DER Aggregations in Wholesale Markets

A REVIEW OF TECHNICAL AND OPERATIONAL COMMENTS MADE IN RESPONSE TO FERC'S NOTICE OF PROPOSED RULEMAKING

PREPARED BY

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EEI Edison Electric Institute

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ABOUT SEPA

SEPA facilitates collaboration across the electric power industry to enable the smart deployment and integration of clean energy resources. Our focus centers on solar, storage, demand response, electric vehicles, grid management, and other enabling technologies.

ABOUT EEI

The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for 220 million Americans, and operate in all 50 states and the District of Columbia. Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

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Executive Summary

For over a century, the electric power sector has provided safe, reliable, affordable, and increasingly clean electricity. As a result of advancements in technology, customer expectations, and state and federal policy goals, the electric power sector is evolving. A part of this evolution is the increased deployment of distributed energy resources (DERs). In late 2016, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR) that, if finalized as proposed, would require regional transmission organizations (RTOs) and independent system operators (ISOs) to facilitate the participation of electric storage resources and aggregated DERs in competitive wholesale markets. Many of these resources are "behind the customer meter" and connected to the electric distribution system—and not part of the bulk electric system. In the NOPR, FERC finds that participating in wholesale markets is seen as critical for the economic development and deployment of DERs. However, the bulk electric system that is supported by the competitive wholesale markets has been designed to move power from the transmission system to the distribution system—and not to move energy and services from the distribution system to the transmission system. As a result, integrating DERs into the wholesale markets could require changes to the way that these systems are designed and operated to ensure that electric distribution companies can continue to provide reliable power to customers, and that the overall grid is operated in a safe, reliable, and cost-effective manner.

This paper, which represents a collaboration between the Smart Electric Power Alliance and the Edison Electric Institute, does not address issues specifically related to the electric storage resources portion of the NOPR and does not address market design issues or compensation for storage resources or aggregated DERs. It also does not address jurisdictional issues raised by many commenters. Instead, this paper catalogs the operational and technical issues related to the participation of aggregated DERs in wholesale markets identified by stakeholders who filed comments with FERC in response to the NOPR. While some stakeholders identified technical and operational concerns and issues, other stakeholders provided a different perspective or suggested potential solutions to these concerns. Given the range of views on these issues, it is clear that further discussion among stakeholders, including the RTOs/ISOs, electric distribution companies, and the providers of aggregated DER services is needed. This paper provides a review of technical and operational issues raised by stakeholders to foster discussion about these issues and their potential resolution.

After reviewing hundreds of pages of comments filed by more than 100 stakeholders, SEPA and EEI identified some key high-level takeaways:

- Commenters generally agree that the operations, reliability, and safety of the distribution and transmission system are important factors when considering DER aggregation.
- Commenters generally support allowing DER market participation via a third-party aggregator, and many commenters recognized that aggregation would allow these resources to overcome minimum size rules and other eligibility requirements for market participation.
- Many commenters generally identified technical and operational challenges related to DER aggregations participating in wholesale markets, but commenters disagreed about the potential severity and difficulty of overcoming them.
- Third-party aggregators voiced a common preference for consistent aggregation rules across the country to streamline market participation, while others asked for maximum flexibility to allow individual ISOs, RTOs, or electric

ELIGIBILITY REQUIREMENTS

DISTRIBUTION SYSTEM RELIABILITY AND DER AGGREGATION PARTICIPATION

- How should distribution system reliability issues be considered when determining DER aggregation eligibility to participate in wholesale markets?
- Should distribution companies require reliability reviews of DER aggregations that want to participate in wholesale markets? Should there be specific parameters for these reviews that would ensure they are not used to limit DER aggregations' access to the wholesale market?

LOCATIONAL REQUIREMENTS FOR DER AGGREGATIONS

- Can stakeholders address concerns about the technical feasibility and administrative and operational challenges of aggregations that are not limited to a single interconnection or node?
- What can stakeholders do to address aggregations located on different sides of a constraint that may challenge reliability or affect pricing and economics?
- Should transmission constraints limit the geographic scope of DER aggregations or can RTOs/ISOs manage more granular (or partial) dispatch of the DERs in an aggregation to address constraints?
- Can the experiences of RTOs/ISOs that already allow aggregations across nodes serve as models to address concerns about reliability and pricing impacts?
- Should rules about the location of DERs in an aggregation be set on an RTO/ISO basis? On a distribution company basis?

DER AGGREGATIONS AND REAL-TIME DISPATCH

- Are real-time dispatch concerns a potential limit to the wholesale market participation of aggregated DERs connected to the distribution system?
- Can the market develop tools (if they don't yet exist) to accomplish real-time dispatch of aggregated DERs to address distribution constraints?

TECHNICAL CONCERNS ABOUT SEPARATING RETAIL PROGRAM PARTICIPATION FROM WHOLESALE MARKETS PARTICIPATION

- Can retail services and wholesale market participation be separately identified and measured?
- Can accounting or estimating methodologies address, identify, and distinguish wholesale from retail activity and would such data need to be further reviewed?
- Can stakeholders use the timing of dispatch to differentiate the retail and wholesale services that may be provided by aggregated DERs?
- Can stakeholders learn from experiences with demand response programs in wholesale markets?

METERING AND TELEMETRY

- How much directly metered data about the operations of aggregated DERs do RTOs/ISOs need? Is the answer different for distribution companies than wholesale markets?
- Could statistical tools provide the kind of information that RTOs/ISOs need?
- Should DERs have communications capabilities to comply with control center obligations?
- Could an aggregation schedule coordinator mediate between the wholesale markets and DER aggregators and owners?

OPERATIONAL COORDINATION BETWEEN AND AMONG THE RTO/ISO, THE DER AGGREGATION, AND THE ELECTRIC DISTRIBUTION COMPANY

- Are new processes and protocols needed to ensure coordination among DER aggregations, electric distribution utilities, and RTOs/ISOs?
- Do electric distribution companies need a communication interface with both the RTO/ISO and the DER aggregator that doesn't currently exist?
- Could RTOs/ISOs use existing protocols to foster coordination and communication with DER aggregations?

distribution companies to develop their own aggregation rules to address their specific system issues and concerns.

- Technical solutions for some of these concerns and potential challenges do not yet exist, and many commenters agreed that coordination and communication among stakeholders is critical to efforts to find solutions.

More specifically, SEPA and EEI identified three main sets of technical and operational issues associated with aggregated DERs participating in RTO/ISO markets and have organized this paper around them:

1. Eligibility requirements;
2. Metering and telemetry requirements; and
3. Operational coordination among the RTO/ISO, DER aggregation and the distribution utility.

The paper reviews specific comments made around each of these topics and uses these comments to synthesize key questions for further discussion. (Please see the questions in the boxes above.)

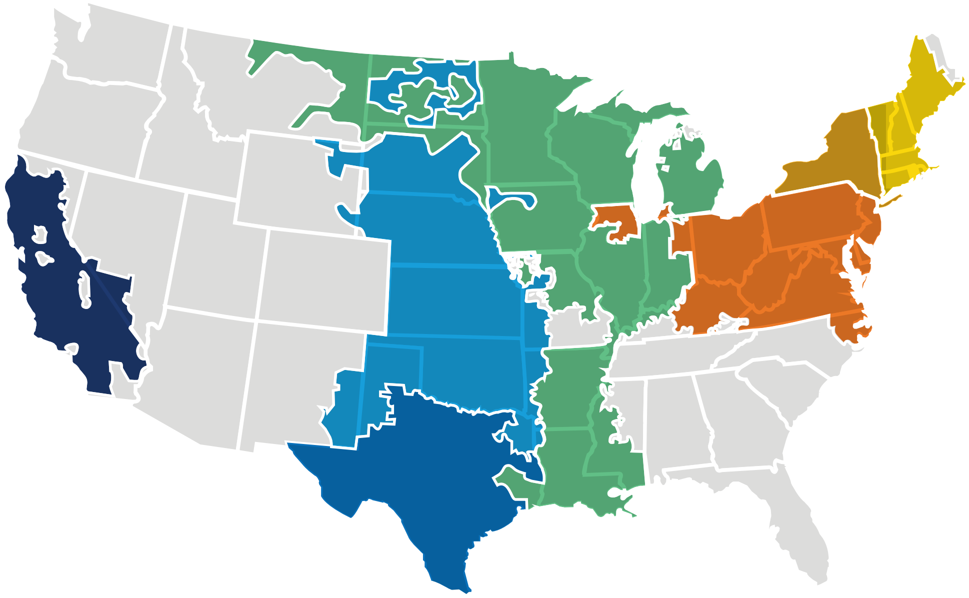
FERC's NOPR was a step in facilitating the participation of aggregated DERs in wholesale markets by removing some barriers. The next step is working through the technical and operational issues to ensure that these resources can participate in these markets in ways that ensure the continued reliable and safe operation of the electric system at both the distribution and wholesale levels.

Introduction

For over a century, the electric power sector has provided safe, reliable, affordable, and increasingly clean electricity. As a result of advancements in technology, customer expectations, and state and federal policy goals, the electric power sector is evolving. On November 17, 2016, the Federal Energy Regulatory Commission (FERC) published a Notice of Proposed Rulemaking (NOPR) addressing *Electric Storage Participation in Markets Organized by Regional Transmission Organizations and Independent System Operators*.[1] In the NOPR, FERC proposed to amend its regulations under the Federal Power Act to remove barriers to the participation of electric storage resources in the energy, capacity, and ancillary services markets operated by regional transmission organizations (RTOs) and independent system operators (ISOs). If finalized, the amendments to FERC regulations would require each RTO/ISO to revise its tariff to establish participation models for electric storage resources that recognize their physical and operational characteristics. Prior to releasing the NOPR, FERC issued data requests to the RTOs and ISOs and received comments on issues related to the participation of electric storage resources in organized wholesale markets.[2] The responses from RTOs/ISOs, as well as those from other interested stakeholders, informed FERC's development of the NOPR.

Somewhat unexpectedly, the NOPR also proposed revisions to FERC regulations to facilitate the participation of aggregated distributed energy

FIGURE 1: MAP OF RTO AND ISO TERRITORIES



- CALIFORNIA ISO (CAISO)
- ELECTRIC RELIABILITY COUNCIL OF TEXAS (ERCOT)
- SOUTHWEST POWER POOL (SPP)
- MIDCONTINENTAL ISO (MISO)
- PJM
- NEW YORK ISO (NYISO)
- NEW ENGLAND ISO (ISO-NE)

Source: Federal Energy Regulatory Commission, 2017[3]

1 Docket Nos. RM-16-23-000 and AD16-20-000; 157 FERC ¶ 61,121.

2 Docket No. AD16-20-000 (Apr. 11, 2016).

3 https://www.ferc.gov/industries/electric/indus-act/rto.asp.

FERC DEFINITION OF DISTRIBUTED ENERGY RESOURCES (DERS)

The definition of DERs varies widely among organizations, but for purposes of the NOPR, they are defined as, "... a source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, thermal storage, and electric vehicles and their supply equipment."[4]

resources (DERs) in the organized wholesale markets.[5] If finalized, the NOPR would require RTOs/ISOs to create participation models for aggregated DERs. In the NOPR, FERC noted significant discussion about the potential for smaller, geographically diverse DERs interconnected to lower voltage distribution systems to contribute to grid services.[6] At present, some of these resources only can participate in wholesale markets individually or only can be compensated via retail programs, which may limit their economic viability. Allowing DERs to aggregate to provide services to the bulk electric system would provide another opportunity for these resources to be compensated.

Over 100 stakeholders filed comments addressing technical and operational issues related to the participation of aggregated DERs connected to the distribution system—particularly behind the meter resources—in wholesale markets.[7] The volume of comments on these technical and operational issues is not surprising as allowing DERs interconnected to the distribution system to participate in wholesale markets represents a significant change in how the transmission and distribution system function today: instead of power flowing from the bulk electric system to the distribution system, power and ancillary services will move in both directions. Given the complexity of the electric system as a whole, there will be challenges to accomplishing this, requiring the cooperation and coordination of many stakeholders.

Knowing that it is impossible to address challenges that you don't know exist, this paper provides a review of technical and operational issues raised by stakeholders to foster discussion among electric distribution companies, RTOs/ISOs, third-party providers and others about these issues and their potential resolution. Regardless of how FERC proceeds with the proposal to require RTOs/ISOs to develop participation models for aggregated DERs, we think that these conversations about technical and operational issues are necessary predicates for DERs to be able to fully participate in wholesale energy markets.[8]

This paper is organized around three main sets of technical and operational issues:

1. Eligibility requirements;
2. Metering and telemetry requirements; and
3. Operational coordination among the RTO/ISO, DER aggregation and the distribution utility.

4 Docket Nos. RM-16-23-000.

5 While FERC's April 16, 2016, requests for comment in AD16-20-000 did address aggregated electric storage resources, the request for comment did not seek comments on aggregating other DERs. Some stakeholders did choose to address aggregations more generally and did not limit their comments to storage aggregations. The FERC also recently accepted California Independent System Operator's proposal to allow DER aggregations in its markets. *See California Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,229 (June 2, 2016).

6 *See* NOPR at P103.

7 A complete list of all stakeholders who filed comments addressing the participation of aggregated DERs in the wholesale markets is included in Appendix A. Not all stakeholders who filed comments in these dockets addressed DER aggregations.

8 This paper does not catalog or address market design issues raised by commenters. To some extent, the distinction between market design issues and technical/operational issues is blurry as technical/operational issues can have a direct effect on market design and function. FERC proposes that DERs participating in retail compensation programs, like net metering, or other wholesale programs would not be eligible to participate in wholesale markets as part of a DER aggregation. *See* NOPR at P134. While not taking a position on this proposed restriction, this paper does catalog concerns and suggested approaches for separately metering or otherwise delineating between retail and wholesale transactions as part of the discussion about metering and telemetry requirements.

Overview of FERC's DER Aggregation Notice of Proposed Rulemaking

In the DER aggregation portion of the NOPR, FERC states that it is "clear…that the ability to meaningfully participate in the organized wholesale electric markets for these smaller distributed energy resources is through aggregations."[9] The purpose of the NOPR is to "remov[e] barriers in current RTO/ISO market rules that would prevent these new, smaller distributed energy resources that are technically capable of participating in the organized wholesale electric markets from doing so."[10]

Specifically, FERC proposes to require that each RTO/ISO revise its tariff to establish market rules to allow participation of DER aggregations in organized wholesale markets. The NOPR identified eight key areas that revised tariffs would be required to address:

1. Eligibility to participate in the organized wholesale electric markets through a DER aggregator;
2. Locational requirements for DER aggregations;
3. Distribution factors and bidding parameters for DER aggregations;
4. Information and data requirements for DER aggregations;
5. Modifications to the list of resources in a DER aggregation;
6. Metering and telemetry system requirements for DER aggregations;
7. Coordination between the RTO/ISO, the DER aggregation, and the distribution company; and
8. Market participation agreements for DER aggregators.[11]

Technical and Operational Issues Related to DER Aggregations in Wholesale Markets

In the NOPR, FERC finds that facilitating aggregation would address commercial and transactional barriers to smaller DER participation in wholesale energy, capacity, and ancillary services markets.[12] However, many stakeholders who filed comments in response to the NOPR raised technical and operational issues related to the interplay between distribution-connected DERs, the distribution system, and the bulk electric system.

This paper catalogs the technical and operational issues identified by a wide range of stakeholders. In general, these issues can be grouped broadly into three categories that capture many, if not all, of the eight key areas for tariff revision identified by FERC.

Stakeholder comments included in this report identify concerns and also provide the range of perspectives on these concerns. Within this paper, SEPA and EEI attempt to fairly and accurately

9 NOPR at P124.

10 *Id.* at P103.

11 *See id*. at P132.

12 *See id*. at P126.

TABLE 1: EIGHT KEY AREAS FOR TARIFF REVISIONS		
SECTION I: ELIGIBILITY REQUIREMENTS	**SECTION II: METERING AND TELEMETRY**	**SECTION III: OPERATIONAL COORDINATION AMONG THE RTO/ISO, DER AGGREGATORS, AND ELECTRIC DISTRIBUTION COMPANIES**
▪ Eligibility to participate in the organized wholesale electric markets through a DER aggregator ▪ Locational requirements for DER aggregations ▪ Distribution factors and bidding parameters for DER aggregations ▪ Information and data requirements for DER aggregations ▪ Modifications to the list of resources in a DER aggregation	▪ Metering and telemetry system requirements for DER aggregations	▪ Coordination between the RTO/ISO, the DER aggregation, and the distribution utility ▪ Market participation agreements for DER aggregators

represent multiple perspectives for each of the key areas, but given space constraints openly acknowledge we could not capture them all. For more detailed information we would recommend readers review all submissions (listed in Appendix A) on the FERC website.[13]

1. ELIGIBILITY REQUIREMENTS

In the NOPR, FERC states that its goal is to ensure that smaller DERs that are technically capable of participating in wholesale markets are able to do so.[14] To this end, FERC proposes to require RTOs and ISOs to allow all technologies to participate in organized wholesale markets via an aggregator.[15] Commenters generally supported allowing DER participation via an aggregator, and many commenters recognized that aggregation would allow these resources to overcome size and other eligibility requirements for market participation. While not objecting to aggregations per se, many comments raised issues about state and federal jurisdiction and cost recovery that are beyond the scope of this paper.

Many commenters identified technical and operational concerns about which resources are permitted to participate in an aggregation and where DERs that participate in an aggregation are located. A common thread in these comments is concern about the impact of aggregated DERs on the reliability of both the distribution and transmission systems.

DISTRIBUTION SYSTEM RELIABILITY AND DER AGGREGATION PARTICIPATION

Some commenters asserted that distribution system reliability issues should govern DER aggregation eligibility. For example, the Massachusetts Municipal Electric Company (MMEC) stated, “It is important for…utilities, who are responsible for the distribution system planning and are charged with ensuring service reliability, to have an ability to evaluate the impact of DER aggregation

13 All filings made in Docket Nos. RM16-23-000 and AD16-20-000 can be accessed on FERC’s website: https://www.ferc.gov/docs-filing/elibrary.asp.

14 *See* NOPR at P103.

15 *See id*. at P124.

on their system reliability, and to place limitations on such aggregations."[16] In particular, MMEC noted the importance of integrating DER aggregations into a distribution company's planning process to identify and address reliability concerns.[17]

Pacific Gas and Electric Company (PG&E) noted that DER aggregations "should not be able to participate if they may pose a threat to the safe and reliable operation of the distribution system...aggregated responses to the wholesale markets may create additional distribution reliability issues that would not have been examined during an interconnection process that examined the effect each DER might have on the distribution grid. That examination would have looked at the effect of each DER only on an individual basis."[18]

Other stakeholders raised similar concerns about the impact of aggregated DERs on the distribution system. For example, AVANGRID recommended that FERC ensure that the distribution company be involved in the initial screening of all DERs included in the formation of an aggregation, as well as any updates as participation in the aggregation changes over time. The involvement of the distribution company would be to address power quality and safety at the distribution level that was reviewed during the individual interconnection process, but may change when the DERs operate in aggregation.[19] The American Public Power Association (APPA) and the National Rural Electric Cooperatives Association (NRECA) agreed that distribution-level safety and reliability, including power quality and worker safety, are critical considerations when determining if a DER aggregation can participate in wholesale markets.

Other commenters noted that reliability considerations may increase as DER deployment increases. According to the New York State Department of State, "[a]t low penetrations, the entrance or exit of a DER and storage resource provider will not likely impact the system. But, as participation increases, the relative impact of these DER aggregations will grow, and it will become necessary to evaluate the reliability of effects of market exits."[20]

While acknowledging that distribution reliability is important, the non-profit, DER advocacy organization Advanced Energy Economy (AEE), asked FERC to provide some standard by which electric distribution companies could demonstrate that a potential aggregation poses a risk to reliability to minimize opportunities for the distribution companies to limit DER eligibility to participate in aggregations.[21] AEE also noted that different types of aggregations would pose lesser reliability concerns and should be subject to lesser reliability reviews. For example, AEE noted that DERs that are not planning to export power to the grid, but instead will curtail their own load, pose "no apparent risk to a distribution system that would require review."[22]

FOR FURTHER DISCUSSION: SUMMARY OF KEY QUESTIONS

- How should distribution system reliability issues be considered when determining DER aggregation eligibility to participate in wholesale markets?
- Should distribution companies require reliability reviews of DER aggregations that want to participate in wholesale markets? Should there be specific parameters for these reviews that would ensure they are not used to limit DER aggregations' access to the wholesale market?

16 The Massachusetts Municipal Electric Company at 3.

17 *See* id.

18 PG&E at 18.

19 *See* AVANGRID at 13.

20 Utility Intervention Unit, New York State Department of State at II.C.

21 *See* AEE at 39.

LOCATIONAL REQUIREMENTS FOR DER AGGREGATIONS

In the NOPR, FERC notes that some current RTO/ISO rules only allow resources located behind the same point of interconnection or a single pricing node to aggregate.[23] FERC recognizes concerns about transmission constraints and price formation, but proposes to require tariff revisions that would allow DER aggregations that are as geographically broad as possible.[24]

Some stakeholder comments identified concerns about the technical feasibility of aggregations not limited to a single interconnection or node. Other commenters, however, found these challenges surmountable.

The New York ISO (NYISO) noted that it has proposed to limit the geographic footprint of a DER aggregation to those resources that connect to the same transmission node, typically a transmission substation, saying:

> *NYISO is concerned about the operational and price formation impacts of a geographically broad DER aggregation due to the highly constrained nature of the New York transmission system. For example, if an aggregation consists of DER that are located on either side of a transmission constraint, dispatching the entire aggregation up or down would further aggravate the constraint. Additionally, there is no way for the ISO to ensure that the aggregator will be able to match the distribution factor and, therefore, the aggregator could further aggravate the constraint if the actual set of DER dispatched differs from the distribution factor. In this circumstance, the ISO would not readily know that the actual set of DER being dispatched differs from the distribution factor, which could affect reliability.*[25]

Indicated New York Transmission Owners agreed, noting that "aggregations spanning more than one transmission zone could present both administrative and operational difficulties for the RTO/ISO and the local distribution utility" and, therefore, should not be allowed.[26] Similarly, the Southwest Power Pool (SPP) stated that "a singled registered aggregate that is made up of Resources located on different sides of a constraint will both challenge reliability and may disturb pricing and economics."[27] SPP also noted that congestion occurs in real-time, so pre-identifying congested areas may not mitigate reliability issues. Accordingly, SPP seeks to limit geographically diverse aggregations to those that provide services that are not location-dependent or are smaller than 10 MW.

Other commenters, such as AEE, however, did not see transmission constraints as a technical or operational concern that should limit the geographic scope of DER aggregations. "For example, aggregation could continue to be allowed up to the load zone level, but the NYISO could have the ability to do more granular dispatch if dispatching at the load zone level would exacerbate constraints within the zone. The NYISO, or any other RTO/ISO developing aggregation rules, could simply require that aggregators provide the customer's location and node when enrolling, and then exclude customers from dispatch when that would aggravate constraints."[28] AEE went on to note that "the [RTOs/ISOs] should be mindful that the entire aggregated resource does not always need to be dispatched, and if there are constraints, there can

22 *See id*. at 40.

23 In wholesale markets, electricity prices reflect the value of electric energy at different locations, accounting for load, generation, and the physical limits of the transmission system. In the different wholesale markets, prices are identified at different locations, often called "nodes." There can be more than 1,000 nodes in some of the markets. If there were no physical constraints in the transmission system, the price at each node would be the same. Physical constraints can make it difficult or even impossible to dispatch resources to different places on the grid—or across nodes—and can have an impact on both price and the reliable operation of the transmission system.

24 *See* NOPR at PP138-139.

25 NYISO at 16.

26 Indicated New York Transmission Owners at 14.

27 SPP at 17.

be partial dispatch.

At minimum, however, aggregation should be allowed across entire load zones within an RTO/ISO, with the burden on the RTO/ISO to support more restrictive requirements."[29] The Advanced Energy Management Alliance (AEMA)—a consortium of DER aggregators—agreed that RTOs and ISOs could manage broad aggregations by dispatching resources "more granularly" if they had constraints that would be exacerbated by dispatching an entire aggregated resource at a particular time or if performance from one customer would not be deliverable to other geographic areas.[30]

Several commenters, such as DER and Storage Developers, also noted that the California ISO (CAISO) currently allows aggregations across nodes.[31] PJM Interconnection (PJM) noted that it "already dispatches demand response resources across varying levels of geographic areas, including across different pricing nodes, depending on different needs and pursuant to carefully developed rules. Accordingly, PJM believes that it can leverage these rules as a foundation for developing similar rules in its stakeholder process for dispatching DERs seeking to inject past the applicable retail meter."[32]

The Solar Energy Industries Association (SEIA) argued that "system constraints may be reduced in a more efficient manner by coordinated operations at complimentary [sic] nodes."[33] Similarly, Tesla and SolarCity suggested that RTOs and ISOs only need to know generally where aggregated resources are located, but do not need to know down to the individual nodes.[34]

Other stakeholders remained concerned about the operational challenges of geographically broad aggregations. For example, the Organization of MISO States (MISO States) noted reliability concerns across what it called "local resource zones,"[35] specifying that "[d]ispatch of cross-zone DERs providing ancillary services would lead to ancillary services being provided in different zones, possible leading to reliability issues." The MISO States did note, however, that energy markets may allow for broader aggregations, pending transmission constraints.[36] The Midcontinent System Operator (MISO) itself noted that RTOs/ISOs "should be given the flexibility to determine locational requirements appropriate for their respective footprints to ensure that DER aggregation is consistent with market efficiency and grid reliability, including the delivery of ancillary services."[37]

Moreover, some commenters asserted that nodal limits serve important functions, both in terms of reliability and price formation, and are not barriers to DER market participation. For example, the PJM Market monitor noted that "[l]ocational requirements are not artificial restrictions in a nodal market but are fundamental to nodal markets. RTOs/ISOs manage geographically dispersed resources with full situational awareness on a regular basis using a fully nodal system. A fully nodal system is the most effective way to maintain this

28 AEE at 46.

29 *Id.* at 47.

30 *See* Advanced Energy Management Alliance at 25.

31 *See, e.g.*, DER and Storage Developers at 4.

32 PJM at 28.

33 SEIA at 19.

34 *See* Tesla and SolarCity at 27-28.

35 MISO operates the transmission system and a centrally dispatched market in portions of 15 states in the Midwest and the South, extending from Michigan and Indiana to Montana and from the Canadian border to the southern extremes of Louisiana and Mississippi. MISO assesses reliability over defined geographic areas, called "local resource zones," to address congestion that limits the ability of the system to deliver resources.

36 MISO States at 6.

37 MISO at 21.

approach."[38] Similarly, ISO New England (ISO-NE) noted that "energy markets are dispatched on a nodal basis. This is one of the fundamental precepts of efficient energy markets in a large transmission system. It allows an RTO or ISO to properly manage and price transmission constraints that arise, often unpredictably, between nodes. If [DER] are permitted to aggregate across more than one node, an RTO or ISO's ability to manage that constraint is diminished, and it will not be able to reflect the constraint's impact properly in energy market pricing."[39]

Other commenters noted that the locational requirements for any DER aggregation must consider the distribution system to which it is interconnected, as well as the operational needs of the RTO or ISO. For example, the AES Companies argued that "[t]he size and shape of the aggregation will be specific to the distribution system, its design, operating characteristics, and existing interconnection and other processes related to resources on their systems. With respect to the interaction between utility-specific aggregation and the RTO/ISO, the operating conditions and needs of each RTO/ISO/[Balancing Authority] differ so there will be no "one size fits all" solution."[40] Similarly, the Bonneville Power Administration (BPA) noted that "Each RTO/ISO has unique transmission topology considerations and may have different constraint management practices that are relevant to development of location requirements" and that, therefore, FERC should provide "each RTO/ISO the opportunity to develop custom location requirements, subject to FERC's review."[41]

Dominion Energy Resources (Dominion) noted that "any evaluation of location requirements must also take into account both transmission and distribution system impacts and reliability. DERs in an aggregation that covers a large geographic area could affect localized power flow, voltages and frequencies. The distribution utility must understand these impacts in order to manage them safely and reliably without adverse impacts to its retail customers."[42]

FOR FURTHER DISCUSSION: SUMMARY OF KEY QUESTIONS

- Can stakeholders address concerns about the technical feasibility and administrative and operational challenges of aggregations that are not limited to a single interconnection or node?
- What can stakeholders do to address aggregations located on different sides of a constraint that may challenge reliability or affect pricing and economics?
- Should transmission constraints limit the geographic scope of DER aggregations or can RTOs/ISOs manage more granular (or partial) dispatch of the DERs in an aggregation to address constraints?
- Can the experiences of RTOs/ISOs that already allow aggregations across nodes serve as models to address concerns about reliability and pricing impacts?
- Should rules about the location of DERs in an aggregation be set on an RTO/ISO basis? On a distribution company basis?

DER AGGREGATIONS AND REAL-TIME DISPATCH

Regardless of market rules and other eligibility requirements, some commenters questioned whether aggregated DER interconnected to the distribution system could actually be dispatched in real time in a way that recognizes unexpected

38 Independent Market Monitor for PJM at 14.

39 ISO-NE at 37.

40 AES Companies at 34.

41 BPA at 6.

42 Dominion at 10.

distribution system constraints. As noted by the Indicated New York Transmission Owners:

> *[U]tilities around the nation (...) are still developing the technology for analytics and control of DER to respond to real-time constraints, which are currently being tested in the context of pilot projects and demonstrations. However, to date, utilities have not developed distribution management system modeling tools to perform system analysis and do not currently have the capability to recognize unexpected distribution system constraints on a real-time basis. Until that capability is achieved, the distribution utility may need to alter the system or otherwise limit participation of DER aggregations in the market without notification. Market rules cannot assume that DER aggregations can be securely dispatched in real-time subject to distribution system constraints until the utility has developed the necessary technological capability.*[43]

Xcel Energy also noted that real-time operations may require distribution system operators to override a market instruction in real time where that instruction would compromise delivery of high-quality power to customers.[44]

APPA and NRECA also noted practical, real-time issues with DER aggregations that participate in wholesale markets. For example, "[DER] aggregators may encounter situations where they cannot participate in wholesale transactions because the local system design and construction may not allow the necessary rerouting around faults or congestion, as is frequently possible in bulk power markets. This is an important technical difference between transmission and distribution grids. The RTO/ISO, which operates the wholesale market and transmission grid, may not be made aware of these utility-specific design and construction constraints."[45]

As noted above, however, some commenters pointed out that RTOs and ISOs, like PJM and CAISO, already do dispatch DERs in real time and can engage in partial dispatch to address transmission constraints and reliability concerns.

FOR FURTHER DISCUSSION: SUMMARY OF KEY QUESTIONS

- Are real-time dispatch concerns a potential limit to the wholesale market participation of aggregated DERs connected to the distribution system?
- Can the market develop tools (if they don't yet exist) to accomplish real-time dispatch of aggregated DERs to address distribution constraints?

TECHNICAL CONCERNS ABOUT SEPARATING PARTICIPATION IN RETAIL PROGRAMS FROM WHOLESALE MARKETS PARTICIPATION

Commenters also identified technical concerns related to FERC's proposal to limit aggregation participation to those DERs that do not also already participate in a retail compensation program, like net metering, or some other wholesale program.[46] FERC proposes this limitation to ensure that DERs are not double compensated for the same service.

Many commenters disagreed with FERC's double-counting premise from a technical perspective. According to AEE, "[T]he very nature of how DERs are utilized and dispatched by the wholesale and retail markets already largely addresses the potential concern that DERs could receive overlapping compensation in the wholesale and retail markets...[retail] programs have fundamentally different goals and dispatch triggers than those used by the wholesale market. The existing examples... show that overlapping compensation concerns have largely been addressed and can effectively be managed."[47]

43 Indicated New York Transmission Owners at 17.

44 *See* Xcel at 11.

45 APPA and NRECA at 31.

46 *See* NOPR at 134.

According to AEMA, "One clear way to tell if the value streams and benefits offered are incremental is to look at the dispatch triggers for each program, the purpose of each program, and how compensation is determined..."[48] Similarly, NextEra noted that a resource that "participat[es] in a retail peak energy program might have no obligations under that retail program in off peak hours, during which it would be available to provide services to the RTO/ISO" without triggering concerns about double compensation.[49] The New York Public Service Commission (NYPSC) also noted that it has been able to separate—and separately compensate—distinct services that demand response resources are providing under both wholesale and retail programs.[50]

Further, some commenters argued that the development of new technologies or approaches to accounting may better address these concerns. For example, some commenters, like Fresh Energy, Sierra Club, and the Union of Concerned Scientists, asserted that "already-anticipated technological advances... will emerge to resolve these concerns" about distinguishing between wholesale and retail market participation to avoid double compensation.[51] Similarly, other commenters supported participation of DER aggregations in wholesale markets if new accounting methodologies were developed. According to Indicated Transmission Owners, "[i]f operational accounting for DER aggregations can appropriately attribute megawatts to the resource providing a particular service, then DER aggregations should be eligible to provide services to the wholesale market and potentially receive a payment for utility retail services."[53]

While Southern California Edison (SCE) agreed that a prohibition on participation in both retail and wholesale programs is necessary now because it is a practical way to prevent double payments, as "new metering and other technologies advance, there may come a point where FERC's proposed prohibition may no longer be necessary or appropriate."[54]

Some stakeholders questioned whether participation in both retail and wholesale programs was actually feasible or would significantly increase operating complexity. For example, AVANGRID noted, "[o]perating coordination will become considerably more complex if [DERs] are considered simultaneously eligible for both retail compensation programs and wholesale market participation and, therefore, must accommodate potentially differing dispatch priorities and direction received from the RTO/ISO and [distribution company]."[55] Others, like the Maryland Public Service Commission and the New Jersey Board of Public Utilities, found that only measurement could ensure that there was no double counting: "Therefore, it is important that specialized metering and telemetry be installed to accurately measure flows associated with the applicable resources...to distinguish their intended uses and ensure the resources are not being inappropriately compensated."[56] Similarly, the Delaware PSC stated that it "questions as fiction any proposal that claims that an accounting or estimating methodology similar to a contract path to identify wholesale service(s) (Where the intention of the services is not dependent on the actual flow of electrons) is adequate..."[56]

47 AEE at 36-37.

48 Advanced Energy Management Alliance at 15.

49 NextEra at 13, n.21.

50 NYPSC at 16.

51 Fresh Energy, Sierra Club and the Union of Concerned Scientists at 3.

52 Indicated New York Transmission Owners at 10.

53 SCE at 10.

54 AVANGRID at 17.

FOR FURTHER DISCUSSION: SUMMARY OF KEY QUESTIONS

- Can retail services and wholesale market participation be separately identified and measured?
- Can accounting or estimating methodologies address, identify, and distinguish wholesale from retail activity and would such data need to be further reviewed?
- Can stakeholders use the timing of dispatch to differentiate the retail and wholesale services that may be provided by aggregated DERs?
- Can stakeholders learn from experiences with demand response programs in wholesale markets?

2. METERING AND TELEMETRY REQUIREMENTS

FERC addresses metering and telemetry issues in the NOPR, recognizing that DERs in an aggregation will need direct metering for settlement purposes and that telemetry data is needed to address real-time operating capabilities; but the NOPR also raises concerns about the costs such equipment could pose for individual DERs.[57]

While commenters generally agreed that the RTOs/ISOs needed metering and telemetry data, stakeholders had a range of opinions on the appropriate level of such data collection. For example, Tesla and SolarCity said that metering and telemetry requirements should not be imposed on the individual DERs in an aggregation, but instead on the aggregation schedule coordinator. They noted that "only the aggregate data are necessary."[58] Similarly, Advanced Microgrid Systems argued that "the wholesale market need not be concerned with the performance of individual resources beyond their impact at the node level captured by distribution factors...each resource's capacity, location and operating limits are functionally irrelevant to the operation of the wholesale market."[59]

Other commenters found that RTOs/ISOs do need more granular information about DER operations. For example, PJM asked FERC to allow it to require metering and telemetry of behind-the-meter resources.[60] SPP asked that FERC not mandate any particular requirements related to metering and telemetry, but instead allow each RTO and ISO to determine what they would need to integrate DERs.[61] Similarly, the Indicated New York Transmission Owners noted that "DERs should have the necessary telemetry such that communications associated with DER aggregations" can comply with control center obligations.[62] ISO-NE said that, at this time, it "is not aware of any approach that can reliably measure the input and output of an aggregation of [DERs] without measuring each

55 Maryland Public Service Commission (PSC) and New Jersey Board of Public Utilities at 4.

56 Delaware PSC at V.

57 *See* NOPR at P150. Many stakeholders identified concerns about the costs of metering and telemetry, noting that such costs can become a barrier to market participation. Cost concerns are outside the scope of this paper, which focuses on technical and operational issues, but it is worth noting that discussions about technical and operational needs for metering and telemetry also should address cost-effective ways to provide needed DER data.

58 Tesla and SolarCity at 30.

59 Advanced Microgrid Systems at 9.

60 *See* PJM at 26.

61 *See* SPP at 22.

62 Indicated New York Transmission Owners at 19.

individual resource comprising the aggregation" and does not think that retail meters alone provide sufficient information to measure wholesale activities separately from retail consumption activities.[63]

Some commenters noted that statistical analyses could supplant metering and telemetry data. For example, Efficient Holdings LLC (Efficient Holdings) noted that statistically driven methodologies can provide information about the operational capabilities of remote DERs.[64] However, other commenters disagreed that models could replace meters. The Independent Energy Producers Association (IEP) urged FERC to "adopt minimum standards for metering and telemetry of storage resources and aggregated distribution resources, particularly for those located behind the meter… Alternative techniques (e.g., estimation, sampling, etc.) are inaccurate by definition and, therefore, insufficient."[65]

While aggregated metering and telemetry data could be sufficient at the RTO/ISO level, the MISO Transmission Owners noted that "distribution utility's need to maintain situational awareness… could require telemetered data." They also noted that DER aggregations across multiple nodes may require additional meters for settlement purposes.[66] Other commenters also found differences between the metering that would be necessary for RTOs/ISOs and the metering needed by electric distribution companies.[67]

FOR FURTHER DISCUSSION: SUMMARY OF KEY QUESTIONS

- How much directly metered data about the operations of aggregated DERs do RTOs/ISOs need? Is the answer different for distribution companies than wholesale markets?
- Could statistical tools provide the kind of information that RTOs/ISOs need?
- Should DERs have communications capabilities to comply with control center obligations?
- Could an aggregation schedule coordinator mediate between the wholesale markets and DER aggregators and owners?

3. OPERATIONAL COORDINATION BETWEEN AND AMONG THE RTO/ISO, THE DER AGGREGATION, AND THE ELECTRIC DISTRIBUTION COMPANY

FERC calls for operational coordination between and among the RTO/ISO, the DER aggregator and the distribution company.[68] Commenters generally agree that such coordination is necessary to ensure that DER aggregations can participate in wholesale markets. Some stakeholders identified technical issues with how to affect this operational coordination.

In particular, stakeholders identified the need to develop and implement new protocols for communications and operations. For example, Dominion noted, "the distribution utilities will have to establish new processes, staffing and infrastructure to handle to coordination contemplated by the NOPR…The distribution utility will likely have to dedicate resources to monitor and coordinate DERs in order to provide real-time grid information and manage reliability. With a large saturation of DERs, the distribution utility will also likely need to set up dedicated communication

63 ISO-NE at 51.

64 *See* Efficient Holdings at 11.

65 IEP at 8.

66 MISO Transmission Owners at 24.

67 *See, e.g.*, SCE at 13.

68 *See* NOPR at P155.

interfaces with both the RTO and the DER aggregator."[69] EEI noted that "there may need to be a process in place for the distribution company to communicate distribution line faults and outages to the RTO/ISO to verify information being provided by the DER aggregator."[70]

CAISO noted that similar communications need to occur between the electric distribution company and the aggregator. "Accordingly, there is a need to implement a process for the distribution utility to inform a [DER] provider of transmissions constraints or topology changes that will limit the resource's capacity to participate in the CAISO market."[71] SPP succinctly noted that "the process and the agreements necessary to accomplish [coordination] will require a significant effort to coordinate with entities with which the RTO/ISO has not previously had two-way communications."[72]

NYISO said that "ongoing, real-time coordination will also be necessary to ensure safe and reliable operation of the transmission and distribution systems. NYISO is currently working with New York State's utilities to develop the procedures and operating protocols that will be necessary to safely and reliably dispatch DER."[73] Similarly, PG&E noted that "more significant upgrades to the electric system, the [electric distribution company's] operating tools, information systems and controls will likely be needed if and as DER applications multiply...areas where upgrades are likely needed will include telecommunications, automation, new operator tools, and integration of existing grid management platforms."[74] The Transmission Access Policy Study Group (TAPS) echoed that utilities, particularly smaller municipal utilities, will need to develop significant new communications and settlements capabilities in order inject themselves into RTO and ISO operations.[75]

Others found that existing protocols could be used. For example, DER and Storage Developers noted that distribution level constraints "could be included in the security constrained economic dispatch of the RTOs/ISOs in order to prevent exceeding any distribution limits. In fact, PJM already calculates constraints and congestions on facilities with voltage as low as 12 kV."[76] Similarly, "[t]he AES Companies advise that a distribution utility that serves DERs does need real-time direct communication with the RTO/ISO, such as in the form of operating procedures or software-enabled communications, in order to operate the distribution system. This communication already occurs at the appropriate level today. However, the aggregator will also need to be a party to some of the communications going forward."[77]

FOR FURTHER DISCUSSION: SUMMARY OF KEY QUESTIONS

- Are new processes and protocols needed to ensure coordination among DERs aggregations, electric distribution utilities, and RTOs/ISOs?
- Do electric distribution companies need a communication interface with both the RTO/ISO and the DER aggregator that doesn't currently exist?
- Could RTOs/ISOs use existing protocols to foster coordination and communication with DER aggregations?

69 Dominion at 13.

70 EEI at 37.

71 California ISO at 43-44.

72 SPP at 24.

73 NYISO at 19.

74 PG&E at 26.

75 TAPS at 21.

76 DER and Storage Developers at 4-5.

77 AES at 42.

Conclusion

As the electric companies work to integrate advanced technology and greater penetration of DERs on the distribution system, and as DER aggregators look to participate in wholesale markets, it is increasingly important to tackle the range of technical and operational issues and perspectives raised by stakeholders throughout the industry. Through our review of the comments submitted to FERC in response to the DER aggregation portion of the NOPR, SEPA and EEI identified five key takeaways about DER aggregations and their potential participation in wholesale markets:

KEY TAKEAWAYS:

- Commenters generally agree that the operations, reliability, and safety of the distribution and transmission system are important factors when considering DER aggregation.
- Commenters generally support allowing DER participation via a third-party aggregator, and many commenters recognized that aggregation would allow these resources to overcome minimum size rules and other eligibility requirements for market participation.
- Many commenters generally identified technical and operational challenges related to DER aggregations participating in wholesale markets, but commenters disagreed about the potential severity and difficulty of overcoming them.
- Third-party aggregators voiced a common preference for consistent aggregation rules across the country to streamline market participation, while others asked for maximum flexibility to allow individual ISOs, RTOs, or electric distribution companies to develop their own aggregation rules to address their specific system issues and concerns.
- Technical solutions for some of these concerns and potential challenges do not yet exist, and many commenters agreed that coordination and communication among stakeholders is critical to efforts to find solutions.

Beyond the technical and operational challenges, a host of other issues have yet to be addressed. Some of these issues include:

- Which agent will evaluate and deploy aggregated DERs? The utility? The aggregator? The RTO/ISO?
- Which entity will manage and prioritize DER dispatch?
- How will stakeholders address concerns about possible double compensation?
- What level of visibility will distribution utilities and RTOs/ISOs need into the operations of aggregated DERs to reliably manage those assets?
- Which entity pays for distribution system upgrades needed to facilitate DER participation in wholesale markets? How will utilities recover costs to enable DER aggregation within their territories?

Regardless of how FERC proceeds with the proposal to require RTOs/ISOs to develop participation models for aggregated DER, it is SEPA and EEI's goal to facilitate these conversations to enable a robust solution set that can eventually enable DERs to participate in the energy marketplace in ways that ensure the continued reliable and safe operation of the electric system at both the distribution and wholesale levels.

Appendix A: List of Commenters for Docket Nos. RM16-23-000 and AD16-20-00

- Advanced Energy Economy (AEE)
- Advanced Energy Management Alliance (AEMA)
- Advanced Microgrid Solutions (AMS)
- Advanced Rail Energy Storage, LLC
- AES Companies
- AF Mensah Inc.
- Alevo USA Inc.
- American Municipal Power Inc.
- American Petroleum Institute (API)
- American Public Power Association (APPA)
- American Wind Energy Association (AWEA)
- AVANGRID
- Beacon Power, LLC
- Bonneville Power Administration
- Brookfield Renewable Energy Group
- California Energy Storage Alliance
- California Independent System Operator Corp. (CAISO)
- California Municipal Utilities Association
- Center for Biological Diversity
- Central Hudson Gas & Electric Corporation
- Cities of Anaheim, Axusa, Banning, Colton, Pasadena and Riverside (Six Cities)
- City of New York
- Connecticut Department of Energy
- Connecticut Public Utilities Regulatory Authority
- Delaware Public Service Commission
- DER and Storage Developers
- Dominion Resources Services
- DTE Electric Company and Consumers Energy Company
- Duke Energy Corporation
- E.ON Climate & Renewables North America
- E4TheFuture
- Eagle Crest Energy Company
- Edison Electric Institute (EEI)
- Efficient Holdings, LLC
- Electricity Consumers Resource Council
- Electric Power Research Institute (EPRI)
- Electric Power Supply Association and the PJM Power Providers Group
- Energy Storage Association (ESA)
- Exelon Corporation
- First Light Power Resources, Inc.
- Fluidic Energy
- Fresh Energy and Sierra Club
- Genbright LLC
- GridWise Alliance
- Harvard Environmental Policy Initiative
- Imperial Irrigation District
- Independent Energy Producers Association
- Independent Market Monitor
- Indicated New York Transmission Owners
- Institute for Policy Integration; NYU
- Invenergy Storage Development LLC
- IPKeys Technologies LLC Motorola Solutions
- IRC
- ISO New England Inc.
- ISO-RTO Council
- Magnum CAES, LLC

- Maryland Public Service Commission and New Jersey Board of Public Utilities
- Massachusetts Department of Public Utilities
- Massachusetts Institute of Technology
- Massachusetts Municipal Wholesale Electric Company
- Microgrid Resources Coalition
- Midcontinent Independent System Operator, Inc. (MISO)
- Midwest Energy Inc.
- Minnesota Energy Storage Alliance
- MISO Transmission Owners
- Monitoring Analytics, LLC
- Mosaic Power, LLC
- National Association of Regulated Utility Commissioners
- National Hydropower Association
- National Rural Electric Cooperative Association
- New England Power Pool
- New England States Committee on Electricity
- New York Independent System Operator, Inc. (NYISO)
- New York Public Service Commission (NYPSC) and New York State Energy Research and Development Authority (NYSERDA) and New York Power Authority
- New York State Department of State, Utility Intervention Unit
- NextEra Energy Resources, LLC
- North American Electric Reliability Corporation (NERC)
- North Carolina Utilities Commission
- NRG Energy, Inc.
- Ohio Consumers' Counsel
- Open Access Technology International, Inc.
- OpenADR Alliance, Inc.
- Organization of MISO States
- Pacific Gas & Electric Company (PG&E)
- Pennsylvania Public Utility Commission
- PJM Interconnection, LLC
- Power Applications and Research Systems, Inc.
- Public Service Commission of Wisconsin
- Public Service Electric and Gas Company (PSE&G)
- Public Utilities Commission of California
- Public Utilities Commission of Ohio
- R Street Institute
- San Diego County Water Authority
- Schulte Associates LLC
- Silicon Valley Leadership Group
- SolarCity Corporation & SolarCity Corporation DER and Storage Developers & SolarCity Corporation Tesla Inc.
- Solar Energy Industries Association (SEIA)
- Southern California Edison Company (SCE)
- Southwest Power Pool (SPP)
- Starwood Energy Group Global, LLC
- Stem, Inc.
- SunRun, Inc.
- Sustainable FERC Project
- TechNet
- TeMix Inc.
- Tesla, Inc. and SolarCity Corporation
- Transmission Access Policy Study Group (TAPS)
- Transmission Bay Cable LLC
- Union of Concerned Scientists (UCS)
- University of Delaware
- Utility Intervention Unit, New York State Department of State
- Xcel Energy Services Inc.

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