DER Integration into Wholesale Markets and Operations

A Report of the
Energy Systems Integration Group's
Distributed Energy Resources
Task Force

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A Report of the Distributed Energy Resources Task Force of the Energy Systems Integration Group

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Disclaimer

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Executive Summary

Distributed energy resources (DERs)—generation, storage, and electric vehicles and other responsive load connected to distribution systems—can provide a range of electricity system benefits. However, realizing these benefits will require closer coordination between electricity distribution and transmission systems. Without coordination, electricity systems risk being over- or underbuilt and will be increasingly challenging to operate, leading to high costs and potentially lower reliability.

Closer coordination implies that distribution and transmission systems will increasingly need to be planned and operated as an interactive, integrated whole, with power flows to and from distribution systems that shift as DERs respond to changing conditions in wholesale markets, and wholesale markets and operations respond to changes in loads and DERs in distribution systems. Moving toward this more interactive grid will require better integrating DERs into wholesale markets and operations as well as distribution system operations. However, regulatory frameworks and market rules to do so remain in the early stages.

In this report, we examine the changes in regulation, market rules, and operating practices needed to better integrate DERs into U.S. wholesale markets and operations, focusing on nearer-term implementation of the Federal Energy Regulatory Commission's (FERC's) Order 2222 as well as on the broader gaps related to DER integration in wholesale markets and distribution systems. The report incorporates discussions from a 10-month-long consultative process with the Energy Systems Integration Group's Distributed Energy Resources Task Force, which includes experts from grid operators, utilities, technology providers, regulators, and research organizations.

The report includes:

- A framework for DER market and system integration
- An examination of possible modes of operational coordination among distribution utilities, DER aggregators, and independent system operators (ISOs)* to support implementation of Order 2222, and an assessment of potential gaps in current practice
- A description of broader gaps for DER market and system integration beyond Order 2222
- Recommendations for state regulatory commissions, distribution utilities, and ISOs to address near-term gaps related to Order 2222 and broader gaps around DER market and system integration

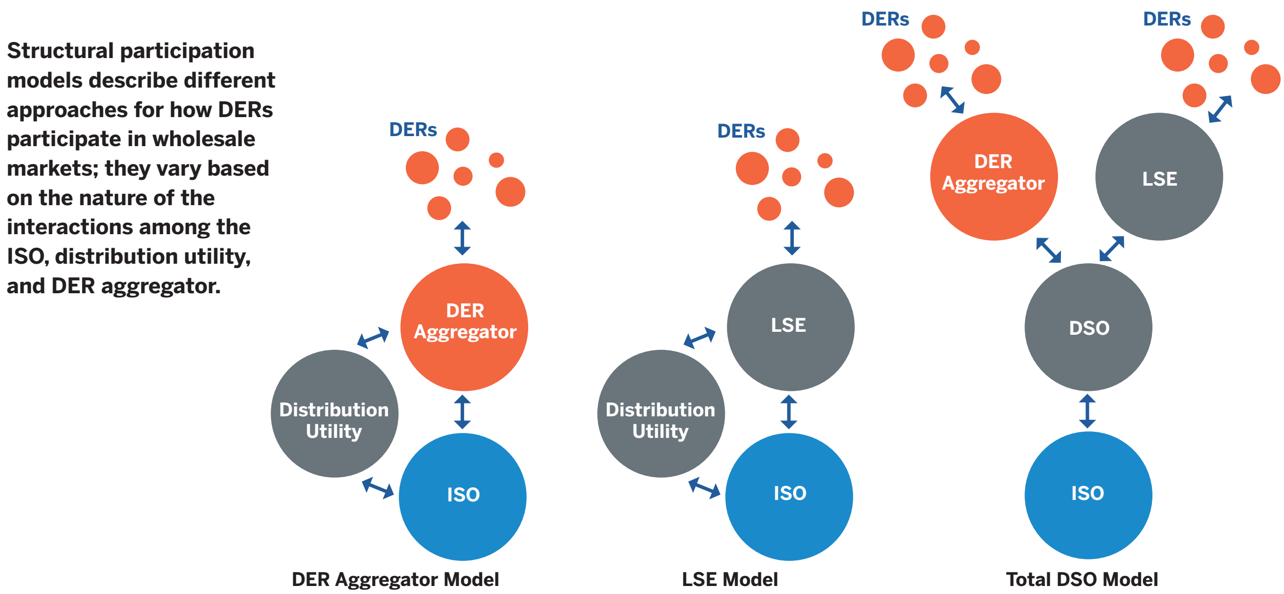
Assessing Three Structural Participation Models

Our framework for better integrating DERs into ISO markets begins with the mechanics of how ISO markets work—who the market actors are, what functions they are responsible for, and within what processes they operate. Using this framework of actors, functions, and processes, we lay out different models for how DERs participate, or could participate, in wholesale markets, which we refer to as structural participation models to distinguish them from ISO participation models for different kinds of supply resources. Structural participation models vary based on the nature of the interactions among the ISO, distribution utility, and DER aggregator.

* We use the term ISO in this report to refer to single-state ISOs and regional transmission organizations (RTOs).

FIGURE ES-1

Three Structural Participation Models for DER Participation in Wholesale Markets



Structural participation models describe different approaches for how DERs participate in wholesale markets; they vary based on the nature of the interactions among the ISO, distribution utility, and DER aggregator.

Note: DER = distributed energy resource; DSO = distribution system operator; ISO = independent system operator; LSE =load-serving entity. In the LSE model, the LSE and the utility may be the same entity.

Source: Energy Systems Integration Group.

Of the three structural participation models described in the report (Figure ES-1), two are in current use in the United States. In the DER aggregator model, long used by demand response providers but broadened under Order 2222, DERs can participate in the supply side of ISO markets through a DER aggregator. In the load-serving entity (LSE) model, DERs passively or actively participate in ISO markets through LSE demand bids or changes in metered demand. Both of these models have drawbacks that could be addressed through the third model, a total distribution system operator (DSO) model, in which a functionally independent DSO ensures that DER supply offers and demand bids do not violate distribution limits before wholesale markets are cleared by the ISO. This total DSO model is still, however, embryonic.

Among these three structural participation models, the DER aggregator model has the most pressing near-term challenges related to Order 2222 implementation. As ISOs continue to make progress with their compliance plans, many of the major remaining gaps will need to be addressed by state regulatory commissions and distribution utilities. We identify four main gaps related to interconnection procedures, DER aggregation review, outage communication, and ISO dispatch overrides (Table ES-1). Few distribution utilities have developed interconnection procedures that are consistent with Order 2222 or rigorous processes for reviewing DER aggregations, communicating outages, and overriding ISO scheduling and dispatch. State regulatory commissions will need to ensure that utilities develop procedures and processes that are efficient, fair, transparent, and non-discriminatory.

A key market design challenge for ISOs will be to develop effective strategies for allowing heterogenous (mixed) aggregations of distributed generation, storage, and demand response to participate in wholesale markets. Because of baselining issues around demand response, there may not be elegant solutions for participation of mixed aggregations on the supply side through supply

TABLE ES-1

Key Areas and Actions for State Regulatory Commissions and Distribution Utilities to Achieve Order 2222 Compliance

Area	Actions Needed by State Regulatory Commissions	Actions Needed by Distribution Utilities
Interconnection procedures	Ensure that interconnection procedures are transparent, are fair, and result in predictable interconnection costs and timely interconnection	Develop new or enhance existing DER interconnection procedures to establish DER performance parameters (e.g., maximum injection limits) and utilities' ability to curtail DER injections for reliability
DER aggregation review	Ensure that utility aggregation review is timely, fair, and flexible, avoiding the need for new interconnection studies	Develop transparent procedures for reviewing DER aggregations within 60 days
Outage communication	Ensure that distribution utility outage communication is timely and fair, allowing DER providers to manage non-performance risks in the wholesale market	Develop new processes and capabilities for communicating distribution outages or constraints to DER aggregators
Utility overrides	Ensure that distribution utility overrides are transparent and non-discriminatory	Develop transparent, non-discriminatory procedures for overriding ISO scheduling and dispatch of DERs that align with expectations set within the aggregation review process

Source: Energy Systems Integration Group

offers. More effective solutions may exist on the demand side through demand bids, either through changes in LSE demand forecasts or through more sophisticated LSE demand bid curves. In the nearer and perhaps even longer term, changes in DER tariff and retail rate design should not be forgotten as an effective way to better integrate DER into wholesale markets and operations.

A National Dialogue Around Broader Needs Regarding DER Integration

An important legacy of Order 2222, regardless of its effectiveness in facilitating participation by DER aggregators in ISO markets, will be in the dialogue that it has spurred on more forward-looking challenges and gaps around DER integration, both into distribution system operations as well as wholesale markets and operations. These gaps are often common across structural participation models and cover a range of activities: transmission and distribution planning, distribution interconnection, communications and data-sharing, distribution operations, market regulation, ISO market design, and utility regulation and business models. Table ES-2 (p. 4) describes more specific gaps for each of these seven areas.

Next Steps for Regulators, Utilities, and ISOs

For those at an early stage of DER integration, issues around FERC Order 2222 implementation and the broader gaps listed in Table ES-2 may appear complex.

Six strategies can help state regulatory commissions, utilities, and ISOs begin the next steps (with relevant actors in parentheses).

For nearer-term compliance with Order 2222, and consistent with the discussion in Section 3 of this report, our first recommendation is to:

- Start from an assumption that only minor changes in distribution planning and operations, and utility investments in monitoring and controls necessary to support them, will be needed for near-term compliance with Order 2222 (commissions, utilities).

To reduce the need for more significant changes to support Order 2222 compliance, our recommendations include the following:

- Enhance utilities' DER database functionality to ensure all DERs are included with their essential characteristics and locations on the distribution system. This will streamline the DER aggregation review and facilitate timely communication of changing grid conditions to affected DER aggregators (utilities).
- Leverage data from both ISO DER registration and previously completed utility interconnection processes to support DER aggregation reviews. In most cases, DER aggregation review should not require redoing interconnection studies (commissions, utilities).

TABLE ES-2
Gaps for Broader DER Integration

Transmission and Distribution Planning
Integration of utility planning, DER interconnection, and operations: Distribution utilities need to more closely align the data and tools that they use in planning, interconnection studies, and operations.
Utility/ISO planning coordination: Utilities and ISOs need more coordination on DER forecasting and planned investments, to ensure that they are using consistent assumptions in infrastructure planning.
Distribution Interconnection
Interconnection standards: State regulatory commissions and utilities need to support longer-term adoption and implementation of interconnection standards.
Flexible interconnection: Utilities need processes and rules for DERs to flexibly interconnect to the distribution system, in which DER owners avoid paying for distribution system upgrades if they agree to be curtailed, or re-dispatched in the case of storage, when needed for reliability.
Communications and Data-Sharing
DSO/ISO communication: Protocols and processes through which DSOs and ISOs can communicate and share data in real-time operations must continue to evolve.
Utility/aggregator data sharing: Utilities need clearer rules regarding the kinds of distribution load and operational data, and their granularity and frequency, that they will share with DER developers and aggregators.
Distribution Operations
Least-regrets operational enhancements: Utilities and state regulatory commissions need to identify enhancements in utility monitoring, communications, and control capabilities that will be desired regardless of how distribution operations are organized.
DSO functions: Utilities, commissions, and ISOs need to identify the operating needs, roles, and functional responsibilities for future DSOs, including monitoring, dispatch, and control needs and interactions among market participants, DSOs, and ISOs.
Market Regulation
Non-discriminatory distribution operations: State regulatory commissions need to identify regulatory changes, including functional independence of the system operator and open access distribution tariffs, to ensure non-discriminatory operation of the distribution system.
State-federal jurisdiction: State commissions and FERC need to develop approaches to managing areas of overlapping state-federal jurisdiction, such as interconnection, dual participation (DERs' participation in wholesale markets managed by ISOs, while also providing retail services on the distribution system), distribution access tariffs, and distribution operations.
ISO Market Design
Demand-side designs: ISOs need to create new market rules that enable enhanced use of demand bids, allowing the demand side to play a more active role in wholesale markets and operations.
Utility Regulation and Business Models
Incentives for maximizing DER value: Commissions need to restructure incentives for utilities, so that they proactively seek to maximize the value of DER on their distribution systems and in wholesale markets.
DER compensation: Commissions and utilities need to develop and implement new designs for tariffs and other approaches to compensation that better align DER operating incentives with wholesale market and distribution system needs.

- Make use of existing protocols and processes for communications and data-sharing among utilities, DER aggregators, and ISOs, rather than create new processes and additional complexity (utilities, aggregators, ISOs).
- Focus initially on developing workable approaches to utility overrides, based on a foundation of efficient outage communication, that are clearly articulated in interconnection and aggregator agreements and can evolve over time (utilities, commissions).
- Prioritize adoption and implementation of the Institute of Electrical and Electronics Engineers (IEEE) 1547-2018 standard, as voltage support provided through compliance with interconnection standards may reduce the need for overrides and distribution upgrades (commissions, utilities).

To serve those states and utilities who are well on the path of DER integration and considering how to manage for higher-DER futures:

- Begin a national, industry-wide dialogue on forward-looking issues where solutions can be accelerated through joint, creative problem solving, including: flexible interconnection (utilities, commissions), coordination between transmission and distribution planning (utilities, ISOs), distribution operator independence and open access distribution tariffs (commissions, utilities), future distribution operations (utilities, commissions), issues around state-federal jurisdiction (commissions, FERC), ISO market designs (ISOs, FERC), and utility tariff designs (commissions, utilities).

Many of these forward-looking issues may not have near-term solutions, but their resolution will require long lead times and it is important to start dialogue on them now. An open networks initiative in the United States, envisioned in the third report in this series and akin to initiatives in Australia and the United Kingdom, could provide a forum for dialogue on the most critical of these issues. This kind of initiative could enable greater national consensus on where key challenges lie, forge some degree of standardization in terminology and solutions, and lay the market, regulatory, and operational groundwork for more interactive, integrated electricity systems of the future.

1 Introduction

1.1 DER Integration into Wholesale Markets and Operations

Growth in distributed energy resources (DERs)—generation, storage, and electric vehicles and other demand response resources connected to the distribution system—is creating the need for better integration of these resources into U.S. wholesale markets and operations.[1] A range of factors are driving DER growth: customer value, technology and business model innovation, competitive forces, state incentives, and tariffs for distributed generation and storage. These drivers and the pace of DER growth will continue to vary across states.

In all states, better integration of DERs will help to deliver a broad range of electricity system benefits, including lower wholesale costs for day-ahead energy, real-time energy, resource adequacy capacity, and ancillary services; reduced transmission congestion; lower transmission infrastructure costs; and lower greenhouse gas emissions. However, realizing these benefits will require more coordination between distribution and transmission system planning, operation, and markets so that they function as a more interactive, integrated whole. In this interactive system, when the transmission system has excess supply, distribution systems can increase demand by shifting load, reducing generation, or charging storage. Conversely, when the transmission system is short of supply, distribution systems can reduce demand by shifting load, increasing distributed generation, or discharging storage.

The transition to this more interactive electricity system will not happen as a matter of course; it will need to be guided by federal and state regulation and driven by proactive, collaborative innovation and problem-solving.

1.2 FERC 2222 and Beyond

The Federal Energy Regulatory Commission's (FERC's) Order 2222, issued in September 2020, supports initial steps toward better integration of DERs into wholesale markets and operations. Order 2222 requires FERC-jurisdictional independent system operators (ISOs) and regional transmission organizations (RTOs) (referred to collectively in this report as ISOs) to create participation models that will enable aggregations of DERs (DERAs) to participate in ISO energy, capacity, and ancillary service markets. Order 2222 recognized that DERs have the capability to provide these wholesale market services, but many DERs are individually too small to meet ISO minimum size thresholds and may individually lack sufficient operational flexibility to meet performance requirements. Order 2222 enables the aggregation of DERs as a means

Order 2222 enables the aggregation of DERs as a means to enable DERs to participate on a level playing field with other resources.

1 This report uses the term distributed energy resources (or, more precisely, distribution-connected energy resources) to refer to the broad range of operational assets for electricity generation, energy storage, load management, and various types of control systems that connect physically to the electricity system at the distribution level rather than to the bulk power system. DERs may connect either directly to the distribution utility's network (front-of-meter DERs) or to the electrical system on a customer's premises (behind-the-meter DERs). The key distinction that defines DERs is their point of interconnection to the power system—distribution level rather than transmission level. Beyond that distinction, DERs may include any and all technology types that physically connect to and affect the operation of the electric power system. This may include traditional types of demand response and energy efficiency as well as electric vehicles and customer loads that shift in response to changing price signals.

to address these limitations and thereby enable DERs to participate on a level playing field with other resources.

As this report is being written in late 2021, the two single-state ISOs have filed compliance plans for Order 2222 (the New York Independent System Operator and the California Independent System Operator (CAISO)), whereas the multi-state RTOs are still in the process of developing their compliance plans and have been granted extensions to spring 2022 (the Midcontinent Independent System Operator, the New England Independent System Operator, PJM, and the Southwest Power Pool). At the distribution level, many state regulatory commissions and distribution utilities are still in the early stages of developing approaches to support compliance with Order 2222. Many of the challenges to Order 2222 implementation will increasingly be on distribution systems.

It remains to be seen whether Order 2222 will unleash extensive DERA participation in wholesale markets. CAISO's Distributed Energy Resource Provider model, which FERC approved in 2016 and was in many ways a model for Order 2222, has had no users to date due to challenges that are outside of CAISO market rules. Such challenges include those related to dual participation, the ability of a DERA to participate in the wholesale energy and capacity markets managed by ISOs while also providing retail services on the distribution system.

Although FERC Order 2222 offers a path to the expansion of supply-side participation by DERs beyond demand response, it is just one of multiple possible models of DER integration into wholesale markets and operations. Currently, many DERs are compensated through retail programs, procurement, and tariffs rather than through wholesale markets. In these arrangements, DER interactions with wholesale markets and operations are intermediated by utilities and other load-serving entities, which participate in ISO markets through demand bids and changes in metered demand rather than through supply offers.

Regardless of Order 2222's direct impact, with this order FERC has triggered a national conversation that covers a broad spectrum of DER market and system integration issues, including more flexible approaches to DER interconnection, transmission and distribution planning coordination, operational coordination between distribution utilities and ISOs, the evolution of distribution system operations and regulation, ISO market designs for responsive distribution systems, areas of overlapping federal and state jurisdiction, and utility regulation and business models. Many of these issues do not lend themselves to quick solutions, but it is important to begin exploring possible solutions now to lay the groundwork for longer-term change.

1.3 Report Contribution and Organization

This report examines the changes in regulation, market rules, and operating practices needed to better integrate DERs into U.S. wholesale markets and operations. The report identifies key gaps for Order 2222 implementation and examines broader gaps to DER market and system integration that go beyond Order 2222. This work incorporates discussions from a 10-month consultative process with the Energy Systems Integration Group's (ESIG's) Distributed Energy Resources Task Force, which includes experts from grid operators, utilities, technology providers, regulators, and research organizations.

The report is organized into four sections.

- **Section 2, A Framework for DER Integration into Wholesale Markets and Operations**, provides an analytical framework for understanding the actors, market processes, and operator functions involved in DER market and system integration, as well as the existing and potential future models for DER participation in wholesale markets.
- **Section 3, DER Market and Systems Integration with DER Aggregators**, examines possible modes of operational coordination among distribution utilities, DER aggregators, and ISOs to support the implementation of Order 2222, and identifies the gaps in current practice.
- **Section 4, Broader Gaps in DER Integration**, describes the broader gaps for integrating DERs into wholesale markets and system operations, beyond Order 2222.
- **Section 5, Conclusions and Recommendations**, provides concluding thoughts and offers recommendations for state regulatory commissions, distribution utilities, and ISOs to address near-term gaps related to Order 2222 as well as broader gaps around DER market and system integration.

This work is intended to complement related efforts on Order 2222 implementation by Advanced Energy Economy, the Electric Power Research Institute, and the North American Electric Reliability Corporation. To enable collaboration and coordination, participants in the ongoing work by these three organizations were included on the ESIG Distributed Energy Resources Task Force and on the project team. The Advanced Energy Economy effort involves distribution utilities and its member organizations, and is focused on developing regulatory recommendations. The Electric Power Research Institute has two related efforts. The first is the TSO-DSO (Transmission System Operator-Distribution System Operator) Coordination working group, which began in 2019; is open to the public; and includes RTOs, utilities, technology providers, and a few regulatory staff. This working group focuses on technical matters of coordination (rather than policy). The second effort is the FERC Order 2222 Collaborative, started in January 2021, which addresses multiple aspects of Order 2222 compliance. Lastly, the North American Electric Reliability Corporation's System Planning Impacts from Distributed Energy Resources (SPIDER) Working Group focuses on the bulk power system impacts of DERs from a transmission planning and system analysis perspective.

This report is the first in a series of three reports by ESIG on DER integration into electric power systems. The second report provides an assessment of the United Kingdom's and Australia's open networks initiatives, with an eye toward assessing lessons for the United States. The third report describes how an open networks initiative in the United States might be focused, structured, and implemented.

2 A Framework for DER Integration into Wholesale Markets and Operations

The integration of distributed energy resources (DERs) into wholesale markets and operations involves core actors that interact through market processes and operator functions. These interactions vary across different models for DER participation in wholesale markets. In this section, we develop a framework for DER integration into wholesale markets and operations, providing an overview of actors, the market processes and operator functions in which these actors interact, and three different models of interactions. An understanding of these different models of interaction provides context and foundation for Sections 3 and 4.

In this section we develop a framework for DER integration into wholesale markets and operations, providing an overview of actors, the market processes and operator functions in which these actors interact, and three different models of interactions.

2.1 Actors

This report defines actors based on functional roles rather than associating a specific actor with a specific entity, because any particular entity—such as a utility—may perform multiple functional roles. DER market and system integration involves two system operators, two market participants, and intermediaries and resource owners.

These categories are not mutually exclusive. For instance, a distribution utility (DU) could be a DER aggregator, be a load-serving entity (LSE), act as its own scheduling coordinator, have a subsidiary that provides energy service company services, and own DERs. However, the categories allow us to focus on four core functional actors that are essential to DER market integration across all cases and scenarios. These include the independent system operator (ISO), the DU, and the two market participants. In cases where a distribution system operator (DSO) exists as a separate entity from the DU, both are core functional actors. (See Table 1, p. 10.)

2.2 Market Processes and Operator Functions

Wholesale market processes involve three main stages:

- **Pre-operations and planning**, which include all of the activities related to infrastructure planning, interconnection, and planned maintenance that occur in advance of when the ISO begins to schedule and dispatch resources to meet expected demand
- **Market and system operations,** which include day-ahead and real-time market functions and physical operations
- **Market settlement**, which includes capacity, energy, and ancillary service market settlement and settlement of transmission and distribution tariffs

Each stage has multiple processes through which market participants and system operators interact. Different system operators have different functions at each stage. Table 2 (p. 11) describes wholesale market processes and system operator functions for each process, focusing on DER participation in these processes, and interactions between distribution operators (DU/DSO) and the ISO that might occur under a range of possible models under which DERs could participate in wholesale markets.

TABLE 1
Actors in DER Integration into Wholesale Markets and Operations

System Operators	
Independent system operators (ISOs)	High-voltage (bulk) transmission system operators that are balancing authorities responsible for real-time supply-demand balancing on the networks they operate In this report, the term ISO covers both single-state ISOs and multi-state regional transmission organizations. The United States currently has seven ISOs, of which six are subject to Federal Energy Regulatory Commission jurisdiction. ISOs in the United States are also wholesale market operators, whereas in other countries, including most of Europe, the balancing authority and wholesale market functions are performed by different entities.
Distribution utilities (DUs)	Entities that own and operate one or more low-voltage distribution systems In this report, we use the term distribution system operator (DSO) broadly, to refer to the entity that is responsible for operating the distribution system. This entity could be a distribution utility or, as on the transmission system, a separate organization.
Market Participants	
DER providers	ISO market participants that may operate individual DERs or aggregate two or more DERs into a DER aggregation (DERA) and submit supply offers into ISO markets
Load-serving entities (LSEs)	ISO market participants that provide retail electricity service and submit demand bids into ISO markets The LSE role may be bundled with the DU or be performed by a separate competitive retail provider, community choice aggregator, or energy service company.
Intermediaries and Resource Owners	
Scheduling coordinators	Entities that perform ISO bidding, scheduling, dispatch, and settlement functions on behalf of market participants
Energy service companies	Entities that provide an array of energy-related services to electricity customers, including equipment installation and performance optimization An energy service company may be a provider of on-site behind-the-meter DERs to retail customers.
DER owners	Entities that own DER assets

Source: Energy Systems Integration Group.

Table 2 (p. 11) illustrates the three main forms of interaction among actors through these processes: communication, dispatch and control, and payments. Communications refers to the exchange of information, such as information developed and collected through DER or DERA registration and interconnection, forecasting, and verification in the pre-operation stage or the exchange of offer, bid, clearing, and settlement information in the market operation stage. Dispatch and control refer to operating instructions, either sent to the resource owner (dispatch) or directly to a resource (control). Payments refer to the exchange of money between actors.

These categories are not exclusive; dispatch and control involve communications and payments, for example. However, the categories help to illustrate the need for different kinds of coordination among different actors, and between distribution and transmission system operators, in particular.

2.2.1 More Frequent and Efficient Communication

DUs and ISOs have not historically required close communication, either in the pre-operation and planning stages or the market and system operation stages, though the overlaps in Table 2 suggest that more frequent and efficient DU/DSO-ISO communication will be an important aspect of integrating DERs into wholesale markets and operations. At one end of the spectrum of possible DSO models, DSOs may be fully integrated into ISO market processes, requiring constant real-time communications between the DSO and ISO. At the

TABLE 2

Market Processes and DU/DSO and ISO Operator Functions Relevant to DER Market Integration

Pre-operations and Planning		
Market Process	**Operator Function**	
	DU/DSO	**ISO**
Registration of market participants and resources	Register market participants (DER providers) and participating resources (DERs or DERAs)	Register market participants (DER providers) and participating resources (DERs or DERAs)
Distribution planning	Plan investments in distribution infrastructure and non-wires technologies	Provide DU/DSO with timely information on planned transmission expansion
Transmission planning	Provide ISO with information to support load and DER forecasting	Plan investments in transmission infrastructure, incorporating forecasted DER growth
DER interconnection	Set interconnection standards; perform screens and studies for individual DERs	Perform deliverability assessments for resource adequacy and other services
Resource verification	Review DERA; review DER aggregator communications and metering	Review DERA's operating characteristics, telemetry, and metering; perform testing for its ability to provide ancillary services
Resource adequacy	Verify deliverability of DERs or DERAs	Undertake load forecasting, reliability studies, capacity crediting, and capacity auctions (where applicable)*
Maintenance scheduling	Manage and report resource and distribution equipment outages	Manage and report resource and transmission equipment outages
Market and System Operations		
Market Process	**Operator Function**	
	DU/DSO	**ISO**
Day-ahead market	Schedule DERs that provide distribution grid services to the DU/DSO	Perform scheduling and unit commitment
Real-time market	Dispatch DERs that provide distribution grid services to the DU/DSO; ensure distribution system security and, in some models, perform economic dispatch	Perform security-constrained economic dispatch
Contingency management	Manage outages and provide emergency control	Manage outages and provide contingency dispatch
Frequency balancing	In some models, maintain local frequency via automatic generator control	Maintain system frequency via automatic generator control
Voltage regulation	Procure and provide voltage support to ensure that distribution voltages remain within limits	Procure and provide voltage support to ensure that transmission voltages remain within limits
Market Settlement		
Market Process	**Operator Function**	
	DU/DSO	**ISO**
Market settlement	Assess penalties for DERs' or DERAs' non-compliance with override instructions; perform market settlement in some models	Settle day-ahead energy, real-time energy, and ancillary service markets; assess imbalance penalties
Network tariffs and settlement	Settle non-wires resources; distribution tariffs; and tariffs for generation, storage, and demand response	Settle transmission tariffs

* In some markets, these functions are performed by utilities, state agencies, or nonprofit organizations and not the ISO.

Source: Energy Systems Integration Group.

other end of that spectrum, DUs may increasingly need to communicate with ISOs in infrastructure planning, deliverability verification, and potentially in outage reporting, but not in their day-to-day activities.

2.2.2 Operational Coordination

DUs and ISOs have also historically not required coordination around operations, although Order 2222 will change this. DUs have historically not been active system operators, in the same sense that the term system operator is used for the bulk power system. Distribution operators of the past were primarily concerned with managing calls from customers who were experiencing outages and dispatching crews to restore service to impacted areas. How distribution system operations will evolve, and the extent to which they will resemble ISO markets, is still an open question. In ISO markets, real-time load-resource balancing is accomplished primarily through 5-minute automated dispatch signals and penalties for uninstructed dispatch, with a relatively small amount of frequency regulation reserves and automatic generation control systems used for final balancing within real-time dispatch intervals. In other words, ISOs' primary tool for operating the transmission system is through dispatch signals rather than direct control over resources.

On the distribution system, DUs historically expanded and upgraded infrastructure to accommodate all loads and resources under normal operating configurations, while minimizing service disruptions. DUs have not traditionally performed dispatch and control of DERs. However, with higher levels of DERs, and analogous to the transmission system, a congestion-less distribution system may not be practical, and may require some form of DU dispatch and control of DERs. Under FERC Order 2222, DUs/DSOs will need to override ISO schedules and dispatch of DERs to manage planned and forced outages of distribution equipment and potential reliability violations when the distribution system is operating under abnormal conditions that were not considered in DER interconnection studies. Order 2222 provides for such overrides and requires the ISO tariff to specify "transparent and non-discriminatory" procedures the DU/DSO will employ for this purpose (FR, 2020, paragraph 310).

It is not yet clear how DUs and DSOs will conduct transparent and non-discriminatory overrides, and in the longer term perhaps dispatch DERs to relieve distribution constraints. However, it will involve some form of operational coordination between DUs/DSOs and ISOs and greater consistency in regulatory treatment between the transmission and distribution systems. On the transmission system, "transparent" has meant that the approach, process, and responsibilities are codified in a tariff. "Non-discriminatory" has meant that resource schedules are curtailed based on market offers or on a pro rata (equal shares) basis for different service categories, such as firm or non-firm service at the transmission level for jurisdictions that have physical transmission rights. We describe possible approaches to DU/DSO overrides under Order 2222 in Section 3, and longer-term issues around distribution operations in Section 4.

Ideally, DU/DSO and ISO coordination around payments would encourage resources to be sited where—and operated when—they have the most value.

2.2.3 Coordination Around Payments

Interactions between DUs/DSOs and ISOs around payment are often indirect but are significant, and often poorly coordinated. For instance, retail tariffs for distribution-level generation and storage are often not well aligned with wholesale market prices, leading to a discrepancy between wholesale value, retail value, and value to the DER owner or aggregator.

Distribution and transmission tariffs can have a significant influence on DER operations. For instance, distribution tariffs may incentivize generation (net load reductions) during distribution peaks that might not be coincident with transmission system peaks. Ideally, DU/DSO and ISO coordination around payments would encourage resources to be sited where—and operated when—they have the most value. Distribution-level tariffs are not a primary focus of this report, but we return to issues around utility regulation and tariffs in Section 4.

2.3 Structural Participation Models

DERs can participate in ISO markets through a number of different participation models, referred to here as structural participation models. We use the term structural participation models to differentiate them from participation models that the ISOs use for different kinds of resources—for instance, different kinds of generation (forecast-based, dispatchable), storage, and demand response. Structural participation models vary based on the nature of the interactions among the ISO, DU, and DER aggregator.

We focus on three structural participation models (illustrated in Figure 1):

- **DER aggregator model.** In the DER aggregator model, the DER aggregator interacts with the ISO and is a supplier in ISO markets. The DER aggregator submits energy and ancillary service offers for a DERA to the ISO, and the ISO schedules and dispatches the DERA as a portfolio rather than as individual resources. The DER aggregator model has been used by demand-response providers for more than a decade but is being expanded under Order 2222.
- **Load-serving entity (LSE) model.** In the LSE model, the LSE interacts with the ISO and is a buyer in ISO markets. In ISO day-ahead markets, the LSE aggregates loads and DER resources, and submits net demand bid curves to the ISO. In current ISO real-time markets, LSEs do not submit bids to the ISO but can adjust net demand in real time to increase or decrease exposure to real-time prices. Most DERs currently interact with ISO markets through the LSE model, but LSEs differ in the extent to which they optimize DER operation against wholesale prices, if at all.
- **Total distribution system operator (DSO) model.** In the total DSO model, the DSO is a super-aggregator at the distribution-transmission interface in ISO markets. The DSO aggregates demand bids and supply offers from DER aggregators and LSEs within its local distribution areas and submits an aggregated net demand bid curve and ancillary service offers to the ISO. The total DSO model is as yet hypothetical, but, as we describe below, it could in principle resolve some shortcomings in the DER aggregator and LSE models.

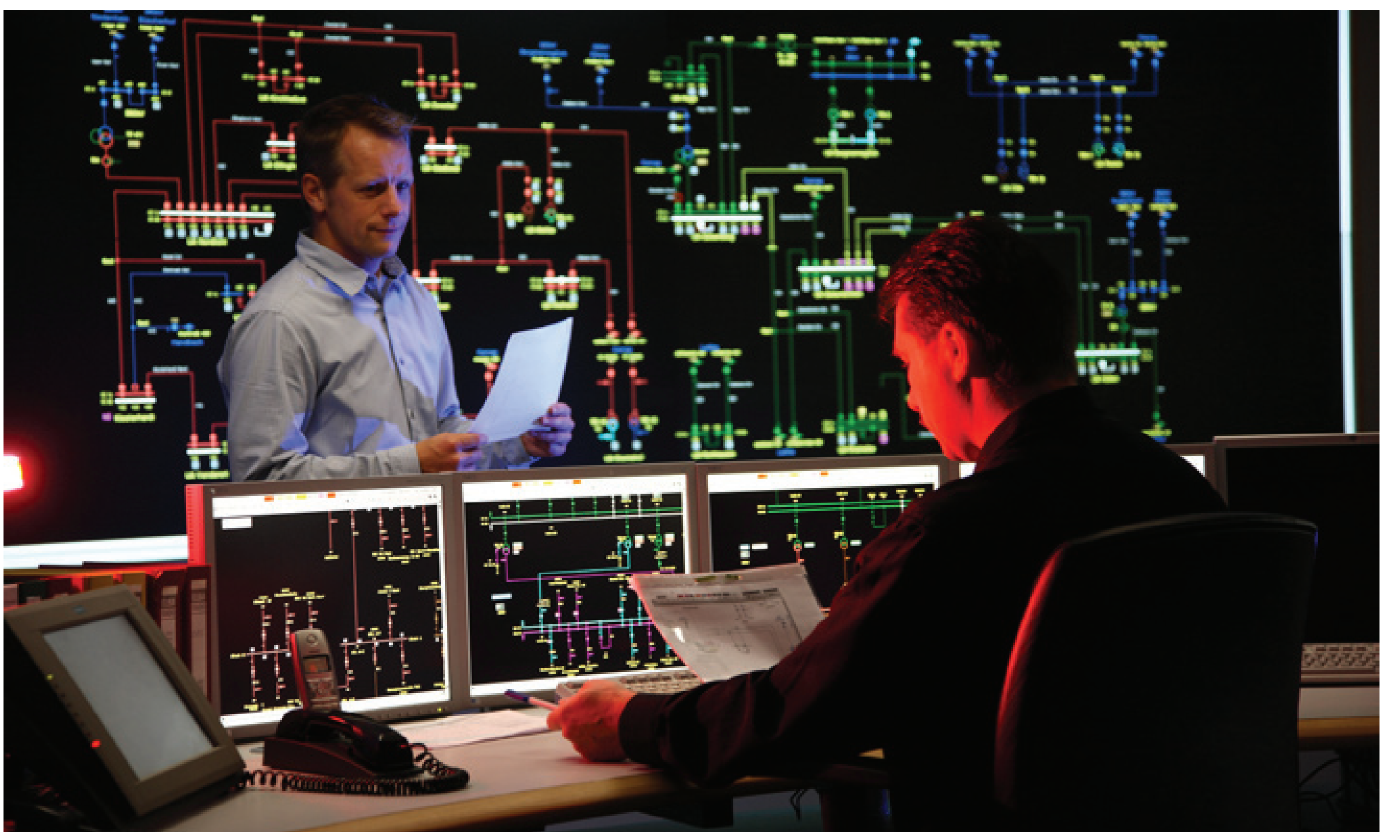
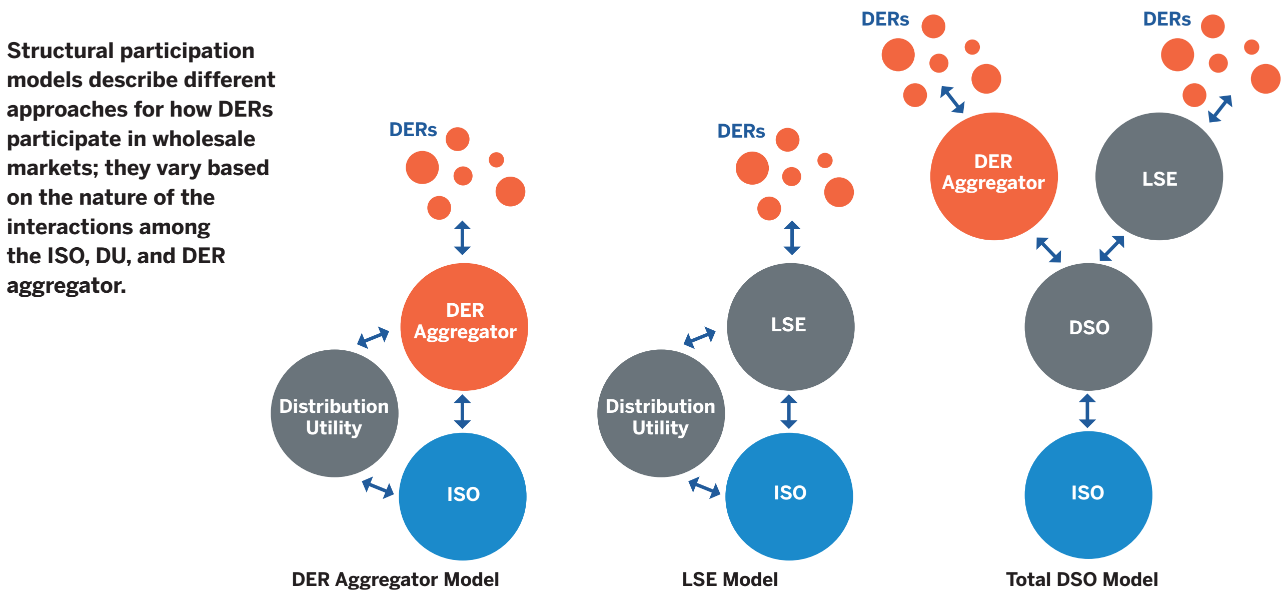


FIGURE 1

Three Structural Participation Models for DER Participation in Wholesale Markets



Structural participation models describe different approaches for how DERs participate in wholesale markets; they vary based on the nature of the interactions among the ISO, DU, and DER aggregator.

Note: DER = distributed energy resource; DSO = distribution system operator; ISO = independent system operator; LSE =load-serving entity. In the LSE model, the LSE and the utility may be the same entity.

Source: Energy Systems Integration Group.

The DER aggregator and the LSE models are not mutually exclusive. For instance, an LSE could aggregate some DERs and offer into an ISO market on the supply side and also have some DERs incorporated into its energy demand bids.

2.4 Market Processes and Operations for Different Structural Participation Models

Within different market processes, interactions among DER owners, DER aggregators, the DU/DSO, and the ISO vary across the three structural participation models. For each model, this section provides a brief overview of interactions around communications, dispatch and control, and market payments in four of the main market processes identified in Section 2.2: day-ahead markets, real-time markets, real-time controls, and settlement.

2.4.1 DER Aggregator Model

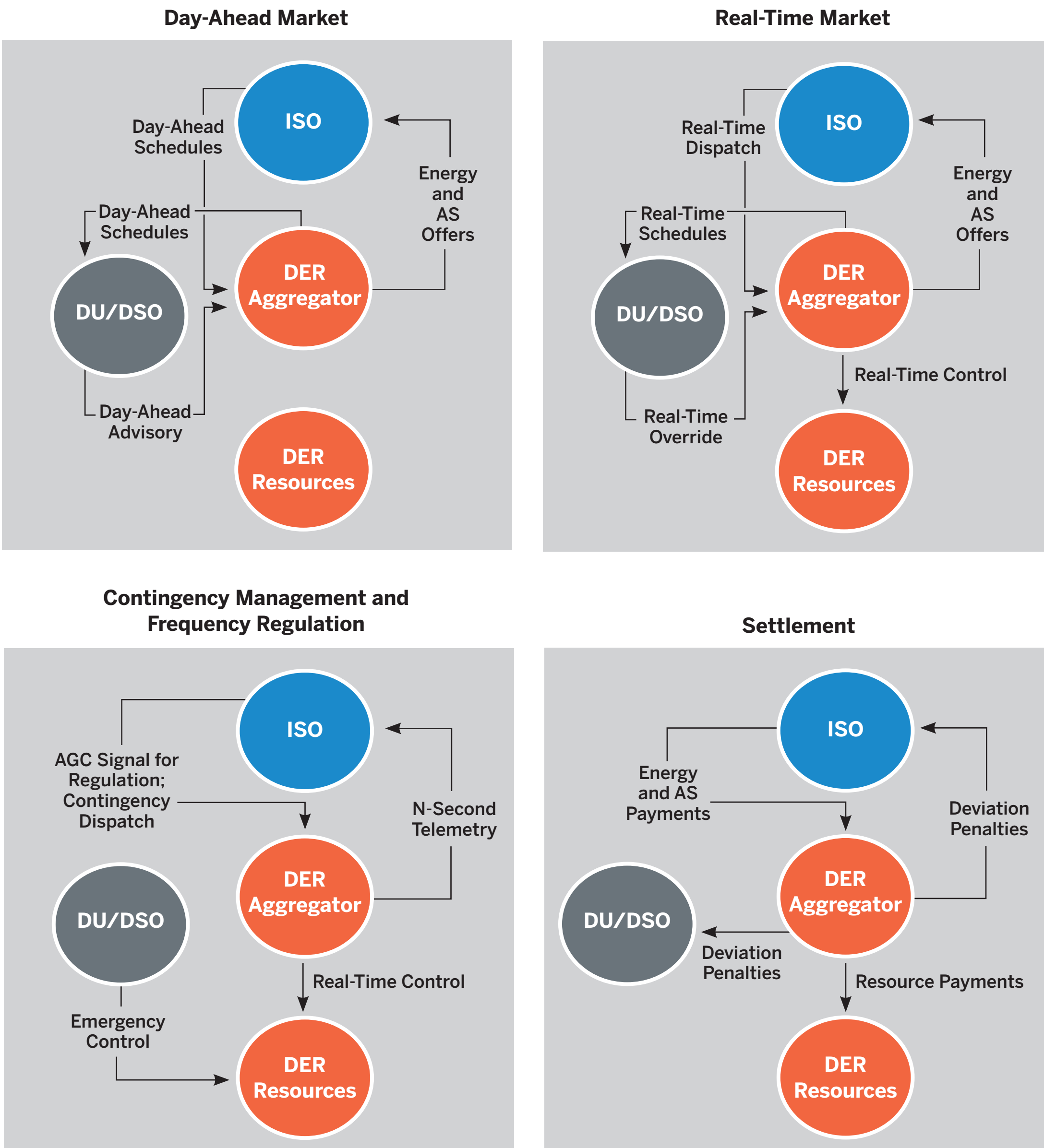
In the DER aggregator model, the DER aggregator is a supplier, and DERs participate on the supply side of ISO markets. Figure 2 shows interactions among DER owners, DER aggregators, the DU/DSO, and the ISO in a plausible implementation of the DER aggregator model.

Day-ahead market. The DER aggregator submits energy and ancillary service offers to the ISO, and the ISO provides cleared hourly DERA schedules to the DER aggregator. The DER aggregator may send cleared hourly schedules for individual DERs to the DU/DSO. The DU/DSO may send an advisory if real-time override is expected to be necessary, based on day-ahead schedules. The DU/DSO may also send an advisory to the DER aggregator before the day-ahead market closes if there are planned or forced outages that are expected to affect feeders that have DERAs.

Real-time market. The DER aggregator submits energy and ancillary service offers to the ISO. The ISO energy management system sends 5-minute dispatch signals for the cleared DERA to the DER aggregator. The DER aggregator may send cleared real-time dispatch for

FIGURE 2

DER Aggregator Structural Participation Model



In the DER aggregator model, DERs participate on the supply side of ISO markets, and the DER aggregator coordinates and manages the participation of DERs in ISO markets.

Note: AGC = automatic generator control; AS = ancillary service; DER = distributed energy resource; DSO = distribution system operator; DU = distribution utility; ISO = independent system operator; LSE = load-serving entity.

Source: Energy Systems Integration Group.

individual DERs to the DU/DSO. The DU/DSO sends any real-time override instructions to the DER aggregator. The DER aggregator controls DERs to meet ISO and DU/DSO dispatch and override instructions.

Real-time controls. The DER aggregator provides real-time telemetry for the DERA to the ISO. The ISO sends automatic generation control signals for any DERA regulation awards to the DER aggregator. The DU/DSO may directly control DERs within a DERA, in addition to the real-time override instruction, within the real-time dispatch interval. The DER aggregator controls DERs to meet its ISO dispatch and DU/DSO override instructions.

Settlement. The DER aggregator receives energy and ancillary service payments from the ISO. It pays deviation penalties to the ISO for any uninstructed deviations from real-time dispatch and pays deviation penalties to the DU/DSO for any lack of compliance with DU/DSO override instructions. It also makes resource payments to DERs.

2.4.2 LSE Model

In the LSE model, the LSE is a buyer, and DERs participate on the demand side of ISO markets. Figure 3 shows interactions among DER owners, DER aggregators, the DU/DSO, and the ISO in an implementation of the LSE model that reflects current practice.

Day-ahead market. The LSE submits a net demand bid (forecasted demand net of power injections to the distribution system) to the ISO. The ISO provides hourly demand schedules to the LSE. The LSE may send day-ahead schedules for DERs, depending on which entity is responsible for determining DER schedules, but either way DER loads and net injections will be embedded in the LSE net energy bid. The DU/DSO and LSE do not interact in day-ahead markets.

Real-time market. The ISO publishes real-time prices after each real-time market run. The LSE, or energy service companies or DER owners, may control DERs to respond to real-time prices. The DU/DSO and LSE do not interact in real-time markets.

Real-time controls. The ISO and the LSE do not interact in real time. The DU/DSO may directly control DERs in real time under emergency conditions.

Settlement. The LSE makes net demand payments to the ISO and makes resource payments to DERs.

2.4.3 Total DSO Model

In the total DSO model, DER aggregators and LSEs participate in ISO markets through a DSO super-aggregator. Figure 4 shows interactions among DER owners, DER aggregators, the DU/DSO, and the ISO in a hypothetical implementation of the total DSO model. New market designs, organizational changes, and regulatory changes would be required to enable the total DSO model.

Day-ahead market. The DSO aggregates day-ahead net demand bids and energy and ancillary service offers in each local distribution area. Subject to security constraints, the DSO converts these bids and offers into a day-ahead net demand bid curve and an ancillary service offer curve at each local distribution area and submits to the ISO. The ISO provides cleared hourly net energy and ancillary service schedules for the transmission–local distribution area interface to the DSO. The DSO sends cleared hourly schedules to DER aggregators and LSEs.

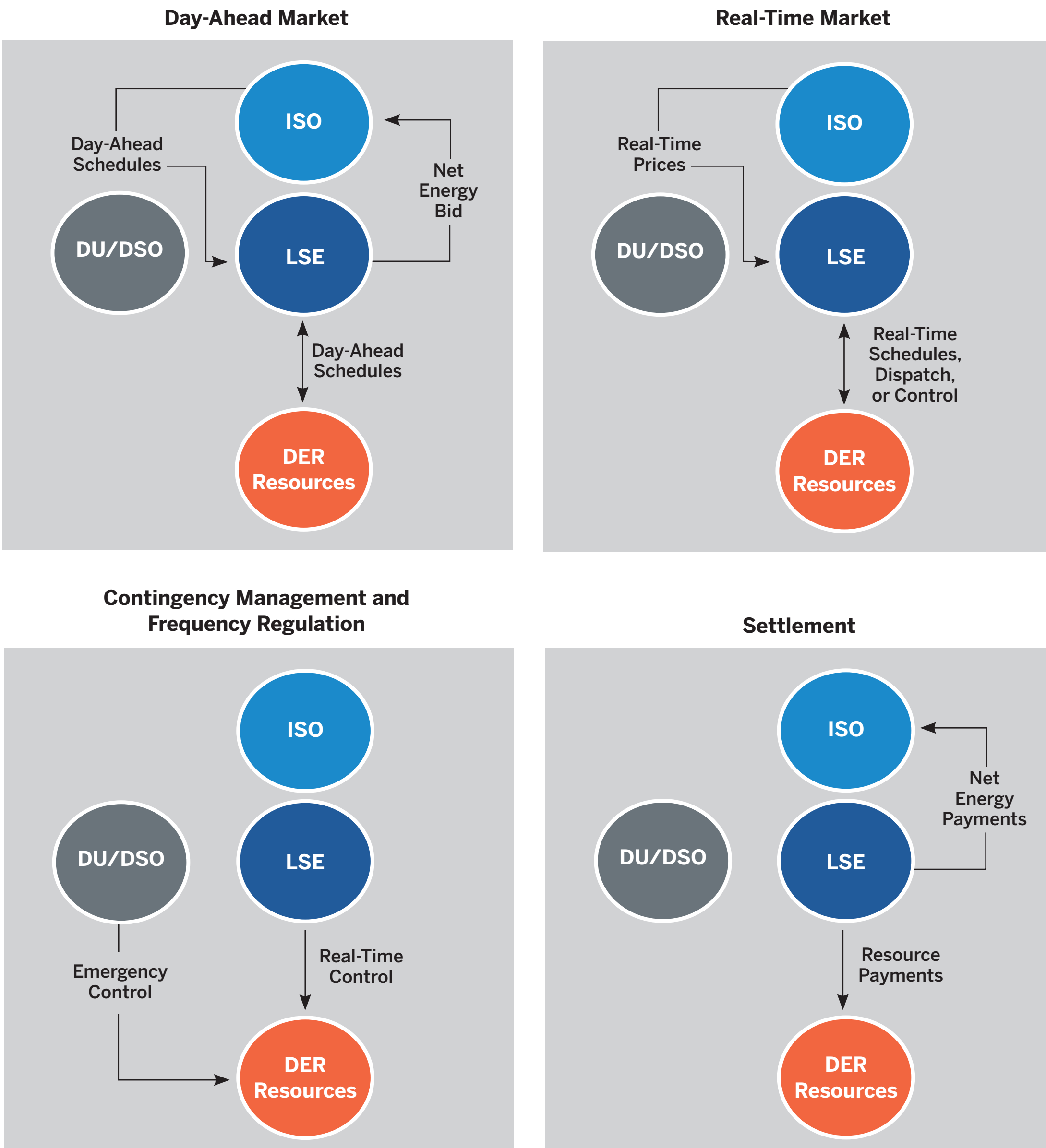
Real-time market. As in the day-ahead market, the DSO converts bids and offers into a real-time net demand bid curve and an ancillary service offer curve at each local distribution area and submits to the ISO N-minutes before the operating hour. The ISO sends automatic dispatch signals to the DSO for net energy and reserves at the transmission–local distribution area interface every 5 minutes. The DSO sends real-time dispatch instructions, for cleared resources, to LSEs and DER aggregators.

Real-time controls. DER aggregators provide real-time N-second telemetry to the DSO. The ISO sends automatic generation control signals for any regulation awards to the DSO, which responds to the automatic generation control signal at the transmission–local distribution area interface using DERs that have regulation awards. DER aggregators and LSEs control DERs in real time to meet DSO dispatch instructions.

Settlement. The DSO settles day-ahead and real-time transactions with DER aggregators and LSEs using ISO locational marginal prices at the transmission–local distribution area interface. The DSO charges DER aggregators and may charge LSEs for deviations from the DSO's

FIGURE 3

LSE Structural Participation Model

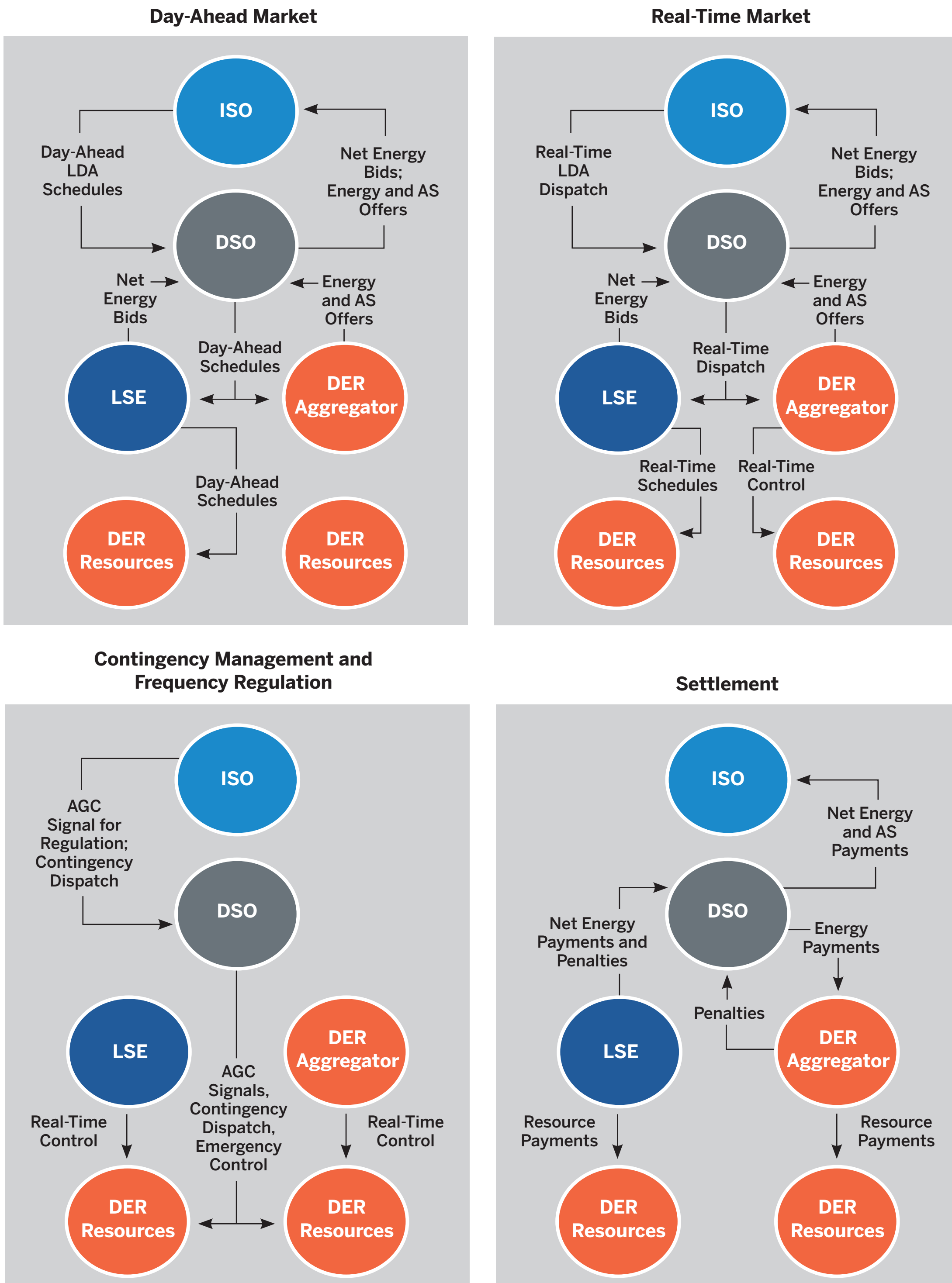


In the LSE model, DERs participate on the demand side of ISO markets, and the LSE coordinates and manages the participation of DERs in ISO markets, potentially with the help of DER aggregators.

Note: DER = distributed energy resource; DSO = distribution system operator; DU = distribution utility; ISO = independent system operator; LSE = load-serving entity.

Source: Energy Systems Integration Group.

FIGURE 4
Total DSO Structural Participation Model



In the total DSO model, both DER aggregators and LSEs participate in ISO markets through a DSO.

Note: AGC = automatic generator control; AS = ancillary service; DER = distributed energy resource; DSO = distribution system operator; DU = distribution utility; ISO = independent system operator; LDA = local distribution area; LSE = load-serving entity.

Source: Energy Systems Integration Group.

real-time dispatch instructions. The ISO charges the DSO for regulation based on deviations from 5-minute dispatch at the transmission–local distribution area interface. DER aggregators and LSEs make payments to DER.

2.4.4 Comparison of Structural Participation Models

The DER aggregator and LSE models represent supply and demand pathways, respectively, for integrating DERs into wholesale markets. If markets are efficient and net demand flexibility is perfectly fungible with supply, these models should lead to equivalent outcomes. From an ISO's perspective (at the transmission-distribution interface), a 1 megawatt (MW) supply offer from a DER aggregator is equivalent to a 1 MW reduction in an LSE's demand bid. A demand response offer should be equivalent regardless of whether the resource participates through the supply or demand side of the ISO market.

At present, DER participation on the supply and demand sides of ISO markets is unlikely to result in equivalent outcomes, because of shortcomings in the DER aggregator and LSE models.

At present, however, DER participation on the supply and demand sides of ISO markets is unlikely to result in equivalent outcomes. The reasons for divergence in outcomes stem from shortcomings in the DER aggregator and LSE models. In the DER aggregator model, DU/DSO real-time overrides may mean that the ISO will clear supply offers that could have been determined ex ante to be infeasible, leading to losses for DER aggregators and, if overridden amounts became large, potentially higher reserve needs for ISOs. Mixed DER aggregations that include demand response may also have less flexibility on the supply side, where baselining is needed, than on the demand side where it is not.

The most important shortcomings of the LSE model are that loads do not participate in ISO real-time markets, loads are charged at aggregated rather than node-specific locational marginal prices, and LSEs may not have adequate incentives to optimize DERs in their day-ahead demand bids and real-time consumption. In current ISO market designs, ISOs clear real-time markets based on the ISO's load forecasts, charge loads based on metered consumption at aggregated locational marginal prices, and allocate the costs of regulation reserves across LSEs on a pro rata basis, rather than on a cost causation basis in which regulation costs would be charged to LSEs based on their real-time imbalances. Incentives for LSE real-time price response are thus not necessarily aligned with system costs or operational needs. In an era when real-time price response was not feasible at scale, this approach made sense, but as that era ends it may be useful to revisit demand-side market designs.

The lack of LSE incentives for DER optimization in wholesale markets may, in cases where the LSE is a utility, stem from utility regulation and business models (see Section 4). For utility and non-utility LSEs, one obstacle to DER optimization has historically been the lack of mature technologies to monitor, communicate with, dispatch, and meter DERs, but technology should no longer be an obstacle. Where LSEs other than the DU are present, independence of the DU/DSO may also be an obstacle to DER optimization.

The total DSO model could address many of the challenges with both the DER aggregator model and the LSE model. In the total DSO model, the DSO conducts its security checks before ISO market clearing, which would address the issue of infeasible schedules. The ISO would clear real-time markets using DSO net demand bids and would charge DSOs for regulation on a cost causation basis, aligning incentives for price response with real-time operating needs. However, this model is complex, and there are still a number of questions about how it would work in practice.

The total DSO model could address many of the challenges with both the DER aggregator model and the LSE model; however, this model is complex, and there are still a number of questions about how it would work in practice.

3 DER Market and Systems Integration with DER Aggregators

This section focuses on one of the structural participation models described in Section 2: the distributed energy resource (DER) aggregator model articulated in Federal Energy Regulatory Commission (FERC) Order 2222. First, it describes aspects of operational coordination between distribution utilities or distribution system operators (DUs/DSOs), DER aggregators, and independent system operators (ISOs). Then, it explores use cases to identify key functional steps involved in the participation of DERs and DER aggregations (DERAs) in wholesale markets where technical or regulatory issues will likely present challenges.

3.1 Functional Steps and Responsibilities of Key Actors

The analytical tool for the use case exercise is a matrix whose rows are specific functional steps or activities required for DERA participation in the ISO wholesale market and whose columns are the key functional actors that have responsibilities for those steps. The complete matrix can be found in the appendix, and a simplified version is presented here to illustrate its structure.

TABLE 3
Sample Matrix Showing Functional Steps and Responsibilities of Key Actors

	Key Actors			
	Independent System Operator	**DER Aggregator**	**Distribution Utility or Distribution System Operator**	**Load-Serving Entity and Relevant Electric Retail Regulatory Authority**
DER aggregation set-up and static information (Steps 1–11)				
Capacity market participation (Steps 12–14)				
Energy and ancillary service market participation and settlement (Steps 15–29)				

In this sample matrix the rows are functional steps or activities required for DERA participation in the ISO wholesale market, and columns are the key functional actors that have responsibilities for those steps. The complete matrix can be found in the appendix.

Source: Energy Systems Integration Group.

The main functional actors for this analysis are the ISO, the DER aggregator, and the DU or DSO. For expediency, we use the term "DSO" in this section to represent any distribution operator, be it a DU or a functionally independent DSO. There is an additional column for the LSE and the relevant electric retail regulatory authority (RERRA), which have important roles for some use cases in a few specific steps. The RERRA is a term used in FERC Order 2222 to refer to the regulatory authority that regulates the DSO, for example, a public utilities commission or a municipal utility governing board.

The analysis of a use case involves tracking it through all 29 steps of the matrix and identifying specific steps that raise issues or unique considerations (see the appendix for a listing of all 29 steps).

The approach is described from the DSO operational perspective: how to enable the DSO to operate a reliable distribution system with DERAs participating in the ISO market.

3.2 Aggregator-DSO-ISO Operational Coordination

Coordination between a DER aggregator, the DU/DSO, and the ISO features prominently in FERC Order 2222. The context is the participation by a DERA operated by an aggregator as a resource in the ISO wholesale market.[2]

This section outlines a high-level approach to operational coordination, focusing on the market-operational time frame beginning with the ISO day-ahead market through the real-time operating interval, including provisions for the DSO to override an ISO schedule or dispatch instruction to the DERA if needed to maintain reliable operation of the distribution system. The approach is described from the DSO operational perspective: how to enable the DSO to operate a reliable distribution system with DERAs participating in the ISO market.

Thus, we assume without discussion that the ISOs will address ISO operational and market issues, such as integrating the DERA into the ISO systems and DERA compliance with ISO market performance requirements.

The approach is structured in four building blocks, of which the first three comprise the one-time set-up activities—interconnection of individual DERs, DSO review of a proposed DERA, and establishment of criteria and procedures for DSO override or curtailment of a DERA—and the fourth is about day-to-day markets and operations. Clearly, each of the building blocks will require more granular details as we consider how to implement all of the elements. But the central focus of this section is to describe the high-level architectural structure of operational coordination in terms of the building blocks, keeping the more granular details for a subsequent exercise.

3.2.1 DER Interconnection and the DER-DSO Interconnection Agreement

Every DER (or at least every power-injecting DER) goes through an interconnection process with the DSO that sets some limits on and requirements for its behavior (e.g., inverter settings for voltage and ride-through, maximum injection/load). To ensure that DER operation is maintained within the required limits, the DSO either needs to have tariff provisions and technical capability for detecting violations of and enforcing the operational restrictions in each DER's interconnection agreement, or must ensure that autonomous controls are in place.

As part of the interconnection agreement, the DER owner/operator agrees to comply with the DSO's rules for curtailing DER operation when necessary. These provisions may vary with the type of interconnection. In the future, flexible interconnections may allow the DER owner to avoid paying for interconnection upgrades if the owner agrees to allow the resource to be dynamically curtailed by the DSO to avoid reliability violations, whereas with firm interconnections a DER owner would pay for the distribution system upgrade in exchange for the equivalent of firm distribution rights.[3] For this discussion we assume that all DER interconnections are firm.

2 A DERA can be viewed as a type of virtual power plant.

3 An injecting DER with firm interconnection status will have equal priority with other firm interconnections to use limited distribution capacity that may result from abnormal distribution conditions. In contrast, a DER with flexible interconnection status will have lower priority than DERs with firm status.

Currently, DERs are required to conduct a new interconnection study whenever the resource is modified, even in cases where modifications do not affect the safety or reliability of the distribution system. Typically, changes to a DER that do not increase its maximum injection or withdrawal rate (MW) should be non-material. For example, if a DER photovoltaics system adds battery storage to minimize curtailment without increasing its maximum injection into the grid, such changes should not require a new interconnection study, with the accompanying delay and expense. DSO interconnection rules could include a distinction between "material" and "non-material" modification to a DER's facilities, whereby the latter allows the DER to modify its interconnection agreement without requiring new interconnection studies. Given the rapid evolution of DER technologies, such a provision could facilitate innovation without compromising distribution system safety or reliability.

DSO interconnection rules could include a distinction between "material" and "non-material" modification to a DER's facilities, whereby the latter allows the DER to modify its interconnection agreement without requiring new interconnection studies.

3.2.2 DSO Aggregation Review of a DERA and the Aggregator-DSO Aggregation Agreement

FERC Order 2222 allows 60 days for the DSO to perform an aggregation review when an aggregator proposes a new DERA. The ISO must have the sign-off of the DSO in order to register the DERA as a market resource. DER aggregation assumes that the individual resources being aggregated have already gone through the distribution interconnection process. While the ISO only requires knowledge of the physical operating characteristics and verification of metering and telemetry for the aggregation, the DSO will need to understand the potential impacts of the individual resources in the DERA on the distribution system. The aggregation review can use information from both the distribution interconnection and DERA registration application to ascertain

what, if any, appreciable impact market participation of a given DERA may have on the distribution network.

Aggregation Review

Aggregation review will likely involve some engineering screens or studies in addition to screening of DERs for eligibility to participate in a DERA. Order 2222 explicitly allows a heterogeneous (or "mixed aggregation") DERA to include both load-modifying and power-injecting DERs. The review would therefore include combined analysis of interconnected (power-injecting) DERs and load-modifying resources to consider what their net impact on the system would be during periods of likely dispatch (given the services, availability schedules, and perhaps forecasted market needs). In some cases, this review may be relatively straightforward, for instance, where dispatch of a DERA is likely to be coincident with periods of high load. In other cases, it may require more sophisticated analysis, such as cases where a DERA is providing ancillary services or where dispatch is likely to contribute to peak load or power export to neighboring grids. At a minimum, and following a conservative approach, the DSO will probably want to study the scenario of simultaneous dispatch of all DERs in the DERA to their full capability under normal distribution system conditions (i.e., the dispatch of the DERA to its full technical capability).

The DSO may also study some other common variants of normal grid configurations, load and generation profiles, and possibly partial dispatch levels of the DERA, but distribution system topology is more frequently variable than transmission topology, and it is not practical for the DSO to examine DERA impacts for any scenarios other than normal configuration and possibly any frequently used switching configurations. A central idea of this coordination architecture is that the curtailment provisions (Section 3.2.3 below) are the recourse that gives the DSO flexibility to deal with situations that were not studied. After this review, the aggregator is allowed to make changes to the proposed DERA composition to address any issues identified by the DSO, and then it can proceed to register the DERA with the ISO market.

Aggregation Agreement

The DSO could create a pro forma DSO-aggregator aggregation agreement, which spells out the responsibilities of both parties, including provisions for the DSO to curtail DERA operation when needed for reliability, adherence by the aggregator to provisions of the interconnection agreement, and provision of information to the aggregator to enable it to estimate likely frequency, timing, and duration of curtailment so that it can estimate potential impacts on DERA financial viability. With such an aggregation agreement in place, the aggregator would be able to submit additional new DERAs without having to execute a new aggregation agreement.

This building block would include provisions for revising the DER members of a DERA when more or less permanent changes are made, for instance, when DERs are dropping out, are being added in, or are being modified with new technologies or technical capabilities.

This building block would also include provisions for revising the DER members of a DERA when more or less permanent changes are made, for instance, when DERs are dropping out, are being added in, or are being modified with new technologies or technical capabilities. For changes to DERA composition, the DSO could define "material" and "non-material" modifications to the DERA, such that the latter do not require re-study or a new aggregation review. This would be analogous to the provision for the individual DER interconnection process as described above.

3.2.3 Transparent, Non-discriminatory Provisions for Override

The DSO needs to establish "transparent, non-discriminatory" procedures for curtailing DERA operations if necessary (FR, 2020, paragraph 310). The timing of curtailment actions is discussed in Section 3.2.4 below. These procedures would probably live in the DSO tariff, with references in the interconnection agreement and aggregation agreement.

Transparency requires clear specification of the causes of curtailment, communication requirements, compliance requirements, and penalties for non-compliance. To be non-discriminatory, the DSO must fairly allocate limited distribution capacity among multiple DERAs that may use some of the same capacity.[4] There are a few possibilities for how to do non-discriminatory curtailment, such as pro rata curtailment, price-based mechanisms, tradable physical rights, or priorities based on interconnection. These are discussed in section 3.2.6 (p. 26).

> **There are a few possibilities for how to do non-discriminatory curtailment, such as pro rata curtailment, price-based mechanisms, tradable physical rights, or priorities based on interconnection.**

To curtail resources within a DERA, the DSO will need to be able to identify distribution system conditions under which DERA operations would lead to a potential reliability violation, and then communicate override instructions to the aggregator and ensure DERA compliance with these instructions. DSO interconnection studies for the individual DERs and the DERA aggregation review will generally ensure that DERA operation will not cause a problem under normal distribution configurations and certain extreme operating conditions such as peak and minimum load. It is likely, therefore, that curtailment instructions to the aggregator in advance of real-time operation will be related to abnormal configurations such as planned maintenance outages or switching of distribution circuits.

If overrides are relatively infrequent, ensuring compliance does not likely mean that the DSO needs telemetered output data for individual resources within a DERA (ISOs will only have telemetry for the DERA, not the individual resources), but it will likely mean that the DSO will need access to meter data for individual DERs within a DERA to be able to verify compliance after the fact, if necessary.

Real-time curtailment of the DERA or some of its constituent DERs would be in the form of direct instructions with which the DERA is legally obligated to comply, or possibly through remote direct control of DER inverters or meters by the DSO. These types of dispatch and control provide greater response certainty to the DSO than a price or other market signal that allows the resource some discretion in its response based on purely financial considerations. As such, these types of dispatch and control are comparable to what the California Independent System Operator (CAISO) calls "real-time operating instructions"—direct instructions which, if not followed, would constitute a tariff violation with legal and/or regulatory consequences.

3.2.4 Day-to-Day ISO Market and Operational Coordination

The DSO establishes procedures for informing the aggregator of the nature and expected duration of any changes to distribution system conditions that would constrain the operation of a DERA for which that aggregator is the operator. Such condition changes may be planned, in which case the aggregator will have advance notice of a need for reduction in DERA capacity; when unplanned, there could be a need for instantaneous reduction in DER capacity. The example below illustrates both types using a scenario involving an immediate reduction in DERA capacity that is expected to persist over 24 hours.

DSO Notification of Aggregator About Constrained Operation of a DERA

In the near term, the DSO notification to the aggregator may be as simple as indicating that a given distribution circuit is available (normal configuration, no constraint) or not available (abnormal configuration, all DERs on that circuit must be taken out of service), plus the expected start and end times of the constraint conditions. Thus, if a DERA spans multiple distribution circuits, the DSO would most likely need to curtail only the DERs on the problematic circuit, not the entire aggregation.

The DSO may be able to specify more granular constraint impacts for a DERA, but that gets more complicated.

4 It is important to note that if the DSO allows flexible interconnections with subsidiary physical dispatch rights relative to firm or deliverable interconnections, it will need such a procedure for allocating limited capacity to flexibly connected resources even under normal grid conditions.

The simple green/red approach above may be a useful starting point for getting the system up and running, to be refined later. The key is that this information will need to be communicated to the aggregator in an efficient, timely manner. Ideally, the communications process will be automated.

Aggregator Notification of the ISO About Reduced Capability

Upon receiving the system information from the DSO, the aggregator is responsible (under the ISO tariff and perhaps also under its aggregation agreement with the DSO) for immediately informing the ISO of its reduced capability through an outage/derate notification and, if necessary, adjusting its offers for future market intervals to be fully feasible in light of the distribution constraint. Failure to submit timely outage/derate notification to the ISO could be a tariff violation, whereas failure to fully comply with a cleared market offer (day-ahead schedule or real-time dispatch) would only be an uninstructed deviation with some financial impact.

An Illustration

Although real-time operations remain beyond many DU capabilities today, below is an illustration for how this could work for DUs in the future (based on CAISO market timelines).

The scenario is as follows. The aggregator has a DERA with 5 MW capacity (maximum power injection) composed of individual DERs distributed over two distribution circuits within a single transmission-distribution interface (PNode). Circuit A hosts 3 MW and circuit B hosts 2 MW of the DERA capacity.

At 9 am Monday, the DSO informs the aggregator of an immediate transformer problem that has taken out distribution circuit B, preventing 2 MW of the DERA capacity on that circuit from operating. The DSO expects the problem to continue for the next 24 hours until circuit B can be restored.

We will assume the time line of the CAISO spot market:

- Day-ahead offers for Tuesday must be submitted for all 24 hours by 10 am on Monday.
- Real-time offers must be submitted by 75 minutes prior to each operating hour (T-75).
- Outage/derate cards must be submitted immediately whenever the event occurs.

The following steps describe how the aggregator would use the DSO constraint information to modify its market offers and inform the ISO of its reduced capacity.

1. The aggregator immediately submits an outage/derate card to the ISO indicating DERA capacity reduction from 5 MW to 3 MW for HE10 (hour ending at 10 am) Monday through HE09 Tuesday.
2. The aggregator structures its day-ahead market offers for the DERA for Tuesday to reflect maximum 3 MW for HE01-09 and maximum 5 MW for HE10-24 (based on the expected 24-hour duration of the circuit B outage).
3. The aggregator structures its real-time market offers for Monday HE12-24 based on maximum 3 MW capacity. This may involve the aggregator buying back portions of the DERA's day-ahead schedules (which cleared in Sunday's day-ahead market) for hours where they exceed 3 megawatt-hours (MWh).
4. The ISO does not receive new real-time offers for 5-minute intervals from 9:10 am until 11:00 am, but the market optimization knows from the outage/derate card that the DERA's maximum output is 3 MW, so it will not dispatch the DERA for more than 3 MW capacity in any interval.
5. For the interval from 9:00 am to 9:10 am the ISO does not perform any new market optimization, so its previously issued dispatches to the DERA would reflect 5 MW capacity. Thus, the DERA may fall short of its day-ahead schedule or real-time dispatch. The imbalance on the ISO system is managed by regulation (automatic generation control) and may subject the DERA to uninstructed deviation charges.

3.2.5 Discussion: Avoiding More Complicated Approaches

We suggest that the approach outlined above can avoid more complicated approaches that have been advanced in some FERC Order 2222 discussions. Examples of these more complicated approaches include the following:

1. The DSO receives DERA day-ahead market schedules and real-time dispatch instructions, either from the ISO or from the aggregator, and reviews them for feasibility and takes some override action if needed.
2. As a further complication of (1), the DER aggregator provides to the DSO its plan for how it intends to dispatch the DERs in the DERA to comply with a given ISO schedule/dispatch (sometimes referred to as a deployment plan), which the DSO reviews for feasibility and takes some override action if needed.

The above features may seem appealing, but it is not clear what the DSO would do in response to this information in the day-ahead market, or whether there would be time to do anything in the real-time market. We suggest that adding these features to the approach outlined above would be costly and complicated, and add little or no incremental value. We suggest starting off with the approach outlined above and trying to identify scenarios where it would fail. Only then should it be considered whether further measures would be needed and would be cost-effective.

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3.2.6 DERA Curtailment Options

Here we describe some of the options for transparent and non-discriminatory procedures for the DSO to override the ISO's schedule or dispatch for the DERA. As noted earlier, Section 3.2 assumes that all DERs have firm interconnection status. Given firm DER interconnections, DSO overrides should not be needed under normal operating conditions, because the distribution system would have already been upgraded as needed to accommodate DER output under normal conditions during the interconnection process.

For the near term, relatively simple approaches for transparent and non-discriminatory procedures for DSO override could be:

- **Full curtailment of all net-injecting DERs on a circuit.** If a distribution circuit has a forced outage or is taken out of service for planned maintenance, the DSO could simply inform the aggregators who have participating DERs on that circuit that those DERs are not able to operate, as is done today.
- **Curtailment based on a percentage of installed capacity.** If DERA-1 has 2 MW and DERA-2 has 6 MW of injecting capacity on a given circuit, and conditions limit the circuit capacity to only 4 MW, then DERA-1 and DERA-2 would be allowed to inject 1 MW and 3 MW, respectively, for the duration of the circuit derate.
- **A "first in, last curtailed" approach.** DERAs would be curtailed on a derated circuit based on a specified key milestone date, such as the start of commercial operation, with the DSO curtailing the most recent date first and working back until the needed level of DER capacity reduction on the circuit is achieved.

For the near term, relatively simple approaches for transparent and non-discriminatory procedures for DSO override could be full curtailment of all net-injecting DERs on a circuit, curtailment based on a percentage of installed capacity, or a "first in, last curtailed" approach.

Over the longer term, more elaborate approaches to transparent, non-discriminatory override of DER schedules may be desirable.

- **Curtailment based on physical rights to the distribution system.** DERs that elected non-firm access (i.e., flexible interconnection) during the interconnection process are curtailed before those that elected firm access and paid for any distribution system upgrades required. A further elaboration of this idea could be to allow firm physical rights to be tradable, where a DER owner or aggregator that owns firm rights can trade them to another DER owner or aggregator for non-firm rights. Physical rights used to be common the transmission system, but have given way to financial rights in ISO markets that utilize locational prices.
- **Economic curtailment.** In this approach the DSO curtails DERs according to some economic bidding structure. One way would be to use the DERA's economic bids to the ISO. For instance, a DER that is part of a DERA that submits a net energy supply bid for $20/MWh would be curtailed before a DER whose DERA submits a bid for $10/MWh. This would require the DSO to have visibility into DERA bids and the software capabilities to do economic dispatch, and therefore is likely to be a longer-term option.
- **Economic dispatch of a distribution-level energy market operated by the DSO.** Under the total DSO model discussed in Section 2, the DSO could optimize the operation of DERs within a local distribution area (i.e., connected to the wholesale market at a single transmission-distribution interface substation) based on their individual bids, subject to distribution system conditions. This would be analogous to the ISO's wholesale market security-constrained economic dispatch. The tariff governing such a market could be designed to satisfy the requirements of transparency and non-discrimination.

3.3 DER Aggregation Use Cases

Here we offer use cases by which to explore different kinds of DERAs providing different kinds of services, to help assess potential gaps in regulation, market rules, and DSO and ISO operating procedures. We analyze each use case using the matrix of functional steps and responsibilities included as an appendix to this report.

3.3.1 Definition of a Use Case

A DERA use case is defined by two sets of attributes. The first set is the physical characteristics of the DERA: the types of individual DERs that comprise the DERA, the quantities of each type and the sizes of the DERs, the physical interconnection point of each DER (behind or in front of the customer meter), and the physical distribution of the DERA (the specific distribution circuits and ISO pricing nodes where the various DERs are located). These characteristics would typically be specified by the DER aggregator at the time of registering the DERA with the DSO and the ISO, and would determine the physical performance capabilities of the DERA.

The second set of attributes is the services the DERA intends to provide, including wholesale market services (energy, ancillary services, capacity), distribution grid services (avoidance of circuit upgrades, congestion relief), end-use customer services (such as retail demand charge management by behind-the-meter DERs), and any retail programs or tariffs that may apply to individual DERs.

3.3.2 Use Cases Considered

The number of possible use cases is essentially unlimited. To make the analysis useful, this report starts with a very simple use case and then constructs a few more complicated variants and sub-cases to identify their implications for the performance of the required functional steps in the matrix included in the report's appendix.

We begin with a very simple use case and then construct a few more complicated variants and sub-cases to identify their implications for the performance of the required functional steps in the matrix included in the appendix.

Use Cases 1a-1d. Front-of-Meter (FOM) DERs; Wholesale Market Services Only

- All DERs in the DERA are connected directly to the distribution wires (i.e., in front of the customer meter) and thus are not co-located with retail load; therefore, there is no uncertainty about whether a DER provided services to the customer or the ISO. The DERA participates in the ISO markets only and does not provide any distribution grid services.
- **Use Case 1a.** All DERs are located on a single distribution circuit below a single ISO pricing node (transmission-distribution substation). The DERA participates in the ISO energy market only.
- **Use Case 1b.** All DERs are located on a single distribution circuit. The DERA provides contingency reserves to the ISO market.
- **Use Case 1c.** DERs are located on multiple distribution circuits below a single ISO pricing node. The DERA participates in the ISO energy market only.
- **Use Case 1d.** DERs are located on multiple distribution circuits below a single ISO pricing node. The DERA participates in the ISO energy, contingency reserves, and regulation markets.

Use Case 2. FOM DERs; Dual-Use DERA

The DERA provides wholesale energy to the ISO and distribution grid services to the DSO, specifically to serve as a non-wires alternative to a distribution circuit upgrade and be dispatched by the DSO for congestion relief on that circuit.

Use Cases 3a-3b. Heterogeneous DERA Containing Both FOM and Behind-the-Meter (BTM) DERs; the BTM DERs Are Co-located with Retail Load

- **Use Case 3a.** None of the BTM DERs participate as demand response resources; therefore, FERC's Orders 719 and 745 do not apply.[5]
- **Use Case 3b.** Some of the BTM DERs participate as demand response resources; therefore, FERC Orders 719 and 745 apply.

5 See FERC Order 2222-B which clarifies the applicability of FERC Orders 719 and 745 to heterogeneous DERAs that contain some DERs that participate as demand response resources but are not entirely composed of demand response resources.

3.3.3 Use Case Analysis Results

In this section we check each use case against the functional steps listed in the matrix in the appendix to identify concerns, issues, or requirements specific to the use case.

Use Cases 1a-1d

FOM DERs, wholesale market services only. All DERs in the DERA are connected directly to the utility distribution system. They are not co-located with retail load; therefore, there is no uncertainty about whether a DER provided services to the customer or the ISO. The DERA provides wholesale market services only, and the DERA is located entirely below a single ISO wholesale pricing node. The DERA does not provide any distribution grid services.

Use Case 1a. All DERs are located on a single distribution circuit below a single ISO pricing node (transmission-distribution substation). The DERA participates in the ISO energy market only.

This is the simplest use case and does not raise any unique concerns beyond the matters which are applicable to all use cases and reflected in the columns of the matrix. One factor that may be a concern for the aggregator is that, because all DERs in the DERA are located on a single distribution circuit, a derate or abnormal condition on that circuit may take out the entire capacity of the DERA. See matrix functions 15 and 24.

Use Case 1b. Single distribution circuit; DER provides contingency reserves to the ISO market.

The added complexity of providing contingency reserves to the ISO may require that the DSO grant the DERA

a higher degree of priority or certainty that it will not be curtailed due to an abnormal distribution system condition. Such a requirement would likely derive from the ISO's criteria for certifying a DER or DERA to provide contingency reserves, but these criteria will probably vary among the different ISOs.[6] This means that if the aggregator wants the DERA to certify for ISO contingency reserves and that requires the DERA to have priority protection against DSO curtailment, there will need to be special provisions specified either in the DSO-aggregator aggregation agreement or in the interconnection agreements with the individual DERs, or possibly both. The question of how the DSO would implement such a priority is an open one. See matrix functions 2, 4, 11, 15, and 24.

Use Case 1c. DERs are located on multiple distribution circuits below a single ISO pricing node. The DERA participates in the ISO energy market only.

This is similar to use case 1a, but now the distribution of the individual DERs over multiple distribution circuits reduces the risk to the aggregator of losing the entire DERA capacity due to an abnormal circuit condition. See matrix functions 15 and 24.

Use Case 1d. DERs are located on multiple distribution circuits below a single ISO pricing node. The DERA participates in the ISO energy, contingency reserves, and regulation markets.

As in use case 1b, this raises the question of the need for special priority against curtailment, for example, firm distribution rights, if required by the ISO's certification criteria. Because the DERA uses multiple distribution circuits, it may be possible to mitigate the risk of reserve curtailment by allowing the DERA to certify for a smaller quantity of reserves than the full amount of capacity it can offer for energy, rather than securing special priority from the DSO. The details of such arrangements would likely vary across the different ISOs based on their criteria for certifying a DERA to provide reserves. See matrix functions 2, 4, 11, 15, and 24.

Use Case 2

FOM DERs, dual-use DERA. The DERA provides wholesale energy to the ISO and distribution grid services to the DSO, specifically to serve as a non-wires alternative to a distribution circuit upgrade and be dispatched by the DSO for congestion relief on that circuit.

This use case brings up functional steps that are not represented in the matrix, which is focused on DERA participation in the ISO markets and not on dual services provided to both DSO and ISO. There are several matters that need to be addressed to enable such dual uses:

- Whether the DSO procures distribution system services from a DERA or from specific DERs within a DERA.
- Whether there are provisions in the aggregation agreement to enable the DSO to "unbundle" a subset of DERs from a DERA to provide distribution services. This will probably be necessary if the DERA spans multiple distribution circuits, because distribution system needs are generally more locationally granular than the span of the DERA.
- How to undertake DSO scheduling and dispatch of DERA/DERs for distribution system services. This requires formulating a coordinated time line that places DSO decisions against the ISO market time line.
- What rules should be in place regarding eligibility for a DER/DERA to provide dual uses and the relative priorities between the services that a DER/DERA can provide. A 2018 decision by the California Public Utilities Commission on storage provided a useful framework for categorizing multi-use applications to determine which pairs of services could be compatible and the relative priorities between members of each pair (CPUC, 2018).[7] Although the decision was issued in the context of a proceeding on energy storage, the findings and the framework are applicable to DERs more generally. It is not clear whether any of the ISOs are utilizing these results in their Order 2222 compliance or are taking some other approach to devise rules for multiple-use applications.

6 CAISO keeps contingency reserves out of the normal real-time dispatch and only calls on them when a contingency occurs. PJM and the Midcontinent Independent System Operator include their contingency reserves in the normal dispatch and apply a constraint in the optimization to make sure there is enough unloaded reserve-certified capacity available to meet a contingency.

7 Appendix B to the decision was the result of a stakeholder workshop process conducted jointly by the California Public Utilities Commission and CAISO to address multi-use applications of distributed storage.

- How to operationalize the telemetry, performance measurement, and settlement of DER/DERA providing services to both DSO and ISO. See matrix functions 6, 8, 9, and 27.

Use Cases 3a-3b

Heterogeneous (or mixed) DERA containing both FOM and BTM DERs; the BTM DERs are co-located with retail load, participating only in the ISO energy market. FERC Order 2222, as clarified by Orders 2222-A and 2222-B, does not apply to aggregations that contain only demand response resources—resources that modify load on the grid and participate as demand response in either an ISO market or a utility program. Order 2222 does allow demand response resources to participate in a heterogeneous DERA that also contains DERs that are not demand response, subject to the right of the relevant electric retail regulatory authority (RERRA) to prohibit demand response DERs to participate in this manner under the opt-out provision that FERC clarified in 2222-B. For a DERA that contains both DERs that are demand response and DERs that are not, prior FERC Orders 719 and 745 apply to the dispatch and settlement of the demand response members of the DERA.[8]

Use Case 3a. None of the BTM DERs participate as demand response resources; therefore, FERC Orders 719 and 745 do not apply.

BTM DERs are typically installed by retail customers to provide services to the customer, which may include load shifting during the day, management of exposure to time-of-use retail rates and demand charges, and resilience services (providing power to the customer when grid service goes out). Because the BTM DERs are co-located with retail load, the provisions for metering and settlement of the DERA must appropriately distinguish services to the customer from services provided to the DSO and to the ISO market. This may require an additional sub-meter on the DER device itself, plus a method to establish a baseline that represents the DER device's normal behavior when it is not dispatched for DSO or ISO services. The DSO review of the proposed DERA would also include verifying that all DERs in the DERA are not under any conflicting retail program or tariff and are eligible to participate in a DERA. This may involve the load-serving entity in jurisdictions where the load-serving entity is separate from the DSO. See matrix functions 3, 8, 9, 27, and 28.

Use Case 3b. Some of the BTM DERs participate as demand response resources; therefore, FERC Orders 719 and 745 apply.

This use case has all of the issues of the previous case, plus the requirement that the ISO apply a net benefits test in making the decision to dispatch the demand response resources. See matrix functions 17, 21, 27, and 28.

Use Case Extensions

Further use cases that can be examined include:

- A multi-node (multiple locational marginal prices) use case building on any of the three primary use case types discussed above. See matrix functions 5, 6, and 7.
- DERA participation in an ISO-operated capacity market (to which Order 2222 applies) or a resource adequacy requirement that is met through bilateral procurement (to which Order 2222 does not apply). This requires rules for determining the capacity value of the DERA and any ISO market participation requirements or must-offer obligations. Again, this can be built on any of the three primary use cases discussed above. See matrix functions 12, 13, 14, and 27.

8 FERC Order 2222-B clarifies the opt-out provision and the applicability of previous FERC Orders 719 and 745 to a heterogeneous DERA that contains some DERs that participate as demand response resources but is not entirely composed of demand response resources.

4 Broader Gaps in DER Integration

Nearer-term implementation issues around Federal Energy Regulatory Commission (FERC) Order 2222 are a small subset of the challenges and gaps for better integrating distributed energy resources (DERs) into wholesale markets and operations, and into the electric power system more broadly. Order 2222 applies only to the DER aggregator model from Section 2 and does not address broader issues around distribution-level integration of DERs. From the perspective of a future state where the distribution and transmission systems are more interactive and integrated, in which DERs may be providing both distribution-level and transmission-level services, the gaps to DER market integration are much broader than those required for nearer-term Order 2222 implementation.

This section describes these broader gaps to DER integration, across seven interrelated categories of activities:

- Distribution and transmission planning
- Distribution interconnection
- Communications and data-sharing
- Distribution operations
- Independent system operator (ISO) market design
- Market regulation
- Utility regulation and business models

4.1 Distribution and Transmission Planning

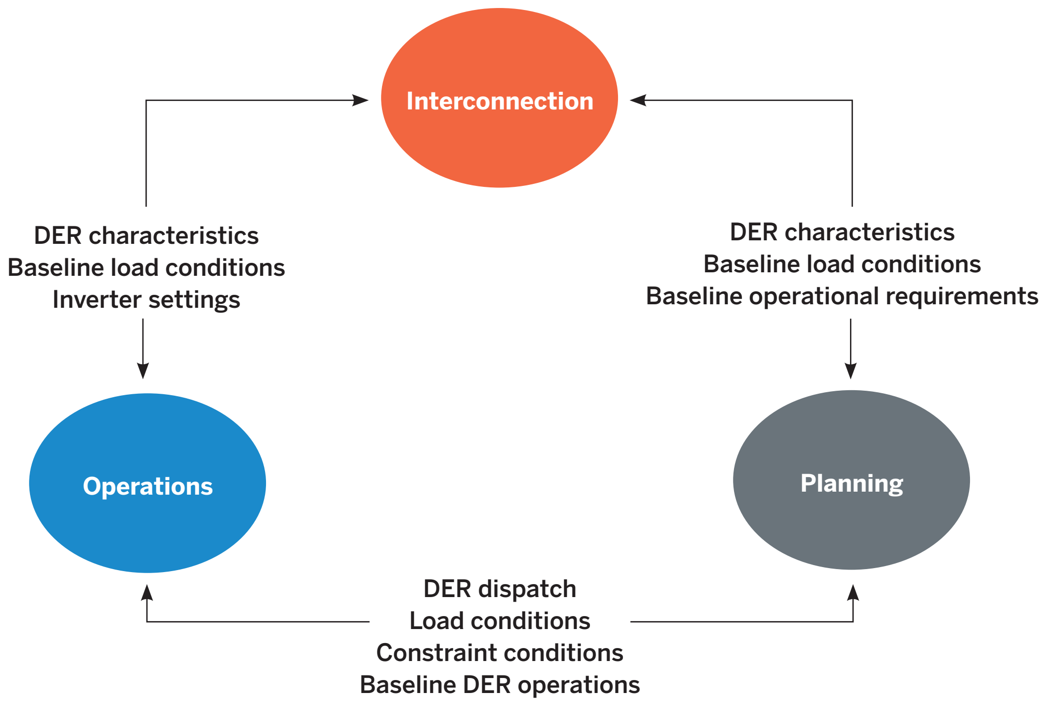
Distribution and transmission systems provide the foundations for electricity markets by enabling wholesale transactions and ensuring that systems can be reliably operated. DER integration will require several changes in distribution and transmission planning, two of which we describe here: a more integrated approach to distribution planning, interconnection, and operations; and closer coordination between planning of distribution systems and transmission systems.

4.1.1 Utility Planning-Interconnection-Operations Integration

Distribution planning, interconnection, and operations are three distinct functions within distribution utilities (DUs). Historically, most DUs have not proactively planned for DER-driven distribution upgrades; rather, upgrades are typically planned to accommodate load growth or are triggered through the interconnection process. To better anticipate longer-term distribution investment needs and facilitate DER development, a growing number of public utility commissions are requiring utilities to incorporate DER forecasts into their distribution planning, including incorporating DERs into load forecasting and generating hosting capacity maps. As more DUs do so, closer integration between distribution planning, interconnection, and operations will help to improve all three processes (see Volkmann (2018)).

Closer integration includes incorporating information from distribution planning into interconnection screens and studies, from interconnection and operations into distribution planning, and from operations into planning and interconnection. Figure 5 illustrates some (though not all) of the information that could be shared between these functions to ensure more efficient integration of DERs.

FIGURE 5
Information-Sharing Among Distribution Interconnection, Planning, and Operations



This figure illustrates some of the information that could be shared between distribution interconnection, planning, and operations to ensure more efficient integration of DERs.

Source: Energy Systems Integration Group.

One example of incorporating information from interconnection into planning would be including inverter settings, as defined in interconnection agreements, in planning models. A lack of integration among these three functions may lead to higher costs, for instance, if DUs make upgrades to the distribution system to deal with reliability violations that are identified in planning or interconnection studies but have not emerged in actual operations. Closer integration will require changes in DU organization and interoperability between different software platforms that integrate information across different parts of the utility.

4.1.2 Utility/ISO Planning Coordination

In areas with high DER growth or complex grid configurations, distribution and transmission planning will need more coordinated processes and a consistent set of assumptions about DER and load forecasts and planned infrastructure investments. Planners will need to account for the amounts, locations, capabilities, services, and profiles of DERs and of loads in their forecasts.

DER forecasting for planning purposes includes both DER adoption levels and the impacts of DER operations on distribution-level and system-level net demand. For electric vehicles and generation or loads paired with storage, DER net demand forecasts will need to determine what should be included in the baseline forecast and what should be incremental to the baseline. For instance, what should the baseline forecast assume about electric vehicle charging profiles? As a second order effect, DER forecasts will also need to account for planned infrastructure investments and their impact on DER development. For instance, new transmission may affect aggregated locational marginal prices and zonal capacity prices, and thus the timing and location of DER investments.

Lack of coordination could result in higher costs and reliability challenges. Under-forecasting of DER growth by ISOs, for instance, could lead to overbuilding of transmission and excess bulk generation capacity, which would lead to higher system costs. Conversely, over-forecasting of DERs could lead to underbuilding of transmission infrastructure and reliability challenges.

Under-forecasting of DER growth by ISOs could lead to overbuilding of transmission and excess bulk generation capacity, which would lead to higher system costs. Conversely, over-forecasting of DERs could lead to underbuilding of transmission infrastructure and reliability challenges.

Two key gaps in planning coordination include poor DER forecasting and the lack of regular, systematic processes for planning coordination. DUs and ISOs will likely use different approaches to forecasting DERs and incorporating DERs into load forecasts, not least because of their different geographic scales and operational perspectives. DUs, however, have access to information through interconnection data and meter data that ISOs do not, which could help to improve the accuracy of ISO load forecasts as DER forecasting improves. Both DUs and ISOs will increasingly need to find ways to coordinate their DER forecasts with state policy goals, for instance, through joint studies.

The recently created Task Force on Comprehensive Electricity Planning of the National Association of Regulatory Utility Commissioners and the National Association of State Energy Officials has done much to advance the conversation on integrating transmission, distribution, and resource planning processes and frame it for different market and grid contexts.[9] An important next step will be in developing processes for DUs and ISOs to collaborate on DER forecasting and develop workable approaches to coordinating their planning processes.

4.2 Interconnection of DERs to the Distribution System

Distribution interconnection is the gateway to DER participation in wholesale markets. There are numerous longstanding and emerging barriers to DER interconnection to the distribution system related to the interconnection process, its technical requirements for interconnecting DERs, and the identification and allocation of any system upgrade costs triggered through interconnection studies.

State regulatory commissions have made significant progress in improving DER interconnection processes over the last decade. However, several gaps remain, two of the most important of which include interconnection standards and the relationship between interconnection and operations, which we discuss under the rubric of "flexible interconnection."

4.2.1 Interconnection Standards

DERs can cause voltage disturbances on the distribution system, including voltage irregularities and/or interaction with existing volt/VAR optimization (or VVO) schemes. However, when DERs are fitted with advanced inverters, they can provide significant benefits to both the transmission and distribution systems, and advanced voltage regulation modes can allow for higher hosting capacity of DERs on feeders. Improved voltage and frequency ride-through characteristics allow DERs to stay online and keep supporting the grid even through grid disturbances. The IEEE 1547-2018 standard provides a means to both address utility concerns around voltage issues and extract the benefits of advanced inverters by requiring advanced inverters that can provide autonomous voltage regulation (e.g., volt-VAR or volt-watt) and have the ability to ride through voltage disturbances (Horowitz et al., 2018).[10] Despite endorsement from the National Association of Regulatory Utility Commissioners in 2020 (NARUC, 2020), only a limited number of states have opened proceedings on the adoption and

9 See https://www.naruc.org/taskforce.

10 For a brief introduction to smart inverters and IEEE 1547-2018, see O'Connell, Volkmann, and Brucke (2019). For a lengthier treatise, see Narang et al. (2021).

implementation of IEEE 1547-2018 (IEEE Standards Association, 2021).

To support the implementation of IEEE 1547-2018, the critical component that DUs need to determine is setpoint guidance for smart inverters, according to the needs of their distribution systems.[11] Some utilities have raised the possibility that direct control of advanced inverters could be necessary to address reliability challenges related to DERs. However, direct control would require more extensive investment in DER management systems or advanced distribution management systems as well as greater intrusion into the behavior of customer-owned on-site assets. To date, the incremental benefits of such measures, beyond what is feasible through implementation of IEEE 1547-2018 for voltage regulation, have not been justified. The discussion in Section 3 suggests that direct control is likely not necessary for the override of ISO schedules or dispatch, but DUs do require a way to determine whether individual DERs are following override instructions.

4.2.2 Flexible Interconnection

Current practice in distribution interconnection is to upgrade the distribution system to enable DERs to be able to deliver their full net output (power injection minus withdrawal) during the normal grid configurations studied during interconnection. Upgrades can lead to significant costs for DER owners to address conditions that may occur infrequently.

As has been the case on the bulk power system, it is unlikely that it will be societally cost-effective to upgrade the distribution system to allow all DER injections to be fully deliverable to the relevant transmission-distribution interface at all times. An alternative is to provide for "flexible" interconnections, whereby the DER may avoid paying for costly upgrades in exchange for agreeing to be curtailed when distribution circuit capacity is scarce. This flexible approach to interconnection has been common practice on the transmission system for more than 20 years.[12]

To allow flexible interconnection on the distribution system, regulators and DUs will need to address two overarching questions. First, how should utilities determine

With a flexible interconnection, the DER may avoid paying for costly upgrades in exchange for agreeing to be curtailed when distribution circuit capacity is scarce. This flexible approach to interconnection has been common practice on the transmission system for more than 20 years.

11 Even with "set it and forget it" settings, utilities should reassess the efficacy of these settings on some regular interval.

12 In 1998, FERC ruled in Docket No. ER98-3853-000 that generators in New England should have the option to pay for re-dispatch rather than pay transmission expansion costs, and that designs for interconnection cost allocation and congestion management should be developed in tandem (see https://www.govinfo.gov/content/pkg/FR-1998-11-27/html/98-31611.htm). Over time, all U.S. ISOs have moved to nodal dispatch and locational marginal prices as an alternative to transmission expansion.

minimum reliability upgrades versus those that could be avoided through curtailment or re-dispatch of DERs? Second, how should utilities ensure that procedures for curtailing or re-dispatching flexible interconnections are transparent and non-discriminatory? A larger number of flexible interconnections could warrant consideration of independent distribution system operations, governed by a distribution open access tariff that stipulates rules for non-discriminatory operations.

The practice of flexible interconnection remains at an early stage in the United States. Some utilities have piloted flexible interconnection,[13] and the Electric Power Research Institute has undertaken studies of the value of and curtailment rules for flexible interconnection (EPRI, 2020; 2021). The experience of the United Kingdom, where utilities now have extensive experience with flexible interconnections, could provide a useful reference for the United States.[14]

In the future, DUs and distribution system operators may need more operational communications with ISOs, including during day-ahead and intraday scheduling, real-time dispatch, automatic generation control signals, and emergency operations.

4.3 Communications and Data-Sharing

The day-to-day and longer-term functioning of wholesale markets relies on frequent communication and sharing of information. Beyond the communication needs identified in Section 3, growth in DERs will create two kinds of communication gaps: operational communication between DUs and ISOs, and data-sharing between DUs and DER aggregators.

4.3.1 DU/ISO Communication

Real-time operational communication between DUs and ISOs is currently limited. In the future, however, DUs and distribution system operators (DSOs) may need more operational communications with ISOs, including during day-ahead and intraday scheduling, real-time dispatch, automatic generation control signals, and emergency operations. Depending on how a regulatory jurisdiction specifies the future DSO's functional responsibilities for DER coordination, ISOs may or may not need more information on distribution system conditions. It will be important to ensure that DUs and ISOs can make use of the information they receive, rather than assuming that more information is always better. For instance, providing DUs with real-time dispatch information for DER aggregations is not meaningful if DUs are not yet optimizing resources on the distribution system.

4.3.2 DU/Aggregator Data-Sharing

In ISO markets, ISOs provide interconnecting customers with an extensive amount of data on demand, demand forecasts, historical market prices, historical ancillary service procurement, congestion, resources in the interconnection queue, and so on. On the distribution system, utilities in some states have begun to provide hosting capacity information to DER developers, to encourage them to make more efficient use of the distribution system. However, the amount of information that DUs provide on loads, anticipated load growth, and DERs in the interconnection queue remains relatively limited. Without this information, DER developers will find it more difficult to know when and where to best site projects.

4.4 Distribution Operations

To support DER integration into wholesale markets, distribution operations will need to become increasingly sophisticated over time, with network monitoring, communications, and control capabilities that mirror those on the bulk power system. For many DUs, this implies first increasing their organizational and functional capacities to meet emerging industry practices around distribution system management, through benchmarking

13 See, for instance, Iberdrola's Flexible Interconnect Capacity Solution pilot at https://www3.dps.ny.gov/W/PSCWeb.nsf/All/B2D9D834B0D307C685257F3F006FF1D9.

14 See, for instance, Western Power Distribution's "alternative connections" option at https://www.westernpower.co.uk/connections-landing/connection-offers-and-agreements/alternative-connections.

existing practices and identifying gaps. In areas with higher DER growth, advancing distribution operations will likely require discussions on the potential functions of DSOs.

4.4.1 Least-Regrets Operational Enhancements

DUs currently manage distribution networks by controlling distribution switchgear and reconfiguring the networks in response to changing loads, generation, or disturbances. Utilities control switchgear using a combination of manual and, to a lesser extent, autonomous controls. With manual controls, distribution operators monitor conditions and manually transfer loads as necessary between feeders and substations. With autonomous controls, intelligent switching reacts to system conditions in real time and, in a worst case, fuses and/or breakers trip to protect equipment from thermal overloading. In more sophisticated networks, there is more of a need for both manual and automated control, as well as tighter integration between supervisory control and data acquisition systems (SCADA), advanced distribution management systems, and customer meter data (advanced metering infrastructure).

DUs vary in their visibility of conditions (voltage, current, equipment status) in different parts of the distribution system, their ability to communicate on shorter time scales with customers (both DER and non-DER), their integration of DER operational data into distribution operations, and their ability to respond manually or automatically to changing system conditions in real time. A first step toward improving distribution operations will be to identify least-regrets enhancements in visibility, communications, DER operations, and real-time controls that will be needed regardless of whether a DU has more limited distribution operations or becomes a total DSO.[15] This process of identifying least-regrets enhancements could be facilitated by the U.S. Department of Energy.

4.4.2 DSO Functions

A fundamental DSO design consideration is the allocation of responsibilities for active coordination of DER activity between the DSO and ISO. More centralized visibility and direction of DER activity under the ISO might seem to be the natural extension of today's centralized optimization by ISOs, but incorporating DERs at large volumes will require ISOs to extend their

15 Ongoing efforts in this regard include the U.S. Department of Energy's Modern Distribution Grid Project (https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx) and technical assistance under the Grid Modernization Laboratory Consortium (https://gmlc.doe.gov/projects/4.2.2).

network models and real-time visibility capabilities to include distribution system conditions. Alternatively, more active management of DERs by DSOs implies the need for capabilities that parallel those of ISOs for the transmission system. The organizational structure (see the section below on market regulation) and the potential functional responsibilities of potential DSOs remain to be determined, and there are likely to be multiple feasible end states and transition pathways.

Key questions for DSO functions include:

- **Monitoring needs:** To what level of spatial and temporal granularity do DSOs need monitoring and state estimation for the distribution system?
- **Dispatch versus control:** To what extent and for what types of functions would DSOs dispatch DERs or send market signals versus directly control their output? A dispatch approach could take several forms. Dispatch could involve a security-constrained market optimization by the DSO that generates dispatch signals, which DER owners and aggregators respond to or face imbalance charges and possibly penalties. Or it could more simply involve performance contracts between the DSO and the DER operators tailored to specific DSO operating needs. In contrast, control implies that DSOs directly operate DERs to manage distribution security constraints. Dispatch and control are not exclusive—ISOs use a combination of dispatch and control—but greater reliance on one or the other involves different levels of sophistication in DSO functions.
- **Market operations:** To what extent would DSOs be responsible for operating markets at distribution level, including market clearing and settlement functions? What products might such markets transact, and what types of actors would participate?
- **ISO interactions:** How would DSOs interact with ISOs, specifically with regard to transmission-distribution interface operations, and what rules and processes are needed to support these interactions?
- **Interoperability:** How can ISOs ensure that distribution systems with different kinds of DSOs are interoperable with their transmission systems and markets?

How these functions might evolve is still a work in progress. Jurisdictions may choose to have more or less active DSOs or may choose different approaches to DSO functions. California's recent Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future will include an exploration of DSO functions (CPUC, 2021), but a national conversation on DSOs could accelerate understanding of potential DSO forms and functions.

4.5 Market Regulation

Changes in market regulation are needed to support DER integration into wholesale markets, both for longer-term implementation of FERC Order 2222 and to enable a broader set of structural participation models for DERs. These changes include rules to ensure non-discriminatory distribution interconnection and operations and the resolution of issues around state-federal jurisdiction.

Approaches to ensuring non-discriminatory distribution operations are in the very early stages. Although individual states may lead in the development of approaches, having some degree of national coordination and standardization in approach would be broadly beneficial for the industry in facilitating efficient implementation across states.

4.5.1 Non-discriminatory Distribution Operations

Distribution operators will be required to ensure that their overrides of DER schedules and dispatch, and in the longer term perhaps their own dispatch of DERs, is transparent and non-discriminatory. DSOs will need to provide non-discriminatory distribution service across a range of DER arrangements: DERs participating in ISO markets through aggregations, DERs operated against a load-serving entity's tariff or procured by a load-serving entity, and DERs procured and operated directly by the DSO for distribution system services.

To align incentives, and similar to FERC Order 888's requirements for the transmission system, non-discriminatory operation of the distribution system will likely require at least functional unbundling of DU operations and infrastructure planning from its retail load-serving entity operations. This may come in the form of some sort of DSO and an accompanying open access distribution tariff, at one end of the spectrum, or it may come in the form of separation in DU functions, akin to the functional unbundling of transmission operators required in FERC's Order 888 issued in 1996. Approaches to ensuring non-discriminatory distribution operations are in the very early stages. Although individual states may lead in the development of approaches, having some degree of national coordination and standardization in approach would be broadly beneficial for the industry in facilitating efficient implementation across states.

4.5.2 State-Federal Regulatory Jurisdiction

Integrating DERs into wholesale markets will create multiple areas of overlapping state and federal regulatory jurisdiction, including distribution planning, interconnection, operations, and markets and tariffs. In Order 2222 and in previous orders, FERC has indicated that states have predominant jurisdiction over distribution systems and retail tariffs. However, in scenarios where larger numbers of DERs are participating in wholesale markets through DSOs, exclusive jurisdiction will need to give way to a more collaborative approach around areas of overlapping jurisdiction. Solutions to overlapping jurisdiction are best negotiated among states and the federal government, rather than being adjudicated by the courts, which suggests the need for a proactive approach to identifying and developing workable solutions to future jurisdictional challenges.

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4.6 ISO Market Design and Demand-Side Designs

ISOs have made significant progress in developing participation models for DER aggregations, supporting implementation of Order 2222. Over the longer term, however, ISO markets may need to support more active participation of DERs through demand bids, which we refer to here as demand-side designs.

Direct load-side participation in ISO markets—participation through demand bids—is typically limited to bidding demand in day-ahead markets, with market settlement at aggregated locational marginal prices. This means that ISOs have limited ability to use demand bids to resolve imbalances and congestion that arise after the day-ahead market closes, resulting in higher costs. Allowing market-based approaches to load participation during the operating day could lower costs and improve reliability, although it would require market design changes.

As discussed in Section 2, ISOs currently clear real-time markets using their own 5-minute load forecasts, address any sub-5-minute imbalances using regulation reserves and automatic generation control, allocate the costs of regulation reserves to all loads, and settle real-time load deviations at spatially and temporally aggregated real-time locational marginal prices. Clearing real-time markets with demand bids would likely require higher regulation reserves and allocation of reserve costs to loads that have sub-5-minute imbalances.

Given the significant number of vertically integrated utilities participating in ISO markets, demand participation in 5-minute markets may raise concerns around demand-side market power. However, between current practice and load participation in 5-minute markets with locational marginal price settlement, there may be other strategies for load-side participation, such as hour-ahead financially settled markets or the California Independent System Operator's 15-minute market. As yet, there has not been a structured discussion on what these options might be. In principle, participation by DERs through demand bids in ISO markets should be a mirror equivalent to participation through supply offers.

For DUs, there are opportunities to better understand customer the behavior to inform day-ahead market demand bids, and possibly to incorporate customer information through direct customer or aggregator interactions. In these interactions, DUs could integrate bid information from customers or DER aggregators directly into their demand bids and settle customers or aggregators using day-ahead market and real-time market prices. For many DUs, this kind of interaction would require new communications tools and enhancements to billing systems.

4.7 Utility Regulation and Business Models

Investor-owned utilities account for around 60 percent of electricity sales in the United States (EIA, 2021). There are several areas of misalignment between investor-owned utilities' financial incentives and the interests of DER customers and aggregators, as well as the broader societal goal of maximizing the value of DERs in the electric power system (see Cross-Call et al. (2018)). Better alignment of incentives will require changes in regulation and tariffs.

4.7.1 Incentives for Maximizing DER Value

Several states have made changes in ratemaking and implemented performance incentive frameworks that attempt to better align utility incentives with maximizing the system value of DERs (Cross-Call et al., 2018). Changes in incentives must address the inherent problem of having a regulated utility involved in distribution infrastructure planning, resource procurement and utility programs, and distribution system operations. This challenge is more significant at the distribution level than at the transmission level, because many DUs also serve at least some amount of retail load. As a result, incentive alignment is likely to be an ongoing challenge that will require focus and resources at the state level.

4.7.2 DER Compensation

A large share of DERs have historically been compensated through utility procurement and programs, net energy metering tariffs, and avoided cost–based PURPA (Public Utility Regulatory Policies Act) contracts. DER participation in utility procurement and programs takes diverse forms. For instance, DERs might provide energy and capacity to a DU through virtual power plants or all-source procurements, or they could more narrowly focus on capacity, such as where DER aggregations are procured for resource adequacy or non-wires alternatives but then otherwise allowed to participate in the wholesale market.

In all of these cases, the goal of DER tariffs and other methods of compensation is to encourage DERs to site where they have the most system value and operate in alignment with system operating needs. This implies aligning DER compensation with wholesale energy, capacity, and ancillary service market prices; marginal transmission costs; and distribution circuit and transformer capacities; which in some cases will mean unbundling utility costs in DER tariffs, as in New York's Value of DER tariff. It also implies providing tariff or other incentives for efficient use of the distribution system. On the whole, tariffs (generation, transmission, and distribution) should be designed to incentivize the flexibility that can be provided through the energy storage and load management that DERs can bring.

Future DER compensation mechanisms are likely to be complex, and regulators will have to navigate between simplicity and efficiency, between marginal cost– and average cost–based tariffs, between tariffs and competitive mechanisms for DER compensation, and between DER-specific compensation and rates that are consistent across all customers (DER and non-DER) within a customer class.

5 Conclusions and Recommendations

With supporting changes in operations, markets, planning, and regulation, growth in distributed energy resources (DERs) has the potential to provide significant value to customers, distribution systems, and wholesale markets. In distribution systems, effective siting and operation of DERs can reduce the need for distribution upgrades while still supporting load growth, increased electrification, resilience to extreme weather, and rising levels of distribution-level generation. In wholesale markets, DERs can provide a new source of operational flexibility and competition, reducing energy and ancillary service market costs, resource adequacy capacity, and transmission charges for load-serving entities. For customers, DERs can be tailored to their needs and preferences while defraying some of their costs by providing and being compensated for distribution-level and wholesale market benefits.

To maximize DERs' value, the distribution and transmission systems will need to be increasingly planned as an integrated system and their operation more closely coordinated. The Federal Energy Regulatory Commission (FERC) Order 2222 provides a push toward this more interactive, integrated electricity system. It remains to be seen how effective Order 2222 will be, but at the very least it will likely spur progress on distribution system monitoring and communications, both related to DERs and more broadly. It has already galvanized new thinking about distribution interconnection, planning, operations, and markets.

Direct participation by DER aggregators in ISO markets, the focus of Order 2222, is one of several pathways—referred to as structural participation models in this report (Section 2)—to integrating DERs into wholesale markets and operations. The United States currently lacks consensus on what the different structural participation models are, how they might evolve, what a tractable number of structural participation models for distribution system operations might be, and terminology around these models and distribution system operations. As shown by the Australian and United Kingdom open networks initiatives (the subject of the second report in this series), it can be productive to undertake a process of building consensus around concepts and definitions of structural participation models and distribution system operators—without attempting to choose which to pursue. Such a process can provide a valuable foundation upon which to begin to address the gaps between distribution systems of today and those of the future.

Many of these gaps are the purview of state regulatory commissions and distribution utilities. Commissions and utilities may feel that resolving these gaps, both around near-term Order 2222 compliance (Section 3) and the longer-term evolution of the distribution system (Section 4), would require extraordinary effort, and may therefore be inclined to preserve the status quo. This report argues, instead, that the transition to future distribution systems can start with small, no-regrets steps and evolve over time. We provide six recommendations (with relevant actors in parentheses) to help commissions and utilities begin the next steps.

Start from an assumption that relatively minor changes in distribution planning and operations will be needed for near-term compliance with Order 2222.

1. Start from an assumption that relatively minor changes in distribution planning and operations, and particularly in utility investments in monitoring and controls necessary to support them, will be needed for near-term compliance with Order 2222 (commissions, utilities).

As described in Section 3, near-term Order 2222 compliance will only require incremental enhancements in utility processes and distribution functionality. The four most important near-term changes are to:

- Develop or improve existing DER interconnection processes to clarify distribution override procedures and conditions, establish DER performance parameters, and facilitate the creation of DER databases.
- Develop transparent processes for DER aggregation review that are distinct from interconnection processes for individual DERs.
- Develop new processes and capabilities for communicating distribution outages and constraints to DER aggregators.
- Develop transparent, non-discriminatory processes for overriding independent system operator (ISO) scheduling and dispatch of DERs.

Nearer-term steps to comply with Order 2222 do not need to solve all challenges related to DER integration into wholesale markets and operations. Commissions and utilities can instead focus on addressing near-term needs for interconnection, DER aggregation review, communications, and overrides in ways that allow for the system to evolve over time. Many of the broader gaps in DER market and system integration described in Section 4 will be addressed on time scales of longer-term planning, rather than those of normal utility rate case cycles.

2. For DER aggregation reviews, leverage data from the registration and interconnection of individual DERs in order to minimize the need for additional study during reviews. In most cases, DER aggregation review should not require redoing interconnection studies (commissions, utilities).

By the time utilities review DER aggregations, ISOs will have collected operational information about the aggregation, the individual DERs comprising it will have gone through interconnection processes, and utilities will have already screened or studied individual power-injecting resources within the DER aggregation. This information can be used in this aggregation review process, so that utilities do not need to undertake more detailed engineering studies. Making this information from registration and interconnection available to the appropriate entity within distribution utilities conducting the aggregation review may require information-sharing arrangements between utilities and ISOs as well as more efficient information-sharing within the utility. If the DER aggregation does trigger additional distribution upgrades, utilities can use existing interconnection rules and processes to ensure that the DER aggregator can begin operating the aggregation in a timely fashion.

3. Make use of existing protocols and processes for communications and data-sharing among utilities, aggregators, and ISOs, rather than create new processes and additional complexity (utilities, aggregators, ISOs).

Order 2222 will require new and improved communications between utilities and aggregators, aggregators and ISOs, and utilities and ISOs. In some cases, existing communications protocols and processes can be extended for DER aggregators. For instance, aggregators will need to follow most, if not all, rules for sharing operating parameters, telemetry, submission of offers, and outage reporting in ISO tariffs. In other cases, existing processes could be adapted for new use. For instance, utilities that lack the ability to communicate granular, real-time data on available distribution capacity can still communicate outage information digitally using tools similar to those used for transmission outages, which share information on outage locations and expected downtimes. Early communication of higher-level outage information may in many cases be more valuable than granular data provided in real time.

4. Focus initially on developing workable approaches to utility overrides, based on a foundation of efficient communication between utilities and DER aggregators, with terms and conditions that are clearly articulated in interconnection and aggregator agreements and can evolve over time (utilities, commissions, aggregators).

Overrides do not necessarily mean that utilities need to directly control DERs. In the absence of flexible interconnection and its periodic curtailment of DERs, overrides should be relatively infrequent because any distribution system impacts under normal operating configurations will have been addressed through DER interconnection studies. In situations where distribution equipment is taken down for planned maintenance or distribution networks are operated in alternative configurations, utilities can communicate outages and override instructions to DER aggregators significantly in advance of the event. During periods when distribution equipment experiences unplanned outages or during abnormal operating conditions, utilities should in most cases still be able communicate override instructions to aggregators rather than needing to directly control DERs. Therefore, in the nearer term, the key to implementing overrides is likely to be in effective and efficient communication systems rather than in systems for control. Over time, with flexible interconnection and larger amounts of DER on distribution systems, overrides can evolve into a system of dispatch for the distribution system.

There are multiple workable approaches to non-discriminatory overrides (see Section 3). The approach that utilities choose will need to be clearly described in utilities' agreements with DER aggregators and should be consistent with procedures described in the utilities' interconnection agreements with individual DERs. The timing of override instructions should give DER aggregators enough time to reasonably hedge ISO real-time market price risk and avoid ISO penalties for not following real-time dispatch instructions. Because overrides may result in financial losses for DER aggregators, regulatory commissions will need to ensure that utilities' approaches to overrides can withstand regulatory and legal scrutiny.

Implementation of IEEE 1547-2018 can help to assuage utilities' concerns over distribution voltage impacts related to Order 2222 and, more broadly, to higher levels of interconnecting generation and storage.

5. Prioritize adoption and implementation of IEEE 1547-2018, as voltage support provided through compliance with interconnection standards may reduce the need for overrides and distribution upgrades (commissions, utilities).

The IEEE 1547-2018 standard requires power-injecting DERs to regulate reactive power as part of their interconnection agreements, similar to requirements for bulk system resources. Implementation of the standard can help to assuage utilities' concerns over distribution voltage impacts related to Order 2222 and, more broadly, to higher levels of interconnecting generation and storage. Regulators, utilities, and their stakeholders will need to ensure that there is a common understanding of the timing, default setpoints, and utility system integration (if any) required. Priority should be given to least-regrets approaches built on best practices that are developed from more mature states, learning from their processes for adjusting regulations as system needs, DER participation, and supporting infrastructure evolve.

6. Begin national, industry-wide dialogue on forward-looking issues where solutions can be accelerated through joint, creative problem-solving and the development of a set of nation-wide best practices.

The transition to future distribution systems will require working through challenging issues around distribution interconnection, planning, operations, markets, and regulatory jurisdiction. Some utilities and commissions have already begun to make changes in DER interconnection, planning, and tariffs that address these longer-term needs. Some states have opened broader regulatory proceedings on future distribution systems. These state efforts will begin to drive a national dialogue, but they currently are largely uncoordinated and lack common framing and terminology.

We have before us today the opportunity to accelerate progress in developing solutions to DER integration gaps through national dialogue and collaborative working groups. This dialogue can be informed by recent open networks initiatives in Australia and the United Kingdom (the subject of the second report in this series), and it can be modeled on the recently established Task Force on Comprehensive Electricity Planning of the National Association of Regulatory Utility Commissioners and National Association of State Energy Officials.

The design, focus, and participation of this national dialogue is the subject of the third report in this series.

There are many topic areas that can be furthered by a collaborative process, including those discussed in Section 3:

- Flexible interconnection (key parties would include utilities and commissions)
- Transmission and distribution planning coordination (utilities, ISOs)
- Distribution operator independence and open access distribution tariffs (commissions, utilities)
- Future distribution operations (utilities, commissions)
- Issues around state-federal jurisdiction (commissions, FERC)
- ISO market designs (ISOs, FERC)
- Utility tariff designs (commissions, utilities)

While these issues may not be easily resolved in the near term, their complexity and importance suggest that initiatives to address them should begin now, to provide sufficient lead time for solutions to evolve.

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Appendix

Functional Responsibilities of Key Actors in the DER Aggregator Model of FERC Order 2222 Compliance

Steps	Key Actors			
	Independent System Operator (ISO) (Including Regional Transmission Organization, Wholesale Market Operator, Balancing Authority)	**Distributed Energy Resource (DER) Aggregator**	**Distribution Utility (DU) or Distribution System Operator (DSO)**	**Load-Serving Entity (LSE) and Relevant Electric Retail Regulatory Authority (RERRA)**
DER Aggregation (DERA) Set-Up and Static Information				
1. Establishment of DER aggregator as ISO market participant	Aggregator executes participation agreement with ISO.	Aggregator executes participation agreement with ISO.	N/A	N/A
2. Interconnection of individual DERs that will comprise the proposed DERA	N/A	N/A	Individual DERs interconnect in accordance with DSO's procedures, prior to formation of DERA. Each DER may choose deliverability or flexible (energy-only) interconnection.	RERRA has jurisdiction over DER interconnection procedures (for some ISOs). TBD. Does Order 2222 reveal a need for change to interconnection rules?
3. Formation and utility review of the proposed DERA	N/A	Aggregator forms DERA and submits to DSO for consent.	DSO reviews for (a) DERs ineligible to participate, and (b) operational or reliability issues, and informs aggregator.	TBD. LSE review may also be relevant, e.g., for potential conflict with retail tariff or program participation by DERs.
4. Resolution of DSO's concerns to obtain DSO consent for the DERA; execution of aggregation agreement	Aggregator and DSO convey DSO consent for the DERA to the ISO.	Aggregator modifies DERA composition or performance parameters as needed to address DSO concerns, culminating in an aggregation agreement between DER aggregator and the DSO spelling out the obligations of each party.	DSO reviews revised DERA and gives consent, culminating in an aggregation agreement between aggregator and DSO spelling out obligations of each party. If the DSO does not give its consent for the DERA, the ISO needs to specify conditions.	TBD

TBD = To be determined; N/A = Not applicable.

Steps	Key Actors			
	Independent System Operator (ISO) (Including Regional Transmission Organization, Wholesale Market Operator, Balancing Authority)	**Distributed Energy Resource (DER) Aggregator**	**Distribution Utility (DU) or Distribution System Operator (DSO)**	**Load-Serving Entity (LSE) and Relevant Electric Retail Regulatory Authority (RERRA)**
DER Aggregation (DERA) Set-Up and Static Information				
5. ISO review and integration of the DERA into market systems and optimization algorithms based on DERA composition and performance parameters	ISO reviews the proposed DERA for conformance to ISO participation model and other requirements, and integrates the DERA into market systems.	Aggregator provides a description of the DERA to the ISO, including detailed composition and performance parameters of the DERA.	N/A	N/A
6. Verification and testing of ISO telemetry and real-time visibility requirements	ISO requirements apply to the aggregator, who is responsible for individual DERs. Requirements may vary with DERA size and services provided.	ISO requirements apply to the aggregator, who is responsible for individual DERs; requirements may vary with DERA size and services provided.	N/A	N/A
7. DERA representation in ISO energy management system and network model	Internal activity within ISO systems.	N/A	N/A	N/A
8. Verification of DSO telemetry and real-time visibility requirements	N/A	TBD	Does the DSO need additional real-time visibility to the DERA beyond what the interconnection agreement specifies for the DERs?	TBD
9. Verification of revenue metering requirements	ISO requirements apply to the aggregator, who is responsible for individual DERs. Requirements may vary with DERA size and services provided.	ISO requirements apply to the aggregator, who is responsible for individual DERs. Requirements may vary with DERA size and services provided.	TBD	TBD
10. Updating of static list of DERA member DERs (infrequent)	ISO approves changes if they are "non-material;" otherwise, it reviews changes for any issues and works out resolution with the aggregator.	Aggregator submits changes to DSO and ISO.	DSO approves changes if they are "non-material;" otherwise, it reviews changes for any issues and works out resolution with the aggregator.	TBD
11. Certification and testing of DERA for ancillary services	ISO evaluates DERA for performance capability, telemetry, and deliverability.	Aggregator requests ancillary service certification for DERA.	TBD. There is a possible role for the DSO to allocate priority use of distribution capacity for DERAs providing ancillary services or to consider physical distribution rights.	N/A

TBD = To be determined; N/A = Not applicable.

Steps	Key Actors			
	Independent System Operator (ISO) (Including Regional Transmission Organization, Wholesale Market Operator, Balancing Authority)	**Distributed Energy Resource (DER) Aggregator**	**Distribution Utility (DU) or Distribution System Operator (DSO)**	**Load-Serving Entity (LSE) and Relevant Electric Retail Regulatory Authority (RERRA)**
Capacity Market Participation				
12. Determination of DERA capacity value and qualifying capacity	ISO applies capacity counting rules to determine DERA capacity value.	Aggregator determines qualifying capacity based on applicable counting rules.	TBD. There may be a role for DSO in determining DERA deliverability (net qualifying capacity).	N/A
13. Submission of DERA offer to participate in capacity market or provide resource adequacy capacity	TBD	DERA submits offer to participate in capacity market or provide resource adequacy capacity.	N/A	Absent ISO-operated capacity market, LSE contracts with DERA for resource adequacy capacity in accordance with RERRA procurement rules.
14. ISO capacity auction (e.g., ICAP, PRA, FCA, RPM) or resource adequacy showing	Upon clearing the capacity auction or resource adequacy showing by LSE, the DERA is subject to ISO participation rules (must-offer obligations).	Must-offer obligations figure into DERA bidding into day-ahead and real-time markets.	N/A	N/A
Energy and Ancillary Service Market Participation and Settlement				
15. DERA outage and derate procedures (any time during market-operational time frame)	ISO incorporates updated DERA capacity into market algorithms.	Aggregator is responsible to notify ISO of any reduction in available capacity.	DSO notifies aggregator of distribution conditions that affect DERA capability, including duration of outage.	N/A
16. DERA submission of offers into ISO day-ahead market	ISO performs pre-market-clearing steps, i.e., bid validation, market power mitigation.	Aggregator is responsible to submit feasible bids based on current resource and distribution system conditions.	N/A	N/A
17. ISO market clearing, day-ahead scheduling	ISO provides day-ahead schedules and ancillary service awards to aggregator.	Aggregator conveys day-ahead schedule to individual DERs and to DSO.	TBD. Does DSO need to receive DERA day-ahead market schedules? If so, who provides them?	N/A
18. ISO-DSO-DERA coordination on day-ahead DERA dispatches and ancillary service awards	TBD	TBD	TBD. DSO may evaluate day-ahead energy schedules and ancillary service awards for distribution issues.	N/A
19. Activities to be carried out between day-ahead and real-time markets	TBD	TBD	TBD	TBD
20. DERA submission of offers into ISO real-time market	ISO performs pre-market-clearing steps, i.e., bid validation, market power mitigation.	Aggregator is responsible to submit feasible bids based on current resource and distribution system conditions.	N/A	N/A

TBD = To be determined; N/A = Not applicable.

Steps	Key Actors			
	Independent System Operator (ISO) (Including Regional Transmission Organization, Wholesale Market Operator, Balancing Authority)	**Distributed Energy Resource (DER) Aggregator**	**Distribution Utility (DU) or Distribution System Operator (DSO)**	**Load-Serving Entity (LSE) and Relevant Electric Retail Regulatory Authority (RERRA)**
Energy and Ancillary Service Market Participation and Settlement				
21. ISO market clearing; real-time DERA dispatch instructions	ISO provides real-time dispatches and ancillary service awards to aggre-gator.	Aggregator conveys real-time dispatch to individual DERs and to DSO.	TBD. Does DSO need to receive real-time market dispatches? If so, who provides them?	N/A
22. ISO-DSO-DERA coordination on real-time DERA dispatches	TBD	TBD	TBD. DSO may evaluate real-time dispatches and ancillary service awards for distribution issues.	N/A
23. Operational coordination after real-time DERA dispatch	TBD	TBD	TBD	TBD
24. Real-time reduction in DERA performance capability (e.g., DSO override for local distribution system conditions)	Within the operational instant, automatic generation control covers any shortfall in DERA delivery of services to ISO.	Aggregator is responsible to notify ISO of any reduction in available capacity.	DSO notifies aggregator of distribution conditions that affect DERA capability, using "transparent, non-discriminatory procedures."	N/A
25. Automatic generation control signal deployment	ISO provides automatic generation control signal to aggregator for a DERA providing regulation service.	Aggregator conveys automatic generation control signal to DERs.	N/A	N/A
26. For ISO emergency condition, ISO's calling on DERA, contingency dispatch, out of market action, etc.	TBD	TBD	TBD	N/A
27. Financial settlement between ISO and DERA, including non-performance penalties	ISO settles with the aggregator, who is responsible for settling with individual DERs.	ISO settles with the aggregator, who is responsible for settling with individual DERs.	N/A	N/A
28. Settlement with individual DERs	N/A	Aggregator settles with individual DERs within the DERA.	TBD. DSO settles with aggregator or with individual DERs for distribution charges.	TBD. LSE may be involved in settlement with behind-the-meter DERs in a DERA.
29. Post ISO settlement	ISO may audit aggregator's submitted settlement data.	Aggregator must maintain settlement quality meter data for individual DERs in the DERA.	Post-ISO settlement audit may affect DSO settlement with DERA or individual DERs.	Post-ISO settlement audit may affect LSE settlement with individual DERs.

TBD = To be determined; N/A = Not applicable.

Source: Lorenzo Kristov, Electric System Policy, Structure, Market Design

DER Integration into Wholesale Markets and Operations

A Report of the Distributed Energy Resources Task Force of the Energy Systems Integration Group

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The report is available at https://www.esig.energy/reports-briefs.

To learn more about the recommendations in this report, please send an email to info@esig.energy.

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