruling which confirmed FERC's legal authority over sale of demand response resources in RTO/ISO markets can be extended and equally applied to the sale of DERAs in the RTO/ISO markets.

FERC also elucidates that only if the DERA sells electric energy into RTO/ISO markets it is a public utility and under FERC jurisdiction. However, it asserts that DERA would not become a public utility if

1. It aggregates only demand response resources, or
2. It aggregates only customers in a net metering program that are not net sellers of electric energy.

While FERC highlights its jurisdiction, it asserts that it recognizes the vital role of state and local regulators with respect to retail services and distribution system reliability and safety, as also demonstrated in Order Nos. 841 and 841-A. It also states that nothing in Order No. 2222 preempts the states' rights to regulate distribution systems in their territory and that all DERs must comply with pertinent interconnection and operating requirements imposed by local regulatory authorities.

Opt-Out

In the NOPR, FERC did not provide a framework by which RERRAs could allow (or opt-in) or bar (or opt-out) the participation of DERs or DERAs in the RTO/ISO markets. Also, as will be presented later in this document, the NOPR required DERAs to attest that their DER aggregation abide by the tariffs and operating procedure of the distribution utilities and RERRAs, including

FERC Order No. 719 by which states can prohibit the participation of demand response resources in the RTO/ISO markets, i.e., opt-out for demand response resources.

Commentary

Several commenters including American Public Power Association/ National Rural Electric Cooperative Association (APPA/NRECA), DTE, MISO Transmission Owners, TAPS urged FERC to include either an opt-in or opt-out mechanism in the final rule. Some suggested an opt-out framework similar to the one established in Order No. 719, while others raised concerns about adopting such opt-out mentioning the consequences of Order No. 719 on demand response development in the Midwest.

NRECA and TAPS mentioned the indirect costs borne by small utilities and endorsed an opt-in mechanism similar to Order No. 719-A to ban DER aggregations located on the system of a utility distributing 4 million MWh or less to participate in RTO/ISO markets unless allowed by the RERRAs.

FERC Decisions

FERC referred to its jurisdiction over wholesale markets and decided not to include an opt-out option for RERRAs to prohibit all DERs from participating in the RTO/ISO markets. However, it includes an opt-in option similar to Order No. 719-A by which:

1. Small utilities (less than 4million MWh annually) must opt-in in order for RTO/ISOs to accept bids or offers from DERs that are their customers. Otherwise, RTO/ISOs cannot accept those bids or offers.

2. For DERs located in larger utilities, RTO/ISOs must automatically accept bids or offers.

3. Each RTO/ISO must explain how it will implement the small utility opt-in.

FERC clarifies that based on Order No. 719, RERRAs may still be allowed to opt-out from allowing aggregations of retail customers as demand response bidding into RTO/ISO markets. FERC also states that it continues to recognize the vital role of distribution utilities and RERRAs, mentioning that similar to Order No. 841, an RERRA can prohibit the participation of individual DERs which are participating in a retail DER program. It also asserts that similar to the ruling in PJM regarding the use of distribution systems by ESRs, distribution systems can on a case by case basis evaluate a wholesale distribution charge on DER aggregators participating in RTO/ISO markets.

Interconnection

In the NOPR, FERC did not propose any modifications to the policies and procedures of RTO/ISOs regarding the interconnection of DERs. However, it recognized that the interconnection process can be prohibitively costly for small DERs. In October 2019, six RTO/ISOs replied to FERC data request regarding their policies and procedures impacting the interconnection of DERs.

Commentary

Several commenters including ISO-RTO Council (IRC), Massachusetts Municipal Electric, Massachusetts States Entities, New England States Committee on Electricity (NESCOE), and Transmission Access Policy Study Group (TAPS) urged FERC to clarify that distribution utilities and the states remain responsible for interconnection of DERs. Several commenters argued that the interconnection study is necessary but not enough, thus asserting the need for further studies by both distribution utilities and RTOs/ISOs on the impact of DERA on transmission and distribution systems.

In response to the FERC data request, ISO-NE, PJM and NYISO referred to Order Nos. 2003 and 2006 to elaborate that they employ the jurisdictional test, a.k.a. the "first use" test, for dual-use resources to find if the interconnection is subject to FERC jurisdiction. SPP stated that it does not apply the "first use" test and asserted that the interconnection is subject to its tariff only if the relevant distribution facilities are under its functional control. CAISO indicated that DER interconnections for participation in CAISO markets are under FERC's jurisdiction pursuant to the utility distribution company's Wholesale Distribution Access Tariff (WDAT).

FERC Decisions

FERC declines to exercise jurisdiction over the interconnection of DERs to distribution networks for those DERs seeking to participate in RTO/ISO markets only as part of DERA, thus state and local utilities would be responsible to oversee such interconnections. FERC asserts that the participation of a DER in RTO/ISO markets through a DERA would not establish a first interconnection for the purpose of making wholesale sales under the "first use" test, whereas the interconnection of a DER for the purpose of directly participating in wholesale markets not through DERA would constitute a "first use" and thus any subsequent DER interconnection for the purpose of directly engaging in wholesale market would be under FERC jurisdiction. FERC also states that any existing interconnection agreements for DERs that were under FERC jurisdictional procedures (i.e., in CAISO) do not need to convert to state or local interconnection agreements.

While declining to create standardized tariff or requirements, FERC encourages RTO/ISOs to coordinate with affected distribution utilities to perform separate studies of the impact on the transmission and distribution systems after a DER joins a DERA.

DER, DER Technologies and Retail Design

Definition of DER and DER Aggregator

In the NOPR, a DER is defined as "a source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter" [1]. The NOPR also mentioned a few examples including but not limited to electric storage resources, distributed generation, thermal storage, electric vehicles, and their supply equipment. The NOPR also defined a DER Aggregator as "an entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy and ancillary service markets of the regional transmission operators and independent system operators" [1].

Commentary

Edison Electric Institute (EEI) urged FERC to use a term besides "source or sink of power" that better represents the resources. Others asked for clarification whether the definition includes behind or in front of the meter resources, energy efficiency resources, demand response resources, and intermittent generation. Also, some suggested that the existing rules for demand response resources should not be changed, even if demand response resources would fall under the definition of a DER. Some commenters think that energy efficiency or load curtailment are not DERs. As for the definition of DER Aggregator, Midcontinent Independent System Operator (MISO) Transmission Owners asked for more clarity whether a utility bidding its existing demand response peak shaving assets into the market is a DER Aggregator.

FERC Decisions

FERC modified the definition of DER in the final rulemaking in Order No. 2222 as "*any resource* located on the distribution system, any subsystem thereof or behind a customer meter." FERC mentioned that using "source or sink" in the NOPR definition may have caused confusion and inadvertently excluded resources (e.g., selling ancillary services may mean it is not a source or sink). FERC clarified that in this definition resources that are in front or behind the customer meter, ESRs, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage, electric vehicle, and their supply equipment are examples of DERs as long as such a resource is "located on the distribution system, any subsystem thereof or behind a customer meter."

FERC also allowed RTOs/ISOs to propose their own definition of a DER for FERC evaluation as long as the scope and applicability of the proposed definitions are consistent with all aspects of Order No. 2222 including its definition of DER.

FERC defined a DER Aggregator in the final rulemaking as "the entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy and/or ancillary service markets of the regional transmission organizations and/or independent system operators". Note that the definition does not imply that a resource is capable of providing a service. FERC also clarified that an aggregator of demand response resources could participate as a DER Aggregator. However, FERC asserted that Order No. 2222 does not impact existing demand response programs, rules and regulations.

Type of DER Technologies

In the NOPR, FERC proposed not to prohibit any particular type of DER technology from being part of an aggregation. FERC asserted that DERs with different technology types can complement one another's capabilities by making an example of an aggregation of ESRs and distributed generation which in aggregate can both meet minimum run time requirements and provide regulation service.

Commentary

Some companies commented that the heterogenous mixing of technologies can lead to complexities, such as making the market optimization more difficult. There are also particular concerns about mixing generation and storage as well as state of charge management for aggregations that include storage. ISO-NE stated that aggregation of load with generation should not be allowed due to the particular credits and charges that are allocated to load. ISO-NE was also concerned about aggregations of demand response and non-demand response resources asserting that it would need to create rules to disaggregate the components for settlement purposes. Furthermore, there could be challenges as markets are moving toward reducing the use of self-scheduling, as commenters believed there may be more likelihood of mixed aggregations self-scheduling.

FERC Decisions

FERC requires each RTO/ISO to modify its tariff to allow single aggregations that consists of different DER technologies, i.e., heterogeneous aggregations. Regarding a concern raised by ISO-NE on settlement of demand response resources in an aggregation, FERC asserts that Order No. 745 would apply to demand response resources participating in heterogeneous aggregations.

Double Counting of Services

In the NOPR, FERC proposed that DERs participating in retail compensation programs, such as net metering, or another wholesale market participation program, such as demand response program, will not be allowed to participate in RTO/ISO markets as part of a DERA.

Commentary

Numerous concerns were raised around different types of duplicate earnings, potential arbitraging between retail and wholesale markets and opportunities for gaming, cherry picking the best features between wholesale and retail and potential price formation issues that may occur. Some proposed a waiting period of at least one year for switching between wholesale and retail participation. CAISO stated that its Distributed Energy Resource Provider (DERP) model currently does not allow wholesale market aggregators to participate in net metering resource of any form (including virtual net metering). Many also asserted that in most regions retail programs and behind-the-meter (BTM) demand response will potentially be more attractive than the DERA programs that may eventually be proposed.

Some commenters stated the RTO/ISO should be responsible for demonstrating how to prevent duplicate compensation for the same service and DERs accountable, while others suggested that RERRAs have the ability to prevent double compensation. Many argued over how narrow one should define “the same service”, referring to it specifically being the same kWh for retail as for wholesale. Others suggested tools are needed to prevent double compensation for the same service. Several commenters stated that DERs should be compensated for each separate or incremental value they provide at both wholesale and retail markets.

FERC Decisions

FERC allows RTOs/ISOs to limit the participation of DERs through DERA for DERs that are compensated for the same service through another program. It, however, required each RTO/ISO to modify its tariff to (1) allow DERs participating in one or more retail programs to participate in wholesale markets, (2) allow DERs to provide multiple wholesale services, (3) include any appropriate limitations on the DER participation in RTO/ISO markets through DERA if service provided is counted more than once, for which FERC provides two examples: (a) a DER that is offered in wholesale market but not added back to a utility’s or LSE’s load profile, (b) a DER that is registered to provide the same service twice in the wholesale market (e.g., in multiple

DERAs, or in a DERA and a demand response program). FERC notes that these limitations are similar to those imposed in Order 719 for aggregations of demand response resources.

DER Aggregation Participation Model

Participation Model

In the NOPR, FERC proposed to require RTOs/ISOs to modify their tariff establishing DERA as a market participant that can participate in RTO/ISO markets under the participation model that best fits the physical and operational characteristics of its aggregated DERs. For instance, if the participation model that best fits the aggregated DERs' physical and operational characteristic is a generator model, the DERA would register and participate as a generator. FERC also proposed to require RTOs/ISOs to revise the eligibility requirements of the existing participation models to allow for participation of DERAs.

Commentary

Several commenters stated that a new participation model need to be established for DERAs to enable their market participation. Others asserted that new and revised market rules are required to integrate DERs but disagree with introducing new costly participation models. Some sought clarification whether certain aggregations such as an aggregation of electric vehicles (EVs) would be considered storage or DERA or both? Others declared that RTOs/ISOs should not require DER Aggregators to choose only one participation model. In addition, some commenters stated that energy-only DERAs should not be required to offer in the day-ahead market (DAM). Others urged FERC not to require RTOs/ISOs to replace existing demand response programs.

FERC Decisions

FERC requires each RTO/ISO to modify its tariff and define DER Aggregator as a market participant, allowing it to register its aggregated DERs under one or more participation model that fits the physical and operational characteristics of its aggregated DERs. FERC states that it is up to the RTOs/ISOs on how they may need to adjust existing participation models or create one or more new participation models for DERAs. RTOs/ISOs can also choose a mixture of these two approaches.

Minimum and Maximum Size of Aggregation

In the NOPR, FERC proposed to require DERAs to meet the minimum size requirements of the participation model they select for participation in RTO/ISO markets. FERC makes an example of a DERA electing to participate in the participation model of an ESR, which needs to be at least 100 kW in size.

Commentary

Several commenters contended that RTOs/ISOs should be allowed to create any minimum size requirement for DERAs that fit their model and dispatch abilities. EPRI raised concerns on challenges and potential costs if a minimum size requirement of 100 kW is adopted. As for the maximum size requirement, CAISO stated that its current DERP model requires a maximum capacity of 20 MW on DERs aggregating across multiple pricing nodes and asserted that such requirement is necessary to ensure transmission system reliability.

FERC Decisions

FERC requires each RTO/ISO to revise its tariff to impose a minimum size requirement not to exceed 100 kW for all DERAs regardless of their participation through existing or newly proposed participation models. The 100-kW minimum size requirement is the same minimum size requirement posed in Order 841 for ESRs. FERC asserts that PJM and SPP have minimum size requirement of 100 kW for all resources, whereas all other RTOs/ISOs have at least one market participation model with a minimum size requirement of 100 kW. While FERC believes that such requirement does not pose challenges to the RTO/ISO market software, it allows RTOs/ISOs to suggest a minimum size requirement above 100 kW at future post-implementation stage, if they demonstrate difficulty calculating efficient market results with no viable software solution.

As for the maximum size requirement, FERC does not institute such a requirement for multi-node aggregations. It, however, states that it does not explicitly require RTOs/ISOs to allow multi-node aggregations of DERs in their markets.

Single Resource Aggregation

In the NOPR, consistent with Order No. 719 for aggregations of demand response responses, FERC proposed to allow a single eligible DER to serve as its own aggregator.

Commentary

CAISO stated that its current DERP model allows a single DER to participate. Some commenters argued that a higher minimum size requirement is necessary for single DERs participating in DERA.

FERC Decisions

FERC asserts that a single DER as an aggregation is allowed with no difference in minimum size requirements.

Bulk System Locational Requirements

In the NOPR, FERC provided RTOs/ISOs with flexibility to describe locational requirements for DERs participating in a DERA that are as geographically broad as technically feasible. It also asserted that different services may require different locational requirements (e.g., energy versus ancillary services).

Commentary

Several commenters suggested multi-node aggregation provides benefits in terms of efficiency and aggregator business models. Many RTOs/ISOs stated that they already allow BTM and demand response resources to aggregate across very broad areas. CAISO agreed with Advanced Energy Economy (AEE) and Advanced Energy Management (AEM) comments that not allowing multi-node aggregation will not meet the existing standard (e.g., for demand response resources) and will erode economics of aggregation (or economies of scale). Many commenters believe that small minimum size requirement, e.g., 100 kW, for participation of DERAs will limit any impacts for multi-node aggregations. RTOs/ISOs that are concerned of multi-node aggregations, are primarily concerned about aggregations on both sides of a transmission constraint. Some commenters referred to frequent variations in congestion patterns and system topology to suggest that multi-node aggregation would have negative implications on nodal pricing approaches.

FERC Decisions

FERC requires RTOs/ISOs to modify their tariff to describe the locational requirements for DERs participating in DERAs that are as geographically broad as technically feasible. To comply with the order, FERC requires each RTO/ISO to describe the geographical scope of its proposed locational requirements, including specific topology of the region and congestion patterns that explain any limits on multi-node aggregations. While FERC acknowledges the benefits of single-node aggregations given potential cost savings from separate telemetry and potential reliability benefits from improved congestion management, it asserts that multi-node aggregations can provide greater participation and enhances the services the aggregated DERs can provide.

Distribution Factors and Bidding Parameters

In the NOPR, FERC proposed to require DERAs aggregating over multiple nodes to provide default distribution factors at registration and update them, if they change, when they submit an offer. A distribution factor is the proportion of the DERA energy that would come from a single a transmission (or pricing) node. They are not related to distribution system location beyond how the energy of the location will impact flow on the transmission system.

Commentary

CAISO currently requires a DER Aggregator aggregating over multiple pricing nodes to submit distribution factors with its bids. These distribution factors reflect the shares of total DERA capacity at each of the pricing nodes comprising the multi-node DERA. Distribution factors are also intended to be relatively static but can be updated periodically as different DERs are removed from or added to the DERA. These distribution factors function as default distribution factors which the DERA can update for each market interval with its bids or offers, to reflect current changes to DER availability or distribution grid conditions. CAISO stated that dynamically updating distribution factors, in combination with the restriction of multi-node aggregations to be within a single Sub-LAP, is an acceptable practice to minimize the risk that a multi-node DERA will contribute to transmission system overloads. Some commenters suggested that with no aggregated DER participant in CAISO, the efficacy of distribution factors on non-demand-response resources has not been tested in practice. NYISO stated that it does not need distribution factors since it limits participation to one transmission node.

Several commenters raised concerns on using distribution factors. SPP and MISO said that adding distribution factors in market clearing software can be complex. SPP and ISO-NE suggested that distribution factors may vary based on actual level of dispatch of the DERA, varying between the minimum and the maximum output limits, potentially causing settlement and reliability concerns. Similarly, others asserted that due to lack of knowledge of grid configuration used by the RTO/ISO and distribution utilities in real-time, stated distribution factors could bear little relation to real-time operations. Also, some commenters suggested that certain issues may be involved due to meshed distribution networks connected to the transmission network, and the DER Aggregator would not know what the distribution factors are. Others proposed that DER Aggregators be equipped with an outage management system to report real-time distribution factors.

Some commenters asserted that RTOs/ISOs may need additional bidding parameters, such as ramp rate or maximum charge limit, from DERAs to accurately represent their physical and operational characteristics. EPRI suggested that the use of a bidding parameter that can reflect the distribution system loss reduction on the system may be advantageous, but the value may need verification by the distribution utility.

FERC Decisions

FERC requires RTOs/ISOs that allow multi-node aggregations to: (1) Require DERAs to give RTO/ISO the allocation from each pricing node, a.k.a. distribution factors, at initial registration and any time they change, and (2) incorporate bidding parameters into participation models to account for physical and operational characteristics of aggregated DERs. In complying with the latter requirement, each RTO/ISO must either include the needed bidding characteristics as part of its new participation model or adjust bidding parameters of existing participation models.

Each RTO/ISO may revise tariff to manage locational attributes of DERAs in different ways reflecting unique network topology or characteristics of the RTO/ISO, but must provide information on how to update distribution factors and other parameters.

Metering, Telemetry and Data Requirements

Information and Data Requirements

In the NOPR, FERC proposed to require DER Aggregators to provide the following information when they register: (1) total capacity, (2) minimum and maximum operating limits, (3) ramp rate, (4) minimum run time, (5) default distribution factors, if applicable, and (6) a list of DERs and their information, such as the capacity, location on distribution system, and operating limits of each DER, in the aggregation. FERC also proposed to require each DER Aggregator to maintain aggregate settlement data for settlement purposes with the relevant RTO/ISO, and to maintain the data for a length of time consistent with the auditing requirements of the relevant RTO/ISO for each individual DER.

Commentary

Many developers stated that the information and data requirements should only apply to the DERA and not to each individual DER. Others asserted that certain information and data requirements applied to other market participants should not be applied to DERAs. For instance, CAISO stated that it does not require meteorological data from DERAs.

FERC Decisions

FERC requires each RTO/ISO to revise its tariff to: (1) define the information and data requirements that a DERA must provide about its physical and operational characteristics, (2) require DER Aggregators to provide a list of DERs in their aggregation and update the list as the DERs in the aggregation change, (3) define any information required to be submitted for individual DERs, and (4) require each DER Aggregator to provide aggregate settlement data and retain performance data for individual DERs. In addition, FERC clarifies that each DER Aggregator is the single point of contact with RTO/ISO and is therefore responsible for metering, managing, dispatch and settlement of individual DERs in its aggregation.

Metering and Telemetry System Requirements

In the NOPR, FERC proposed to require each RTO/ISO to establish necessary metering and telemetry requirements for DERAs and individual DERs. FERC also stated that while it recognizes that metering and telemetry systems are often expensive and potentially a barrier for the participation of DERAs in RTO/ISO markets, RTOs/ISOs need metering data for settlement purposes and real-time telemetry data to efficiently dispatch resources.

Commentary

Some suggested individual DERs to have the same metering and telemetry requirements as all other resources. Current CAISO's DERP model requires the same standards as other resources for DERAs. DERAs in NYISO must provide 6-second real-time metering and telemetry, which can be submitted either directly to NYISO or through the utility. Others suggested that requiring DER Aggregators and, in some cases, individual DERs participating in DERAs to follow the same metering and telemetry standards as other resources is too much of a burden. Some stated that the requirements are only needed at the aggregation level as it is cost prohibitive for individual DERs.

Some said metering/telemetry requirements may depend more on the size of the DER rather than whether it is in a DERA or not. Some commenters suggested alternatives to metering such as sampling, end-use metering devices, or verifiable behavioral actions, while others argue that statistical estimation can introduce error. Several commenters asserted that DERAs whose aggregation span multiple nodes need to provide telemetry data at different locations.

Some commenters stated that distribution utilities may provide metering data to RTOs/ISOs through a third-party agreement, while others suggested that relying on meter data from distribution utilities can introduce new cybersecurity and privacy implications. Several commenters stated that metering and telemetry data should be shared between RTO/ISO, relevant distribution utilities, and DER aggregator.

FERC Decisions

FERC requires each RTO/ISO to create market rules that address metering and telemetry hardware and software requirements for DERAs in its compliance filing. RTOs/ISOs are given flexibility to propose metering and telemetry requirements for both individual DERs and the DERAs. However, they should explain in their compliance filings why requirements are just and reasonable and do not impose unnecessary and undue barrier to individual DERs within an aggregation. For instance, they need to explain why the proposed metering requirements are necessary (e.g., to prevent double counting), or why the proposed telemetry requirements are necessary (e.g., for situational awareness). RTOs/ISOs are also required to explain whether their proposed requirements are close to those for other resources participating in the same service. However, it does not require that the requirements be identical to those of existing resources or that they be different.

In addition, FERC requires that metering data for the purpose of settlement at an aggregation level be consistent with those of other resource types. FERC mentions that specific DER telemetry requirements, e.g., whether telemetry requirements apply to individual DERs, may depend on whether multi-node aggregation is allowed and how it is implemented. FERC also acknowledges that requirements may differ depending on the services or type/size of DER or

DERAs. For example, if the DERAs provide frequency regulation, it may require more granular and accurate telemetry.

FERC also clarifies that the requirements should solely be applied for purpose of RTO/ISO market participation or to provide ISOs with real-time information needed for reliability. In addition, it requires ISOs/RTOs to use the existing metering and telemetry infrastructure whenever possible and avoid proposing new requirements. FERC expects that metering and telemetry come from DER to DER Aggregator and from DER Aggregator to RTO/ISO, but if any of this must also go through the distribution utility, there must be coordination to establish protocols for sharing the data and minimizing costs. FERC also asserts that the metering and telemetry requirements must be included in the tariff, as opposed to business practice manuals due to their significant impact on rates, terms, and conditions.

Coordination between the RTO/ISO, Aggregator, and Distribution Utility

Market Rules on Coordination

In the NOPR, FERC proposed to require RTOs/ISOs to establish market rules for coordination between the RTO/ISO, the DER Aggregator, and the distribution utility with respect to: (1) the registration of new DERAs, and (2) ongoing coordination including operational coordination. FERC stated that the goal is to ensure the reliable and safe operation of transmission and distribution systems.

Commentary

Pacific Gas & Electric (PG&E) referred to its previous involvement in implementing CAISO’s DERP model and asserted that such coordination is vital. Others suggested that the coordination could be improved with the development of Distribution System Operators (DSOs). Commenters said that no DSO really acts in that role in the United States and so it is hard to see what the benefits would be. Southern California Edison Company (SoCal Edison) contended that it is already performing initial functions of a DSO and is ready to play this role in the future.

FERC Decisions

FERC modifies the NOPR by adding RERRAs to the coordination framework. Therefore, FERC requires each RTO/ISO to modify its tariff to create market rules for coordination between the RTO/ISO, the DER Aggregator, the distribution utility, and the RERRAs.

Role of Distribution Utilities in Coordination

In the NOPR, FERC proposed to require RTOs/ISOs to incorporate distribution utility review of the DERs located in their distribution systems and registering in a DERA before those resources can participate in the wholesale market. FERC mentioned a few reasons for such a review: First, to make sure that the wholesale market participation of DERs through DERA would not impose significant reliability issues to the distribution system. Second, to ensure that individual DERs are not participating in any other retail compensation program.

Commentary

Some commenters suggested that the DU permission is required before participation and operation of the DERs in the DERA. Others stated the DU role may act as a barrier to participation with the DU in a gatekeeper role. Commenters did not agree on the scope of the DU review process. Several commenters believe that DER participation should be denied only if specific reliability concerns exist. Some commenters suggested that DU be required to identify to RTOs/ISOs specific areas of their distribution network where they have limited ability to accommodate additional DERs. AEM suggested the only time DUs can review is if the DERs are exporting to the grid. DER providers believe that if the DER completes state interconnection process, no review by DU is needed. Tesla/SolarCity suggested that proper communication between RTO/ISO and DU eliminates the need for a DU review.

Some commenters stated that DUs should be prevented from adding DERs in their own DERAs that have been prohibited from participating in other DERAs. While DUs asserted that they need a reasonable timeline to conduct the review, several commenters believe that there should be a time limit for review, e.g., 10 days or CAISO's current 30-day timeline. Some RTOs/ISOs discussed the need for a guideline on how disputes on the DU review should be resolved.

FERC Decisions

FERC requires each RTO/ISO to modify its tariff to include comprehensive and non-discriminatory process for timely review by DU of individual DERs in a DERA, triggered by registration of DERA in the RTO/ISO market or incremental change (addition or removal of DERs) to the DERA already in the market. To comply with the order, RTOs/ISOs are required to coordinate with DUs to determine criteria that DUs would use to determine whether (1) each DER is eligible to participate in the DERA, and (2) if the participation of a DER in a DERA would pose significant risks to the reliable and safe operation of the distribution system. RTOs/ISOs are required to share necessary information regarding individual DERs in a DERA to facilitate the DU review process. The results of the DU review process must be considered in the DERA registration process.

In addition, FERC requires RTOs/ISOs to demonstrate in their compliance filings that the DU review process is transparent, includes specific criteria, and is conducted in a timely manner. FERC requires each RTO/ISO to put a reasonable time limit for DU review process to be completed. FERC expects that this time limit should not exceed 60 days. Regarding criteria, FERC states that it allows for regional flexibility without prescribing anything about specific criteria. As an example of criteria, the DU should alert RTO/ISO and recommend removal of DER from DERA if its participation will impact distribution system reliability. However, processes can be placed to contest this recommendation. Finally, FERC requires any disputes between RTO/ISO, the DUs, and the DERAs to be processed according to the dispute resolution provisions in the RTO/ISO tariff as part of proposed DU review process.

Ongoing Operational Coordination

In the NOPR, FERC proposed to require each RTO/ISO to modify their tariff to describe a framework for ongoing operational coordination between itself, the DER Aggregator and the DUs to ensure that the DER Aggregator disaggregates the dispatch signal in a way that respects operational constraints in the distribution system. In addition, FERC proposed that the DER

Aggregator must report to RTO/ISO any changes to its offer parameters, e.g., offered quantity and the pertinent distribution factors, caused by distribution line outages or faults.

Commentary

Several commenters highlighted that distribution safety and reliability takes priority over wholesale market participation. For instance, Xcel Energy urged FERC to allow DUs to constrain energy injections and ancillary services from particular DERs. Commenters raised concern on the required process to warn DERAs regarding problems on distribution systems. SPP stated that there may be difficulty in establishing coordination with entities that do not already have two-way communication. CAISO suggested that, similar to its current DERP framework, a process is needed for DUs to notify a DER Aggregator of changes to the distribution system that will affect the DERA ability to perform. Some commenters asserted that the DUs should have ability to communicate topology change information in real-time.

Commenters suggested that the current data acquisition technologies are manual but may be adequate at least initially for coordination. Some mentioned that there needs to be a timeline in place for preventing dispatch and notifying the DERA of a curtailment. Recognizing the DERA need to estimate the risk of curtailment, Lorenzo Kristov asserted that the framework in which a DU overrides a dispatch instruction should be clear and transparent. Some commenters suggested that when the DU alerts the DERA of potential problems on the distribution system, the DERA may be able to re-adjust its disaggregation. Others said that the DU should not be able to override dispatch. The commenters disagreed on whether the DERA should be penalized for a reduced energy provision if it is caused by a distribution system outage.

FERC Decisions

Recognizing the need for real-time coordination to ensure safe and reliable operation of transmission and distribution systems, FERC requires each RTO/ISO to create a process for ongoing coordination addressing data flow and communication among itself, the DER Aggregator and the DU. In addition, each RTO/ISO must require the DER Aggregator to report to the RTO/ISO any changes to offered quantity and the relevant distribution factors that is caused by distribution system outages. Furthermore, each RTO/ISO must include coordination protocols and processes for the operating day that can allow distribution utilities to override the RTO/ISO dispatch of a DERA when such override is necessary to maintain the reliable and safe operation of the distribution system. The override processes must be in the tariff, be non-discriminatory and transparent. FERC allows each RTO/ISO flexibility in developing the approach to operational coordination.

Each RTO/ISO is also required to apply existing resource non-performance penalties to DER Aggregators when the DERA does not perform because of an override. FERC believes that this requirement will incent the DER Aggregators to only register DERs on less-constrained portions of the distribution network to avoid penalties.

Role of RERRAs

The NOPR did not address the role of RERRAs in coordination with RTO/ISO, the DERA, and the DU.

Commentary

Most commenters asserted that RERRAs play a key role in coordination efforts recognizing their main responsibility as supervising DU review of DER participation in a DERA. Distribution utilities stated that other roles of RERRAs include assessment of DER interconnection to distribution systems, supervising distribution system operation and reliability, data sharing, and establishing metering standards. For instance, commenters mentioned that retail regulatory authorities in California approve utility distribution company (UDC) tariffs. Some commenters believe that RERRAs may be able to set rates to recover and allocate the costs associated with facilitating wholesale market participation. Others believe that the role of RERRAs should be limited to ensuring non-discriminatory interconnection process and safe operation of distribution networks in presence of DERs participating in DERA.

FERC Decisions

FERC required each RTO/ISO to explain in its tariff how they involve RERRAs in coordinating the participation of DERAs in its market. FERC stated that it endorses CAISO's approach in the DERP framework which requires DER Aggregators to abide by the applicable DU tariffs, and operating procedures in those tariff, and applicable requirements of the local regulatory authority. In addition, FERC provided examples of the roles that retail authorities may play in coordination, which include

- Interconnection agreements and rules,
- Developing local rules to ensure distribution system safety and reliability,
- Data sharing and/or metering telemetry requirements,
- Overseeing distribution utility review of DER participation in DERA,
- Establishing rules for multi-use applications,
- Resolving disputes between DERA and DUs over issues such as access to DER data

FERC also asserts that any such role must be developed in consultation with the RERRAs and must be included in the RTO/ISO tariff. When metering and telemetry flows through DU, RTOs/ISOs must coordinate with DUs and RERRAs to establish protocols for sharing that data to minimize costs and other burdens.

Coordination Frameworks

In the NOPR, FERC requested comments on how detailed each RTO/ISO should establish the ongoing coordination framework between itself, a DER Aggregator, and DUs.

Commentary

Commenters described coordination frameworks as the best way to exchange information and control signals across bulk system, distribution system, and customer level. Some suggested that FERC should specify a broader coordination structure encompassing operational, planning and markets frameworks, whereas others urged FERC to give flexibility to each RTO/ISO to develop the needed frameworks in coordination with RERRAs, and DUs. Some commenters asserted that the coordination framework could encourage technological innovation. Others stated that data creation, communications, and analytics are fundamental to successfully integrating DERs. Commenters emphasize that there are no best coordination frameworks yet to adopt.

FERC Decisions

FERC encourages but does not require RTOs/ISOs to develop coordination frameworks that addresses the needs of its region. FERC notes that coordination framework was not fully considered in the record and still developing. It also suggests consideration of the interoperability of new information technology and communications systems. Coordination framework would be a more structured plan for coordination and include planning, registration, and operational coordination.

Modifications to the list of resources in aggregation

In the NOPR, FERC proposed to allow a DER Aggregator to change the list of resources in its DERA without re-registering all resources if the change in the list will not lead to reliability or safety concerns. FERC notes that such modification may need DU review process.

Commentary

Commenters believe that such consideration is necessary and assert that the DU review process should be as streamlined and transparent as possible.

FERC Decisions

FERC requires each RTO/ISO to establish rules that address modification to the list of DERs in a DERA. In addition, the DER Aggregator must update the list of DERs in each aggregation, and any relevant information and data but does not have to re-register or re-qualify the aggregation. FERC emphasizes that any modification to the list will trigger the DU review process. FERC believes however that each entry and exit will have minimal impact on distribution system and suggests an abbreviated review process be sufficient compared to the beginning review process. During the review of the changes, DER Aggregator should be able to participate its unmodified portion of the aggregation in RTO/ISO markets. DER Aggregator must also modify information on physical or operational characteristics of its aggregation if the change in DER makeup changes the performance of the aggregation.

Market Participation Agreements

In the NOPR, FERC proposed to require each DER Aggregator to execute a market participation agreement with the RTO/ISO in which the DER Aggregator attest that its aggregation abides by all relevant provisions in the RTO/ISO tariff. The market participation agreement must also require the DER Aggregator to confirm that its aggregation complies with the tariff and operating procedures of relevant DUs and RERRAs. The agreement, however, may not limit the business models that the DER Aggregators may adopt. The agreement also should not prevent DUs or microgrids from participating in the wholesale market as a DER Aggregator.

Commentary

ISO-NE suggested that standard generic market participant agreement is sufficient and there is no need to accommodate DER Aggregator differences because of coordination process. Others expressed concerns that the market participation agreements may not fully address state and local regulatory concerns. Commenters suggested that there may be a need to have the participation agreements formed in a way to accommodate evolving technology changes. Some suggested a three-party agreement between DER Aggregator, DU, and RTO/ISO. Others suggested two two-party agreements: one between RTO/ISO and DER Aggregator and one between the DER Aggregator and DU.

Some suggest that DERAs must demonstrate rather than simply attest that the RERRA has authorized wholesale market participation by all DERs in the DERA. Some supported the language that allows a DU to act as a DER Aggregator. Others suggested that such language may be too vague and could lead to yet to be designed business models, that could inappropriately limit the ability of the RTOs/ISOs to prevent such that it could threaten grid reliability.

FERC Decisions

FERC requires RTOs/ISOs to establish rules that address market participation agreements for DER Aggregator including a standard market participation agreement defining the DER Aggregator role and responsibilities, and the DERA relationship with the RTO/ISO. The DER Aggregator must execute this agreement before participating in RTO/ISO market. The agreement must also attest that the aggregation is compliant with the tariffs and operating procedures of the DUs and rules/regulations of the any RERRA. FERC believes that this attestation requirement will allow the agreement to be just between the RTO/ISO and DER Aggregator and not require retail authority or DU to need to be party to the agreement. The participation agreements must not limit the business models under which DER Aggregator can operate (i.e., not exclusive to third party aggregator companies). No other requirements are stated for the agreement, and FERC allows the ISOs and stakeholders to develop the agreements based on specific needs.

Administrative

Compliance Timeline

In the NOPR, FERC proposed to give each RTO/ISO six months from the date the final rule was made effective in the Federal Register to submit their compliance filing. In addition, it proposed to require each RTO/ISO to implement the proposed modifications 12 months after the compliance filing date.

Commentary

Most of the RTOs/ISOs suggested that they would need to modify existing rules to integrate DERAs into their markets. Dominion suggested that a pilot project should be conducted first.

Key Decisions

FERC requires each RTO/ISO to submit tariff changes within 270 days from when the final rule was made effective in the Federal Register. Therefore, tariff filings are due by July 19, 2021. Rather than specifying the implementation date, FERC allowed each RTO/ISO to propose a final implementation date in its compliance filing.

Out of Scope Topics

Commentary

The following issues were raised by some commenters but not addressed in the NOPR:

- Modernizing distribution system equipment such as DER Management Systems (DERMS)
- Cyber security and privacy concerns

- Impact of DERAs on distribution system operations and reliability and necessary distribution system adjustments

Key Decisions

FERC decided not to address the above-mentioned issues as it found them to be outside the scope of the NOPR.

3
STATE OF THE ART

FERC Approved DERA Participation Models

In this Chapter, we review the DERA participation models that two of the ISOs, namely CAISO and NYISO, filed with FERC and received approval for prior to the issuance of Order No. 2222. Table 3-1 compares the existing DERA participation models in CAISO and NYISO.

Table 3-1
Comparison of existing DERA participation models in CAISO and NYISO

	CAISO	NYISO
Filed Tariff Revisions / FERC Acceptance	March 2016 / June 2016	June 2019 / January 2020
Market Participation Eligibility	Energy and Ancillary Services (CAISO does not operate a capacity market and DERAs are not eligible to provide resource adequacy)	Energy, Ancillary Services, Capacity Market
Min Aggregation Size	500 kW for DERs; 100 kW for ESRs	100 kW
DERs Not Allowed to Participate	• Individual generators 1 MW or greater • Demand Response (DR) participating through reliability or proxy demand response • Resources participating in retail net metering program	• Individual generators 20 MW or larger • Prohibits Single DER participation Except for DR • Generators with Public Utility Regulatory Policies Act (PURPA) contracts, limited control run-of-river resources, Behind-the-Meter Net Generation resources, municipally-owned generation, system resources, and control area system resources.
Locational Requirements	• Multiple pricing nodes (Must be in a single sub-LAP) • Maximum aggregation size of 20 MW for multi-node aggregations only • Dispatch instructions according to distribution factors • Paid weighted-Average LMPs across multiple nodes	• Single transmission pricing nodes • List of nodes updated annually
Dual Participation	• DERAs are settled in the CAISO markets for all energy injected or consumed in all intervals, including intervals for which the DERA did not submit a bid. • Disallows resources participating in net metering program • Currently working with stakeholders to further evaluate dual participation	Tariff revisions in May 2020 allowed DERs to provide services to a local distribution utility and participate in NYISO at the same time

Table 3-1 (continued)
Comparison of existing DERA participation models in CAISO and NYISO

	CAISO	NYISO
Capacity Markets	CAISO does not recognize DERAs as resource adequacy (RA) resources	Plan to modify eligibility, participation, and payment rules so that DERAs can become installed capacity (ICAP) suppliers (effective March 2021)
Metering and Telemetry	• DER Aggregators must follow the same metering and telemetry standards • Real-time 4-second telemetry if more than 10 MW or providing ancillary services	• Each DER required to have adequate metering • Real-Time 6-second telemetry for DERA
Potential Changes for Compliance with Order No. 2222	• Reduce minimum aggregation size to 100 kW • Resource adequacy eligibility • Operational Coordination?	• Allow for single DER participation • Demonstration of geographical scope limit to one node • Operational Coordination?

CAISO

On March 4, 2016, CAISO filed proposed tariff revisions to facilitate participation of Distribution Energy Resource Aggregation (DERA) in its energy and ancillary services markets. FERC accepted CAISO's proposal on June 2, 2016 [6]. The proposal defines a new market participant called DER Provider (DERP) as "the owner or operator of DER aggregation for purposes of wholesale market participation," i.e., essentially the same as DER Aggregator in the terminology of Order No. 2222. CAISO establishes differences between DER providers and Demand Response Providers and provides rules for DER aggregations. Although the DERP model has been in place since 2016, the CAISO has not had a DERA actively participating in its markets [8], [9]. A coordination effort between CAISO and UDCs in 2017 identified several challenges and barriers hindering the participation of DERA in CAISO markets [10]. Furthermore, since 2015, CAISO has been leading an initiative on Energy Storage and Distributed Energy Resources (ESDER) focusing on improving the ability of energy storage and distributed energy resources to participate in CAISO markets. The outcome of the initiative so far was three sets of tariff revisions accepted by FERC. The initiative is currently in its fourth phase of development [11].

DER Definition

CAISO defines DER as "any resource with a first point of interconnection to a utility distribution company or a metered subsystem." DERs could be in front of or behind the meter. Examples include distributed generation, energy storage, and plug-in electric vehicle charging stations. CAISO mentions that it considers the DERA, instead of individual resources, as the market resource, which is consistent with Order No. 2222. CAISO imposes certain size and locational requirements for DER aggregations. The 2016 DERP tariff includes a pro forma DERP agreement between the CAISO and the DERP, to which the DERP attaches an appendix for each DERA it intends to offer for market participation. For all matters not addressed in the DERP agreement, DERPs are subject to the existing rules contained in the CAISO tariff unless noted otherwise. For instance, a DERA that desire to offer ancillary services (AS) must comply with the corresponding technical requirements in the CAISO tariff. DERPs are exempt to follow the

CAISO tariff provisions in two instances: 1) DERAs that include renewable generation do not need to abide by the meteorological data requirements that apply to certain intermittent resources since CAISO believes that it could cause an excessive burden to individual DERs that are less than 1 MW in size, 2) DERAs are not treated as resource adequacy (RA) resources, which means they are not subject to must-offer obligations to submit bids to the CAISO markets.

According to the DERP framework, each DERAs must comply with applicable UDC tariff and local regulatory authority requirements, in addition to complying with CAISO's tariff, operating procedures and business practice manuals (BPM). Furthermore, DERPs must operate their aggregations considering the limitations or operating orders they receive from the UDC.

Existing Participation Options

Current participation models for aggregated DERs include Demand Response (DR) Aggregation in addition to DERA. Aggregated DR resources may participate in CAISO markets as reliability DR and proxy DR or may choose to participate in DERA. Note that DR resources participating as reliability or proxy DR are not eligible to participate in DERA. CAISO states that this limitation is in place to prevent double counting.

Proposed Aggregation Participation Model

The current DERP model requires that each aggregation must be 0.5 MW or greater; CAISO is expected to reduce this requirement to 0.1 MW to comply with Order No. 2222. Individual generating units that are 1 MW or greater are not eligible to participate through a DERA. Individual generating units that are between 0.5 MW and 1 MW, and DR resources participating through reliability or proxy DR, are not eligible to participate through DERA unless they terminate their current participating agreements. In addition, CAISO states that it does not allow resources participating in retail programs, such as net metering, to participate in DERA. CAISO explains that resources participating in California's current net energy metering program already receive compensation for exported energy through the program, so being compensated by CAISO's wholesale energy market would constitute double payment.

Offer Parameters

Offer parameters for DERAs include economic bids (i.e., price/quantity pairs, price in $/MWh and quantity in MWh) for the aggregation, distributed across multiple pricing nodes in accordance with the aggregation's generation distribution factors. The distribution factors are incorporated into CAISO's market optimization algorithms, dispatch instructions and market settlement. Although aggregated across multiple pricing nodes, DERAs must provide a response at the pricing node level that is consistent with their generation distribution factors. In this regard, DERAs will be charged an uninstructed imbalance energy deviation charge if their response deviates from their dispatch instructions. However, it is worth noting that they will not be levied with this deviation charge in instances that their response is fully aligned with the dispatch instructions, but it is deviated from their distribution factors.

Pricing and Settlement

CAISO settles DERAs aggregating across multiple pricing nodes according to a weighted locational marginal price (LMP) based on the energy delivered at each pricing node.

Ancillary Services

Distributed energy resource providers that want to offer ancillary services must abide by the technical requirements to do so as described in CAISO tariff. DERAs providing ancillary services must submit real-time data through telemetry to CAISO's energy management system (EMS) like a participating generator.

Capacity Markets

CAISO does not operate a capacity market; resource adequacy capacity is procured by load-serving entities via bilateral contracts. CAISO does not recognize DERAs as resource adequacy resources, and therefore does not require DERAs to comply with the must-offer obligations that apply to resources providing resource adequacy.

Physical Size

CAISO states that each aggregation may be 0.5 MW or greater. In addition, individual generating units that are 1 MW or greater are not eligible to participate through DERA. Individual generating units that are between 0.5 MW and 1 MW are also not eligible to participate through DERA unless they terminate their current participating agreements. CAISO allows multi-node aggregation but imposes a maximum aggregation size requirement of 20 MW to ensure that DERs aggregating across multiple nodes will not exacerbate congestion in CAISO's system.

Multi-Node Aggregation

CAISO emphasizes that similar to its reliability and proxy DR programs, it allows multi-node aggregation for DERs. CAISO introduces the following rules to ensure that congestion implications of these resources are accurately modeled: (1) Aggregation across multiple pricing nodes cannot be larger than 20 MW in total, and (2) Each DERA must be physically located in a single sub-load aggregation point (also referred to as a sub-LAP in CAISO). The second requirement is also imposed on aggregations of DR resources participating in reliability or proxy DR.

Dual Participation

The CAISO's DERP framework requires DERAs to be settled for energy produced or consumed in all intervals of the wholesale market, including intervals in which the DERA has not submitted a bid. This is consistent with the treatment of all resources in the CAISO markets that inject power into the system. It also prohibits participation of resources that are already participating in a retail net energy metering program. The CAISO, however, is currently working with its stakeholders, including the California Public Utilities Commission (CPUC), to evaluate the feasibility of multiple use applications for DERs.

Metering and Telemetry

The DERA framework applies existing metering rules and telemetry standards to DERAs. The current procedure for DR resources participating in CAISO markets require that the associated scheduling coordinators (SCs) submit validated meter data to CAISO. In case of DER aggregation having a rated capacity of 10 MW or greater or DERAs providing ancillary services, CAISO requires the aggregation to provide real-time data through telemetry to CAISO's EMS. CAISO receives the telemetry data at the aggregated level; CAISO does not require data from individual DERs in the aggregation, and it does not ask for data associated with individual pricing nodes in case of DER aggregations across multiple pricing nodes. There are, however, differences between DER aggregation and DR aggregation: while demand response providers must submit settlement quality meter data for the settlement interval in which they responded to a CAISO dispatch instruction, DER aggregations are required to provide this data in all operating intervals. CAISO does not require settlement data for all DERs that participate in DERAs, but has the authority to audit a DERP's settlement data for individual DERs if warranted.

Coordination

DERPs need to submit information to CAISO for each DERA identifying the individual DERs included in each DERA. The UDC in which individual DERs are located is given 30 days after the DERP submits information to CAISO to comment on the accuracy of the information about individual resources and identify certain circumstances that would impact the ability of individual resources to participate in the aggregation. Such circumstances include DERs that: "(1) are participating in another distributed energy resource aggregation; (2) are participating as a proxy demand response resource or a reliability demand response resource; (3) are participating in a retail net energy metering program that does not expressly permit wholesale market participation; (4) do not comply with applicable utility distribution company tariffs or requirements of the relevant local regulatory authority; or (5) may pose a threat to the safe and reliable operation of the distribution system, if operated as part of a distributed energy resource aggregation." CAISO requires the UDC's statement of concurrence before accepting the DERA as a market resource.

NYISO

NYISO in collaboration with its stakeholders developed and issued its Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets (DER Roadmap) in February 2017. The DER Roadmap includes preliminary market design concepts to better incorporate DERs into NYISO's markets. Subsequently, NYISO's DER Market Design Proposal was issued in December 2017. It includes a discussion around: 1) aggregations and modeling, 2) measurement and verification, and monitoring and control, 3) performance obligations, and 4) dual participation in wholesale and retail markets [12]. Furthermore, NYISO filed proposed revisions to its Tariffs on June 27, 2019 to incorporate a new participation model for aggregations, i.e., Aggregation Participation Model, and corresponding requirements that will enable such aggregations of resources to participate in its energy, ancillary services, and capacity markets. FERC accepted NYISO's proposal on January 23, 2020.

DER Definition

An Aggregation is defined as – "A Resource, comprised of two or more individual Generators, Demand Side Resources, or [DERs]; or one or more individual Demand Side Resources at separate points of interconnection; and that are grouped and dispatched as a single unit by the ISO, and for which Energy injections, withdrawals and Demand Reductions are modeled at a single Transmission Node." The proposed definition allows for both homogeneous and heterogenous aggregations. Homogenous aggregations, excepting Demand Side Resources (DSRs), will be subject to existing rules of the specific Resource type in addition to the general rules that apply to all Aggregations. Heterogeneous aggregations or aggregations that include only Demand Side Resources will be described as DER Aggregations. DER Aggregation is defined as – "An Aggregation consisting of one or more Demand Side Resources, or two or more different Resource types." DER Aggregations will be subject to the general rules for Aggregations in addition to a few DER Aggregation-specific rules. Demand Side Resources have been provided with the exception to register as a single-facility DER Aggregation to maintain consistency with its existing requirement of allowing individual Demand Side Resources to participate in NYISO's Day-Ahead Demand Response Program and Demand Response Ancillary Services Program that the ISO intends to replace with its proposed Aggregation Participation Model.

With regards to the definition of DER, NYISO defines an individual facility in this context as either: 1) a single facility at a distinct physical location (for instance, street address and utility account number), or 2) a single physical location with greater than one facility with different points of interconnection with the distribution system and/or utility account numbers and operated independently from the other facilities at that physical location.

Existing Participation Options

The participation opportunities for DERs in NYISO are limited due to the inability of DERs to individually satisfy the existing eligibility/qualification criteria or performance requirements under an existing participation model. The present-day participation opportunities are restricted to: 1) reliability-based demand response programs, 2) emergency demand response program, 3) special case resource (SCR) program, 4) economic demand response program, 5) day-ahead demand response program, 6) demand response ancillary services program, or 7) behind-the-meter net generation resources (should have the capability to inject at least 1 MW). DERs can also be utilized by load serving entities to reduce their wholesale load.

Proposed Aggregation Participation Model

Under this participation option, an Aggregator may combine multiple individual DER facilities, located on either the transmission system or the distribution system, as a single Aggregation (or a single unit) for participation in NYISO-administered markets. Resource types that are excluded from participating as a part of an Aggregation include generators with Public Utility Regulatory Policies Act (PURPA) contracts, limited control run-of-river resources, Behind-the-Meter Net Generation resources, municipally-owned generation, system resources, and control area system resources. The main objective is to remove the existing barriers to entry that are to do with existing participation options such as facility size, minimum run-time requirements, physical or operational characteristics, or commitments (or obligations) to the local distribution system or host load, as proposed in the original NOPR issued in November 2016 [1]. Aggregations will need to meet the existing minimum eligibility and performance requirements in order to participate in the ISO-administered markets; however, this requirement does not apply to the individual facilities that comprise the Aggregation unless specifically noted.

NYISO has stated that majority of its other existing bidding and scheduling market rules will also apply to Aggregations analogous to traditional resources. Additionally, NYISO has proposed numerous new requirements to enable the participated of Aggregations in its energy and ancillary service markets. The proposed Aggregation Participation Model will be a dispatch-only model. In other words, the proposed participation model will not incorporate commitment constraints such as minimum off and run-times and startup and shutdown constraints since the individual facilities that constitute an aggregation may be providing other services outside the NYISO's markets.

An Aggregation also has the option to opt for either the self-scheduled fixed bidding mode, the self-scheduled flexible bidding mode, or submit an offer as a price taker for it to be scheduled by the NYISO to meet a local reliability need or to achieve a desired schedule when providing a service/product outside the wholesale markets. The one caveat to an Aggregation being scheduled by the NYISO in consistency with the aforesaid options is when there is a conflicting bulk power system operational or reliability concern.

Offer Parameters

A DER Aggregation has the option to offer into the market as a single resource. All bidding and offer obligations will apply to the Aggregator or Aggregation and not the individual facilities that constitute the Aggregation. For a heterogenous Aggregation, its bid is required to reflect the net offer, i.e., any expected potential energy withdrawals should be reduced from the energy that the Aggregation is capable of injecting. Dual participating Aggregations are required to bid in a way that warrants that they will be dispatched by the NYISO for each operating interval in sync with the way these Aggregations will operate to satisfy obligations outside of the wholesale market (for instance, by self-scheduling in the DAM consistent with retail obligations, or by submitting price-sensitive offers that reflect the Aggregation's retail obligations). The retail obligations in this context refer to any direction from the New York Transmission Owners (NYTOs) or distribution system operator (DSO) to operate a constituent facility in a specific way that satisfies a distributed system need, and/or provision of a product or service that is compensated by the TO or the DSO.

A few stakeholders had expressed concerns about NYISO's bidding parameters not allowing for specific retail applications to be reflected in the Aggregator's market offers, and also requested that the NYISO modify its proposal to only require wholesale offers for a retail service when the retail service overlaps with an instance when the DER also has a must-offer obligation into the wholesale market. However, NYISO has required that the Aggregation offer in a way that it will be dispatched by the NYISO's real-time market (RTM) consistent with its operation to meet the NYTO's or DSO's direction/instruction even during the hours that are outside of the peak load window to enable the operators or the ISO RT commitment and dispatch software to consider the operation of such dual participation resources appropriately especially when determining the schedules for the other participating resources.

Pricing and Settlement

Compliance for settlement purposes will be based on the net performance of the Aggregation as a whole. As per NYISO, Aggregations will be eligible to receive real-time Bid Production Cost Guarantee (RT BPCG) payments, analogous to conventional generating resources, if they are operated out-of-merit or as part of a supplemental resource evaluation to satisfy New York Control Area (NYCA) or local system reliability. Furthermore, an ISO-committed flexible homogenous Aggregation, which includes ESRs that self-manage its state of charge will also be eligible for RT BPCG payments. NYISO has proposed that ESRs and Aggregations will not be entitled to receive a RT BPCG payment for a day if their RT market bids for any operating hour of the corresponding day disallows them from receiving a zero MW schedule. Given that the NYISO is replacing its Day-Ahead Demand Response Program and Demand Response Ancillary

Services Program with its proposed Aggregation Participation Model, the NYISO has proposed to eliminate the BPCG payments for demand reduction in the DAM, Demand Side Resources providing Operating Reserves and/or Regulation Service in the DAM and in the RTM. In accordance with Order No. 745, the NYISO will continue to compensate the Aggregation for its demand reduction in the energy market at the LMP.

Ancillary Services

The qualification criterion for an Aggregation to offer ancillary services is dependent on what the individual facilities in the Aggregations are qualified to provide. For instance, in order to provide Regulation Service, NYISO's eligibility criterion requires that each of the generating resources that constitute the Aggregation use inverter-based energy storage technology given that the corresponding Service requires a resource to be synchronous to the grid and responsive to six-second dispatch instructions. The NYISO has also proposed numerous new requirements for Aggregations that desire to participate in the provision of reserves and voltage support services.

Capacity Markets

The NYISO has proposed to modify its installed capacity (ICAP) market eligibility, qualification, participation, and payment rules to enable Aggregations to become ICAP Suppliers. The corresponding Tariff revisions are envisioned to become effective on March 1, 2021. In order to enable emerging technologies to participate in NYISO's ICAP market, NYISO has proposed to modify its approach to valuing capacity that presently allocates the same capacity value to resources with and without daily duration limitation of four hours (GE Energy Study [13], Potomac Economics [14], Astrapé Study [15]); thereby, expanding the eligibility and qualification requirements that apply to ICAP suppliers. NYISO has stated that it will now assign a lesser capacity value to resources with daily duration limitations while considering their contribution to RA during an eight-hour peak load window. The GE Energy Study proposed to lengthen NYISO's present four-hour minimum run time requirement in order to address the RA issues that were observed, within a daily eight-hour period, in the simulations with an evolving resource mix and system peak demand. The proposed modifications are further defined by a 1000 MW incremental penetration level. In order to qualify as an ICAP supplier, the NYISO has proposed to lower the qualification criteria to correspond to a resource's capability to "provide energy for a prescribed consecutive hourly duration." Lastly, NYISO has proposed to permit ICAP suppliers, potentially also including Aggregations, that have a run-time of greater than or equal to six consecutive hours to receive full capacity value when the incremental penetration levels are less than 1000 MW. The requirement will be increased to at least eight consecutive hours for penetration levels that are greater than or equal to 1000 MW.

Physical Size

NYISO has not imposed an upper bound on the number of individual facilities that constitute an Aggregation, or the total MW quantity of an Aggregation, or the amount of demand reduction that a DER participating in an Aggregation may provide. However, in order to utilize NYISO's proposed Aggregation Participation Model, the DER will need fall under one of the three potential categories: 1) a facility comprised of greater than one Resource type behind a single point of interconnection with an injection limit of twenty MW or less, 2) a Demand Side Resource, or 3) a Generator that is electrically located in the NYCA with an injection limit of twenty MW or less. Therefore, the upper bound on the physical injection limit for each individual DER facility that constitutes an Aggregation is twenty MW, and will be set to equal the facility's nameplate capacity except when the facility establishes that it has the necessary physical protections and/or control schemes to restrict its physical injection to twenty MW or less.

The minimum offer size for provision of ancillary services, capacity, and energy by an Aggregation is set to equal 100 kW in compliance with FERC Order No. 2222. Furthermore, if the Aggregation offers a combination of energy injections, withdrawals and/or demand reductions, the Aggregation is required to offer the minimum offer size for each given that the NYISO will process injections, withdrawals and demand reductions separately in the settlements evaluation as per Order No. 745. NYISO proposes to recombine the separate components later to settle the Aggregation as a whole on a net basis.

Multi-Node Aggregations

NYISO has required that each individual facility that constitutes an Aggregation be electrically located in the NYCA and electrically connected to the same Transmission Node (or Pricing Node: include an associated Location Based Marginal Price, LBMP). NYISO has proposed that it will pre-determine the subset of Transmission Nodes and their corresponding electrical facilities, e.g., distribution feeders, to which individual facilities may aggregate in consultation with (NYTOs. The subset of Transmission Nodes will be reviewed and updated in its Procedures on an annual basis in order to account for the changing system conditions. Multi-node aggregations are proposed to be disallowed to manage transmission constraints and reliability concerns appropriately. An individual facility will be allowed to leave an Aggregation but will need to provide NYISO with at least thirty calendar days' notice and obtain approval from the ISO before participating in a new Aggregation. The change will be effective at the start of a calendar month.

Dual Participation

NYISO incorporated amendments to its Service Tariff (revisions effective since May 1, 2020) to allow generators, Demand Side Resources, and DERs to offer energy and other services to a local distribution utility or host load and participate in the ISO-administered markets simultaneously. However, the market participant will still be responsible to satisfy all applicable rules and obligations set forth in the Tariff failing which may result in financial penalties and/or termination from wholesale participation. Consecutively, as per its proposed dual participation rules, NYISO has also proposed to modify the definition of Behind the Meter Net Generation resource to remove the dual participation prohibition. NYISO has acknowledged that its proposal will permit resources that are engaged in dual participation to be scheduled for economic efficiency, while also providing the Market Participant with the option to request for a schedule (via offers) that may be warranted by the TO to address local reliability concerns when the resource is not otherwise scheduled by the NYISO. The Aggregator is responsible to satisfy any other wholesale market obligations, e.g., day-ahead schedules, when submitting offers to also meet a TO's local reliability needs.

Metering and Telemetry

NYISO has stated that each Aggregation is required to have adequate metering, that includes each individual facility in the Aggregation. In addition, NYISO proposed a few modifications on metering requirements and correspondingly revised its Tariff that became effective on November 1, 2019. As per the specifications set forth in the ISO's procedures, the NYISO has also proposed that the Market Participant is required to provide real-time telemetry for Aggregations nominally every six-seconds analogous to other traditional resources (note that the six-second telemetry requirement presents a significant economic barrier for smaller resources that are less than 100 kW since present-day metering and sub-metering and utility smart meters support one-minute or five-minute telemetry). However, as per NYISO, the six-second telemetry is required to maintain situational awareness, optimize system operations and satisfy mandatory reliability criteria in addition to enhancing the ISO's ability to respond to emergencies. Note that the ISO is presently evaluating alternative telemetry communications infrastructure in a pilot program that may potentially help with reducing the telemetry costs while maintaining the six-second scan rate. Furthermore, the NYISO has also stated that it will send real-time dispatch instructions to (and obtain real-time telemetry from) an Aggregation and not the individual facilities that comprise the Aggregation in addition to similarly collecting revenue-quality meter data from the Aggregation (and not the individual facilities) for both measuring performance and settlement purposes. The cumulative telemetry signal will be used in RT to assess the response to dispatch in aggregate. The Aggregator will be held responsible for the measurements from all the individual facilities in the Aggregation during dispatch, and for ensuring that all the measurements for metering and telemetry for the individual facilities it represents are obtained either from directly measure values or from calculated values (via a NYISO-approved methodology for facilities that are smaller than or equal to 100 kW) or a combination thereof as per the requirements set forth in the ISO procedures. Homogeneous aggregations will be subject to current metering and telemetry requirements for that resource type.

Coordination

NYISO has determined that the Aggregator will be responsible to interface with the market, register Aggregations, and enroll individual facilities in each Aggregation in accordance with the ISO Procedures; thereby; categorizing their role as the "Supplier" under its Tariffs. Aggregators will be required to register as a NYISO customer. NYISO has stated that it will consult with NYTOs to coordinate the schedule and dispatch of Aggregations that are engaged in dual participation, but will retain the authority to schedule and/or dispatch all the Market Participants including the Aggregations that are involved in dual participation and are providing services to the distribution system and/or a host facility. NYTOs will still have the option to use NYISO's supplemental resource evaluation procedures that provides them with the option to contact the ISO and submit requests to schedule resource(s) that are necessary to address local reliability needs.

Other ISOs

While only CAISO and NYISO have FERC approved tariff changes to accommodate DERAs into their wholesale markets, the other RTOs/ISOs have made progress in allowing for DERA participation through their stakeholder processes and most have begun new stakeholder groups and initiatives to address the order. Each of these designs may change substantially as these

ISOs/RTOs are addressing the requirements of the order, or in the case of ERCOT and IESO, going through lengthy processes. The discussions here are current as of the end of January 2021.

ISO-NE

ISO-NE initiated its stakeholder process on FERC Order No. 2222 on December 8, 2020 with an overview of the order requirements [16]. The interested stakeholders were requested to provide their comments and viewpoints by December 22, 2020. ISO-NE plans to further discuss the comments with the stakeholders impacted by the order in January and February 2021 following which ISO-NE intends to develop a proposed method for consideration in the New England Power Pool stakeholder procedure.

ISO-NE received several comments from various stakeholders including comments from DER Stakeholders. DER Stakeholders assert that while some DERs are currently able to participate in ISO-NE markets using existing participation models (e.g., load curtailment and infrequently dispatched distributed generation (DG) can participate through existing active DR program; behind-the-meter solar, residential storage and energy efficiency can participate using passive DR options), certain DERs face substantial barriers to participation. DER Stakeholders point out that active DR baseline rules and prohibition on real-time energy market participation for DR prevent these resources from participation. Examples of such resources include behind-the-meter technologies that frequently dispatch (e.g., storage/electric buses) and/or provide retail services (e.g., a Non-Wires solution to a distribution utility). Another barrier identified by DER Stakeholders in ISO-NE is its metering and telemetry requirements along with lack of Advanced Metering Infrastructure (AMI) which challenge the participation of residential and small commercial dispatchable resources (e.g., electric vehicle charging). DER Stakeholders present a few solutions to address the barriers [17]. ISO-NE received several other comments from interested parties. In response to the feedback it received, ISO-NE states that it anticipates that the resources currently participating under existing participation models will not be impacted by Order No. 2222. It also asserts that resources will be allowed to participate in either the Demand Response Resource program or the DERA, but not both. The ISO also plans to create and manage a central system for the purpose of identifying, tracking, and mapping of DERs and DERAs. ISO-NE is also considering introducing a new participation model for heterogeneous DER aggregations which allows injection, withdrawal and regulation capabilities [18].

Draft Compliance Proposal

In a draft compliance proposal, ISO-NE states that it does not plan to modify the existing participation models as thousands of MWs of DERs are currently participating in its markets through existing participation models. ISO-NE believes that a DERA does not pay for demand reduction and therefore, it does not need a baseline to calculate demand reduction. In order to prevent double counting, part of the ISO's draft proposal is to count the load along with behind-the-meter generation. ISO-NE does not recommend sub-metering due to concerns regarding load reconstitution.

Proposed Participation Options. As the existing participation models in ISO-NE do not allow aggregations of DERs injecting energy with DERs withdrawing energy, the draft proposal introduces two new participation models: Settlement Only DERA (SODERA) and Dispatchable DERA (DDERA) [19]. Note that aggregations of DERs can still participate through existing participation models that they qualify for, but the ISO does not plan to modify the existing models. While both new participation models allow for injection and withdrawal, DERAs registering a DDERA can provide reserves and/or regulation services as well. Both participation models allow participation in the ISO's Forward Capacity Market (FCM – ISONE's long-term wholesale electricity market that ensures resource adequacy, locally and system-wide). A SODERA is a real-time price-taker model whose schedules are not optimized by the ISO. While it must meet proposed revenue quality metering requirements, it does not need to meet telemetry requirements. A SODERA can participate in energy markets as two assets: the DERA Settlement Only Resource (SOR) representing its generation capability, and the DERA Load Asset representing its consumption capability. Note that SOR and Load Asset are existing participation models in ISO-NE. A SODERA is also allowed to submit fixed or price-sensitive demand bids in the DA market for the load portion of its resource.

Contrary to SODERA, a DDERA is dispatchable and must meet proposed telemetry and revenue quality metering requirements. A DDERA can participate as three assets: the DERA Generator representing its generation capability, the DERA Dispatchable Asset Related Demand (DARD) representing it consumption capability, and the DERA Alternative Technology Regulation Resource (ATRR) representing its regulation capability. Note that Generator, DARD and ATRR are existing participation models in ISO-NE. A DDERA can bid into the DA and RT energy markets, or self-schedule to ensure it is committed in each hour or declare unavailable. Similar to its existing Continuous Storage Facility (CSF) participation model (proposed by ISONE for ESRs), a DDERA can set DA and RT LMPs and its dispatch is equal to Generator Desired Dispatch Point (DDP) - DARD DDP + ATRR Automatic Generation Control (AGC) setpoint. A DDERA is allowed to participate in both wholesale markets and retail programs under certain conditions.

Physical Size and Aggregation. As for the size requirements, ISO-NE's proposal requires an individual DER with generation capability greater than 5 MW to be its own DDERA. In addition, such DER cannot be SODERA. Furthermore, the ISO allows any DER greater than or equal to 100 kW to be its own DERA. As for locational requirements, ISO-NE requires the DERs within an aggregation to be in the same metering domain [20]. In addition to being in the same metering domain, individual DERs in DDERA are required to be within a Demand Response Resource (DRR) Aggregation Zone to minimize the impact on transmission congestion. It is worth noting that ISO-NE's market clearing software models each DRR Aggregation Zone as a single pricing node; therefore, DDERAs are dispatched and settled at a single pricing node. As a result, the ISO does not require DERAs to provide distribution factors. Note that if an aggregation of DERs at a single substation is greater than or equal to 5 MW, it will be mapped to the substation pricing node and will not be allowed to aggregate with other DERs.

Metering and Telemetry. DERAs participating in ISO-NE Energy Market are required to provide interval metering data at the aggregation level only. ISO-NE determines the maximum interval length as hourly and indicates that 5-minute interval data is optional. Individual DERs within an aggregation are required to have Revenue Quality Metering (RQM). SODERA does not need to have telemetry, but DDERA requires telemetry for each DER constituting the aggregation. If the DDERA provides capacity, energy, and Thirty-Minute Operating Reserve (TMOR) only, telemetry data is required every 5 minutes. If, in addition, the DDERA provides ten-minute reserve and/or regulation it needs more granular telemetry data (i.e., 10-seconds data if providing ten-minute reserve and 4-seconds data if providing regulation).

Coordination. The proposed DU review process is initiated when the DER aggregator informs the ISO and the DU of its plan to register a DERA with an anticipated participation target date at least 20 days out. The DU will have 60 days to perform the review which includes DER eligibility, distribution network safety and reliability checks, and any additional DU/state-established criteria. In addition, ISO-NE requires DER interconnection information to conduct a review of potential transmission impacts. As for ongoing coordination, ISO-NE proposes data flow and communications in DA and RT scheduling processes. In the proposed DA operational coordination, the DERA submits aggregated DA offers to the ISO. Then, the ISO clears the DA market and notifies the DERA of its DA awards. The DERA then determines a resource-level operation plan and sends it to DU to be checked against distribution network reliability constraints. If there are any reliability issues, the DU notifies the DERA of any operating constraints on individual resources. The DERA then updates its physical parameters or financial offers with the ISO during the daily Re-Offer period (after the DAM). A similar operational coordination procedure is also proposed for the RT market.

MISO

In MISO, the Distributed Energy Resources Task Force (DERTF) is responsible for establishing the ISO's Order No. 2222 compliance filing and engaging relevant stakeholders to develop the required coordination frameworks. In a January 4, 2020 meeting, the DERTF provided an overview of existing DER programs, a review of the FERC Order No. 2222 requirements, and the relevant workplan at MISO [21]. According to MISO, Demand Response and Demand Side Management constitute much of the existing DERs in its footprint. In addition, existing Load Modifying Resources have increased. As MISO is evaluating their options for compliance with the order, it states that its current plan is to check the possibility of compliance by editing its existing market participation options (or models) including Demand Response Resource – Type I (DRR-I), Demand Response Resource – Type II (DRR-I), Dispatchable Intermittent Resource (DIR), Storage Energy Resource Type I (SER-I), Storage Energy Resource Type I (SER-II), and future ESR models. In a February 1 stakeholder meeting, the DERTF stated that the existing participation models allow limited participation and none of them is fully compliant with the requirements of the order [22]. For instance, Table 3-2 shows that DRR-I and DRR-II have minimum size requirements above the 100-kW size requirement as per the order.

Table 3-2
Characteristics of existing DER participation models in MISO [22]

Characteristics	Existing Participation Models			
	DRR-I	ESR	DRR-II	DIR
Multi-Node	yes	no	no	no
0.1 MW resource size	no	yes	no	yes
Capacity Market	yes	yes	yes	yes
Energy Market	yes	yes	yes	yes
Regulation	no	yes	yes	no
Spin/On-line Supplemental	yes	yes	yes	no
Off-line Supplemental	no	yes	yes	no
Ramp Capability	no	yes	yes	yes
Short-Term Reserve (STR)	yes	yes	yes	no
MISO Commit	yes	Self-commit	yes	yes
MISO Dispatch	block	yes	yes	yes
Risk	Currently Being Evaluated By MISO			

PJM

In PJM, the DER and Inverter-based Resources Subcommittee (DIRS) is engaging with interested parties on the participation of DER aggregations in the ISO's wholesale markets as it is preparing its compliance filing. On December 7, 2020, PJM held a stakeholder meeting to discuss the status of compliance with the order using their current participation models [23]. Relevant participation models in PJM are DR, Small Generation, and Dual Model (DR+DER, with injection).

Existing Participation Options. DR participation model in PJM is a load reduction model that does not allow injection of energy. DR allows all technologies that can modify load to participate. Examples include arc furnace curtailment, residential load control, batteries, generators, etc. However, the payment only applies to load modification and does not include injection past the retail meter. The interconnection requirements for DR are met at the utility/state level and there is no PJM interconnection study. DR in PJM must go through registration process. DR allows for aggregation of demand response devices with a minimum size requirement of 100 kW for the aggregation. Telemetry data for DR is required only if DR is providing regulation service.

The Small Generation model requires resources to go through PJM interconnection process. It only allows homogenous aggregations (hydro or combined cycle) with a minimum aggregation size requirement of 100 kW. Telemetry data is required on each individual resource if the units provide capacity and ancillary services. If the resources provide energy, they need to have telemetry if 10 MW or larger.

The Dual model consists of generation and demand response. The load modification aspect is addressed with the DR model, whereas the injection aspect is addressed with the Generation model. Separate interconnection process and telemetry requirements apply to the generation and DR parts as well. Regulation service solely operates under the DR rules. The minimum size requirement for participation is 100 kW.

On January 7, 2021, PJM staff provided their initial thoughts on a few aspects of the order including interconnection, maximum sizing of resources and aggregations, locational requirements, and opt-in process for small utilities [24]. PJM believes that many DERs on the distribution system will not inject energy onto the transmission network, even if they inject past their retail load meter. The initial thought is to identify the resources (in aggregation on a distribution system) that inject to transmission in coordination with distribution companies and transmission operators. This subset of resources would then need to go through the PJM interconnection studies. The initial thought on a maximum size requirement for individual DERs is 5 MW such that DERs 5 MW or larger must participate in the market individually and not as part of a DERA. As for a maximum size requirement for the aggregation, PJM states that there will need to be a limit depending on the locational requirements but does not present a value.

SPP

SPP created the Order 2222 Task Force to determine tariff modifications needed to comply with the order and held a kickoff meeting on December 14, 2020 [25]. SPP staff provided their preliminary thoughts regarding several aspects of the order during a stakeholder meeting that was held on January 20, 2021. The order allows for modification of existing participation models, introducing new participation models and a hybrid approach. SPP staff mentioned that their initial thought is to modify existing participation models so that DERAs could participate accordingly. Also, directions will be provided to DERAs so that they are able to select appropriate participation models that fit better with their physical and operational characteristics.

SPP staff stated that a maximum 10 MW size for individual DERs would likely be placed so that DERs larger than 10 MW participate individually in the markets and not as part of a DERA. Additionally, concerns regarding the modeling and locational impact to transmission constraints were raised with the task force understanding that their initial compliance filing would be focused upon aggregations behind a single node. Multi-nodal aggregation, if pursued, would be addressed after SPP's first compliance filing with Order No. 2222. An interesting discussion was the possibility for different locational requirements for ancillary services versus energy, as SPP staff asserted that ancillary service is not a nodal service and therefore DERAs providing ancillary services could potentially be allowed to aggregate over multiple pricing nodes while energy provision (i.e., a nodal service) is still permitted for DERs behind a single node.

ERCOT

In 2015, ERCOT published a concept paper in which it outlined three options for integration of DERs in bulk market operation: DER minimal, DER light, and DER heavy [26]. In the DER minimal option, the net injection from the DER is paid at the zonal price by load in a price-taking procedure. In the DER light option, the DER is bid into the wholesale markets as a price-taking self-scheduled resource and is paid at the corresponding node's LMP in each interval. In the DER heavy option, similar to a conventional generator, the DER is offered into the markets with three-part cost offers. In this arrangement, DER energy injection is remunerated at nodal LMP, but its withdrawal is charged at zonal LMP. ERCOT also published a follow-up report in 2017 to underscore the potential impact of high DER penetration levels on bulk system reliability [27].

ERCOT refers to DER as Distributed Generation (DG) and defines it as "an electrical generating facility located at a Customer's point of delivery (point of common coupling), 10 megawatts (MW) or less, and connected at a voltage less than or equal to 60 kilovolts (kV), which may be connected in parallel operation to the utility system". This definition does not include demand response. There are three types of DGs in ERCOT [28]:

1. Unregistered DG: These resources are typically less than 1 MW and are not required to be registered with ERCOT. Resources that are greater than 1 MW but do not inject into the grid also fall in this category. They are not compensated by ERCOT but may be compensated by their electric provider. In 2019, ERCOT estimated these resources at 850 MW, of that 710 MW is rooftop solar.
2. Settlement-Only Distributed Generation (SODG): These resources are self-dispatched resources greater than 1 MW and can inject energy to the grid. They are compensated by ERCOT for the energy they export to the grid. These resources include utility-scale solar, commercial solar, gas-fired generators, and diesel generators. In 2019, ERCOT estimated these resources at 849 MW.
3. Distribution Generation Resource (DGR): These resources are bid into the markets and are compensated for energy and/or ancillary services. Currently, all resources in this category are batteries. In 2019, ERCOT estimated these resources at 2 MW (operational) with an additional 374 MW in interconnection queue.

IESO

In September 2020, the IESO published a report in which it estimated that more than 4,000 MW of DERs have been contracted or installed over the past 10 years in Ontario with solar accounting for more than half of the total DER capacity [29]. As DER deployment is expected to grow even higher in the coming years, the IESO has developed a series of white papers and started pilot programs to understand the impacts of DERs on the transmission-distribution interface. In a 2019 white paper, the IESO presented existing participation models for DERs and potential options to expand the models in the future [30]. The white paper also identifies several barriers that may hinder the participation of DERs in the wholesale market. In a separate white paper, the IESO investigates the coordination necessary for DERs to provide distribution services through Non-Wires Alternatives (NWAs) and also participate in transmission-level markets [31]. A transmission-distribution interoperability framework is developed in [32] to maximize the potential of DERs in providing services.

The IESO initiated a non-wires alternative demonstration project in York Region to explore market-based approaches in which DERs can provide energy and capacity services. The project is funded by the IESO's Grid Innovation Fund and Natural Resources Canada and will be delivered by Alectra Utilities. IESO ran the first Local Capacity Auction in November 2020 in which 10 MW were cleared form 7 customers including aggregated residential customers with controllable smart thermostats, industrial customers, and small-scale generators [33].

International Experiences

Great Britain

Great Britain has one of the highest growth rates of renewables and DER around the world. Several services, initiatives, and pilot programs have been created by National Grid ESO, the system operator in the UK, to incentivize DERs in cooperation with the distribution network operators.

The primary access points to energy markets for distributed resources and customers are through aggregators active in the forward energy markets and balancing mechanism. Changes to the balancing and settlement code in 2019 enabled the participation of aggregations in the real time balancing market which is used to manage residual market positions against forecasted demand, operational forecast uncertainty, to restore frequency after events and for transmission congestion management.

Additional products have been established by the system operator to manage challenging system conditions from a balancing point of view. The demand turn-up (DTU) is a service introduced in 2016 to encourage resources to either increase demand or reduce generation when renewable output is high and national demand is low (e.g., overnight and during weekend afternoons in the summer) [34]. The minimum resource size for DTU provision is 1 MW. Aggregation of resources is allowed, but each resource must be at least 100 kW. The average deployment time in 2016-2018 was around 4 hours.

In 2019, National Grid ESO announced that it will not procure DTU anymore citing a few barriers including the offline dispatch process, long notice period for delivery, small volume procured, and lack of sufficient financial incentives for service providers [35].

The service was replaced in 2020 by the Operational Flexibility Downward Management (OFDM) to bring resources that traditionally did not participate in balancing markets into the dispatch process during periods of light system load. This product is contracted seasonally and manually activated. Providers of such services include DER portfolios that are pre-cleared by DSOs to participate and large, inflexible conventional plant, such as nuclear generators.

Aggregations of DERs can provide Short-Term Operating Reserve (STOR) in Great Britain. The minimum aggregation size is 3 MW and the minimum deployment time is 2 hours [36]. Triad management is another initiative that has substantially incentivized DER adoption for commercial and industrial customers in the UK [37]. Network charges for these customers are calculated based on each customer’s consumption during the three half-hour settlement periods of highest demand on the transmission system between November and February (inclusive) each year, denoted as triads. Because network charges are a significant part of a customer’s bill, customers are incentivized to try to predict when a triad may happen to reduce their consumption. An auction trial commenced in 2020 for static under frequency response (trigger at 49.6Hz vs 50Hz nominal) with significant supply originating at the distribution level.

In collaboration with UK Power Networks (UKPN), National Grid ESO launched a pilot project called Power Potential to demonstrate the use of DERs to address thermal constraints and under/over voltage issues [38]. The set points for each resource are determined by the DSO through a DERMS, based on input from the TSO as to the requirements for active and reactive power flows at the interface between the two system operators. The participants are several PV power plants, wind farms, batteries and storage sites, synchronous generators, aggregators, etc. located in South East area of England.

Many of the issues raised by Order No. 2222 have been the subject of the Open Networks Project (ONP) [39] in the United Kingdom, which has been ongoing since 2017. The ONP is a participatory stakeholder process being conducted by the Energy Networks Association (ENA) comprised of both transmission and distribution operators (TSOs and DNOs/DSOs[3]). It was formally initiated by the national regulator Ofgem to focus on TSO-DSO coordination, specifically in order to optimize the use of flexible DERs to support reliable operation of the whole power system, with growing amounts of renewable generation at all levels of the system.

Of particular relevance to Order No. 2222 is the ONP's emphasis on T-D coordination, which makes up a major section of the FERC Order. The ONP specified a set of alternative DSO models, each of which implies a corresponding T-D coordination framework, whose details were developed by stakeholder working groups and then simulated for performance comparison and assessment [40].

In parallel to the Open Networks Project, the two largest DNOs in UK have issued, for public comment, strategic plans outlining a progression from their current roles and functions as DNOs to more advanced DSOs with functional capabilities to maximize the benefits to end-users and the power system of high volumes of DERs on their systems [41]. At this time the ONP has moved into a DSO implementation process phase [42].

The European Union inquiry on T-D coordination is also relevant to Order No. 2222 and reflects much of the jurisdictional diversity of the US with numerous TSOs and more than 2000 DSOs. During 2017 the four DSO associations that together include all the EU DSOs collaboratively developed a conceptual TSO-DSO coordination framework, with specific policy recommendations to the European Commission to achieve optimal use of flexible DERs to meet both distribution and transmission level needs for reliable operation. They published their results and recommendations in February 2018 [43].

Netherlands

Renewables in Netherlands are increasing at a fast pace as national policies have established a 50% renewable energy target by 2030 and 100% emissions-free by 2050. The Dutch transmission system operator (TSO), Tennet, collaborates with multiple distribution system

[3] In UK terminology, the "transmission system operator" (TSO) is the same corporate entity as the transmission asset owner, but it is functionally separate and its role is to provide transmission scheduling and real-time balancing services, not wholesale energy markets. There are separate power exchanges for wholesale energy trading. In the case of UK's largest TSO, National Grid, the TSO function is called the "Electricity Network Operator" (ENO). The "distribution network operator" (DNO) in UK is equivalent to the UDC or DU in the US, with one difference that the DNO is unbundled from the retail function, which is performed by separate retailers. The term "distribution system operator" (DSO) in UK generally refers to a not-yet fully implemented future enhancement of the DNO. In the European Union the term DSO refers to the distribution utilities as they exist today, but the overall industry structure is pretty much the same as in the UK.

operators (DSOs) to plan and operate the grid. In 2018, Tennet and Stedin (the DSO for Rotterdam, Utrecht, and surrounding areas) initiated a six-month trial in which DER owners and consumers could participate in a pilot market [44].

In January 2019, Tennet (Dutch TSO) in collaboration with four DSOs including Stedin, Liander, Enexis Groep and Westland Infra launched a congestion management initiative called Grid Operators Platform for Congestion Solutions (GOPACS) [45]. GOPACS is an intraday congestion management platform which uses congestion spreads to coordinate between TSO and DSO activation of DER. In the GOPACS model the grid operators predict congestion situation and notify the market participants through the platform. Market participants including DERs can place a buy or sell order in the congested area through a local energy market. To maintain the balance of energy, the buy order must be combined with a sell order outside the affected area. The TSO in collaboration with the DSOs ensure that the redispatch does not negatively impact other parts of the grid. The price difference between the buy and sell orders, a.k.a. the "spread", is paid by the grid operators.

Germany

The four German TSOs have experienced substantial increase in out-of-market redispatch activities in recent years due to retirement of conventional generators and significant adoption of renewables. The installed PV, onshore wind, and offshore wind capacity at the end of November 2020 in Germany were approximately 53.6 GW, 54.6 GW and 7.74 GW, respectively [46]. Several measures have been introduced in the past few years to integrate renewables into the market and utilize them to support system needs. Direct marketing was one of the main developments that required renewables to be bid into the market by a balance-responsible party (BRP) [47]. In addition, when redispatch is required, a feed-in management process to curtail DER (called EinsMan) is undertaken by DSOs and TSOs to manage system reliability. Total feed-in management actions in Germany in 2016 resulted in 3.7 TWh of curtailments from renewables and CHP resources on both the bulk and distribution systems (3.5 TWh for wind and 184 GWh for solar) [48].

4
RELEVANT RESEARCH GAPS

FERC Order No. 2222 Research Areas

In this Section, we present the research needs across the different aspects of the order. Open questions are posed related to the different sections of the order, which relate to potential future research actions that may address them. The areas also include the relevant EPRI programs where the types of research typically reside. These questions will be discussed further in the six workstreams that are part of the FERC Order No. 2222 Phase 1 Supplemental Project. These questions are developed from the EPRI internal research team and do not necessarily align with the questions that the industry or participating project members would have.

Participation Model for DERAs

EPRI research in this area generally falls within Program 39. Research questions relevant to DERA participation models include:

1. Can an aggregation of DERs of the same technology type (i.e., a homogenous aggregation of DERs) fit into an existing participation model analogous to those that already exist for single transmission-connected resources (e.g., variable energy resource, or VER, electric storage resource, or ESR, generator, etc.)? Research can investigate why this may or may not be possible or why changes are required within the tariff, market clearing software, or due to bidding or data requirements.
2. What participation model would make the most sense for multi-technology heterogenous DERAs? What complications could occur if these DERAs attempt to fit into their "closest" participation model? Are new participation models required for these, and will those differ from homogenous DERA participation models?
3. Evaluate all unique characteristics, bidding parameters, and data requirements that may be a part of various DERA participation models including multi-node characteristics (distribution factors), distribution system curtailment possibility, distribution losses impact on dispatch, etc.

Type of Technologies

EPRI research in this area generally falls within Programs in the Energy Utilization (e.g., P170, 18, 204) and DER Integration (e.g., P174, P94) Research Areas as well as Program 39 on Market Design. Research questions and questions relevant to DER technologies are summarized below:

1. What are the penetration levels of different technology types connected to the distribution system that may be aggregated as a market resource and how may that evolve based on policies, cost projections, and technology advancements?
2. What are the operational characteristics of different technology types that may inform DERA representation in market clearing, transmission operations/planning, or distribution modeling?

3. Evaluate the potential bidding strategies of diverse heterogenous DERAs, to see whether they would lead to any potential reliability or efficiency concerns.
4. Evaluate the potential of ESR and non-ESR aggregations to understand how state-of-charge can be impacted and if there is a need to monitor or consider state-of-charge.

Double Counting of Services

EPRI research in this area falls within Programs 170, 182, and 39. Research questions regarding double counting of services are summarized below:

1. What operational or participation scenarios raise concerns about double counting?
2. In what cases of wholesale and retail programs for which DR/DER participates is dual program participation allowed and under what conditions is dual participation explicitly disallowed?
3. How is priority over DER dispatch established when a resource may be relied on by multiple entities for different purposes (e.g., energy economics, grid reliability, and customer needs)?
4. What is considered double counting when also considering non-dispatchable retail programs like time of use rates?
5. Are there guiding principles that can help indicate what services and participation options can be considered as double compensating for the same service?
6. How can DER participation in aggregators, retail tariffs and specific services be tracked in a transparent fashion that protects consumers' private information?

Minimum and Maximum Size of Aggregation

EPRI research in this area generally falls within Program 39 and P170. Research questions relevant and questions to minimum size requirements for DERAs are summarized below:

1. What are the computational impacts of having large numbers of DERAs of small size? Will there be any corresponding computational issues with the proposed participation models?
2. What size thresholds for resource aggregations lend to robust models of aggregated resource capability and availability
3. Should unit commitment be allowed (or is unit commitment needed) for DERAs?

Bulk System Locational Requirements

EPRI research in this area generally falls within Program 39. Several research problems and questions related to locational requirements are summarized below:

1. Proven engineering methods to determine the geographical extent of an aggregation given transmission topology of system. What tools or study methods can be used to validate that certain multi-node areas can allow for DERAs without measurable impact to reliability or price formation.
2. Evaluate operational impacts on economic efficiency, reliability and incentive compatibility under different scenarios and events with multi-node aggregations. Evaluate the impact of transmission congestion between the nodes/buses over which the DER aggregates.
3. Evaluate price formation and settlement impacts, forecast error impacts, and metering challenges with multi-node aggregations.

4. Estimate adoption of DERs with multi-node aggregation compared to single-node aggregation. If multi-node aggregation is allowable, will aggregations form in this way, or will incentives lead to single-node aggregations regardless?
5. Evaluation of sub-transmission system impact (e.g., sub-transmission system that RTO/ISO does not see may mean that even locally consistent aggregations will have impacts to different transmission system nodes).
6. Evaluation of the impact of DER aggregations on contingency analysis and definitions

Distribution Factors and Bidding Parameters

EPRI research in this area generally falls within Programs 39 and 173. Several research problems and questions regarding distribution factors and bidding parameters are summarized below:

1. Test out distribution factors for different types of multi-node DERAs in unit commitment and economic dispatch software, potentially changing in each market interval, to understand complexities and other potential issues including transmission reliability.
2. Evaluating practical aggregations consisting of large number of DERs of different types, on how much the distribution factors may change depending on the dispatch level of the aggregation.
3. How are distribution factors considered for when aggregations include VERs and cannot be predicted with high accuracy?
4. How can a distribution factor be used where distribution systems are not radial to the transmission system or where sub-transmission is not modeled by the ISO/RTO, such that any DER may have sensitivity to multiple nodes on the transmission system?
5. Evaluate the use of a distribution system losses bidding parameter and how that may affect dispatch and prices or ensure DER Aggregator is aware of distribution loss impact of different DERs in determining offer and dispatch strategy across the DERA.

Metering and Telemetry System Requirements

EPRI research in this area generally falls within Program 161, Program 183, and Program 170. Relevant research problems and questions are as follows:

1. What cyber security risks and opportunities are involved with significant DER participation?
2. Demonstration and testing of new cost effective and reliable methods beyond direct metering.
3. Communication procedures that are more than one way (RTO/ISO, DER, DERA, Distribution Utility).
4. What are the privacy concerns of three (or more) parties sharing information (e.g., for registration validation by the DU (from the DERA) or DER to RTO/ISO exchanges; for DERA metering audit by the RTO/ISO)?
5. Since Order No. 2222 directs the DER Aggregator to be responsible for metering and telemetry of the individual DERs that comprise a DERA, how might Aggregator’s implement this in a cost-effective and secure manner?
6. What are the cyber security concerns associated with maintaining integrity of real-time control and telemetry?

7. What practical cyber security threat models can be used to analyze, classify, and mitigate attack vectors and risks associated with the exchange types used by the RTO/ISO?
8. What standards exist to meet the data exchange requirements? Are there widely deployed interfaces that could be a basis for standardization?
9. What methods for telemetry have been demonstrated with lower cost potential for smaller resource aggregations or individual DERs?
10. What alternative methods have been proposed and are being considered to provide operator real-time visibility to DER/DR assets and resources (e.g., statistical sampling, virtual gateways).

Role of Distribution Utilities in Coordination

EPRI research in this area generally falls within Program 174 and Program 200. Relevant research problems and questions are as follows:

1. What are the primary needs and potential issues for the DU that coordination must address?
2. What risks does the participation of DER in the wholesale markets pose to the reliable and safe operation of the distribution system? To what extent do existing interconnection screens and studies capture or account for these risks?
3. What criteria, metrics, or analyses can be used by DUs to determine if individual DERs within DER aggregations would breech the physical or operational limits of the distribution system by participating in wholesale markets?

Ongoing Operational Coordination

EPRI research in this area generally falls within Program 174, Program 200, Program 161, Program 173, and Program 39. Relevant research problems and questions are as follows:

1. What are the new or emerging roles and responsibilities of a DSO that are required to enable wholesale market participation of DER? How have DSO roles evolved in jurisdictions with existing DERA participation models?
2. What technology solutions (software and hardware) for near-real time situational awareness are needed to enable market participation and override process based on existing planning, interconnection, protection, and control/communication practices.
3. What criteria can the DSO use to justify the override of RTO/ISO dispatch signals in order to maintain safety and reliability? What tools and data are needed to evaluate those criteria?
4. What are the coordination needs across DU, RTO/ISO, and DER Aggregators with different communication procedures that occur during a potential curtailment need?
5. How can regions develop comprehensive awareness of the characteristics of assets connected to the distribution system to support planning and operational analyses.

Coordination Frameworks

EPRI research in this area generally falls within Program 174, Program 161, Program 200, Program 173, Program 39, Program 40, Program 170 and Program 183. Relevant research problems are summarized below:

1. Explore different concepts of coordination frameworks.

2. New information technology and communications systems that could enable efficient coordination frameworks.
3. Evaluate innovative market designs that may more appropriately accommodate coordination frameworks such as peer-to-peer, platform, or transactive market exchanges.
4. How can blockchain be utilized within coordination frameworks?
5. What cyber security challenges are associated with potential coordination frameworks? What are the responsibilities that must be defined among parties to adequately coordinate cyber security protections that address data privacy and operational integrity requirements?
6. What standards exist to meet the data exchange requirements? Are there widely deployed interfaces that could be a basis for standardization?
7. What are the processes and tools for coordination across relevant functions of market operation, scheduling, transmission operation, distribution operation, DER aggregation, and energy retailing, in order to facilitate aggregated DER market participation aligned with multi-stakeholder objectives?

Program Identification

Program 18: Electric Transportation

Program 39: Grid and Market Operations

Program 40: Transmission Planning

Program 161: Information and Communication Technology

Program 170: Customer Technologies

Program 173: Bulk system renewables and Distributed Energy Resources Integration

Program 174: Distributed Energy Resource Integration

Program 182: Customer Insights

Program 183: Cyber Security for Power Delivery and Utilization

Program 200: Distribution Operations and Planning

Program 204: Advanced Buildings

5
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