# Activation of Distributed Energy Resources in the Energy Market

*Electric Power Research Institute (EPRI) Report for the Australian Energy Market Operator*

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# ABSTRACT

Emerging customer behavior and public policy are driving the growth of smaller-scale distributed energy resources (DER) such as solar photovoltaics (PV) and battery storage in many systems around the world. In regions such as Australia, the pace of this power system evolution is rapid and sustained. Small-scale, distribution-connected resources typically differ from conventional, transmission-connected resources in numerous ways, but the most notable include the relative lack of real-time observability (or predictability) and controllability of DER and the incentives driving their operation. Without observability and control or market incentives, system operators are likely to experience an erosion of their means to cost-effectively maintain power system reliability.

This report reviews how comparable systems around the world are considering the integration of DER into their energy markets and resolving the associated system challenges. In market-based regions, ensuring that all generation resources are subject to equivalent signals that reflect system and market conditions is essential to system operation and economic efficiency when DER are prevalent. Recommendations are drawn together for consideration in the Australian context, laying out sets of choices to integrate DER, along with higher-level principles that can be established to build an understanding of, and trust among, actors in the power system. In doing so, the report aims to expedite the process of efficient DER integration within traditional energy systems.

**Keywords**

Direct market participation
Distributed energy resources (DER)
Heterogeneous aggregations
Homogenous aggregations
Indirect market management
Integration options

# EXECUTIVE SUMMARY

Emerging customer behavior and public policy are driving the growth of smaller-scale distributed energy resources (DER) such as solar photovoltaics (PV) and battery storage in many systems around the world. In regions such as Australia, the pace of this power system evolution is rapid and sustained. Small-scale, distribution-connected resources typically differ from conventional, transmission-connected resources in numerous ways, but the most notable include the relative lack of real-time observability (or predictability) and controllability of DER and the incentives driving their operation. Without observability and control or market incentives, system operators are likely to experience an erosion of their means to cost-effectively maintain power system reliability.

This report reviews how comparable systems around the world are considering the integration of DER into their energy markets and resolving the associated system challenges. In market-based regions, ensuring that all generation resources are subject to equivalent signals that reflect system and market conditions is essential to system operation and economic efficiency when DER are prevalent. Recommendations are drawn together for consideration in the Australian context, laying out sets of choices to integrate DER, along with higher-level principles that can be established to build an understanding of, and trust among, actors in the power system. In doing so, the report aims to expedite the process of efficient DER integration within traditional energy systems.

### Overall Framework Principles for Integration of Distributed Energy Resources into Markets

Given the scale of existing wholesale markets, the complexity and nuance of extending the market to resources connected beyond the transmission system creates the potential for both technical and market efficiencies, as well as risks, to arise. Experiences from initiatives around the world are beginning to converge on framework principles for successful DER integration. This framework can be summarized in terms of the following six guiding principles:

- Design to do no harm
  - Design to do no harm in terms of reliability impacts to distribution or transmission grids or overall system operation.
- Ensure that observability and controllability come together
  - Provide for the measurement and control needs of system operators and market participants in running efficient markets and reliable and safe networks.
- Design for a new type of market participant
  - Reflect different resource constraints and barriers and prosumer[1] motivation.

[1] A *prosumer* is both a demand customer and an owner or operator of generation, understood to be distribution connected.

- Design for a congested grid
  - With predominantly low marginal cost resources, energy markets should reflect system stresses to provide meaningful signals to move the operating point into a secure operating region and to ensure service deliverability.
- Design for system flexibility
  - Encourage market designs that reduce uncertainty and maximize access to resources to manage variability.
- Design a level playing field
  - Carefully consider how routes to market are affected by non-market incentives.

### Enabling Features for the Activation of Distributed Energy Resources in Energy Markets

Each system commenced its energy transition from a different starting point, reflecting the cumulative, historic decisions that now shape a system's ability to integrate DER into energy markets. Such distinguishing features include the following:

- Grid code requirements for DER behavior and control, such as legacy ripple water heater controls in Germany, and so on[2]
- Metering infrastructure for DER, such as previously mandated smart metering in Europe and parts of the United States
- Distribution network hosting capacity, connection practices, and active system management capabilities; for example, systems with declining loads had more headroom to start with
- Permissible granularity (temporal and spatial) of aggregations of DER participating in markets[3]
- Distribution and transmission loss factors and network use of system charges; that is, peak import capacity charging versus volumetric versus flat access charging tariffs
- Industry and market structures; that is, unbundled locational marginal price (LMP) energy market, vertically integrated utility

[2] Many distribution grid codes or interconnection standards for devices have been evolving rapidly over the recent past. The recent IEEE 1547:2018 standard has been updated to provide a comprehensive set of requirements for behaviors and capabilities to support system stability and interoperability with control systems.

[3] *Temporal granularity* refers to the time resolution of market operations, decision-making processes, and data availability. More frequently updated information and shorter interval blocks allow for a wider range of capabilities to be leveraged but have a larger communications and infrastructure requirement than seasonal contracting for long-interval (such as evening peak) products. Higher spatial granularity allows for finer control of DER to resolve congestion but reduces the size of aggregations. Fine granularity can result in the potential for market power issues but can also reduce the benefit of aggregating resources.

Each of these features influences the choices available and their effectiveness in integrating DER into markets. The presence of existing advanced metering infrastructure coupled with DER that are required to have remote control capability through standard protocols and significant available distribution network hosting capacity is a substantially easier proposition than the absence of those capabilities and a congested grid. Where progress is being made on DER integration, such factors are key driving forces for the decisions made.

### Data, Control, and Observability

Activation of DER in markets is contingent on high-quality, accurate, and timely data flow between market participants, systems, and market operators. The Australian system is starting from a different position than other systems that may have substantial advanced metering infrastructure or legacy systems for residential load controls. Investments in monitoring and control are likely required to enable DER activation, including the need to activate previously passive DER installations, improve observability, and inform the grid operator decision support tools that may leverage the capabilities offered by DER. The following recommendations for observability, control, and data management should be considered as part of the efficient integration of DER into both energy markets and integrated grid planning and operations:

- Establish DER data requirements, standards, and custodians of that data
- Leverage common data formats to store and exchange data (such as common information model)
- Establish interconnection requirements that support interoperable control and observability
- Establish telemetry requirements rooted in operational need
- Establish metering requirements that enable accurate settlement
- Map DER to transmission system busses as it connects
- Establish an effective data-sharing architecture

### Actions to Activate Distributed Energy Resources in Wholesale Energy Markets

The final set of principles relate to the inclusion of DER into wholesale markets. These are not intended to be a complete set of recommendations for DER but necessary issues that require resolution as part of the process for DER integration. These principles are the following:

- Establish desired outcomes for DER market integration.
  - Integration into energy and ancillary service markets equivalent to conventional generators or more passive responding participant with reduced responsibilities.
- Determine the appropriate depth of integration for the anticipated DER penetration and whether a direct or an indirect route to market may reach established objectives.
  - Shallow to deep. Shallower approaches are based on passive reaction to market signals, whereas deep approaches integrate DER into the market-clearing process.
  - Direct or indirect. Direct approaches explicitly represent DER aggregations in market clearing, whereas indirect approaches bring DER to market as part of a portfolio of generation and demand.

- Establish a governing philosophy for DER stacked service offerings.
  - Understand how DER's participation in energy markets is affected by provision of asset upgrade deferral or other ancillary services and how that should be governed.
- Determine how distribution congestion will be managed.
  - Operational coordination is required between the market operator, the transmission network service providers, and the distribution network service provider to facilitate DER participation in wholesale markets to ensure DER operate within network limits.
- Determine the scope limits of aggregations.
  - Geographical scope (can aggregations include assets across transmission nodes or zones?) and scope of resources contained therein (must all resources be the same kind?).
- Determine offer parameters for aggregations.
  - Aggregators may have different resource constraints or abilities to provide flexibility beyond the traditional model for conventional generation. Decision required on how DER appears in the market-clearing software.
- Determine settlement procedures and the treatment of native load and charging.
  - Resolution required for potential issue with multiple applications of network use of system charges for resources such as distributed storage.

### Distributed Energy Resources Routes to Market

Emerging experience from DER market activation initiatives around the world indicates that the routes to market being pursued by each region are heavily dependent on the type of DER, the stage the system is at with the integration of DER, and the objective of the market integration. In regions such as Electric Reliability Council of Texas (ERCOT) in Texas, where there is a substantial penetration of megawatt-scale backup and co-generation facilities, market integration proposals are focused on direct consideration of those resources in system operations but shallower integration with the market-clearing process (that is, a more passive response to a pricing signal).

In regions such as the United Kingdom, where DER is composed of a multitude of resource types, including a very significant penetration of small-scale residential and commercial solar PV, a more direct approach to representing aggregations of DER is emerging in the energy and ancillary service markets. This represents a similar level of integration and participation responsibilities as conventional generating resources and depends on advanced enabling control and communications technologies. Although this is more complex to implement, it offers the greatest possibility to leverage DER's flexibility to support system operations.

In examples such as Green Mountain Power in Vermont, an indirect approach to aggregating a portfolio of customer-sited battery storage type DER is being leveraged to provide backup power to customers, but also as part of the portfolio the utility controls to manage price exposure in the Independent System Operator (ISO) New England capacity and energy markets, exploiting stacked services from batteries.

Finally, in high PV penetration systems such as in Hawaii, interconnection to the grid for new systems includes provisions either to restrict export during certain hours of the day or to offer remote curtailable control to system operators to network manage congestion issues using metering and control infrastructure. This is similar to a time-of-use approach, adjusting customers' incentives for net injections but without explicit representation in energy scheduling and market clearing. Although this is the least complex option in terms of implementation, it may restrict the ability of resources to support system needs.

### Key Conclusions

There are several key insights to consider from this review of DER market participation, including the following:

- Participation of DER—particularly small-scale PV—in energy markets is immature in most systems, and proposals are rapidly evolving after demonstration phases.
- Each system is starting the process of DER integration into markets from a different starting point and each faces different challenges that have informed the initial course of action.
- Metering, control, and communications infrastructures—as well as standardization of data exchange, grid code capabilities, and communications protocols—significantly affect what course of action is possible in the near, medium, and long term.
- Direct and deep approaches to DER market integration provide greater long-term potential to provide flexibility and value to markets and system operators for ancillary services compared to more passive, indirect, and shallow approaches.
- Successful market integration will require strong coordination between DER, suppliers, aggregators, networks, and market operators. Establishing guiding principles that reflect the concerns of each party is an important step in creating effective routes to market for DER.

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# 1
# INTRODUCTION

## Report Objectives

The purpose of this report is to document international experience in mechanisms to include distributed energy resources (DER) in energy markets. The focus is principally directed to energy market participation as a means to improve the cost efficiency of bulk system markets with high penetrations of DER and to ensure continued operational reliability. The report includes some incidental consideration of DER participation in ancillary services, but this is not the core purpose of this report. By examining the international experience to date and considerations for representing DER in energy markets, this report seeks to identify several options for integration practices and an analysis of their accompanying relative merits. Specifically, the report answers questions posed by the Australian Energy Market Operator (AEMO). Those questions and the report sections in which they are addressed are listed in Table 1-1.

**Table 1-1**
**Report objectives**

| Question | Addressed in Report |
|---|---|
| Who has been successful in leveraging DER to provide system services? | Section 3, International Experience Summary |
| In what environment were they operating? | Section 2, Distribution System Interaction with Wholesale Markets<br>Appendix A, International Review of Existing Initiatives<br>Appendix B, International Proposals for Distributed Energy Resource Market Integration |
| How do they do it? | Section 3, International Experience Summary |
| What guidance can be provided for DER market integration for the national energy market (NEM)? | Section 4, Market Design Options for Distributed Energy Resources<br>Section 5, Integration Option Comparison |

## Background

As power systems rapidly evolve from traditional, centralized generation and transmission designs to those that incorporate significant generation at the grid edge, planning and operational practices must also evolve to ensure continuous safe, reliable, affordable, and sustainable electricity supply. This is evident in many regions around the world as the energy transition from central to distributed generation takes hold and develops momentum.

DER represent the emergent class of devices and capabilities that are at the core of this evolution. DER can be defined differently depending on the context. In this report, a resource is understood to be a DER if the following statements hold true:

- The resource is connected to the distribution network, either in front of or behind the customer meter or independently connected.
- The resource's capacity is less than the minimum size required for mandatory telemetry for participation in bulk system energy markets or services.
- The resource can either produce or alter consumption, or both, either passively or in a controlled fashion.

This class of resource can include, but is not limited to solar photovoltaic (PV), battery energy storage, backup generators, combined heat and power (CHP), wind turbines, small-scale hydro, or demand response, including electric vehicle (EV) charging. A further distinction is made between utility-scale DER and small-scale DER and another between controllable and passively acting DER.

For the purpose of this report, a differentiation is drawn based on capacity and connection—resources qualify as utility-scale if the individual resource capacity is greater than 100 kW and each resource has a dedicated, metered connection [1]. Small-scale DER have smaller capacities and are typically connected at low voltage levels and may be behind the meter (customer-sited PV and storage) or individually connected (such as public EV charging). In Australia, the threshold between utility-scale and small-scale is likely to be higher (perhaps starting at 1 MW).

## Distributed Energy Resource Growth in Australia

The Australian power system has experienced substantial growth in DER recently, and this trend is expected to continue for the coming years. This has materialized predominantly, but not exclusively, through the growth of solar PV in specific Australian territories. Solar PV has grown to just below 8 GW to date, with substantial coverage of residential dwellings in several states, as illustrated in Figure 1-1. As a proportion of the peak national energy market (NEM) demand of 32.5 GW in 2016–2017, this ranks among the synchronous areas with the highest penetration of DER internationally.

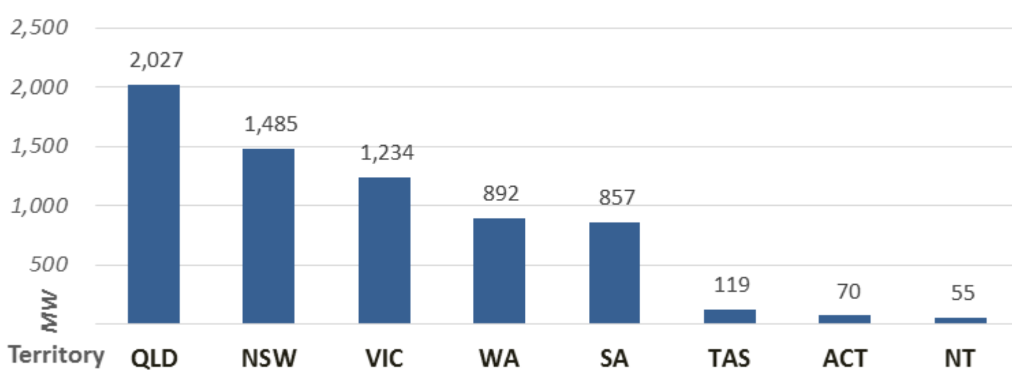


**Figure 1-1**
**Installed solar photovoltaic capacity by territory**
*Source: Australian Photovoltaic Institute Solar Map, funded by the Australian Renewable Energy Agency, accessed from pv-map.apvi.org.au on June 25, 2018.*

Similarly, a nascent but rapidly growing energy storage industry is increasing the penetration of small-scale DER across Australian power systems. It is estimated that approximately 170 MWh of battery storage was deployed by the end of 2017. This storage is largely, but not exclusively, related to incentives such as self-consumption with solar PV (for instance, net metering to avoid higher retail electricity costs). Therefore, the operation of these small-scale storage resources may not be completely aligned with objectives at the bulk system level.

Similar transitions are seen in areas such as Germany, the United Kingdom, Hawaii, California, and Italy, where deployments of DER have substantially altered the generation mix. What differentiates Germany, California, and Italy from the others is their interconnectedness with a wider synchronous system. The NEM on the east coast and the Wholesale Electricity Market in Western Australia share similarities with island systems such as the United Kingdom, Texas, Hawaii, and Ireland given their relative isolation and high penetration of non-synchronous, inverter-interfaced generation sources. In such isolated systems, some technical issues arise earlier in the energy transition than in interconnected areas, including the following:

- Frequency control due to decreasing system inertia
- Post-fault voltage recovery
- Protection coordination for reverse flow on distribution networks
- Changing flow patterns on distribution and transmission grids
- Increased needs for production forecasting and adjustments to operating reserves and balancing requirements, stability in weak grid conditions, and so on

Improving DER capabilities, observability, incentives, and controls help to resolve several of these issues.

## Why Is Distributed Energy Resource Growth Consequential for the Bulk System?

### *Impact of Passive Distributed Energy Resource Production on Bulk System Reliability*

In most systems at present, small-scale DER may export onto the distribution network with little restriction and without intervention from network operators. For utility-scale DER, this may also hold true, depending on the size of the resource and the rules surrounding market participation. In isolation, passive behavior by a single or relatively small penetration of DER dispersed across a network does not present a challenge for system operation. As the penetration of DER increases or concentrates in certain areas of a network, control of utility- and small-scale DER may be the most cost effective—and potentially the only—solution to ensure system reliability and security in alert or insecure system conditions. This growth makes an increasingly material difference for the following four main tasks conducted at the bulk system:

- Maintaining balance between energy demand and supply
- Maintaining network voltage and power quality within operational limits
- System defense and protection to ensure continuity of operation through disturbances such as generation or network asset loss
- Restoration of the network in the aftermath of a full or partial system blackout

In Australia, these tasks are coordinated at present between the market operator, AEMO, transmission operators, distribution system operators, market participants, and generation owners. System control with DER is different from that with traditional centralized generation for the following main reasons:

- Increased complexity of monitoring and control a substantially more diverse, numerous, distributed, and potentially aggregated set of resources
- DER connection through a power electronic, inverter interface
- Potentially competing owner, network operator, and market control objectives for DER

Operational issues require mitigation through the provision of services or through mandated responses. Energy and system services have traditionally been provided by transmission-connected, central station generators that were subject to multiple requirements and real-time telemetry. Distribution networks were designed for radial flows from primary substations down to the largely single-phase, low-voltage service connection point through a relatively passively operated system. Operational visibility of distribution networks is relatively sparse at the low and medium voltage levels, as network reinforcements have traditionally ensured that network states will remain within operational limits, without the need for active management. Hence, the requirement for visibility and control of the initial group of DER was less critical, and they were not subject to the same telemetry requirements.

The growth of DER presents challenges for distribution networks as much as it does for bulk system operations when a significant enough density is reached—which may be different in different parts of the network (that is, DER located at the end of feeders presents issues sooner than DER concentrated near the primary substation). Distribution utilities must manage customer access requests by ensuring that the network can support the needs of each of its customers in an economic fashion.

Increasingly, DER integration results in the potential for reverse flow from the distribution network to the bulk system, with consequential issues for voltage management and, in some circumstances, resulting in the need for distribution network reinforcement. Without reinforcement, there may be implications for the DER's ability to deliver on its wholesale market commitments while ensuring that distribution asset ratings and protection schemes remain within normal limits.

Reinforcement can potentially be avoided by leveraging DER to manage congestion on the distribution system through active system management or non-wires alternatives such as demand response or the application of reactive power to manage local voltage issues. This potentially creates an additional value stream for DER while simultaneously potentially interacting with the economics of participation in the wholesale energy market. This capability requires the ability to monitor and control resources in operations. Although in some regions DER connection requirements specify required active and reactive power control capability [2], exploitation of these resources for bulk system operations is largely limited to control for emergency actions at present (such as during periods of severe over-generation) where that capability exists, such as Germany. However, this situation is rapidly evolving—using DER to manage energy balance and grid congestion is an increasing reality, but one that requires keener awareness of the grid's state and an ability to call upon a service.

Internationally, the growing presence of DER has exceeded, or is expected to exceed, the threshold whereby the impact of its passive operation becomes material to the reliability and economic efficiency of the system. In Europe, the United States, and Australia, market design reforms have come to address this question. The issue has started to become a binding constraint to system operation in several regards, as follows:

- Load served by the bulk system during periods of elevated solar PV production creates a net load profile (with minimum demands during the middle of the day) that is challenging for the remaining generation resources that were developed with alternative projections of net load. This presents issues of reliability as well as economics.
- System operation at low net load may require conventional generators to be kept online for reasons of voltage control, system stability, or insufficient flexibility from the generation fleet to cycle. A threshold is met when the minimum production from the minimum set of generators that can be kept online exceeds the minimum net load or local voltage issues arise.
- Export of DER through the distribution system onto the transmission system that is concentrated to a specific zone or region may result in flows that exceed network ratings or operational security constraints (such as voltage stability).
- Uncertainty related to the output of variable DER must be managed by the bulk system, which requires the provision of balancing or frequency regulating resources.
- Coordination between wholesale and distribution level markets may be desirable to avoid conflicting incentive signals or the introduction of reliability issues at different voltage levels.

It is widely recognized that the response of low marginal cost generation, such as renewable generation, to market signals increases the economic efficiency of a market and reduces the need for out-of-office transactions. This may result in the curtailment of output from PV, wind, or hydro generation when it is economic or a necessity for reliability to do so. This principle can be extended to the participation of DER in markets as it appears to the bulk system, although to do so may require changes to the market and operational or regulatory arrangements.

## Regulatory Initiatives Supporting Direct Distributed Energy Resource Participation in Markets

As the generation mix rapidly evolves and decentralization of generation continues to occur, the operation of wholesale bulk system electricity markets is changing in tandem. Macro level changes to regulation are taking place that aim to facilitate this transition efficiently. The following subsections summarize significant, recent regulation developments in the United States and Europe.

### *Federal Energy Regulatory Commission*

The Federal Energy Regulatory Commission (FERC) regulates interstate commerce for the energy industries in the United States. As part of its purview, it establishes regulations for the operation of the organized independent system operator/regional transmission organization (ISO/RTO) markets. FERC has recently had three main initiatives focused on the broad umbrella of DER integration—order-on-demand response, energy storage, and an ongoing proceeding on DER.

FERC Order 745, introduced in 2011, mandated that ISO/RTO markets allow access for demand response to organized energy markets and requires that compensation be on a like-for-like basis with conventional generation [3]. This includes a net benefits test to prevent overcompensation of demand response in the markets as compared to other resources.

FERC Order 841, introduced in 2018, directs the ISO/RTO markets to develop and implement a participation model for electric storage that accounts for its physical and operational limitations and provides the option to the asset owner to manage its own state of charge (SoC) [1]. This is designed to remove the existing barriers that prevent the DER from participating in multiple market products, such as ancillary services, capacity, and energy. Furthermore, the minimum size threshold for participation models is lowered to 100 kW for both multi-node and single-node aggregations to reduce the participation barrier and encourage participation from DER aggregations that are required to be located at a single pricing node.

In its original Notice for Proposed Rulemaking in 2017, FERC required the ISO/RTO markets to allow for DER resources to aggregate and participate in the wholesale electricity markets. FERC is currently in the process of creating an order to determine and set the related rules; it held a technical conference on the topic in May 2018. The envisaged participation models should be such that the DER can participate in the wholesale electricity markets—that is, the DER are dispatchable, able to set the wholesale market-clearing price or the locational marginal price (LMP), and are settled at the LMP for energy, analogous to the conventional resources.

Contemporary market practices limit the participation of electric storage in markets as either a demand participant or a generation participant. Furthermore, electric storage is not allowed to participate in multiple markets simultaneously, such as the co-optimized energy and operating reserve markets found in the United States. Presently, all the ISO/RTO markets are in the process of modifying and updating their procedures and software to comply with FERC Order 841, the deadline for which is December 2019.

### *European Commission*

In its 2016 review of the performance of the existing European internal energy market, renewable energy, risk preparedness policies, and subsequent proposals for amendments to each, the European Commission identified several key changes to the operation of the European power system focused on improving the ability of the consumer to engage with the energy market. These proposals were finalized in early 2019 [4]. As part of the proposed regulations, changes are envisaged to accomplish the following:

- Make mandatory the practice of bidding output from renewable generation into the market (for resources with a capacity greater than 500 kW, moving to 250 kW by 2026), ensuring that transmission system operators (TSOs) have access to DER for frequency control ancillary services
- Establish an equal footing between generation, storage, and demand response across energy, balancing, and ancillary services
- Improve convergence between transmission and distribution tariff structures
- Improve data exchange by standardizing formats and data collection

Although these proposals are at earlier stages of negotiation than the decisions taken in the United States, they set the tone for the likely technical requirements that will be enforced across Europe in the future.

# 2
# DISTRIBUTION SYSTEM INTERACTION WITH WHOLESALE MARKETS

## Introduction

DER observability and deliverability were identified as critical for successful integration of DER into energy markets. DER being connected to distribution systems are outside the traditional observability domain of wholesale market operators. The first requirement for both the energy market and system operators to run a system with significant DER penetration is to obtain visibility of the static characteristics and sufficient real-time operational behavior of those resources to as great an extent that is effective.

When delivering DER production to market, the primary impact of DER occurs on distribution networks where pockets of high concentrations of DER, even at a relatively low penetration over a whole system, may result in congestion or other operational issues for distribution network operators. Network constraints are not a new issue for energy markets, with a variety of approaches taken to include the effect of transmission congestion in existing markets around the world, ranging from detailed LMPs to single-price markets with redispatch. However, the need to dynamically manage distribution congestion in operations is a newer phenomenon. Combining wholesale energy markets and distribution congestion management is one of the more complex aspects of DER market integration. The services that DSOs and TSOs would like to either procure or facilitate can have different relationships, potentially reinforcing or counteracting each other.

## Market-Induced Distribution Impacts

Transmission and distribution network operations are largely carried out independently at present. Although some interaction does occur to coordinate outages and switching schedules, systems are designed to interact at the transmission connection point or at the primary substation with the bulk system. The distribution system’s main objective is maintaining voltage, whereas the bulk system ensures power delivery into the distribution network. The growth of DER is challenging this paradigm as the distribution system is increasingly involved in serving load and generation. With more variable flows from both transmission and distribution, the need for coordination is increasingly required to provide certainty to operational decision making. A key learning from many initiatives in which DER is being integrated across transmission and distribution operations is that the development of a mutual understanding of their adjusted processes and duties is critical to progressing such initiatives.

To some extent, small-scale DER's impact on the grid is driven by netting DER production from demand. This brings with it a natural variability and a geographical distribution of net injections across a set of resources that may alleviate or exacerbate the potential for congestion on the distribution system. System hosting capacity analysis is typically conducted to identify the point at which a DER penetration can no longer be reliably facilitated with passive distribution network operation. The hosting capacity varies based on the types of resources considered, their relative locations, the relative strength of the network, the network's design, operational standards, and the operational behavior of the DER.

The goal of market participation of DER is to move from a passive, price-taker behavior to an active, coordinated response to a control signal such as energy price or dispatch. The effect of this active response will create strong correlations in output between resources with similar costs and availabilities such as solar generation. This correlation erodes the natural variability of a set of more passive resources to some extent, which may result in a thermal, voltage, or reverse power protection limit being reached in the distribution network. For resources with similar marginal costs, this can result in rapid fluctuations in production when prices reach that threshold value.

For the bulk energy market, active participation from DER helps to accurately and efficiently clear the market in a reliable way by increasing market liquidity and reducing renewable production forecast uncertainty. For systems in which the market is cleared with transmission constraints included in the market-clearing formulation, this also efficiently manages much of the transmission congestion issue. However, because the market clearing does not consider distribution constraints, the price signal set in the market does not ensure deliverability of DER to the primary substation; rather, it assumes it. With a substantial penetration of DER acting in a coordinated way in response to a bulk system energy market signal, this may have consequences for the distribution network to which DER is connected.

### Control Interactions

Aligning wholesale market instructions with transmission and distribution operational requirements is a non-trivial task that affects the effectiveness of DER engagement in energy markets. At a certain level of DER penetration, distribution networks will seek to adopt active network management techniques (when available) to solve distribution reliability issues. These actions can include voltage regulation, tap changing, switching operations, reactive power, battery, demand response actions, or curtailment of production from renewables, and they may result in a change to the interface flow between transmission and distribution.

In the bulk system context, actions that are taken by the network operators to maintain system reliability by altering generator production from the cleared market position is known as *redispatch*. Out-of-market, redispatch transactions are executed by the system operator to ensure that energy balance is achieved while also resolving the original reliability issue, such as congestion management. Energy balancing at the synchronous area level and resolving local congestion are inextricably linked when active power redispatch is involved. Historically, these typically do not have material impacts on DER or the operation of the distribution network, as connection agreements are typically specified to allow full output at all times.

In the emerging case for active distribution management to resolve medium- and low-voltage congestion, a different issue arises. In the case that a distribution utility redispatches DER to alleviate congestion, that active power change will require rebalancing by some other resource in the synchronous area. This can be done in a number of ways, including the following:

- Redispatch of the DER on the same distribution feeder. This has the advantage of maintaining the interface flow, but it may be more expensive than balancing using resources elsewhere in the system, given the potential illiquidity of that market.
- The imbalance results in a change in interface flows that the bulk system operator balances using bulk system–connected resources. This has the potential advantage of cost savings with respect to the feeder-based option. One risk is that with significant enough actions from distribution utilities across multiple feeders, this could place a large balancing requirement on bulk system operators.
- The imbalance results in a change in interface flows that the bulk system operator balances using both transmission- and distribution-connected resources. The advantage to this setup is that it has the largest pool of resources available for balancing energy, but it may initiate a feedback loop should DER be redispatched on an already congested network.

In the first two options, control interactions are minimized at the potential expense of higher balancing costs for redispatching. The third alternative creates the potential for a cyclic interaction between the bulk system and the distribution system unless some coordination scheme is in place to ensure that both bulk system and distribution system actions are aligned. This is an option under consideration internationally in both a proactive and a reactive guise. These options are described in the next section. This results in a need to consider congestion management and coordination principles for DER in both energy markets and redispatch.

A further consideration is that many energy markets with a pool structure and commitment and dispatch clearing engine settle using a marginal price, whereas others use a pay-as-bid settlement structure. When congestion is implicitly managed within the market, the impact of congestion constraints are reflected in the marginal pricing approach. When the congestion is managed through redispatch or out-of-market actions, settlement for those actions is usually on a pay-as-bid or make-whole approach (that is, reimbursing the generator for their administratively determined costs). Ensuring that market design for DER settlement is consistent with conventional generation is potentially important to ensure that market manipulation opportunities are minimized.

### Congestion Management Principles

Current energy market designs are based on a philosophy of congestion management. Four market philosophies are commonplace in energy markets around the world, as follows:

- Single market price with congestion managed through redispatch (such as Alberta ESO)
- Multiple zonal prices, with transfer limits between zones and internal or residual congestion managed through redispatch (such as Italy)[4]

[4] In some cases, wholesale energy markets are run by one entity with separate markets or contracting for redispatch carried out by transmission system operators.

- Zonal prices calculated using full network constraints in market clearing with disincentives for dispatch setpoint deviation, with residual congestion managed through redispatch (such as NEM)
- Full LMPs for generators and zonal prices for demand, with residual congestion managed through redispatch (such as PJM)

Each option has associated advantages and drawbacks that make them better fits for a system at a given time. When a market design is committed to, the opportunity for inefficiencies or gaming are best mitigated by treating new resources entering the market either along the same principles as existing resources or by reviewing market design arrangements for all resources. Should congestion management be managed through redispatch and the associated costs socialized at present, market designs should ideally treat DER entering the market in a similar vein.

Distribution congestion does not arise when a feeder can manage the most severe export or import condition without taking operational actions. As this practice of continuously uprating is cost prohibitive at a certain level, market-based means to manage congestion can be effective. When considering how congestion affecting DER can be managed effectively, the following five options are being described at present by system operators around the world:

- **Manage distribution congestion in redispatch.** In this option, DER bids into an energy market and any redispatch action needed to alleviate distribution constraints is handled by a distribution utility through a redispatch market or service. This requires the distribution network operator to have visibility of expected dispatch of each DER connected to its network from the energy market to forecast the potential for congestion to arise and also to establish a market or contractual arrangements at a resource level to enable redispatch.
- **Pre-screened offers.** In certain systems, grid connection to the transmission system is granted on a firm or non-firm basis for a certain level of capacity. These connection agreements allow for export from the resource up to the determined level for firm access. When a transmission system operator needs to constrain the production from that unit for operational reliability reasons, this may incur constraint payments in certain cases. For non-firm access, grid operators may limit the production from that resource during periods of congestion or other system stress. Typically, this system has not been common practice for DER connecting to distribution networks, but this situation is changing (see Hawaii example in Appendix A).

  One potential means to enable DER access to the market is to establish rights to produce DER and for the distribution utility to effectively pre-screen DER offers into the market, either in advance of gate closure or during market clearing, to ensure that, should the asset be cleared along with other DER on the same feeder, operational reliability issues could be resolved without redispatch. This would require a computational platform to do so and an accurate expectation of likely DER dispatch on the feeder. This option is presently under consideration alongside others in some European countries.

- **Congestion spreads.** The concept of a congestion spread is one of the initiatives considered in the Netherlands [5]. Network operators determine the set of trades that resolve anticipated congestion, based on the bids and offers available at gate closure or in continuous trading. Then the system operators contribute an "adder" or the congestion spread that would be required to make each of those trades clear, resolving the congestion.

  After that trade is cleared, it also becomes binding for physical and financial settlement. In this way, the DER is removed from the set of options for subsequent actions in that interval, which may counteract the original instruction. This requires both distribution and transmission operators to have real-time forecasts for anticipated constraints in the system and to have direct involvement in the market-clearing process. The mechanism as proposed, and as tested in the Dutch pilot projects, also suits a bilateral commodities type market.

- **Single-price distribution submarkets.** Another alternative is that submarkets are formed on each distribution feeder where individual DER offers into each submarket. The distribution network operator or other service provider agent determines the equivalent supply curve that reflects the DER offers from resources on each feeder that could be delivered while respecting network operational limits. This supply curve is offered into the bulk energy markets by the distribution system operator or other party.

  When cleared for production in the markets, the distribution market operator dispatches the DER in turn, based on the merit order of the offers received. In this example, the distribution utility or service provider acts as the aggregator for the feeder; therefore, many aggregators would likely be participating in the bulk system market. Although some local markets have been established to date, these are typically for financial settlement between customers and less for direct integration into bulk system markets and congestion management.

- **Locational prices extended to distribution.** Proposals have been made to extend bulk system LMPs, individual prices generated for a wide range of transmission busses, to distribution nodes. This might be achieved either through expanding the set of nodes for which LMPs are calculated or to include those in the distribution network. A derivate approach is to determine resource-specific adders to bulk system LMPs that reflect the impact of the resource on the distribution network, similar to that which is calculated for distribution loss adjustment factors in many systems around the world. This approach could either be done as part of a distribution market or potentially as part of an extension of the bulk system market. However, concerns arise for the latter option due to the increased scale and complexity of the market-clearing program in a case with substantially increased numbers of pricing nodes.

  Furthermore, the use of LMPs in wholesale markets creates a need for congestion risk hedging mechanisms such as financial transmission rights, also referred to as *congestion revenue rights*. In Australia, these are known settlement residues and are dealt with in settlement residue auctions [6]. These products entitle rights holders to congestion rent that is collected by the system operator over each path or set of pricing point combinations. Extension of this to distribution networks may not be practical in the short term, given the complexity of the market arrangements to do so.

## General Considerations for Coordination

Each of the options listed in the previous section may achieve efficient energy market access and network congestion management, with correct adaptation to local circumstances. Some consideration should be given to the following network characteristics that may inform the development of market proposals:

- **Aggregations at the wholesale level versus resources at the distribution level.** Aggregations of DER are likely preferable to interact with, as compared to individual small-scale DER for market and transmission network operators. Assuming that appropriate locational constraints are enforced on the constituent parts of the aggregations, the incremental benefit from the granularity of interacting directly with individual small-scale DER in real time may not be cost effective at present. For distribution network operators, however, management of specific constraints would likely need to target a specific set of DER on a feeder. Therefore, two different levels of resource resolution are needed to facilitate interaction.
- **Grid codes and DER control.** Each distribution network and region has local interconnection requirements for DER, which may be based on national or international standards and legislation (such as AS4777 or IEEE 1547:2018). Although some DER may have the capability for remote control capabilities, activation of this capability may not be required under local requirements. Older devices may not even have this option in place. For newer smart inverters, the capability to control the production based on a variety of controls or instructions through remote interaction over standard protocols is commonplace.[5] Ultimately, DER cannot be effectively included in the energy market without both some ability to control the output of the DER resources and a means to effect that control (that is, communications).
- **Distribution network hosting capacity and active system management.** *Distribution hosting capacity* is defined as the amount of DER that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades. Systems with low remaining hosting capacity cannot accept more DER on the system without some active network management or other intervention to maintain reliability.

  If systems have limited hosting capacity remaining, it is highly possible that congestion management on the distribution network will frequently be an active constraint to delivery of DER to the wholesale market. If such a case is envisaged, managing congestion implicitly in the market process may yield cost efficiencies relative to a redispatch option.

  If the distribution network can observe and actively manage DER and network conditions, DER access to wholesale markets may be determined closer to real time using realistic conditions, rather than based on planning time frame assessments, which may be more conservative. Therefore, the transition from passive distribution network operator to active system operator may allow a more operational assessment of hosting capacity that can improve wholesale market efficiency and protect distribution reliability.

[5] Examples of these protocols include SunSpec Modbus, IEC 61580, and DNP3, details of which are provided in Appendix C.

- **Metering infrastructure.** As well as a degree of control over the DER, metering of the resources requires that settlement be possible at the same interval as the market processes. This may result in the need for DER metering accuracy that is equivalent to that of the bulk system for active power and that the values be recorded and archived at the same temporal resolution. This feature is common for many smart meters that are commonly deployed alongside DER installations at present. However, metering data collection or backhaul may be required on a more regular basis to facilitate timely settlement calculations. Access policies for meter data may also require revisions to enable DER market settlement to occur.
- **Distribution and transmission loss factors and use of system charges.** Loads and resources connected to the transmission and distribution systems are levied system usage charges with differentiation between costs to demand and costs to generation. In certain charging regimes, it is possible that DER that can both consume and produce might be liable for both charges under existing tariff arrangements. However, resolving this issue should be examined in the context of each system and tariff.

  Similarly, in wholesale systems network, loss adjustment factors are levied on the output of generation, such as the loss factors in the Western Energy Market and distribution loss factors in the NEM. These loss factors are calculated by the network operators and used in settlements for utility-scale DER settlement at present. Consideration should be given to what a loss factor calculation may constitute for an aggregation of DER spread across multiple feeders at varying voltage levels from sub-transmission to low voltage.

# 3 INTERNATIONAL EXPERIENCE SUMMARY

## Insights for Australia from International Experience

The degree to which DER interacts with and impacts capacity, energy, and ancillary service markets will vary depending on a wide range of variables, local policies, and market design constraints. This section summarizes experience from around the world with regard to DER activation in energy markets and then synthesizes that experience into principle options that should be considered as part of development of a program to integrate DER into energy markets.

A key insight from a preliminary review of DER activation in Europe and the United States is that, although systems are making efforts to include distributed PV and wind generation in energy markets, progress thus far has been focused on utility- and commercial-scale resources, be they transmission- or distribution-connected resources (such as > 200 kW to megawatt scale).

Notwithstanding that fact, there have been efforts to develop routes to market for smaller-scale PV and storage in the range of tens of kilowatts, but these efforts have largely come through existing demand response programs that have traditionally focused on control of discretionary load reduction and both space and water for heating and cooling.

DER participation in energy markets is viewed as the principal method by which it can contribute to the reliability of the power system in the first instance, by providing the flexibility required to ensure that power balance is achieved. The second means of contribution is to achieve economic efficiency. The prevailing view is that energy and ancillary service markets are the key mechanisms through which operational efficiency is achieved, with secondary effects from network charges and other incentives. However, non-market-based incentives, regulations, and individual preferences (that is, the use of DER for self-consumption) play a greater role in influencing consumption and generation behavior and choices that customers make today than is historically the case. Successful integration of customer-owned DER into energy markets relies on close alignment between policy, regulatory and non-market incentives and charges, and the objectives of the energy and ancillary service markets.

## United States Independent System Operator Markets

Although there are differences between the seven ISO markets in the United States, there are certain similarities between them. Notably, the ISO energy markets are all structured according to a market-clearing algorithm that results in LMPs at each pricing node for production while demand pays a zonal price, and that these markets are typically run day-ahead at hourly resolution (financial settlement) and again in real time at 5-minute resolution.

In some, but not all cases, energy markets are co-optimized with ancillary service markets for frequency control operating reserves in the day-ahead or real-time market or both. They share some similarities with the NEM in terms of being a pool-based market with three-part offers (startup, no-load, and marginal cost) and in terms of timing, but they differ in terms of philosophies for congestion management and pricing.[6] Each of these systems is experiencing different types of DER connecting to distribution service providers within their footprint at differing paces. The ERCOT, a 73-GW peaking system, has an estimated 1100 MW of customer-sited backup generation connected within its service territory [7], whereas the California ISO (CAISO), a 63-GW peaking system, is approaching 12 GW of installed DER capacity, primarily solar PV [8]. Other ISOs such as PJM, the Midcontinent ISO, and ISO New England are also experiencing rapid growth in the penetration of distribution-connected PV at both utility scale and residential scale within subregions of their multi-state service territories due to state policies and incentives.

Through a series of FERC orders in recent years (Order 745 on demand response and Order 841 on energy storage), ISO markets have made various provisions to enable new resources such as demand response to actively participate in energy, ancillary service, and capacity markets, where they exist. DER is subject to a separate proposal-making process at present.

DER is typically considered by the ISOs to be in the range of aggregations of 100 kW or greater. The principal mechanism to enable DER to actively participate in the ISO markets thus far is as part of a demand response program. DER is dispatched alongside the adjustment of load to respond to economic or reliability signals from the ISOs. In the case of CAISO, DERs also have an opportunity to register as a DER provider (DERP), which enables the resource to directly offer production from DER into the market [9]. No operational coordination is required between the ISO, the transmission service provider, and the distribution utility to deliver DER's output to the bulk system because DER must obtain clearance from distribution utilities to participate in the market as part of a prequalification process. Further information is provided in Appendix A on the provisions for DER in California and other ISOs in the United States.

Evidence from the options available to DER to participate in the CAISO market to date suggests that the potential for DER such as backup generators or energy storage to act as part of demand response programs is the preferred route to market. The principal reason stated for DER to participate in the demand response program over the DERP approach is the reduced complexity, duration, and cost for smaller-scale DER to implement the telemetry (equivalent requirements to conventional generators, summarized in Appendix C) and market information requirements (such as nominate scheduling coordinators, ensure outages are cleared by ISO, and so on). This situation may change in the coming years as the generation mix in California continues to mature and the value to direct market participation increases when compared to the demand response route.

A key insight from the California proposal is that the most significant barrier to being able to leverage DER independent of demand response lies with the cost of implementing telemetry systems for the ISO through remote terminal units (RTUs) on each resource. Although this is an insignificant cost to large conventional resources, the cost of adopting this capability is sufficiently high to dissuade DER owners to follow this path despite the ample opportunities to reach the market through DER programs and to provide stacked services in the process.

[6] ISO markets in the United States remunerate generation at locational marginal cost but charge load at a zonal weighted average cost.

The ERCOT system has a substantial set of DER connected in its service area that have been leveraged to date to provide 10- and 30-minute reserve services through the Emergency Response Service [10]. Combined demand and aggregations of generation provides approximately 5 GW of this type of response, with an ambition to increase it further in coming years. ERCOT has conducted several stakeholder group projects to identify potential routes to the energy market for DER, ranging from shallow, passive response to price signals to deep integration in the market-clearing process [11]. A key learning from the work is that when load and generation are remunerated in different manners (that is, zonal for load versus nodal price for generation in this instance), an opportunity may be missed to induce DER, bid as part of demand receiving zonal signals, to support transmission congestion relief as would have been the case had it been exposed to LMPs at a node. Although this issue is somewhat unique to LMP-based markets, a significant driver for the integration of DER into energy markets is to improve the resources available not only to ensure power balance but also potentially to resolve network constraints if so desired.

Through this process, the group identified several practices related to metering configuration (see Appendix C) and mapping of DER to locations on the transmission network model. A key insight from this work is that meter configuration influences what can be settled in the market. Therefore, the time intervals, meter read frequency, ability to read bidirectional flows separately, accuracy of the meter, and the location of the meter in the customer's network influence the types of products that can be cleared with a similar degree of certainty as conventional generation. The location of submeters is critical to enable accounting of the energy flows from DER as distinct from customer demand, which may have implications for the application of network tariffs. The metering issue requires coordination between market operators and metering operators to align the practices and meter capabilities with the service being measured.

Three options for DER integration were laid out with corresponding implications for metering configuration (see Figure 3-1). The DER minimal option represents DER responding passively to price signals, with no explicit settlement for that resource in the energy market. DER light represents a case in which the intended production profile from DER is included in the market-clearing process but is not issued dispatch instructions and acts as a price-taker resource. DER heavy is a proposal akin to extending the market to include offers from DER and aggregations directly in the market-clearing process, to issue dispatch set points and require a quality of service provision from those resources. These options are described further in Appendix B. ERCOT is currently considering a proposal to offer LMP price signals to DER opting in through a DER minimal type approach.

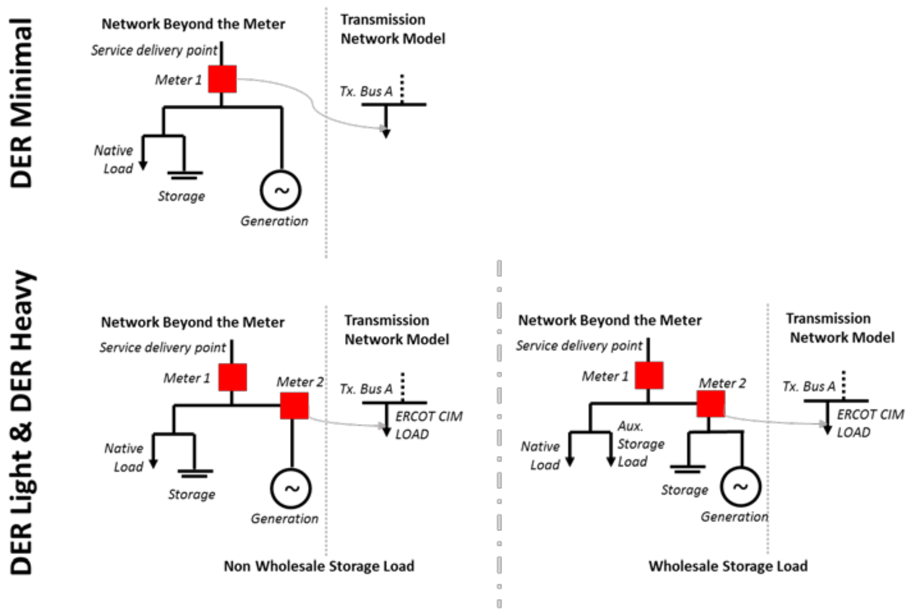


**Figure 3-1**
**Proposed metering configurations in Electric Reliability Council of Texas distributed energy resource integration proposals**
*Based on "ERCOT Concept Paper on Distributed Energy Resources in the ERCOT Region" [11]*

The ERCOT group also identified the role that network tariffs play in potentially influencing the bidding behavior of storage resources that levy different network use of system charges for consumption than for production. This raises the broader point of non-market charges and incentives made earlier in a specific instance when socialized system costs (such as cost of balancing, black-start plant, ancillary services) are typically attributed to consumption, as is the case in Australia. Broad attribution of costs to consumption will increasingly include storage devices with the potential for unintended consequences as a result.

Similar to ERCOT and others, the New York ISO (NYISO) has pursued a process of DER integration into energy [12], ancillary service, and capacity markets through the New York Reforming Energy Vision. Through the development of this proposal, NYISO clearly identified the need to consider the desire of multiple actors to leverage the same DER for different purposes, as well as interfacing with the energy market, as shown in Figure 3-2. Current proposals have highlighted the need to consider questions such as clarification of which party is responsible for the management of SoC for a duration-limited battery connection and, consequently, how that is represented in the market-clearing process [13].

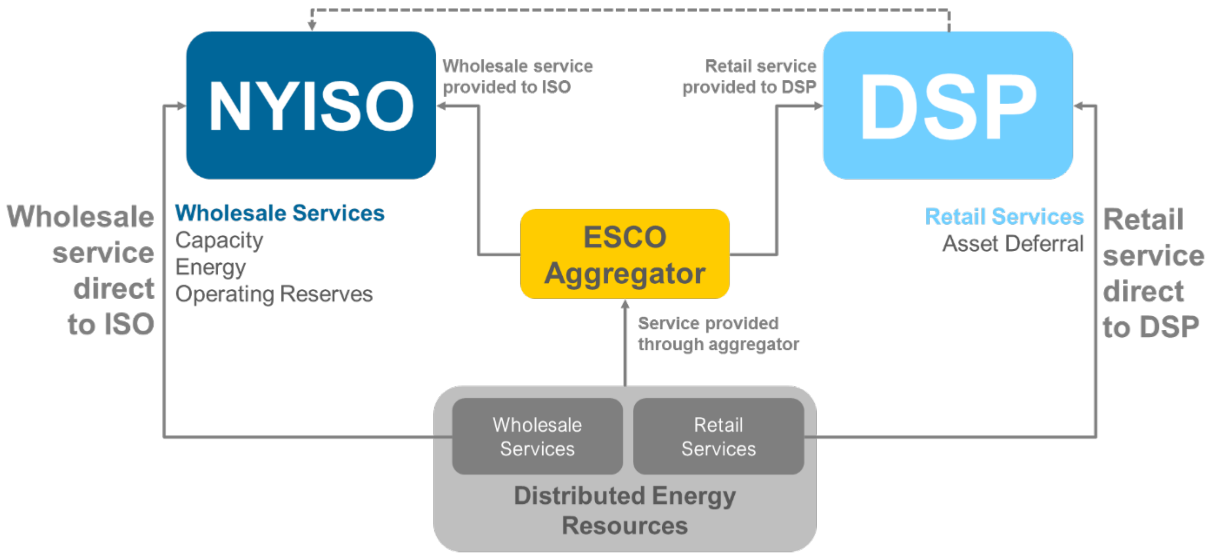


**Figure 3-2**
**Schematic view of envisaged distributed energy resources participation in New York independent system operator markets**
*Based on "Distributed Energy Resources Market Design Concept Proposal" [13]*

The NYISO case demonstrates the need to establish overall guideline principles for cooperation between bulk system and distribution network operators, suppliers, and consumers to enable the stacking of service provision from DER. Similar discussions are ongoing at other ISOs in the United States (see Appendix B for details).

## European Systems

European countries have experienced sustained growth in renewables since the early 2000s, with concentrations in the growth of small-scale DER in specific countries, most notably Germany and the United Kingdom. European power markets are increasingly coordinated and harmonized across the majority of the European continent through a price-coupling mechanism between power exchanges in day-ahead and intraday trading. European markets operate on a portfolio trading principle, in which balance-responsible parties strive to achieve a low imbalance position between generation and demand at the time that final notification of the operating plan must be given to generators and system operators 90 minutes to an hour before the start of each trading interval. A balancing market is run by TSOs to procure balancing power (also called *control power*) from generators, aggregators, and demand in real time. Grid congestion is managed through a day-ahead process run by each TSO and through corrective actions within the operating day, up to real time.

Given the already significant and growing penetration of DER and renewables in general, the importance of reflecting those resources' contributions to meeting energy demand in energy markets is of acute importance. European countries have pursued a variety of approaches to do so, primarily based on an approach of a requirement to participate in the energy market associated with feed-in tariff incentives.

Germany is often cited as the leading example for renewable and DER integration, with more than 105 GW of such technology installed in recent times [14]. Of the 105 GW, solar represents approximately 47 GW of capacity, almost entirely located on the distribution system. The distribution system in Germany may extend up to the high-voltage level (such as 220 kV) but varies according to distribution system operator (DSO), of which there are in excess of 800. Trends of increasing periods of negative prices and curtailments (largely of wind power at medium- and high-voltage levels) related to grid congestion on medium voltage levels and above indicate a rising need for flexibility to manage both net load uncertainty and network reliability.

This issue has been approached in two ways in particular. As of 2017, new renewable resources greater than 100 kW in capacity and receiving a feed-in tariff must be brought to market by a marketing party and economically bid into the day-ahead and intraday markets [15]. Renewables are remunerated based on their market earnings topped by a marketing premium to bring to the agreed-upon strike price. Since 2009, resources less than 30 kW in size must also be capable of either restricting their export onto the grid to 70% of rated capacity or responding to DSOs' curtailment signals during periods of system stress. Controllability is mandatory, but monitoring is not, on assets larger than 30 kW (see Germany). This communication is made possible through legacy infrastructure (Versacom or ripple control) that was introduced in the 1970s and 1980s to provide system flexibility through water heating controls. This is being replaced by a newer system based on smart metering. The key insight here is that alignment is needed across multiple parties to meet their specific needs, from regulatory alignment to the market's need for observability in reducing uncertainty, and both the balance-responsible parties' and system operators' requirement for flexibility to maintain balance and grid reliability.

Similar approaches have been taken in other countries, such as France, where a similar model to ensuring DER's forecast production is made available to the market, is implicitly considered in market clearing, and has incentives to respond to signals emerging from that market. This direct approach to integrating renewables in the market is also complemented by a long-standing history of time-of-use tariffs to alter customer behavior (see Appendix A).

Similar market-based measures are emerging to focus on DER's participation in congestion management in Europe. Most DSOs have granted "firm" connections to DER to export up to their capacity limit given the native hosting capacity of a grid. In this case, the system is designed to cope with coincident extreme operating conditions. This approach may require substantial reinforcement of the networks to continue to connect DER into the future. Increasingly, the residual capacity to host new DER is diminishing, and an emerging trend is for DSOs to offer "flexible" or "non-firm" connections to DER, which may curtail during stressed periods to avoid reliability issues.[7]

In the United Kingdom and the Netherlands, markets for system operators to procure response from DER to support the system during periods of stress are being demonstrated. The use of DER as a congestion management device competes with its potential use as a resource in the energy market. Although it is structurally different from the NEM, the market pilot with the Energy Trading Platform Amsterdam in the Netherlands demonstrates how new trading

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[7] An example of such a connection offer is shown at https://www.ssen.co.uk/FlexibleConnections/ for the Scottish and Southern Energy service territories of the United Kingdom.

platforms can simultaneously facilitate the goals of market participants in buying and selling power and network operators seeking to resolve forecast congestion through the innovative use of financial spreads (see Appendix A).

These types of demonstrations provide useful insights into the mechanisms that are possible to coordinate between functions and stakeholders and to understand whether DER are interested in leveraging such opportunities. Being demonstrations, many of these are in their infancy, and conclusions declaring outright success are premature. The ability to reach the demonstration point displays some degree of consensus having been achieved between network operators on the role DER can play in energy markets and congestion management into the future.

### Utilities and Suppliers

Innovation is also occurring to encourage DER to provide flexibility to support system reliability in integrated utilities and electric supply companies. This is occurring through traditional air conditioning (A/C) and water heating load control programs benefiting from increasingly smart control technology, enabling increased customer load shifting while limiting the impact on customer comfort. Examples of these types of programs pervade around the world and serve a useful purpose in limiting network and generation capacity needs, as well as alleviating negative price conditions when energy supply is abundant. Newer customer devices are joining the traditional load control appliances, including electric car charging and battery storage.

Virtual power plant (VPP) resources are emerging in some countries that aggregate many such devices with the capability to offer capacity, energy, and ancillary services directly to a market or to electric supply companies to alter the exposure of its customers to elevated market prices and to take advantage of lower price periods. Appendix A outlines several of these programs from the United States and Europe, focused on different enabling technologies but which indirectly influence market outcomes. The key insight from such initiatives is that, to build aggregations of meaningful scale, VPPs may need to combine multiple resource types over a relatively wide geographical area in a way that may not correspond to existing models of resources in the market-clearing engine. These differences arise not only because such aggregations may be able to both consume and produce at different times but also that the settlement for the resource may be over several pricing areas or zones unless otherwise restricted. In the case that a VPP spans multiple pricing areas, a provable response is also required to determine net injection impacts of the use of that resource.

# 4

# MARKET DESIGN OPTIONS FOR DISTRIBUTED ENERGY RESOURCES

Thus far, the report has delved into the various efforts undertaken to achieve DER integration into energy markets. This section is focused on synthesizing the overarching set of options that define a route to market for DER. Figure 4-1 highlights the main dimensions on which market integration options can be formed, indicating certain dimensions that are on a continuous scale (such as depth of market integration) and others that require discrete choices to be made (such as asset class representation).

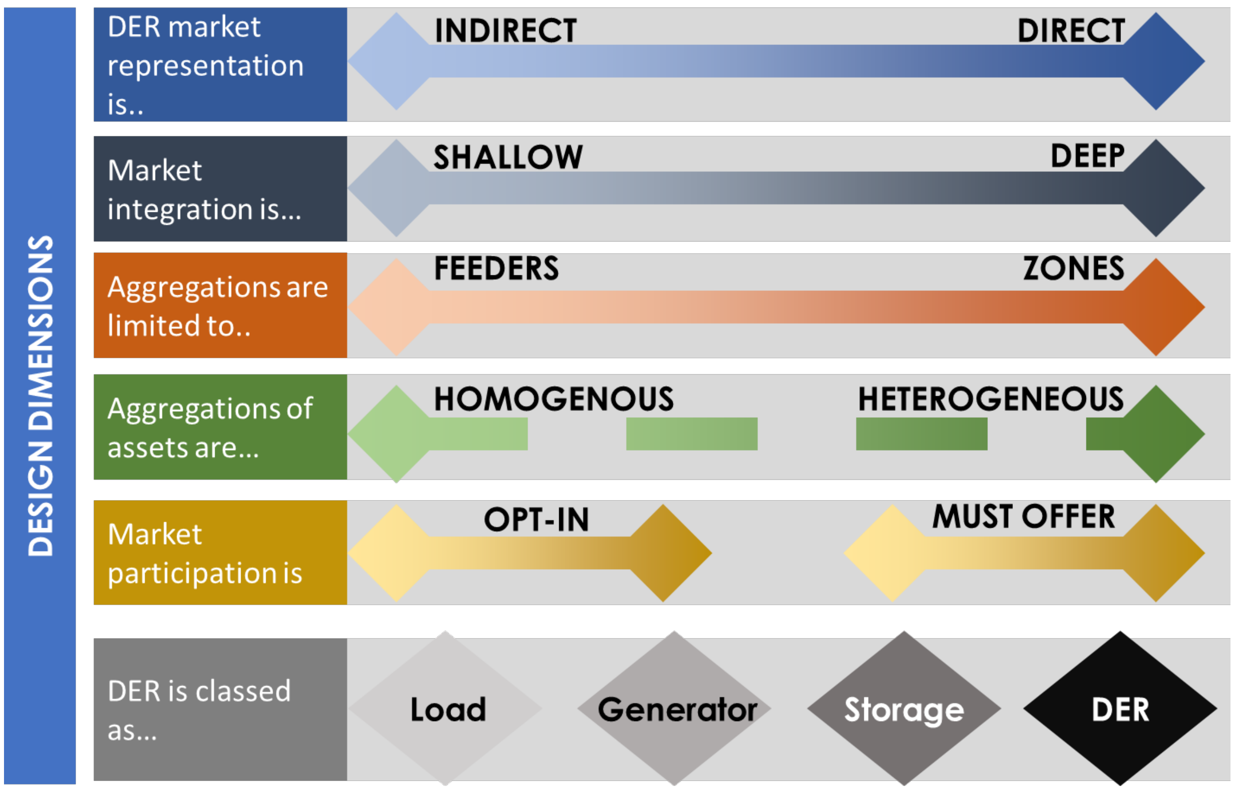


**Figure 4-1**
**Market design dimensions for distributed energy resource integration**

## Indirect and Direct Approaches

The DER program review has shown that there are numerous ways in which DER can be brought to market. At a high level, the integration philosophies fall into two camps: 1) direct bidding of DER or DER aggregations or 2) indirect management of DER to influence bulk system load levels that offset market parties' exposure to those markets. Each approach presents the opportunity for DER capabilities to be leveraged to different extents.

### Indirect Management

In the indirect approach, load-serving entities (LSEs) or retailers or those with generation obligations use DER either in advance of or after market clearing to manage either demand or generation that appears on the bulk system. Motivation to do so comes from the avoidance of energy market costs or the mitigation of demand during specific periods when cost allocations for network capacity charges are determined.

In the indirect process, the DER may adjust output based on a time-of-day or condition-based tariff or may have a relationship with an aggregator working on behalf of a market party who is hedging either load or generation through out-of-market actions, without allowing control over the DER aggregations to be taken by the market operations. In this case, when DER generates at times when the market price is lower than the marginal cost of the unit, the cost inefficiency is incident on the aggregator or individual DER asset itself, rather than socialized

This approach has merit, particularly at low penetrations of DER in which its aggregate impact on the market is relatively low and communication infrastructure between the DER and the aggregator or distribution utility is not prevalent or is expensive to install. The aggregate effect of the response is monitored through meter readings at the primary substation in systems without retail choice or individually at the customer meter in those with retail choice, as is the case in the NEM. This option is effective for services that are rarely activated, such as annual peak avoidance, at low levels of DER penetration or when the supply curve of the DER aggregations is a close approximation of the wholesale market supply curve. Use of DER in such a manner is common at present in the United States and in Europe, primarily through hot water or A/C control, and more recently, through the control of battery storage devices, as described in Appendix A.

However, drawbacks are apparent at higher penetrations of DER when total DER has a material impact on price formation in energy markets. System operators retain the responsibility to forecast the anticipated behavior of DER and prepare the system accordingly. In this case, the incidence of any balancing or congestion management costs incurred due to uncertainty are incident on the system operator. In the indirect approach, a risk exists, too, that DER passively reacting to a market price signal may rapidly induce either over- or under-supply situations requiring balancing actions.

Furthermore, indirect management of DER by LSEs in price-sensitive regions of a network may have incentives to operate DER that are incompatible with the maximization of the social welfare objective of the bulk power system in limited circumstances. Opportunities may exist to force an over-generation condition through market power, bringing prices increasingly negative during lower load periods. In addition, this may lead to a lack of operational visibility by the system operator.

Examples of an indirect approach include the Hawaii Electric Company’s Customer Grid-Supply Plus (CGS+) tariff for small-scale solar connections, Green Mountain Power’s use of behind-the-meter batteries to manage forward capacity cost risk, or Great River Energy’s use of domestic water heaters to mitigate high prices in the Midcontinent ISO’s real-time energy market (see Appendix A for details).

## Direct Participation

In the direct participation approach, DER are offered into the market by a scheduling entity as an individual resource or set of aggregated resources, independent of demand or other resources, in a similar fashion to generators at present. This allows the market for energy at day-ahead or real time to adjust based on the offered capability of the DER units and their associated costs. Requirements for the dispatch of the DER subsequent to a market run may vary, depending on the settlement arrangements.

In principle, this process alleviates the observability issues with DER and provides a mechanism for a more precise dispatch of both conventional generation and DER, with reduced reliance on heuristics to manage uncertainty, such as adoption or production forecasts and locational distribution of DER through the network. Direct participation also provides a path to market for DER through non-LSEs, such as third-party aggregators or other service providers, and allows for the provision of both energy and ancillary services. This route also mitigates some of the market power risk associated with DER when coupled with demand in sensitive regions of a market area.[8]

The disadvantages associated with direct participation are the administrative overhead associated with bringing the DER to the wholesale market, the need for communication and control capability between a scheduling entity and the DER, extended responsibilities of existing actors (or creation of new actors) to facilitate distribution market transactions, the requirements for revenue-grade metering on the output of the DER akin to existing practice, and finally, relatively more onerous public engagement required to encourage DER owners to participate in the market.

Examples of direct participation are highlighted in Appendix A, which highlights the cases of PV in France and Germany, the use of batteries and DR in energy and ancillary markets in Switzerland, and the DER provider in the CAISO market. Ultimately, each of these market designs are still relatively nascent and typically do not extend to residential-scale DER at present. Where participation is more widespread, such as France and Germany, it is typically leveraging communications infrastructure that has been in place since the 1980s. Although, in most countries, DER penetrations are not sufficiently high to cause reliability issues that market-based mechanisms are deployed to resolve, the implementation of such active system management is taking place in regions such as Germany, where local issues may arise, causing congestion.

## Modeling Distributed Energy Resources in Energy and Ancillary Service Markets

A decision may also arise as to what class of resource an aggregation of DER represents in the market. Most pool markets are cleared using a unit commitment and economic dispatch model to produce day-ahead or intraday dispatches, ancillary service allocations, and prices. This model includes constraints that reflect the technical characteristics of generators and the network, forecast availability from producers, forecast demand, and the economic offers from each actor.

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[8] The potential to exert market power exists when a primarily load-serving entity such as a supplier has a concentration of DER that it can use to reduce wholesale demand so that sufficiently negative prices are induced. The risk of this occurring in practice is highly dependent on the system conditions and on the relative costs of the DER and the system supply curve slope at low demand levels.

The exact formulation of the optimization model differs from region to region. Some jointly include a co-optimization of energy with frequency control ancillary services in some or all markets (such as day-ahead, intraday, or real-time) where the opportunity cost of providing services are reflected in the allocation of energy and ancillary services to units and largely ensure that price signals are compatible with incented resource behavior. Similarly, treatment of network constraints or forecast horizons may differ substantially.

Within each model, each class of resources (such as demand, thermal generation, hydro, storage, and utility-scale wind and solar) are represented with a different set of constraints, dispatch offer parameters, and settlement methods, which are suitable for the range of services and inherent limitations of those resources. These classes are not used in commodity or power exchange type markets. The question for DER is whether it can be represented in the market using existing classes or a new class is required to be defined (and if so, why). This arises as DER has multiple potentially unique combinations of characteristics, including production, consumption, energy delivery limitations, dispersion across locations, and availability uncertainty, to name a few. It also may be the case that DER determines its own schedule to inform the market, in which case this may also require a new or altered representation in the market-clearing engine.

### *Load Class*

Load or demand resources may be included in markets to represent system load, from an individual retailer or distribution utility or from a significant transmission- or distribution-connected load such as a data center, furnace, or other industrial complex. The constraints associated with loads can include demand forecasts, associated bid curves, penalty prices, ancillary service provision, availability windows for demand response, or service deployment limits. Typically, the load is defined at each primary substation or at the regional level in a wholesale market and where a demand curve is included.

### *Generator Class*

The generator represents conventional, large-scale, hydro-thermal generators, including their offer prices and technical characteristics that are reflected through associated constraints. These constraints may not replicate the behaviors of each individual resource, but they provide a sufficiently general set of constraints to replicate the behavior of most. These are typically at one location, which may differ from a DER aggregation spread across multiple sites. Generation class resources also are typically restricted from consuming power. Variations of the class are common, such as pumped hydro storage, CHP, and combined cycle gas turbines, for which additional constraints such as energy limits may be needed.

### *Storage Class*

This type of resource may represent short-duration storage, such as batteries, or longer-duration resources, such as hydro pumped storage. These resources' SoC may be optimized by the market-clearing engine themselves or be included in the market based on offer curves. This class allows for consumption and production and also considers the energy-limited nature of the resources in question.

### *Distributed Energy Resource Class*

A further option may be to create a new class of resources that replicates the capabilities of the DER and aggregations in question. This option may be better suited for aggregations that have a mix of technologies with a wider potential injection range and wider spread around the network, as described later. ISOs in the United States are considering this need at the moment in the context of the FERC proposals for direct DER market participation.

### *Matching Distributed Energy Resources to Asset Classes*

Table 4-1 presents examples of how various DER technologies can be included in a market, either directly or indirectly, through each of these asset classes.

**Table 4-1**
**Direct and indirect distributed energy resource market participation modes and examples**

| Mechanism | Participation Model | |
|---|---|---|
| As load | DER included as net load in price responsive demand offer (such as Repower VPP in Switzerland)<br>Demand response offer (such as PJM, France) | DER used to manage scheduled load (such as water heaters in Great River Energy, France) |
| As DER individual or aggregation | Demand response (such as Great Britain)<br>DER aggregation (such as California)<br>Bidirectional resource (such as UK) | Tariff and incentive structures (such as triad avoidance in Great Britain)<br>Connection agreements (such as Hawaii) |
| As generation | Generation aggregation (such as France) | Self-consumption (such as Australia)<br>Passive actor (such as Australia) |
| As storage | Storage (such as PJM) | Storage as a backup resource |

## Shallow to Deep Integration

In the case that a direct participation approach is the desired path, the question arises as to what degree DER can influence market clearing and be responsible for meeting supply obligations. In a *deep integration* scenario, DER is represented in all market services with similar participation and control requirements as generators do presently. *Shallow integration* involves issuing market signals that incent, but do not necessarily require, DER's dispatch behavior to reflect system stress.

In its proposal, the ERCOT report highlighted three options for DER integration into the Texan market—DER minimal, light, and heavy—this section refers to the latter two as *shallow* or *deep integration*.[9] Two of the options presented in the ERCOT recommendations [11] reflect the bookends to the range of possibilities for DER integration, from indirect to direct.

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[9] The DER minimal case effectively matches the status quo in which DER can be indirectly leveraged to influence bulk system load.

### *Shallow Integration*

On the shallow end of the range of market integration options, the availability of DER is made known to a market at or before gate closure, so that anticipated forecast information can be taken into account in the dispatch and commitment process. However, unlike the case for conventional generators, the anticipated generation or consumption from the DER aggregation is not financially binding for settlement; rather, the individual DER is responsible for responding accurately as a “price-taker” to a price signal that is generated through the energy market-clearing process that endogenously considers the anticipated behavior from DER. Settlement is based on meter readings, which must be recorded with at least the same resolution as the market interval length.

This way, if a DER resource produces when market prices are lower than the marginal cost of the unit, that risk is borne by the DER or scheduling entity. Balancing costs for over-generation are still incident on the system operator and dealt with in the established manner. If the market price is higher than the marginal cost of the resource, the DER is correctly incentivized to produce and will recover the infra-marginal rent, based on the settlement.

The advantages to shallow integration mean that real-time supervisory control and data acquisition (SCADA) between the resources and the bulk system is not needed; more onerous market participation requirements and financial offers are not required in this mode. DER uncertainty risks remain incident on the system operator, but the magnitude of the risk is abated through improved visibility by requiring submission of smart meter readings shortly after the delivery period. No substantial changes are required to the market-clearing process because DER acts effectively as self-scheduled generation or demand.

However, some drawbacks remain for shallower integration related to the ability of the market to leverage specific capabilities of DER, such as energy storage or demand shifting, or for ancillary services. Similarly, the system operator may, depending on the exact setup, also not be able to manage congestion or other operational reliability issues through processes such as reliability unit commitment and dispatch, reducing the potential value that could be derived from DER. Penalties for deviation from dispatch instructions cannot be applied, creating a discrepancy between the dispatch of conventional generation resources or larger-scale renewables and storage and the same equipment connected at distribution level. The drawback of the absence of SCADA is a reduction of operational visibility, which is of particular importance during price spikes.

### *Deep Integration*

On the deep end of the range of integration spectrum, DER capability is offered into markets as either individual or aggregated resources. In a scenario with high DER penetration, deep integration is more likely to be the integration model of choice. In this option, dispatch set points are established for each DER resource, either individually or as part of an aggregation such as VPPs, which are binding for delivery, performance assessment, and settlement as part of the market design. This type of integration is currently an option in California, France, and Germany as described in Appendix A.

In this scenario, resources hold the same or substantially similar obligations as conventional resources in terms of responsibility to follow dispatch, inform the market of availability or unavailability (that is, make outage requests to the system operator), integrate with bulk SCADA systems, and any related obligations from ancillary service contracts. DER net injections for individual resources or aggregations are mapped closely to transmission nodes. Resources may be used to provide energy and ancillary services in a co-optimized fashion.

The advantages to deeper integration are manifest in the ability to clear energy and ancillary service markets with a larger resource pool with greater specificity regarding their capabilities and locations so that transmission congestion management can be carried out implicitly in the market-clearing engine. Although transmission congestion management is a separate process from distribution congestion management, the two are heavily interrelated, as described in Section 2. The additional responsibilities for DER reduce operational uncertainty and balancing needs and abates implicit preferential treatment for certain resource classes within the same energy market.

The communications, market participation, and administrative overhead requirements for DER owners and aggregation entities in deep integration is substantial, relative to the other options. This may include the need for SCADA-like connection to each resource, which may be costly or infeasible for remote or isolated resources.[10] In addition, high-resolution metering for the provision of fast-acting ancillary services from DER will likely be required. Although DER may represent a materially large part of the generation mix in a system, the potentially small size of individual market resources may pose a challenge. Market operators may encounter numerical solution issues in unit commitment optimization with the inclusion of several small resources, relative to the size of the system.[11]

### Opt-In and Must-Offer Approaches

In some of the market designs proposed by ISOs and included as part of the direct market participation of renewable schemes in Europe, DER may be required to offer its capacity into the energy market at all times if DER is awarded contract for long-term services or participating in an incentive scheme. The availability of capacity may depend on a multitude of factors such as thermal ratings during the summer months, deratings during planned maintenance, weather, hydro inflows, and so on.

A contrasting viewpoint is that market participants should be allowed to participate at will, determining when and what amount of capacity to offer to the energy market at each time. This is complicated by the fact that DER may offer other services to distribution utilities outside the traditional market arrangement. These questions should be considered as part of DER market integration design, as described in Section 2.

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[10] Extensive research and development work is under way around the world to develop lower-cost remote terminal unit equivalent options to resolve this cost issue for small-scale resources

[11] This may be overcome by numerical techniques such as grouping similar DER units together by pricing node to create an equivalent generation and demand offer, with disaggregation as a post-processing step, as is under evaluation in United States ISO markets. This issue does not materialize in the same way for more commodity type markets, such as those in Europe.

### *Opt-In*

For systems such as those in Australia, without long-term contracts for capacity or flexibility products, energy and ancillary service markets operate over a relatively short horizon, usually up to the end of the next day. For a variety of reasons, resources may desire or be required to withdraw the availability of capacity from the market. This voluntary participation model enables flexible participation in the market, allowing resources to determine their own degree of participation in energy markets. In the case of conventional resources, market rules typically require the provision of intended production profiles and SCADA measurements so that the energy market can adapt in day-ahead and real time.

The ability for a resource to determine its own production schedule is commonplace in most energy markets. Mandatory participation is usually enforced through capacity or flexibility products (for example, resources cleared in PJM markets must offer that capacity into the energy market [16], or counted toward the Flexible Resource Adequacy Criteria–Must-Offer Obligation (FRAC-MOO) in California [17]), or through subsidies such as in Germany and France [15].

The advantages to an opt-in model are that new resources or resources with conflicting operational requirements or incentives can selectively determine when to interact, as well as to experiment with market participation modes. This may support stacked service offerings that helps to justify the development of DER, which is an advantage to this approach. Disadvantages to the voluntary opt-in model includes a relative reduction in predictability of market liquidity for various services. Opt-in requirements are distinct from observability requirements, which means that, in the short term, a requirement may or may not exist to notify the market of the intent to participate or not, and if not, what the anticipated production or consumption is expected to be.

### *Must-Offer*

In systems with capacity remuneration schemes, such as capacity markets, strategic reserve, or forward capacity auctions, awards in these markets are typically accompanied by obligations for the units to be available during peak demand periods and to offer the contracted capability into day-ahead or real-time markets. Similarly, this obligation has been levied on qualifying resources participating in the Californian Flexible Resource Adequacy requirements for system operators.

For conventional generation operating in mandatory pool markets, must-offer obligations are commonplace. However, residential-scale DER, particularly those with self-consumption incentives in which production incentives are not always aligned between market signals and tariff structures, are not experienced with must-offer obligations and managing energy availability to comply with such offers. Customer purchasing decisions are typically made based on expected returns, which exploit self-consumption and tariff minimization. Choices for DER market integration should consider must-offer requirements and the extent to which these might be extended to DER. Although it may be a logical step to extend must-offer obligations to all resources in a single market, this decision may affect the uptake of market participation by DER owners unless it is mandatory or incentivized to do so.

Must-offer obligations reduce the risk of scarcity conditions existing in day-ahead and real-time markets due to withholding of resources and to improve observability to the market. The degree to which the obligation holds may be determined based on the set of services that DER may simultaneously provide, in the case that DER is leveraging to defer the uprating of network assets or construction of new equipment.

### Heterogeneous and Homogeneous Aggregations

DER is a wide-ranging term encompassing many underlying technologies, and these technologies have different capabilities and limitations. When aggregated together, resources can provide a more robust and reliable response to system signals. The most efficient market outcomes tend to arise when resource capabilities are accurately and precisely reflected in the market-clearing algorithm, with appropriate trade-offs against the numerical solution issue in market-clearing. Management of these constraints can be achieved through implicit modeling of specific resource types' abilities or through market offers that reflect the expected behavior.

An example from conventional technology is the combined cycle gas turbine, in which sometimes complex interactions between combustion turbine and steam turbine units mean that simple representation of ramp rates, startup times, or minimum up or down times may under- or overestimate the true capabilities of the plant. In some markets, this has been abated by improving the modeling of these unit types implicitly in the constraints, whereas others rely on the asset owners to choose the appropriate parameters to reduce the possibility of dispatch set point deviation due to plant constraints. The same example could be extended to other technologies such as energy storage and demand response in which similar efforts are currently being made in ISO markets in the United States. The question for market design options for DER is whether aggregations contain resources of the same class (homogenous) or whether a mixture is acceptable (heterogeneous). For resources with charging profiles, such as energy storage, questions also arise as to whether consumption of energy and production of energy should be settled within the same market (retail or wholesale) or even whether the asset could be able to bid as both a load and a generation asset in the same bid.

#### *Heterogeneous Aggregations*

Heterogeneous aggregations allow resources of multiple classes to be aggregated together and offered to the market as a single resource. The resource may appear as a conventional generator, schedulable load, or some other existing class of resource in the market and offer according to the parameters available (such as capacity, minimum stable load, start time, ramp rate, minimum up or down times, incremental costs, start costs, and so on).

An advantage to the heterogeneous approaches is that they reduce the overall number of aggregations in the market for the same number of resources. This may result in more accurate and reliable response to dispatch instructions over time. Grid code requirements for DER connection should specify standards for response to set point instructions and other behaviors. For example, many systems are evaluating the specification of IEEE 1547: 2018 provisions for DER as the basis for active participation in system services [2]. The management of individual resource constraints is done by the aggregator, who has a direct relationship with the asset owner and allocates dispatch among the resource portfolio, potentially through a distributed energy resource management system (DERMS).

There are some potential drawbacks to this approach, as noted earlier. For energy storage resources acting as part of a proxy generator, the optimization of the periods in which storage charges may not be possible. This may not be an issue with relatively few storage resources in a portfolio but may become more significant as the capability increases. This can be avoided to some degree by creating a new DER aggregation class in the market that acts as a hybrid of an energy storage resource, a price-sensitive load, and a generator. No such classes have been defined to date in markets to our knowledge, but they have been discussed.

#### *Homogenous Aggregations*

Homogenous aggregations include resources of a single class. *Class* here is defined loosely as representing one of four options: pure generation resource (such as PV or backup generation), energy storage resource, energy-limited resource (such as demand response), and pure consumption resources (such as demand turn-up). Other classes may be possible for other technologies.

Homogenous aggregations allow for more accurate modeling of the resources' constraints. For resources such as energy storage or demand turn-up services, this may result in more efficient outcomes than otherwise might be the case. The increased control may come at the price of having more, smaller aggregations active in the market, which may prove challenging for market solution engines at small scale unless resources are aggregated together at a node, potentially defeating the purpose of the initial disaggregation depending on the technique used.

### Geographic Granularity

The final set of main options to consider for DER representation in the energy market relate to the geographic resolution of the resources. The NEM clears the energy market through a multi-period, dc optimal power flow representation of the network with associated offers and costs. Pricing is determined on a zonal, incremental cost basis at a selected transmission node that corresponds with the largest demand center within the region. Hence, congestion management is implicitly included in the NEM's constraints, but rather than generators being paid nodal LMPs, settlement is by region, as is the case for demand.

This market construct raises a design question relating to DER aggregations. Limiting the geographic scope of a DER aggregation may be desirable from a transmission congestion management point of view. The following subsections describe three distinct options for geographic scope design options.

#### *Regional Mapping*

The first option is not to limit the scope of the aggregation but to require that the set of transmission busses across which an aggregators resources may be connected are made known to the system operator. The ratio of the aggregation's portfolio in each region may then be used to determine the settlement for the aggregation. A decision is required as to the location of the reference node or set of nodes and participation factors to which DER is assigned within each region for purposes of market clearing.

The advantages with regional mapping are that it allows a large geographic scope for aggregators to build portfolio depth and the mapping to regions allows for some basic representation of the impact of the aggregator portfolio on inter-regional congestion and related pricing impacts.

However, the issue of congestion management within each region is not considered in this model. This may not be an issue at relatively low levels of DER, but it is likely to become more pronounced as the potential to influence transmission flows from controllable DER increases. This has a knock-on consequence, potentially resulting in redispatch for congestion management.

### *Transmission Node Mapping*

Aggregations could be limited to resources within a certain set of transmission busses within a region. Resources within each aggregation would be mapped to each node, with operational changes updated by the aggregator to the system operator of the location of the net injections associated with an aggregator's dispatch in real-time operation.

The advantage to restricted scope aggregations is that congestion within a region can be managed as part of the scheduling process, without the potential for an additional redispatch. However, the smaller the geographical scope, the smaller the potential size of the associated DER aggregation.

### *Distribution Node Mapping*

At the other end of the spectrum of options, aggregations could be limited to a collection of certain distribution nodes when wholesale market pricing is extended to include distribution nodes. This method would implicitly manage congestion at both the transmission and distribution levels in the market-clearing algorithm and reflect prices accordingly. This option would substantially increase the size of the market problem and may not be feasible to solve within sufficient time for a large enough system. Hybrid approaches to hierarchical aggregation of resources in sequential transmission and distribution markets may be possible to formulate to mitigate this issue.

The advantage to extending the prices to the distribution level is that the locational value of DER may be captured to a greater extent than it might be otherwise. However, considerable research should be carried out before proceeding with this option, as questions arise not only about the feasibility of the solution but also about the ability to generate accurate network models, the stability of prices, and the potential need for financial transmission rights to be extended, among others.

# 5
# INTEGRATION OPTION COMPARISON

Given the range of options available to consider for DER inclusion into the market, this section summarizes some of the relative advantages and disadvantages to bringing DER to market through direct and indirect mechanisms and as represented by different asset classes. One initial evaluation of whether each design is fit for purpose is to evaluate incentive compatibility between market signals and resource behavior.

*Incentive compatibility* establishes whether resources are likely to behave in the manner desired by the market outcome when prices are set. Designs that are incentive compatible implicitly align the objectives of the resource with the objective of the market. Incompatibility requires additional measures such as deviation penalties or other market mitigation actions to ensure that resources follow the dispatch established by the market outcome.

Figures 5-1 and 5-2 demonstrate how, depending on who is responsible for bidding the DER into the market, incentive compatibility issues may arise. In Figures 5-1 and 5-2, the incentive for DER to respond accurately to market signals is evaluated at three price points—a price higher than the DER's offer to produce, a price lower than the DER's offer but higher than zero, and a negative price situation. These three cases are evaluated when DER is bid by an LSE to manage scheduled load, price responsive demand, or by another aggregator as DER or generation. These compatibility checks are necessary to understand what behavior is expected from resources under varying conditions. When incented behavior matches expected behavior, the design is compatible and efficient.

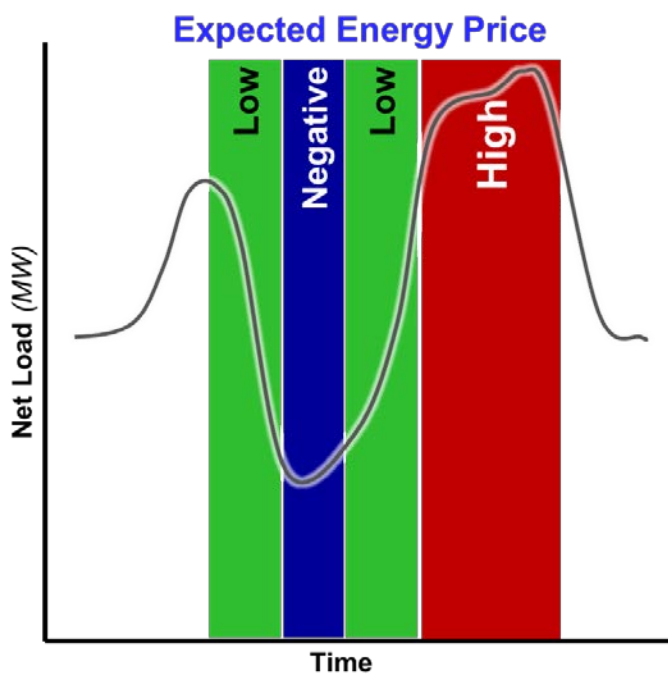


**Figure 5-1**
**Categorization of expected energy prices for incentive compatibility evaluation**

| DER Participation | | During High Prices | | During Low Prices | | During Negative Prices | |
|---|---|---|---|---|---|---|---|
| **Bid As** | **Incentive** | **Behaviour** | **Compatibility** | **Behaviour** | **Compatibility** | **Behaviour** | **Compatibility** |
| Scheduled Load | Reduce cost to load | Reduce demand by dispatching DER to Max | ✓ | Demand bid with DER dispatch to 0 MW | ✓ | Dispatch DER to max if profitable | ✗ |
| Price Responsive Demand | Reduce cost to load | Offer DER and dispatch to max | ✓ | DER dispatch costs included in demand bid but not dispatched | ✓ | Do not bid price responsive demand if Demand >> DER | ✗ |
| DER Aggregation | Maximise Profit | Offer capability and dispatch to max production | ✓ | Offer capability but no dispatch | ✓ | Offer capability with net withdrawal | ✓ |
| Generation | Maximise Profit | Offer capability and dispatch to max production | ✓ | Offer capability but no dispatch | ✓ | Offer capability with net withdrawal | ✓ |

**Figure 5-2**
**Incentive compatibility when distributed energy resource is bid as load, price responsive demand, distributed energy resource and generation for various energy prices**

## High and Low Positive Prices

In the high price case, DER is incentivized to follow the dispatch signal to maximize its revenue in all cases. When prices exceed the DER's offer, the DER will want to dispatch to maximum. Conflicting behavior is known to occur during high prices across a region but when resources' dispatch instructions are lower than maximum due to internalized congestion. This has been the impetus for the development of nodal markets or high dispatch instruction deviation penalties (which require monitoring and control to enforce). DER is incented to reduce output when the price is non-negative but lower than the DER's offer, assuming no out-of-market incentive such as a feed-in tariff.

## Negative Prices

When prices are negative and less than the offer of the DER, incentive incompatibility arises when DER is bid in combination with demand. During periods of negative pricing, generation is incented to reduce production, or demand responds by increasing consumption to alleviate oversupply. Assuming that the load cost is larger than the opportunity cost to DER and that prices are sensitive to the output in the DER production, a party bidding net load (that is, the residual after DER production is removed from native demand) into the energy market is incentivized to create more significantly negative prices to reduce cost paid to the system to serve load. This is a specific condition in which market power may exist.

In cases in which market power can exist today, mitigation measures can be taken to prevent such behavior. A clear proposal for how this might be achieved for DER should be developed in cases in which DER is integrated through the market by load-serving market participants. Mechanisms to offset this risk include the study of potential risk of energy prices being affected by a single such market participant in a certain region and the establishment of administrative procedures to clear the market in such an instance. Identifying the occurrence of such practices will depend on the availability of metered DER production and demand data to be assessed alongside market actions by each actor.

Aside from the incentive compatibility check, there are several other pragmatic characteristics of each option for bringing DER to market that may be considered. These include the potential overhead associated with market integration, the likelihood of DER participating in the service, the requirement for substantial overhaul of the market, and metering arrangements, among others. These may lead to suboptimal technical outcomes when technical and physical system needs are balanced against these practical aspects. Table 5-1 summarizes several of the options for direct market integration of DER as load, DER, demand response, or generation.

**Table 5-1**
**Advantages and disadvantages of distributed energy resource direct market participation when bid as load, generation, and distributed energy resource**

| Direct Mechanism | Advantages | Disadvantages |
|---|---|---|
| As load | Existing customer relationships leveraged<br>Limited changes needed to existing market structure<br>Metering arrangements unchanged for market operator | Incentive compatibility not guaranteed in all circumstances<br>Limited access to ancillary service markets or energy markets during low load<br>No opportunity for co-optimization of energy and ancillary services |
| As individual DER or aggregation | Accurately represents aggregated DER capability range<br>Potential for aggregation across multiple transmission nodes within a zone<br>Allows opportunity for participation in ancillary services markets<br>Direct visibility of DER | Requires metering for market settlement which may be prohibitive for small DER, depending on implementation<br>Increases number of small resources in market solution<br>Complex constraint formulation may affect market clearing in LMP, unit commitment and economic dispatch type markets |
| As demand response | Existing market mechanisms in place (where the exist)<br>Allows opportunity for participation in ancillary services markets | Only allows DER to act as a withdrawal from the system |
| As generation | Limited changes needed to existing market structure<br>Good incentive compatibility<br>Allows opportunity for participation in ancillary services markets<br>Visibility to TSO of scheduled production locations and assets | Only allows DER to act as an injection into the system<br>Limits DER to a single location<br>May not replicate energy limits for certain underlying DER asset types |

Table 5-2 shows this analysis for indirect market integration options. These options are wider, varying in nature from markets run on a distribution feeder level that has an interface to a bulk system market (secondary distribution markets) to regulated arrangements such as time-of-day tariffs for exports, to non-firm connection agreements (that is, maximum export capacity not guaranteed at all times, limited export when system under stress), to more passive customer based schemes such as self-consumption (minimization of grid imports or peak demand).

**Table 5-2**
**Advantages and disadvantages of indirect market integration options for distributed energy resources**

| Indirect Mechanism | Advantages | Disadvantages |
|---|---|---|
| Secondary distribution markets | Coordinated dispatch with distribution and transmission scheduling<br>Direct visibility and control of DER | Complex market design setup may be required for certain transmission and distribution coordination schemes<br>Extensive telemetry and metering requirements |
| Tariff structures | No changes to market required<br>Update could be done through transmission use of service or distribution use of service charges | No visibility of DER location or output<br>Crude time windows (seasonal, daily) would need to be predetermined<br>Limitations to scale of the approach |
| Connection agreements | Clearly established rules for DER curtailment (such as measured voltage lower than x, primary transformer loading greater than y)<br>Enforcing real-time pricing tariff improves ability for voluntary control | No visibility of DER location or output<br>Crude time windows (seasonal, daily) would need to be predetermined |
| Incentive structures | Enforcing real-time pricing or alternative metering policies may guide investment behavior to dispatchable plant types<br>Through incentive scheme can gain static information on DER location | Long-term policy with little operational control or visibility of DER output |
| Self-consumption | Retailer tariffs providing time-of-use tariff to customers optimizing self-consumption<br>Relatively straightforward implementation | Relies on accurate retailer pass-through of tariffs that are incentive compatible with system operations.<br>Inefficient market operation, oversupply during the day may result in high levels of curtailment at the household level |
| Passive actor | No action required by market operators | Relies on consumers' initiative<br>Will eventually encounter severe operational issues. Or over-invest at the distribution level |

Figure 5-3 compares the market integration approaches.

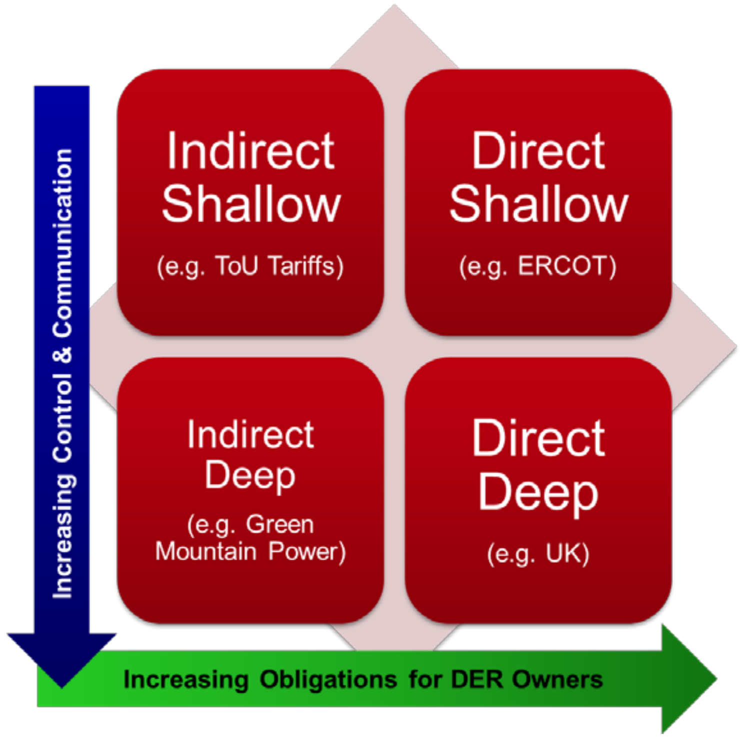


**Figure 5-3**
**Comparison of distributed energy resource market integration approaches**

Given the array of options and combinations, qualitative illustrations of how potential integration scenarios compare in terms of system operations integration, aggregator responsibilities, and DER owners' duties may be instructive. Three scenarios are chosen to illustrate some of the possible routes to market ranging from deep integration to indirect integration and an intermediate step. The scenarios are assessed from the perspectives of the DER owner and aggregator and from a market integration point of view.

### Direct, Deep Integration Bookend

In the deep integration bookend scenario, DER would be directly represented in the market through an aggregator in all markets (deep integration). Participation in the market would be mandatory as long as the DER is registered as a market participant and not on outage. Aggregations would be limited in scope to a set of tightly electrically connected busses within a region and of a single asset class.

### *Distributed Energy Resources Owner*

In this scenario, the DER owner will be required to install revenue-grade metering and real-time telemetry to an aggregator or metering operator from the DER assets in accordance with settlement rules. The DER owner may engage a third-party aggregator to manage market interactions on their behalf and to dispatch the resource accordingly. DER capacity will be unavailable for sharing between services beyond market participation, such as for self-consumption, or for services to the distribution network. However, segmentation of the asset into different blocks of capacity and energy may be possible. The DER owner has a duty to inform the market, potentially through the aggregator, of the intention to change availability, such as to take an outage on the resource for maintenance.

### *Distributed Energy Resources Aggregator*

The aggregator must recruit several DER resources of the same class within each specific area, as determined by a system operator. The aggregator registers the location of each DER in its portfolio with the system operator, as well as information regarding the capabilities of each of those units. The DER aggregator then must forecast the availability of each resource in the portfolio and offer them into the energy markets.

The aggregator should have established telemetry links with each DER and separately with the system operator though the SCADA system and to the market information system. The aggregator provides the system operator with information relating to the net injection from the aggregation at each transmission node. When it receives a dispatch instruction from the market operator, it must dispatch requisite resources in turn. Deviation from the dispatch set point by the DER may create a deviation or imbalance charge for the aggregator.

### *Market and System Operations*

The system and market operators include new aggregators in the market-clearing model and map the production to the selected nodes for each resource. The system operator and aggregator conduct a prequalification process to ascertain the degree to which the aggregation is capable of responding to dispatch signals and other required capabilities. A constraint is added to the market engine to scale the net injection at each modeled transmission node in proportion to the nodal participation factors provided by the aggregators. This reflects the aggregation's impact on transmission congestion.

When new aggregators are added to the system and the size and offer costs associated with them are deemed to be smaller than the expected mixed integer program gap of the market solution engine, aggregators are combined into an equivalent aggregator for the market run. The market clears, and dispatch for DER aggregations are sent to each aggregator. For equivalent generators, post-processing of the dispatch instruction is required to subdivide the dispatch obligation. In the case that a remedial reliability or emergency action must be taken outside the market-clearing process, the system operator may issue instructions directly with the DER aggregator.

## Indirect Integration Bookend

In the indirect bookend case, DER is used by LSEs as a resource to manage the demand bid into the bulk energy market. This could be carried out by the LSE or DER aggregator acting on behalf of the load-serving entity based on anticipated prices in the market.

### *Distributed Energy Resources Owner*

In this scenario, substantial flexibility exists as to what the performance obligation is for the DER resource based on the relationship between the DER owner and the aggregator or LSE. It may be the case that the minimum requirement is that DER be capable of receiving one-way broadcast messages. It may be the case that the DER is used for a variety of services and not just energy market participation.

### *Distributed Energy Resources Aggregator*

The DER aggregator or LSE forecasts future supply curves in the energy market and dispatches the DER within its aggregation on that basis, or the supply curve of the DER portfolio is netted from the demand curve of the LSE, resulting in a price-sensitive demand curve that is bid into the energy market. Based on the market-clearing outcome, the DER may be dispatched by the aggregator. An opportunity may exist for LSEs that also have generation to exercise market power in certain specific circumstances.

### *Market and System Operations*

Substantial changes beyond implementation of price-sensitive load offers and market mitigation schemes to manage market power are not required to market-clearing engines or to system operations. System operations may not have visibility of the DER on the system through any information directly provided by DER. The operators may not have access to DER for emergency or reliability actions. The aggregation is limited to a regional scope with no mapping of the DER to transmission nodes.

### *Case Spotlight: Great River Energy and Green Mountain Power*

Examples of indirect deep approaches to DER integration are fairly numerous, given the provenance of demand control schemes in place for heating and cooling applications and, increasingly, battery storage in areas without retail choice, so that the impact of DER is measured indirectly through metering at primary substations (such as Great River Energy in Minnesota and Green Mountain Power in Vermont). Examples of shallow direct programs are extremely numerous in the form of time-of-use tariffs that are commonplace around the world.

## Direct, Shallow, Opt-In Integration Model

This scenario presents a halfway house between the two bookends presented, in which DER expected production is forecast by aggregators and posted to the market for information. In this example, the aggregation is limited to DER within a certain region with mapping of each DER in the portfolio to transmission nodes. The market clears with this anticipated behavior at each nominated location. This opt-in method allows the DER to influence price formation and improve operational reliability while creating a pricing mechanism for DER output that sets incentives to follow price signals.

### *Distributed Energy Resources Owner*

The DER owner is likely to require revenue-grade metering and telemetry back to the aggregator and potentially the metering operator. The resource may be available to provide multiple services and to offer or withhold capacity from the energy market based on the revenue streams available to it. The DER owner engages with an aggregator to interact with the markets on its behalf.

### *Distributed Energy Resources Aggregator*

The aggregator forecasts the production from DER for the period ahead or offers a supply curve. The market clears with this, and the aggregator evaluates whether DER should produce or not based on the market prices. The aggregator is responsible for settlement with the market and for dispersing revenues back to the DER owner.

### *Market and System Operations*

The market operator clears the market with the production forecast from the aggregator, with the DER injection either located at the reference pricing node or distributed among an administratively determined set of resources in each region. The operators may or may not have SCADA telemetry information from the DER aggregators to inform expected real-time production for balancing actions and to support state estimation. Settlement is carried out with the aggregator based on the meter readings for the DER in each portfolio and the market price.

### *Case Spotlight: Electric Reliability Council of Texas*

Examples of direct, shallow DER integration are relatively less numerous but are starting to appear in some regions around the world. One such example (reviewed in Appendix A) is the case of the Electric Reliability Council of Texas (ERCOT), which is the ISO and market operator for most of Texas. In May 2018, a proposal was made to give DER the option to receive LMP signals from the system operator for the transmission node to which it is most directly connected.

## Summary

The three options reviewed highlight the two bookends and a midpoint on the continuum of options for DER integration into energy markets. Each of these options weighs the potential benefit to system operations and wholesale market efficiency against the obligations and requirements for DER owners and aggregators. It is clear that at relatively lower levels of DER output when the opportunity for reliability issues to occur or when market inefficiency is not substantial, an indirect or shallow approach to DER market integration is likely to be effective in gaining participation.

Although reliance on indirect or shallow integration methods is likely less efficient than deep integration in terms of market outcomes, the up-front metering or retrofit costs or other barriers to market entry for DER owners and aggregators may dissuade them from participation in deep, direct market constructs. A phased DER integration roadmap may be beneficial to transition DER into a wholesale bulk energy market engagement mindset. However, there are two key drawbacks with a shallow approach relating to concentrated effects and long-term trends that should be considered.

First, even at relatively low penetrations of DER on a system-wide basis, DER is likely to be concentrated in certain areas of the system, usually co-located with demand, where prices are relatively higher due to transmission congestion to serve the load. This means that a relatively small, but concentrated, amount of DER may impact market outcomes due to the sensitivity of each binding constraint. Second, increasing DER penetration shifts the value of a shallow approach to a deep approach (either direct or indirect) over time.

The transition from shallow to deep requires DER control and monitoring requirements to be implemented early on to avoid the need for retrofitting programs. If this is the case, the remaining barrier is the enabling administrative issues that may make shallow and deep, indirect and direct DER market participation simultaneously feasible, as desired. These options should be considered as part of the establishment of framework principles described in Section 6.

# 6
# FRAMEWORK PRINCIPLES FOR DISTRIBUTED ENERGY RESOURCES INTEGRATION

Although DER participation in markets is at an early stage for even the most advanced markets, several key insights can be drawn from experience to date and from the consensus that emerges independently in multiple market development initiatives. This section draws together some of the key insights to inform DER integration from a technical point of view. The section is split into recommendations for general framework principles for DER integration, preparatory steps, and DER implementation options.

## Framework Principles

Given the scale of existing wholesale markets, the additional nuances and complexity of extending the market to resources connected beyond the transmission system creates the potential for technical and market inefficiencies to arise. Many initiatives have laid out guiding framework principles upon which the remainder of the DER integration plans are built. Without restating common objectives for reliable power system operation and well-functioning markets, the following additional principles have been added that are universally applicable:

- **Design to do no harm.** When leveraging DER for any purpose, take care that the action does not induce a reliability issue on a related distribution or transmission network.
- **Observability and controllability come together.** To effectively run transmission and distribution operations and to carry out wholesale market operation, market and network operators must have visibility of current and anticipated DER production and consumption. These data must be of sufficient quality, granularity, and availability to be effective in decision making and should avoid unnecessary duplication of effort.
- **Design for a new type of market stakeholder.** As much as anything else, successful DER integration relies on human factors and mutual understanding between asset owners, network operators, retailers, aggregators, and market operators. Barriers to market participation can be numerous and well founded, but appropriate use of language and terminology, recognition of a non-traditional stakeholder group's background, the need for straightforward rationalization, and explanation of processes and requirements help to build trust among all parties.
- **Design for a congested grid.** In an ideal world, congestion would not be an issue at any voltage level. The reality is that it is increasingly the case that transmission and distribution congestion materializes that must be managed economically. Consideration should be given from the outset to how wholesale markets reflect that need with the anticipated markets for DER.

- **Design for system flexibility.** Similarly, systems increasingly require flexibility to respond to changing conditions on the grid. Designs that more fully reflect the capability of each resource type lead to a better functioning system and market operations. It is also the case that the requirements for flexibility will grow instinctively, and that market design itself will likely evolve further based on future needs and emerging trends. Clear signals of need and intent for future designs help to enable parties to engage in the wholesale market.
- **Design a level playing field.** Notwithstanding the need to differentiate resources based on capabilities and existing intention to do so in wholesale design, differentiation that implies preferential treatment of a resource class due to its type, location, or voltage level are best avoided. Obligations on resources for market participation should be rooted in a technical or economic need and applied equally.

The following sections focus on how these principles should be practically achieved, to reach a fully formed future in which DER is integrated into markets. The data, control, and observability principles should be aligned with the DER implementation principles, as there are many design considerations that impact both.

## Data, Control, and Observability

All the principles laid out in the previous section are contingent on high-quality, accurate, and timely data flow between market and system operations actors. The following recommendations may assist with the efficient integration of DER:

- **Establish DER data capture requirements, standards, and custodians of that data.** DER data become increasingly critical for system and market operation as the penetration of DER increases. To clear markets and conduct operational reliability analysis, system and market operators require a DER data set to inform decision making, regardless of whether the DER is a market participant or not. These data may include, but are not limited to, information related to type, location, characteristics, and operational status. After a list of data is determined, roles and responsibilities for collecting, governing, and ensuring quality of the data can be determined.
- **Leverage common data formats.** Given the rapid proliferation of data and the need to interface between multiple parties, use of common data formats such as the IEC common information model standards can be considered. This has the potential to reduce costs for a variety of actors and enable efficient data exchange.
- **Map DER to transmission system busses.** Almost all proposals indicate that DER should be mapped to the transmission bus at which its injection materializes in the wholesale market. This may include a primary and a secondary bus mapping to account for periods when outages or switching shift the output of the DER and may be carried out by a distribution utility and maintained with the other related DER data.
- **Establish interconnection requirements that support system and market operation.** Many grid codes and interconnection standards are under review at present to determine whether the provisions stipulate sufficient capabilities to support both system and market operation. Aside from reliability-related provisions such as ride-through and droop control, standard communication interfaces and protocols help to support the integration of DER.

- **Establish telemetry requirements rooted in operational need.** Telemetry requirements should be established for resources based on their controllability, market offering, and the need for observability. When DER participates in a real-time energy market with 5-minute intervals, the telemetry refresh rate should be commensurate with that service. When DER is providing frequency regulation or fast ancillary services, the refresh rate can be adjusted to capture such behavior. Telemetry can be directly with the resource or indirectly through an aggregator, but it should be recalled that DER offering multiple service may have multiple counter parties with different requirements for spatial granularity (such as wholesale market at aggregation level, distribution redispatch at resource level). Common telemetry protocol implementation supports lower-cost operations and may reduce DER barriers to market entry.
- **Establish metering requirements that enable accurate settlement.** Metering configurations should be able to correctly account for the products settled in the market, be it consumption or production. Specifying preferred metering configurations can enable multiple settlement options while giving increased visibility to system operations. Metering intervals should be commensurate with market intervals and readings should be provided promptly to the market for settlement.
- **Establish a mechanism to govern DER market participation.** In many regions, systems have been developed to track DER participation in incentive programs, demand response programs, and aggregators and to enforce exclusion rules regarding simultaneous participation in multiple programs. An assessment of the need to implement such a system should be undertaken along with an assessment of the roles and responsibilities regarding its potential implementation.
- **Establish an effective data-sharing architecture.** Data collection will naturally occur at multiple locations in the system by multiple actors. Access to data collected outside each party's silo is important for system operation. A data-sharing architecture that ensures access to data where it is needed, while respecting privacy and data protection obligations, should be agreed on early in the process to facilitate metering, monitoring, dispatch, congestion management, and settlement across multiple parties.

### Distributed Energy Resources Implementation in Wholesale Markets

The final set of recommendations relate to the inclusion of DER into wholesale markets. The following recommendations are not intended to be a complete set of recommendations for DER but considerations to be addressed as part of the process of developing a proposal for DER integration:

- **Establish desired outcomes for DER market integration.** The integration of DER into wholesale markets is driven by the objectives of such a design change. Establish a clear statement of both why DER integration is needed and the ultimate objective of the process. For example, the need may be driven by the potential for reliability issues to arise in the absence of DER control, and the ultimate objective may be to include DER for mitigation measures through indirect incentives or to fully integrate DER into energy and congestion management markets to resolve such an issue. The implications of objectives should be considered carefully from the outset, as they will require substantially different solutions.

- **Determine the appropriate depth of integration for the anticipated DER penetration and whether a direct or indirect approach may reach established objective.** The degree to which DER can be effectively leveraged in the wholesale market is dependent on the objectives set, the availability of DER, and the willingness of the DER owner to participate. At relatively low levels of DER, a less intensive integration of DER may give the desired result. For more critical system needs such as reliability or flexibility, a deeper, direct market integration approach may be required.
- **Establish an enabling philosophy for DER stacked service offerings.** Given that DER may be fulfilling multiple roles alongside the energy market, consideration should be given to first establishing a philosophy for DER participation in multiple services. Philosophies may include determining that mutual exclusivity should be enforced between certain services or that DER are responsible for managing the risk for non-performance through pay-for-performance or penalty schemes.
- **Determine how distribution congestion will be managed.** The issues of congestion management and wholesale markets are deeply intertwined and should be considered together. Consideration should be given to the scope of the implicit representation of network constraints in the market, the determination of export capacity from DER, and the mechanisms to coordinate redispatch and congestion management between distribution and transmission network operators. A phased approach to integrating both congestion management and wholesale markets may be taken, particularly at lower levels of DER when distribution congestion is less likely, but a clear roadmap should be in place from the outset to resolve the issue as it becomes binding across all distribution service territories.
- **Determine the scope limits of aggregations.** When DER aggregations are the route to market for most DER, consideration should be given to effective geographical scope limitations so that the dispatch of such a resource does not induce congestion management issues. This scope limitation should be considered at the same time as potential limits to the size of the aggregation for the same reason. Finally, consideration should be given to what resource types may constitute an aggregation and where the responsibility lies for the management of energy-limited resources.
- **Determine offer parameters for aggregations.** Based on the characteristics for DER aggregations, a set of constraints and offer parameters can be determined to model the potential response from DER aggregations. These may reflect capacity, ramp rate, duration, or storage limits, for example. It should also be determined whether the DER aggregation has an obligation to offer capacity into the market or whether participation can be on a voluntary basis, with fluctuating capacity offers from aggregators.
- **Determine settlement procedures and the treatment of native load and charging.** Consideration should be given to the settlement of DER if it spans multiple price zones, the responsibility for aggregation of meter readings, and the treatment of consumption for wholesale market purposes (such as demand turn-up and charging) as compared to native load. This distinction may have implications for the application of network usage charges, which should be considered at the outset as it may affect the likelihood of DER market participation.

## Summary

This report summarizes current industry experience and initiatives in integrating DER into electric wholesale market operations from around the world. Each day, new advances and adjustments are made to existing proposals, which will move systems closer to realizing DER integration into markets. Although it is complex and multifaceted, this issue will be critical for the safe, reliable, sustainable, and economic operation of power systems in the rapidly approaching future. Australia has an important part to play in vanguard of power systems facing this era defining energy transition.

The Electric Power Research Institute’s (EPRI’s) most critical finding to date from applied research on DER integration, the transmission and distribution interface, and wholesale market development is that stakeholders in the power system engage with the need to evolve power systems in a collegial manner and in good faith to build the trust among entities that underpins every technical and market development.

# 7
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# A

# INTERNATIONAL REVIEW OF EXISTING INITIATIVES

This appendix draws together insights from existing and planned initiatives to represent DER in energy markets and reviews select capabilities and business models for the aggregation of DER. Although there is a paucity of mature markets with active and direct participation of DER as defined in Section 5, indirect use of DER to manage apparent demand on the bulk system has been more pervasive to date. The examples in this appendix cover both types of market integration. Table A-1 provides an overview of reviewed DER programs.

**Table A-1**
**Overview of reviewed distributed energy resource programs**

| Country / Region | Program | DER Penetration | Description | Direct / Indirect | Opt-in / Must-Offer | Aggregation Limits | Maturity |
|---|---|---|---|---|---|---|---|
| Netherlands | Energy Trading Platform Amsterdam (ETPA) | Low | Intraday congestion market | Direct | Opt-in | No | Trial |
| Great Britain | Demand Turn-Up | Med | Balancing service to increase net load | Direct | Opt-in | No | Mature |
| Great Britain | Short-Term Reserve | Med | Operating reserve to manage net load uncertainty | Indirect | Opt-in | No | Mature |
| Great Britain | Triad Management | Med | Network capacity charge reduction | Indirect | Opt-in | No | Scale Up |
| Great Britain | Balancing | Med | Intraday balancing market for congestion and forecast uncertainty management | Indirect | Opt-in | No | Mature |
| Great Britain | Piclo | Med | Local energy market for congestion management and asset deferral | Indirect | Opt-in | Yes | Scale Up |
| U.S. – HI | Smart Export | High | Time-of-use customer tariff | Indirect | Mandatory | Yes | Mature |
| U.S. – HI | Customer Grid-Supply Plus (CGS+) | High | Grid operator controllable customer solar and storage program | Direct | Mandatory | Yes | Mature |
| Germany | Direct Marketing | High | Inclusion of DER above 250 kW capacity into energy market | Direct | Mandatory | Yes | Mature |
| France | NEBEF | Low | Demand response program used for balancing operations | Direct | Opt-in | No | Mature |
| France | Heures Creuses | Low | Time-of-use program | Indirect | Opt-in | No | Mature |

**Table A-1 (continued)**
**Overview of reviewed distributed energy resource programs**

| Country / Region | Program | DER Penetration | Description | Direct / Indirect | Opt-in / Must-Offer | Aggregation Limits | Maturity |
|---|---|---|---|---|---|---|---|
| France | Tempo | Low | Time-of-use program | Indirect | Opt-in | No | Mature |
| U.S. - MN | Great River Energy DR | Low | Controllable water heater program used as variable load bid in energy market | Indirect | Opt-in | Yes | Mature |
| U.S. – VT | Green Mountain Power – Forward Capacity | Low | Customer-sited battery storage used for backup power to also manage energy and capacity market exposure | Indirect | Opt-in | Yes | Scale Up |
| U.S. – CA | Reliability Demand Response | Med | Demand response program used in certain market processes but not real time that can include DER | Direct | Mandatory | Yes | Mature |
| U.S.-CA | Proxy Demand Reponses | Med | Demand response program used in all market processes that can include DER | Direct | Mandatory | Yes | Mature |
| U.S.- CA | DERProvider | Med | DER aggregation that can participate in all energy markets | Direct | Mandatory | Yes | Initial |
| MISO | Battery integration | Low | Process for including batteries into energy and ancillary service markets | Direct | Mandatory | Yes | Initial |
| ISO-NE | Storage market integration | Low | Process for including batteries into energy and ancillary service markets | Direct | Mandatory | Yes | Initial |
| Switzerland | Repower | Low | Aggregated customer storage bid into operating reserves market | Indirect | Opt-in | No | Scale Up |
| U.S. – CA | EV Charging | Med | Aggregated charging capability providing curtailable load for operating reserve | Direct | Mandatory | Yes | Initial |
| Spain | EV Charge Tariff | Low | Time-of-use tariff for electric car charging | Indirect | Opt-in | No | Initial |

## Netherlands

### *Regional Context*

The Netherlands has a winter peaking power system with a maximum demand in the region of 25 GW. The TSO, Tennet, works together with multiple DSOs—including Alliander, Essent, and Stedin—to plan and operate the system. The Netherlands has full, legal unbundling of the utilities, which separates the DSO from the retail utility. Although the system has experienced substantial growth in onshore and offshore wind generation at the transmission level, a rapidly growing build-out of PV has resulted in 4 GW being installed by the end of 2017. National policies have established a 50% renewable energy target for electricity by 2030 and 100% emissions-free by 2050. Furthermore, the Dutch government has signaled intent to eliminate the sale of combustion engine cars by 2030.

The Dutch system is part of the larger Central European power system and is integrated into the day-ahead and intraday energy markets. Real-time balancing is conducted by the Dutch TSO on a national basis. Prices are set on a zonal basis, with a pay-as-bid market up to real-time gate closure. Key issues facing the Dutch system include difficulties building new transmission and larger distribution reinforcement, the integration of substantial amounts of offshore wind, and unscheduled cross-border transmission flows with neighboring countries.

Furthermore, recent European Commission intentions published in the Clean Energy for Europeans package to pursue market design options that enhance consumers' and smaller-scale actors' access to energy markets. Several local energy trading platforms have emerged in regions around the world. In the Netherlands, the Energy Trading Platform Amsterdam (ETPA) was established to enable smaller actors to have access to energy markets with a more limited overhead than in larger power exchanges.[12] Similar initiatives have emerged in the Netherlands, Denmark, Germany, Norway, Belgium, the United States, and the United Kingdom. As of April 2018, ETPA has become a fully owned subsidiary of Tennet.

With the need for increased access to balancing and congestion management resources foreseen as the penetration of DER grows at the distribution and transmission levels, TSO and DSOs have had to evaluate possible methods to cooperate in the future. Discussions are ongoing, but several joint white papers and reports on the topic have highlighted multiple possibilities for cooperation, as described in Section 2. The discussions are taking part in a context of a wider European discussion focused on the topic of TSO–DSO cooperation.

[12] Larger power exchanges in Europe have market participation fees upwards of 5000 EUR plus volumetric fees, as well as minimum orders greater than 1 MW, which are prohibitive for most small-scale DER or demand owners.

### *Program Overview*

As part of a joint initiative between Tennet and Stedin (the DSO for Rotterdam, Utrecht, and surrounding areas) and the ETPA local market, a recent trial has begun to test mechanisms to coordinate congestion on the transmission and distribution networks in the intraday time frame. This is a challenging issue because TSOs, DSOs, and DER all have different and sometimes counteracting incentives. The goal of the six-month trial was to recruit consumers and DER owners to participate in a pilot market that facilitates trades between market parties but that also allows the TSO and DSO to observe trading and to find transactions that resolve congestion issues in a mutually compatible fashion. This trial commenced in the second quarter of 2018 and is completing at present.

As part of the trial, Tennet and Stedin are developing a congestion management platform for both transmission and distribution to interact with the intraday market. The purpose of this platform is to accomplish the following:

- Forecast the potential for and location of congestion on each party's network
- Evaluate the availability of bid–offer pairs in an area to alleviate anticipated congestion
- Determine economic adders on the bids to encourage clearance of advantageous trades
- Coordinate redispatch actions between TSOs and DSOs

The goal of the platform is to coordinate the network operation's expected operating state and to enable operators to take advantage of potentially mutually advantageous bids. This intraday congestion spread (IDCONS) platform then interfaces with power exchanges that expose their order books. The schema of this process is shown in Figure A-1.

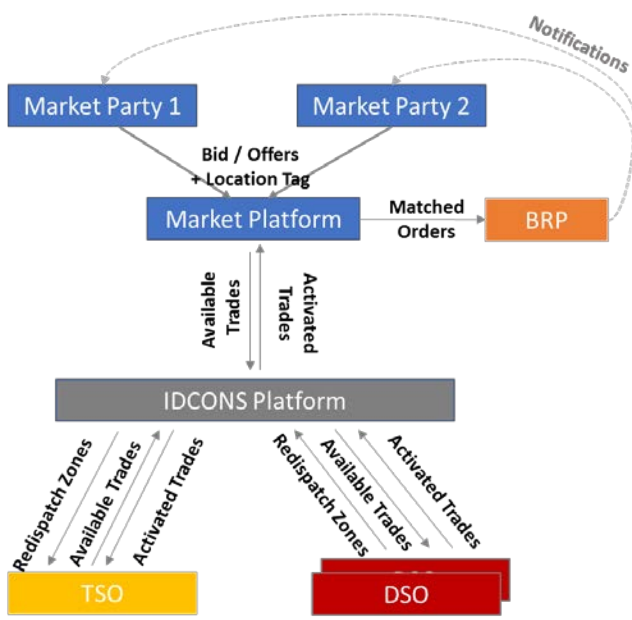


**Figure A-1**
**Schema of interactions in Energy Trading Platform Amsterdam market pilot for intraday congestion**
*Based on "Market-Based Redispatch in the Netherlands" [5]*

At present, the main DER targeted by the market for inclusion are those from the strong agricultural industry in which CHP and solar PV generation are used for processing and greenhouse heating. These technologies may be bidirectional in that they can both consume and produce, giving rise to a more complex capability than simple demand response. It is envisaged that the appeal could be broadened should the trial prove to be effective.

### *Market Integration*

The ETPA market pilot is focused on congestion management after gate closure for intraday wholesale energy markets [5]. In the Dutch system, gate closure for intraday trades is an hour in advance of each 15-minute market interval. The market is based on similar principles to the single European market—it is based on a commodity style trade between market parties with notification to the TSO at gate closure of those trades and their allocation to physical resources. Markets operate on a zonal basis, with market coupling between countries. To resolve congestion issues at the transmission level, TSOs run technical constraints resolution processes to mitigate congestion or other operational reliability issues after gate closure. These can be market-based or more bilateral arrangements between TSOs and resources, depending on the region.

Because final physical notifications have been posted in such a manner that active power balancing should have been achieved, maintenance of that neutral position is important to prevent inducing imbalances through congestion relief actions (that is, dispatching down a unit for congestion relief must be counteracted by increasing production from another unit elsewhere to maintain balance). To avoid this issue, the congestion spread concept was devised. The congestion spread is the price difference between bid–offer pairs that have not cleared in the market and that would resolve an anticipated congestion issue. An example is shown in Figure A-2 in a simple, two-bus excerpt from a network.

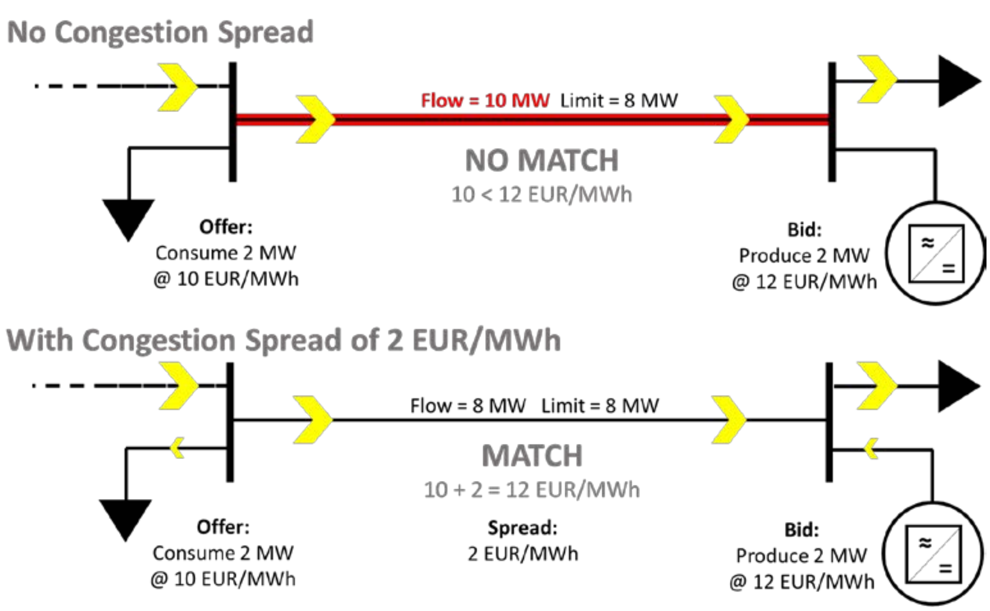


**Figure A-2**
**Example of congestion spread in market clearing**

In the top part of Figure A-2, the pre-redispatch case forecasts a line flow that exceeds the limit by 2 MW. Two unmatched bids are available for production and consumption of 2 MW, at 12 and 10 EUR/MWh, respectively. To resolve this, the network operator sees that a spread of 2 EUR/MWh between offers exists that can resolve the congestion. Therefore, by contributing toward or underwriting the loss of the 4 EUR transaction, the transaction would clear, and the congestion would be alleviated. The network operator is also not left with a non-neutral energy balance position; it has merely influenced the trade. In this trial, congestion was resolved at a resolution from the 38 kV network upwards for a small portion of the system.

To judge which trades are likely to resolve congestion and which are not, the market clearing is depending on locational information being appended to bids. In this case, meter codes or postcodes are used to identify locations of resources. These, in turn, are mapped to points on the distribution and transmission network where the DER's effect materializes. The inclusion of locational identifiers with offers to market is optional for each trade. When such a trade clears, it is removed from the order book, and other market operators are prevented from making counteroffers for the congestion spreads on the trade.

Market parties are notified up to 45 minutes before the commencement of the delivery period (which, for the trial, is 1 hour) whether a trade has cleared. The minimum bid size is 1 MW at present, with locational bids on a per meter basis. Notification of the successful bid comes through the balance-responsible party (that is, the entity responsible for reporting the DER's position to the bulk system market) by an electronic message through the market portal.

### *Metering and Telemetry*

For the purposes of the trial, responses to market trades are metered using individually metered resources with interval meters. Real-time telemetry is not deployed for this trial; rather, settlements are determined ex-post.

### *Relevance for Australian Systems*

Although they are still at an early stage, the Dutch market pilots can be instructive to Australia, despite the difference in market styles. The Dutch system does not have the same degree of penetration of DER at present, but it does have an incentive to gain access to DER for management of congestion issues, similar to the case that is expected in Australia.

The market pilots will test smaller-scale resources' (minimum size of 500 kW) ability and interest to participate directly in the energy market, while also providing a route to market for three of the key services that are critical to stacked benefits—capacity, energy and congestion management (including asset deferral). The natural position taken by networks operators in the market to encourage economic solutions to congestion is of relevance as a potentially efficient method for clearing mutually beneficial trades. Although this pilot focuses on redispatch over longer periods, the market settlement using meter data from interval meters is a low-overhead mechanism to establish a route to market.

## Great Britain

### Regional Context

Great Britain has experienced some of the fastest growth rates of renewables and DER around the world. In excess of 13 GW of distribution-connected solar PV is currently installed, with a further 4 GW of distribution-connected generation that includes combined heat and power (CHP) and backup generators. The system has 19 GW of wind power in total, of which 7 GW is offshore and 5 GW is located on the distribution network. The system peak load reached 50 GW in March 2018, with reductions expected to continue in the coming years. Furthermore, minimum demand has been seen to decrease to an expected 17 GW in summer 2018. This has challenges in terms of low system inertia levels, as well as high-voltage issues on the bulk transmission system. The Great Britain system is interconnected with the continental European and Irish power systems by several high-voltage dc interconnections totaling 3.75 GW at present. An additional 2 GW of high-voltage dc is under construction and several other projects are under consideration, including additional links to Ireland, Denmark, and France.

This market operates similarly to the Dutch market in that it is a zonal market coupled to other European markets that runs day-ahead and intraday up to 1 hour ahead of real-time delivery. National Grid, the system operator for both electricity and gas, has responsibility for system balancing when real-time gate closure is reached. National Grid has sought to involve DER increasingly in the operation of the system for both frequency management and voltage control. These initiatives stem from several studies of future power system needs and the operational capabilities required to meet those needs.

### Program Overview

In the recent past, several initiatives and trials have been established to encourage active participation of DER in system services. Four services are reviewed in this section, along with a pilot project that has recently begun [18]. The services include the following:

- Demand turn-up
- Short-term operating reserve (STOR)
- Triad management
- Balancing

*Demand turn-up* is a service that is sought by the system operator to manage flexibility during the summer seasons. This requirement for sustained increase in demand or consumption from storage devices reached 115 MW in 2018 [19]. The product is procured by the system operator for delivery between the start of May and the end of October. Eligible resources include aggregations of resources such as demand response, distribution-connected generation, and energy storage. Aggregations of 1 MW or more are eligible for consideration, with each asset within the aggregation having to be larger than 100 kW. When called on, resources contracted to provide demand turn-up service must typically deploy for a minimum of 4 hours, with shorter duration responses possible for select situations. Resources offer their capability into a tendering process that is cleared on a per-offer basis.

*STOR* is a reserve product, to increase production or reduce demand, that can be called on by system operators for a variety of conditions. The reserve can be called on during two availability hours, coinciding with the morning rise and the evening peak. Response time for STOR is between 20 minutes and 4 hours, with deployment lasting up to 2 hours. Aggregations of DER are permitted to offer services when larger than 3 MW and smaller than 9 MW. Thus, the response from each resource cleared in the STOR procurement process will be different, depending on the constraints associated with the underlying assets offered and contracted for. National Grid contracts approximately 2.3 GW of STOR for 2018–2019 that is dispatched through manual operator actions [20].

*Triad management* is the principal driver of DER adoption for commercial and industrial customers, as network charges are determined in the United Kingdom based on each consumer's production during three stress events during the year, denoted as *triads* [21]. These triads may occur between November 1 and February 18, can be no closer than 10 days apart, and are determined ex-post. Because network charges constitute a substantial part of a consumer's final bill, there is strong incentive to attempt to predict when a triad event may occur. For customers co-located with DER, that resource can be used to try to reduce the customer's consumption during a period that is expected to be a triad interval. Therefore, DER are incentivized to produce when the system is stressed. This is an indirect incentive, and it has also resulted in a feedback loop between DER increasing production in anticipation of a potential triad period and the avoidance of that period qualifying as a triad interval. Availability of resources to provide other ancillary services—such as fast-acting enhanced frequency response—can be limited based on owners' desires to retain control over dispatch during triad periods. Although downward-acting frequency control services are abundant at peak periods, upward-acting services can become scarce in these conditions. Furthermore, if the trend of increasing deployment of customer-sited DER to manage exposure to triad costs continues, gross load on the transmission system is likely to decrease below a point at which system peak demand stresses the transmission network capacity in an aggregate sense. Although triad periods are used as a cost-allocation mechanism, the costs being allocated may change in such a manner that it changes DER incentives to provide other services. This example illustrates the web of interactions between tariffs and energy and ancillary service market design that influence DER behavior.

*DER for balancing* is the final service reviewed [22]. Suppliers in the Great Britain market must declare energy-neutral positions at gate closure or have the system operator cover the imbalances. One option for suppliers is to procure the services of a DER aggregator to manage forecast uncertainty between day-ahead and real time. In this arrangement, there is a bilateral agreement between the aggregator and the supplier. A key limitation for DER to participate in the balancing mechanism individually or in aggregate is the need to have meters for each resource associated with a supplier agent in the market. This has been identified as an area for improvement in the Great Britain Balancing and Settlement Code. A recent modification to the code has been proposed to create a new balancing entity that may bid DER aggregations across multiple grid supply points. This modification is due to come into force in 2019, according to a recently published roadmap for balancing market access. Therefore, this option is not used widely at present to bring DER directly to the balancing market, but some aggregators (such as Limejump) have recently commenced trading in the balancing marketby becoming a registered supplier, leveraging DER and other resources to provide balancing flexibility [23].

### *Market Integration*

The market for balancing and longer-term operating reserves is operated by National Grid. Each product is cleared with a separate set of tendering rules for various delivery periods. These tenders are typically cleared through a pay-as-bid mechanism. Limitations exist to restrict simultaneous participation of certain mutually exclusive services, but these apply uniformly for all generation types.

Although distribution-connected resources are providing the response to the bulk system, contracting is independent of the distribution network operators. DER connection practices for distribution utilities vary from place to place; however, the majority of connections are granted on a firm access basis. The DER can export to the system at any level up to the amount specified in the connection agreement with the distribution network operator, based on a customer's connection request. To connect DER in areas where significant reinforcements are required to ensure that a DER requesting connection could export at a limit in only a few conditions that otherwise may not be possible, non-firm connection agreements have been offered in certain circumstances.

Non-firm connections allow the DER to export up to its limit except for certain circumstances when congestion arises and its output is curtailed. This can be done through either local, autonomous control based on local voltage or flow measurements; time-profiled connections (that is, connections with varying export limits based on time of day and season); or redispatch from a distribution management system for larger DER resources. An example of this can be found in the UK Power Networks (UKPN) distribution service territory in the southeast of England. Flexible generation connection agreements can be offered wherein UKPN may be able to curtail generation during periods of congestion on the 33-kV or 132-kV network [24]. DER larger than 1 MW are connected with the UKPN distribution management system's SCADA using inter-control center communications protocol (ICCP) through a range of communications options ranging from 3G cellular to satellite and direct firer connections. At present, the use of this control is limited to resolving congestion issues in the distribution network through a last-in, first-out priority list. These options have been available since 2016 for some regions, with a goal to expand across the broader service territory by the end of 2019.

As part of this effort to use DER to manage congestion on the distribution system, DNOs in the United Kingdom are holding location-specific auctions through market platforms such as the Piclo platform [25]. This platform allows DER to participate in auctions to provide a targeted amount of capacity (such as 6 MW) to the network operators during certain periods (such as 16:00–20:00) on certain days, across a given time horizon such as the winter months. These auctions require that resources be prequalified to provide the response and can sustain that response for a minimum duration. As part of the auction process, the resources are given notice of the expected number of calls to that resource over the period and the average duration of each event. Figure A-3 shows a screen capture from the Piclo platform.

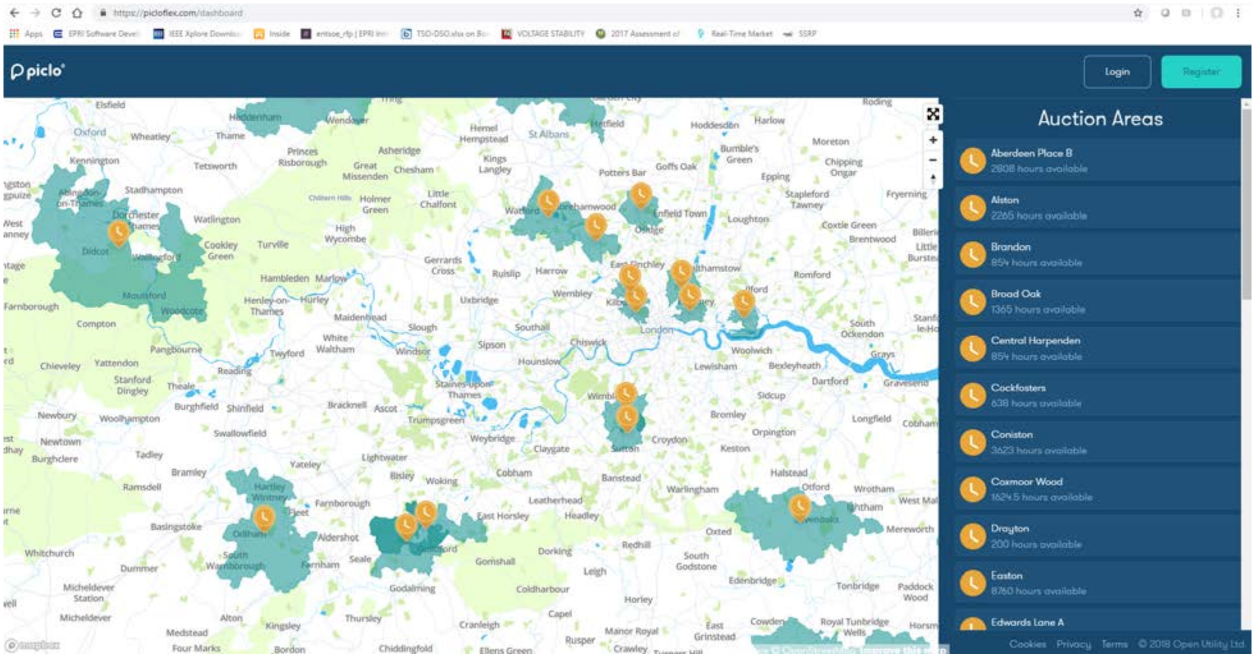


**Figure A-3**
**Screen capture from the Piclo market dashboard**
*Source: http://www.picloflex.com*

When these non-firm resources participate in bulk system services, the potential for conflicting instruction sets may arise. At present, this is managed by the aggregator, using its portfolio of resources to balance the requirement for provision of service to the bulk system with individual resource contribution limits, in a similar fashion to demand response. Through consultation, UKPN documented the compatibility of their flexibility procurement for congestion relief with other services provided to the bulk system operator and with triad avoidance [26]. Their assessment indicated that the provision of congestion relief was largely compatible with capacity market obligations, triad avoidance, and energy and balancing markets, with some conflicts arising in those use cases arising due to the recovery time for those assets before they could be called again or the need to recharge energy stores. The consultation found that compatibility with frequency control services and demand turn-up services was neutral, with potential competing interests between provision of congestion relief and upward reserves, as well as exclusivity of contracts for STOR, preventing resources from simultaneously providing congestion relief.

One pilot that is under way at present will address the coordination issue specifically. The power potential project is jointly run by National Grid and UKPN. The goal of the project is to demonstrate the use of DER for congestion management (thermal and voltage issues) on both the distribution and transmission networks. In this pilot, DER will be controlled through a remote terminal unit (RTU), equivalent to those used for communication with larger-scale plants, located at the resource site. The set points for each resource are determined by the DSO through a DERMS, based on input from the TSO as to the requirements for active and reactive power flows at the interface between the two system operators. The pilot is currently at a recruitment phase for participating resources and is expected to run to 2020.

### *Metering and Telemetry*

Telemetry requirements vary depending on the service provided. For STOR, resources should be capable of interfacing with the system operator over the Modbus protocol through an Integrated Services Digital Network (ISDN) gateway at the site [27]. The scan rate for STOR is on a 1-minute interval. There is a requirement that communication equipment for this service should be on an uninterruptible power supply with 8-hour standby time. The power potential project will implement a DNP3 protocol interface between the DER and the DERMS, with an ICCP interface between the DNO and the TSO. For demand turn-up service, notification is by e-mail and short message service (SMS), which is a lower threshold for participation in bulk system service provision.

Metering requirements for participation in the capacity remuneration mechanism stipulate that four-channel meters should be used on eligible generation, separately measuring active and reactive power exports and imports. At the customer's point of connection with the distribution system, recently deployed smart meters are capable of metering export and import independently. At present, renewable generators smaller than 30 kW capacity are not required to have export meters.

### *Relevance for Australian Systems*

Similar to the Dutch market, the British energy market clears according to a different market design philosophy than Australian NEM. Nonetheless, several aspects of the Great Britain system are of relevance for Australia. The United Kingdom has adopted a progressive approach to including DER in system operation with a range of options for DER and DR aggregations of various sizes and with different obligations. At present, direct integration of DER into the energy market is limited; however, the isolated nature and substantial deployment of DER in both systems creates a demand for similar services—flexibility for longer-term energy balancing, congestion management, and operating reserves.

## United States—Hawaii

### *Regional Context*

The isolated nature of the Hawaiian Islands makes the cost of fossil-fired generation in that region relatively more expensive than in most parts of the world. Substantial development of renewable generation has occurred in the recent past, with more than 23% of the islands' energy coming from renewable sources back as far as 2015. The state has set renewable portfolio standards of 52% in 2021 and 100% in 2045 [28]. Each island has its own system, with no interconnection between the islands. These systems are operated by subsidiary companies of the Hawaiian Electric Company (HECO), and various independent power producers own the generation assets in the state. The systems are operated according to a vertically integrated utility paradigm. The most populous island, Oahu, has a system peak load of 1300 MW, whereas the other islands range from 5 MW to 200 MW.

Given the high prices and early incentives experienced in the state, there is substantial residential-scale solar deployment to date, with more than 20% of customers having PV installed, similar to certain parts of the Australian power system [29]. Proposed energy storage incentives may further increase that penetration of renewables as commensurate flexibility is added to the system. The small size of each island's power system and the high penetration of renewables has led to the need for control over smaller-scale resources to manage balancing and congestion issues on the grid. New programs are focused on developing smaller-scale DER that can support system operation.

### *Program Overview*

HECO service companies have offered a variety of programs for connection of DER in the recent past. For demand response, the Energy Scout program has contracted with ~18 MW of load spread across more than 40 commercial and industrial customers to provide dispatchable load reductions and curtailable load during under-frequency events [30]. These loads individually vary between 5 kW and 5 MW in size, but they can be aggregated for use by the system operator. Residential programs have also been deployed to encourage air conditioning and water heaters to respond to incentives from the system operator through cellular networks.

A bill credit is paid to participants for the availability of the service and for deployment of the response. For residential customers, rebates of USD 5 and USD 3 per month for the participation of air conditioning and water heating, respectively, are offered. For commercial and industrial consumers, two programs are in place—a 40-event call program and an 80-event call program. Availability payments of USD 5/kW/year are available for the 40-event call product and are doubled for the 80-event call product. This distinction allows customers with more marginal business cases for providing demand response to restrict the exposure to demand reductions, while also gaining income for the flexibility provided. When called, deployed energy is remunerated at a flat charge of USD 0.5/kW.

For behind-the-meter solar PV generation and storage, the utility is offering the following two routes for new DER to connect to the grid at present [18]:

- **Smart Export.** Customers under this tariff may produce from their own DER at any time but may only export back to the grid after 4 PM and before 9 AM. Exports outside this blackout zone are remunerated at a fixed tariff ranging between 11 cents/kWh and 20.79 cents/kWh for five years. This program will suit storage resources to a higher degree, given the indirect signal for the market to focus on energy arbitrage. This is limited to 25 MW in Oahu and 7 MW each in Maui and Hawaii Island, allowing up to 4500 customers to connect with this option.
- **Customer Grid-Supply Plus (CGS+).** Under this scheme, behind-the-meter generation may be controlled directly by the utility to alleviate congestion or other system issues. This requires the implementation of smart inverter functionality with which the utility's operators can interact. Export from the PV is remunerated at the tariffs shown in Table A-2. Curtailed energy is not remunerated. This is limited to 35 MW in Oahu and 7 MW each in Maui and Hawaii Island, allowing up to 6000 customers to connect with this option. Similar to the Smart Export option, tariffs are fixed for five years.

**Table A-2**
**Customer Grid-Supply Plus tariffs**

| Island | CGS+ Credit Rate (cents/kWh) |
|---|---|
| Oahu | 10.08 |
| Maui | 12.17 |
| Lanai | 20.80 |
| Molokai | 16/77 |
| Hawaii | 10.55 |

The latter ability to dispatch DER so that export to the system may be constrained during certain periods can be leveraged by the utility for several functions related to higher-voltage or lower-voltage network congestion relief or systemic issues such as energy balancing. Although there is no energy market in Hawaii, centralized generation scheduling takes place, which may have the opportunity to leverage these resources, as well as energy storage devices that are connecting to the network.

### *Metering and Telemetry*

For both the Smart Export and the CGS+ programs, communication and metering are provided through the smart metering gateway at each customer site. The smart meters connect back to the utility's advanced metering infrastructure system over a radio frequency system, with the cellular network providing backup for select regions. The cost of the metering is borne by the utility that operates the metering infrastructure.

### *Relevance for Australian Systems*

Despite the industry structure differing substantially between Hawaii and Australia, the ability of a system operator to control DER to resolve operational reliability issues is a common need. The Hawaiian case demonstrates that at high penetrations of renewables, by current standards, direct control of DER such as that enabled in the CGS+ model, is required to maintain system operability. Residential-scale DER connected through the CGS+ tariff can be curtailed at the discretion of HECO, but only after utility-scale DER has been curtailed. For smaller systems such as those on the Hawaiian Islands, individual control of DER may be an option for a system operator of both the transmission and distribution network; however, this may not scale up to larger systems. The role of aggregators or other third parties such as distribution utilities in the relationship between the TSO and DER is less emphasized in this case.

The Smart Export plan represents a heuristic approach to manage solar back-feed during periods of already high solar production, on average. However, there may be overcast periods, or periods of abnormally high demand, or periods with outages of utility-scale PV plants between 9 AM and 4 PM, when the support from DER may be of use to a system operator. Heuristic options such as these, although simpler to comprehend and implement, may be a conservative approach to system operations, depending on risk and economic tolerances. The alternative option in the CGS+ tariff offers the opportunity to leverage the DER exports in conditions when it can support grid operations.

For many demand profiles, the relatively lower daytime demand and higher midday production from solar plants mean that battery storage is incented by participation in the Smart Export program, whereas the relatively less potential curtailment that CGS+ tariff customers are likely to experience may reduce the incentive for behind-the-meter storage for equivalent demand and solar profiles.

## Germany

### *Regional Context*

The growth of renewables in Germany has been well documented recently. The growth of renewables due to substantial subsidies provided in earlier versions of the Renewable Energy Sources Act, commonly referred to as *Erneuerbare-Energien-Gesetz (EEG) regulations*, has continued, albeit at a less aggressive growth rate under updated tariff regimes [15]. As of the start of 2018, in excess of 43 GW of solar PV is in service in Germany, the significant majority of which is located on distribution networks. This is in addition to the 39 GW of wind generation, both onshore and offshore [14]. As a result of the closure of several large nuclear and other fossil generation plants in the south of Germany, as well as the emergence of renewables, the four German TSOs have experienced a growth in the cost and volume of out-of-market, redispatch actions in recent times.

Although the bulk of the new redispatch costs are related to reported transmission congestion, increased visibility and participation of renewables have been sought for both transmission- and distribution-connected resources. For small-scale PV, and initially for larger-scale renewables, TSOs were responsible for bringing the forecast production from those resources to market, balancing the system, and paying resource owners according to the feed-in tariff. This is because renewables under the feed-in tariff scheme were covered by a priority dispatch (that is, generation must be taken by the system unless there is a reliability reason not to) [15].

Earlier deployments of solar PV, as well as some other DER, presented an additional issue regarding the behavior of those resources during system over-frequency events. The configuration of protection on those resources were set to trip at 50.2 Hz. With a substantial deployment of PV already in place, this presented a considerable risk to system operation on the continental European system if simultaneous tripping of those resources should occur during a period of high PV output. A program of work was undertaken to manually update the configuration of those resources to resolve this issue in 2013.

### *Program Overview*

As part of the major reform of the renewable feed-in tariff and energy law in 2014 and 2017, several measures were introduced to bring renewable resources into the market and to have them support system needs. One of the main developments has been to introduce the direct marketing paradigm. Direct marketing requires renewable resources to be bid into the market by a balance-responsible party (BRP) [15]. In European markets, balance-responsible parties trade positions on day-ahead and intraday markets across a portfolio of resources and loads. When gate closure arrives, BRPs must notify the TSO in each control area of their position and the allocation of load and generation to physical resources.

The change required the same principles to be applied to renewables greater than 100 kW as of January 2016. This measure applied to resources built before 2014 that were greater than 500 kW. The measure also changed the format of the feed-in tariff from a flat rate to be based on a *market premium*—the difference between a reference tariff and the average market revenue from energy. An additional premium is paid to the BRP for the costs associated with bringing the renewable energy sources to market. This reference rate to determine the market premium tariff is updated each quarter or based on the deployment of PV and other DER covered by the scheme.

When redispatch is required, a feed-in management process to curtail DER (called *EinsMan*) is undertaken by DSOs and TSOs to manage system reliability. This curtailment can affect BRP expected positions, and considerable effort has recently been expended by market parties to develop forecasting capabilities to determine the likelihood of grid congestion restricting the output from DER before market closure, to reduce the potential exposure to TSO balancing costs. Total feed-in management actions in Germany in 2016 resulted in 3.7 TWh of curtailments from renewables and CHP resources on both the bulk and distribution systems (3.5 TWh for wind and 184 GWh for solar) [32].

### *Metering and Telemetry*

By national legislation, all DERs with a nameplate rating of 100 kW or higher must be equipped with a communication interface that allows for both measurement and control of active power. PV systems with a nameplate rating between 30 kW and 100 kW that went into operation on or after January 1, 2009, must be equipped with a communication interface that allows for control of active power; no measurement and real-time reporting of power output is required. PV systems smaller than 30 kW have the option to waive the controllability requirement but must restrict their export to 70% capacity. Discussions in Europe indicate the potential to extend this requirement to smaller capacity resources.

Until recently, Germany did not require any standardized DER communication interface. Instead, low-cost, unidirectional audio or radio frequency ripple control is used to send “curtailment” signals to small-scale (< 100 kW) DERs; use of this technology elsewhere is limited, as more modern communications options have developed. Many DSOs elsewhere require a more sophisticated, bidirectional interface from medium-scale (> 100 kW) DERs that allows for integration with their SCADA system. However, in the German case, DER–DSO communication uses the older IEC 60870-5-104 rather than the newer IEC 61850 communication protocol.

Estimates from Ecofys from 2013 indicate that 19,400 MW of DERs in the German power system were not equipped with any communication and control capability due to size or age exemptions [33]. About 2000 MW of DERs were controllable but could not report their power output to the grid operator in real time. The remaining 62,800 MW of renewable and CHP plants (many of them are not of a “distributed” nature) had communication capability to report their actual power output and receive active power dispatch signals in real time. This capability is used to control the DER for grid congestion. Figure A-4 shows DER controllability requirements for existing generation in Germany.

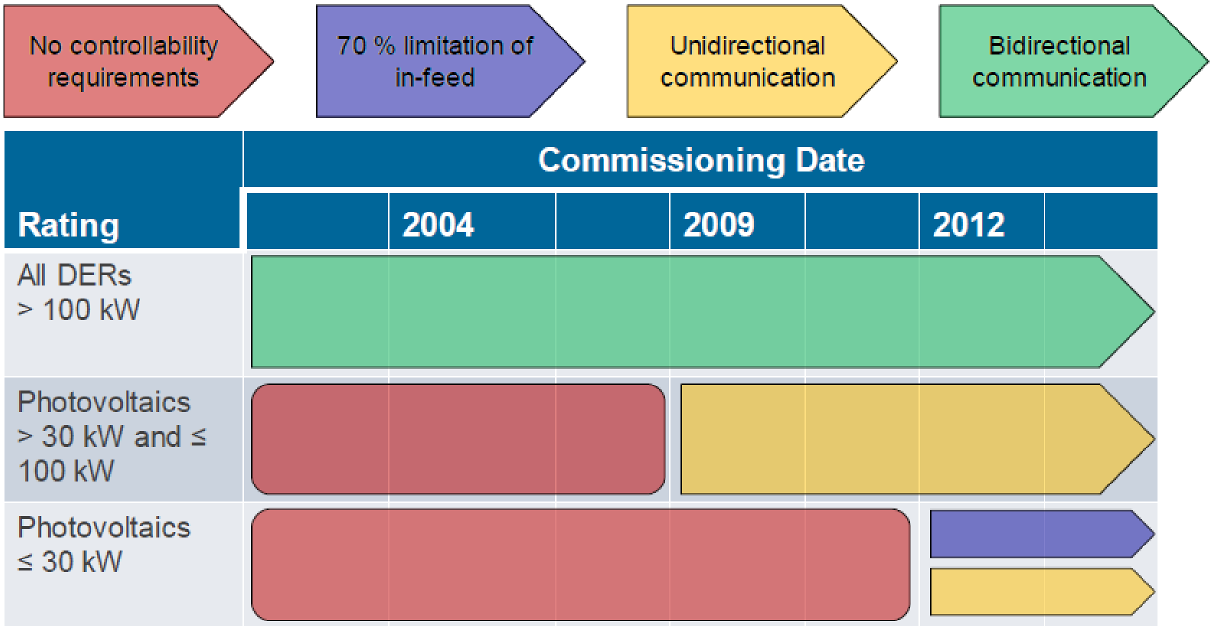


**Figure A-4**
**Distributed energy resource controllability requirements for existing generation in Germany**

Major changes in the requirements for communication and remote control capability of DERs in Germany have recently been introduced by the German Digitization of the Energy Turnaround Act in August 2016 [34]. This legislation enforces a nationwide rollout of advanced metering infrastructure, called *intelligent metering systems (iMSys)*, over the next 15 years, including smart meter gateways (SMGw), which are controllers for loads and DERs. Table A-3 summarizes the new requirements in Germany.

**Table A-3**
**Provision for telemetry requirements for distributed energy resources in Germany**

| **DER Size (optional)** | **DER ≤ 7 kW (≤ 1 kW)** | **7 kW < DER ≤ 30 kW (> 1 kW … ≤ 7 kW )** | **30 kW < DER ≤ 100 kW** | | **DER > 100 kW** |
|---|---|---|---|---|---|
| Commissioning date | Any | Any | Before Jan. 1, 2009 | On or after Jan. 1, 2009 | Any |
| Enforcement date | None | From Jan. 1, 2025 | From Jan. 1, 2025 | Already enforced with existing IT technology (such as ripple control) | |
| Technical requirements | None | Choice:<br>Smart meter gateway, ripple control, or static 70% limit | iMSys | iMSys and S<Gw on or after Jan. 1, 2025 | |
| iMSys | | ✓ | ✓ | ✓ | ✓ |
| SMGw | | By choice | | ✓ | ✓ |

All existing and new DER with a nameplate capacity of 7 kW to 100 kW must be equipped with one of the communication interface options by the end of 2024. The rollout for DERs larger than 100 kW will occur three years later, lasting until the end of the year 2027, owing to the persistence of the ripple control system. DERs of 1 kW to 7 kW can optionally be equipped with a communication interface. All these efforts will significantly reduce the amount of non-visible and non-controllable DERs connected to the German power system.

### *Relevance for Australian Systems*

Lessons from the German experience are relevant for all systems experiencing sustained growth of DER. In particular, lessons learned regarding the need for visibility of those resources and their output has been well established in Germany, leading to the requirement for enhanced communications and controllability of DER, as well as direct participation in the market. Coupling these requirements with the feed-in tariff provides a strong incentive to provide the visibility and control needed in the system. Furthermore, the option for smaller-scale DER to either implement communication and control as well as direct marketing or be subject to an export limit, which is at 70% of the rated capacity, incentivizes the development and deployment of lower-cost communication and control technology options.

## France

### *Regional Context*

The French system is an 85 GW winter peaking demand system, with approximately 63 GW of nuclear generation meeting 75% of demand. The system is heavily interconnected with other neighboring systems in Europe such as Germany, Italy, Spain, Belgium, and Switzerland. The penetration of renewables has steadily grown in recent years, culminating in more than 14 GW of wind power (mostly transmission-connected) and 7 GW of solar generation (mostly distribution-connected) being installed by the end of 2017. Substantial growth is expected in these sectors in the coming years as reliance on nuclear generation is forecast to be reduced in the years ahead.

The French system has significant electrification of domestic space and water heating and cooling due to the established regime of low power prices associated with the nuclear generation fleet and widespread interconnection across Europe. It is estimated that there is some 20 GW of residential space heating load on average in the winter, together with up to 12 GW of water heating demand. As a result, demand is highly sensitive to temperature changes, with a 1°C (34°F) drop in temperature during the winter equating to almost 2.5 GW of increased demand. This substantial electrification of the heating sector has a large flexibility, which has been leveraged historically for balancing and peak load management of the French power system.

### *Program Overview*

France has a long-standing requirement for flexibility for balancing. Despite the flexibility of the current nuclear fleet, demand-side flexibility was required from the 1970s onward for system balancing. This led to the development of residential programs of various forms, as water heating became ubiquitous. These programs have evolved through market liberalization to support system operation.

Similar to many other systems, two-part rate structures developed in the 1970s were based on a high and low price, based on time of use. Ripple control of devices or internal clocks were used to guide behavior to make use of rate differentiation. The Heures Creuses program allows for dynamic setting of low and high price periods [35]. Within a given day, 8 hours are set at a low tariff and 16 hours are set at a higher tariff. The hours from 08:00 to 12:00 and from 17:00 to 20:00 are high, and the eight low price hours are distributed across the remainder of the day. This differentiation is determined by Enedis, the DSO, for each location based on anticipated network constraints [36]. The low hours typically either cover an 8-hour period in 22:00 to 7:00 or a 5-hour period in the middle of the night (20:00 to 08:00) and a 3-hour period between 12:00 and 17:00. The difference between the two tariffs is of the order of 3.7 cents/kWh. Enrollment on such tariffs is managed by suppliers, rather than a network operator. Participation data on these tariffs are limited, but evidence from before the advent of retail competition indicated widespread satisfaction with the programs. RTE, the system operator, counts on just under 1 GW of response from these programs during the winter season.

An alternative program, Tempo, added an additional differentiation between days. In the tempo program, which is now closed to new customers, days are categorized as red, white, or blue days, corresponding to high, medium, and low price days, with a high and low tariff in each, resulting in six possible tariffs. The distribution of the days through the year ensures that there are 22 red (high) days, 43 white (medium) days, and 300 blue (low) price days. Within each day, a high and low tariff is offered. The higher price is active from 6 AM to 8 PM, and the low price is active for all other times. Example tariffs for a 12 kVA connection are shown in Table A-4.

**Table A-4**
**Tariffs in French Tempo program**

| Connection Level (kVA) | Monthly Subscription (€/Month) | Blue Tariff* | | White Tariff* | | Red Tariff* | |
|---|---|---|---|---|---|---|---|
| | | Low | High | Low | High | Low | High |
| 12 | 13.90 | 11.13 | 13.27 | 13.47 | 16.29 | 17.47 | 54.82 |

* Rates are in cents per kilowatt hour

*Source: Électricité de France [37]*

Although residential tariff design has been successful in encouraging indirect participation in congestion management and peak avoidance, direct market participation options also exist for larger demand resources and DER. In 2014, a new demand response program was launched under new rules focused on establishing a footing for demand response in the energy, balancing, and capacity markets. This mechanism gives demand response aggregations larger than 1 MW with a duration between 30 minutes and 2 hours access to the balancing market [38]. Units within this aggregation must be larger than 100 kW. This mechanism has been used frequently since inception, deploying approximately 78 GWh of energy, primarily during winter peak conditions in 2017. This response is remunerated on a tariff basis and based on the mechanism used to monitor the output of the aggregations. Aggregators have an option to be remunerated on the basis of a profiled response (that is, historical profiles for customers without a smart meter) or a metered response. Metered responses command higher compensation than profiled responses but require the smart meter to have been installed, as described in the next section.

As the penetration of solar PV increases, new options have also emerged to bring that energy to market. Rules established in 2015 have brought direct marketing options for solar PV to be traded in energy markets. These rules, binding since 2016 for solar plants larger than 500 kWh, offer incentives to resource owners based on the difference between the sum of energy, capacity, and certificate of origin revenues and a bid price. This difference is called the *market premium* and is paid only for periods when prices are non-negative. Therefore, the resource is incentivized to trade positions in the energy market that are commensurate with conventional generation. This also adds an overhead of bringing the PV to market through a BRP (the scheduling coordinator in European markets) who must forecast and sell the output on a day-ahead or intraday basis. Recovery of this overhead is provided for in the tariff structure through a management premium. Although the tariff means that the energy must be sold on the market, it does not require remote control of the site, but the BRP is liable for imbalance costs for a non-neutral position. As a result, smaller-scale plants do not require telemetry as is the case in Germany.

### *Metering and Telemetry*

Traditional demand response programs have depended on a combination of interval meters and radio frequency or power line communication (PLC) technology. At present, the rollout of the Linky smart metering program in France will replace existing technology, enhance the potential for interaction with other forms of DER, and enable a metered response for demand response participants [39]. The Linky smart meter devices include PLC to base stations in distribution cabinets. DER connected to the low-voltage network are required to be connected to a Linky meter. The meters themselves include the possibility for direct interfaces with devices, as well as the ability to load tariff information, similar to smart metering programs elsewhere. Metering rollout is expected to be completed with 31 million installations by 2021. For aggregations participating through the demand response mechanism, dispatch signals are sent from RTE, the system operator, to the aggregator through a custom information technology system based on HyperText Transfer Protocol (HTTP). Communication between the aggregator and the consumer is managed by each aggregator individually and can leverage a variety of communications infrastructures and protocols. One such example is the use of the Tiko system by Direct Énergie, a supplier and aggregator of which Total is a majority shareholder. This system is akin to that in Switzerland; it leverages cellular networks to communicate between a proprietary back-end system and customer-installed receivers, which in turn communicate with customers' devices using standard protocols such as DNP3 or Modbus.

### *Relevance for Australian Systems*

The measures taken in France to ensure direct marketing of larger-scale solar facilities through the feed-in tariff mechanism are instructive. As the build-out of solar generation and other DER continues apace, feed-in tariff design has played an important role in ensuring that larger resources respond to pricing signals indicative of system needs. Although the French system has extensive existing communications and metering infrastructure to draw on to realize a widespread residential demand response program, experience with simplified dynamic tariffs indicates that potentially valuable demand response can provide support to system operations during peak demand periods or other periods of system stress.

## United States Utilities

### *Regional Context*

Integrated generation, transmission, and distribution utilities operate within all the ISO markets in the United States. Well-known examples of these include Pacific Gas & Electric in the California ISO market, Consolidated Edison (ConEd) in the New York ISO market, and Centrepoint Energy in the ERCOT market. These utilities optimize their generation and other assets based on the market context within each region. The availability of DER within these utility footprints have been leveraged by the utilities to indirectly manage market exposure of generation portfolios to date. This section focuses on two examples, but other such utility programs that leverage DER can be found throughout the ISO markets in the United States. These examples are representative of the emerging uses of DER and demand response for utilities and distributors in the ISO energy markets.

The first example is that from Great River Energy (GRE), a generation and transmission cooperative that operates in the Midcontinent ISO (MISO) market footprint. GRE is responsible for bidding demand from customer distribution utilities and generation into the MISO markets, as well as ensuring capacity adequacy within its footprint.

The second example is Green Mountain Power (GMP) in Vermont, which is the integrated utility that is a participant in the ISO New England market. In this market area, a forward capacity market is established that incurs an obligation to procure sufficient capacity resources based on the forecast demand level. The utility is also exposed to LMPs in the day-ahead and real-time energy markets, as well as socialized demand charges for a range of system services. As the northeast of the United States experiences extreme conditions, particularly during winter, reliability for customers in more remote parts of the area is lower than that of the major metropolitan areas. This has led the utility to offer a customer residential energy storage program as backup generation. Similar programs are proposed or under way at other utilities in the same area.

### *Program Overview*

#### Great River Energy

A long-standing residential electric resistance water heater control program has been used by GRE since the 1980s to provide system support, typically during peak demand periods. GRE currently has more than 100,000 water heaters under control, with a typical rating of 26 kWh each [40]. Customers each have a relationship with the local supply cooperative, which acts as their retailer. GRE is responsible for the transmission, central generation, and market representation for the set of cooperatives. These cooperatives offer customers the opportunity to participate in water heating control as part of the regular set of customer choices. Charging demand for the water heater fleet may consume up to 1 GWh of energy per cycle. This charging is controlled by dispatch signals sent by GRE to the water heaters, typically based on energy prices in the MISO energy markets. The water tanks are typically a larger 300-liter (80-gallon) capacity with extensive thermal insulation, so that dispatchability of the heaters does not affect customer comfort, given regular hot water usage.

Although the water heaters' normal duty cycle is to heat during the night, other cycles are called upon depending on the season, including peak period reduction. As the penetration of wind generation in the MISO market has increased, the flexibility of the demand modification supported the utility's operations in the market.

### Green Mountain Power

GMP's pilot program to deploy 2000 residential battery storage systems to customers in their territory for the dual purpose of local backup generation and support of utility operations. Through a special set of regulations applied to pilot programs, the utility was permitted to offer the storage devices to customers for a one-time charge of USD 1500 or USD 15 per month for a 10-year term [41]. The remainder of the asset costs are included in the utility's rate base but must demonstrate cost recovery over the course of the pilot.

The batteries selected for the trial were the Tesla Powerwall 2, which are 13.5 kWh batteries rated for 5 kW continuous output or 7 kW for short periods. GMP also deployed Tesla's Gridlogic communication and control platform to interact with the batteries to send charge and discharge signals based on responsibilities to the customer, as well as the economic optimization of the storage systems within the GMP portfolio. This flexibility can be used by GMP to manage load during high price periods and to manage exposure to capacity adequacy obligations in the forward capacity market. Average forward capacity costs for 2019–2021 amount to almost USD 4.97 per kilowatt per month, making the assumption that the amount is representative of the value over the 10-year horizon, equates to almost USD 1500 at a 5 kW rating (assuming 50% capacity value for 2-hour batteries).[13] The capacity mitigation, as well as the customer-borne backup power payment provides substantial recovery of the investment costs, estimated to be in the region of USD 5000 per unit, leaving the remainder to be made up from energy arbitrage revenue streams over the life of the asset.

## *Market Integration*

Both programs indirectly represent DER in energy and capacity market operations through management of demand bids. Although this means that optimization of the resource is carried out by the utilities without co-optimization of the resources with all other resources in the same ISO market, indirect or expected market conditions guide the deployment of the load modification. The specifics of the operation of these VPPs depend heavily on the underlying assets, contractual arrangements between operator and customer, and market rules.

[13] USD 4.97 per kilowatt per month for 120 months for a 5-kW system, de-rated by 50%, equals USD 1491.

## California Independent System Operator

### *Regional Context*

CAISO operates the energy market and is the RTO for significant parts of California. The California market also includes its Energy Imbalance Market with neighboring balancing authorities in the Western Interconnection of the United States. The ISO footprint covers much of the state, with the notable exception of several large municipal utilities, including the Los Angeles Department of Water and Power. The California systems are heavily interconnected with neighboring balancing areas in the Western Interconnection. The region is served by imports from conventional generation located in Arizona, New Mexico, and Wyoming, and by hydro generation located in the Pacific Northwest.

Within the ISO, three main investor-owned utilities serve the majority of the customer base—Southern California Edison, Pacific Gas & Electric, and San Diego Gas & Electric. Several independent power plants also participate in the ISO market, as well as several community choice aggregations that operate similarly, but not equivalently, to municipal retailers.

CAISO operates day-ahead and real-time markets that are cleared on a nodal basis through the use of security-constrained unit commitment and economic dispatch. The region has established renewable portfolio standards of 33% of renewable energy sources by 2020 and 100% by 2045. The 2020 target excludes production from large hydro facilities. The 2020 requirement also includes specifications on the minimum composition of the renewable energy source, which requires 8 GW of large-scale renewables and 12 GW of DER. *DER* in this context was defined as installations less than 20 MW and separately metered. This includes behind-the-customer-meter solar, of which more than 6.7 GW is installed. A net metering policy is also in place.

To date, more than 17 GW of large-scale renewables and 11.7 GW of DER have been deployed, with approximately 340 MW pending, giving an expected total of close to 30 GW installed. Peak demand across the California balancing areas is approximately 60 GW. As of 2017, the state produced, or procured from neighboring areas, 81 TWh from non-hydro renewables, meeting 32% of demand. Furthermore, the state has established a 1.3 GW target for distributed battery energy storage, with several large projects under way, and a target for new homes to be net energy-neutral balance between annual energy demand and annual rooftop PV production by 2020.

Given the substantial deployment of renewable energy sources, several studies have been conducted on the California system to understand future system operation. These studies identified, at an early stage, the evolving net load profile, a major differentiating characteristic of which is the presence of a midday valley in net load, now known as the *duck curve* (see Figure A-5). The identification of this characteristic, in particular, spurred considerable focus on the flexibility of supply resources and, eventually, the need to increase the participation of a wider set of resources and management of imbalances across the Western Interconnection in the United States to facilitate energy balancing and the provision of ancillary services.

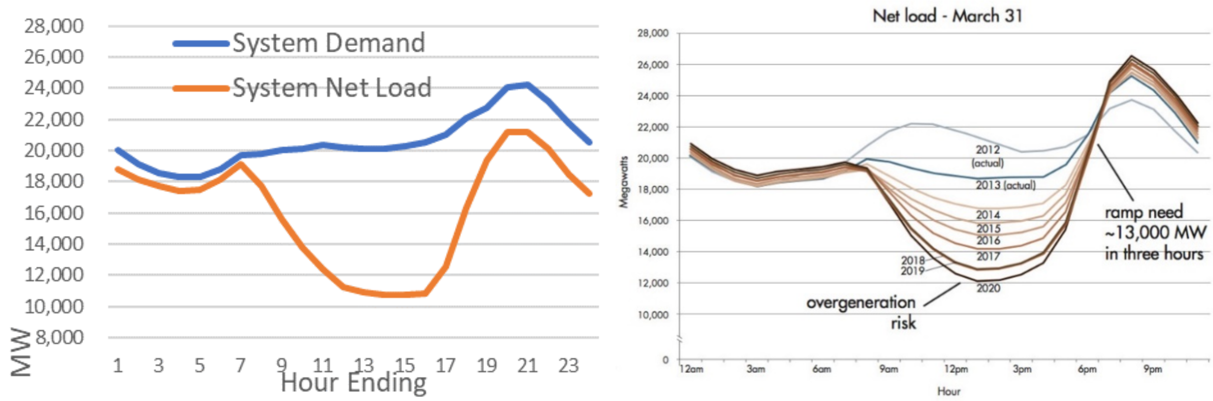


**Figure A-5**
**Original 2008 California independent system operator duck curve projection (left) and net load in California on March 31, 2018 (right)**
*Source: California Independent System Operator Open Access Same-Time Information System (OASIS) (http://oasis.caiso.com/mrioasis/logon.do)*

### *Program Overview*

Several initiatives have been pursued to increase participation of resources in energy markets and ancillary services. Initially, these initiatives relate to participation of centralized generation through initiatives such as the Flexible Resource Adequacy Criteria—Must-Offer Obligation (FRAC-MOO), which sets a mandatory requirement for LSEs to ensure that generation resources' three grades of flexibility characteristics are made available to the market for scheduling during certain periods of higher variability, such as the midday cycle and the rise to the evening peak [42]. This initiative is currently under review to determine a method to more accurately determine the contribution that each resource makes to providing system flexibility.

Two additional initiatives are focused on increasing participation of emerging resources such as demand response and small-scale DER. Larger-scale DER are also eligible to participate in the CAISO energy markets as non-generating units to benefit from locational prices that offer better returns than net metering value streams. These programs are focused on demand response and DER providers and are designed to provide an initial direct route to the energy and ancillary service market for these resources whose operational characteristics or limitations (such as energy availability limits) differ from those of conventional generating resources. These services are reviewed in the following sections.

### *Demand Response Providers*

The inclusion of demand response in organized ISO markets stems from FERC Order 745. This standard mandates that demand response grant access to participate in all markets. Specific application of this rule differs from market to market, with various options and requirements specified for each. In California, two options for DR participation are offered—proxy demand response (PDR) and reliability demand response (RDR) [43].

The PDR approach enables DR to be aggregated across multiple busses within a sub-load aggregation point (that is, a load region) and bid into day-ahead and real-time energy and non-spinning reserve markets, as well as being used in the residual unit commitment process, which is run to ensure that operating states throughout the following day are within security limits by bringing online, or constraining offline, generation resources to resolve network constraints. These resources can include conventional generators or aggregators. The minimum size of the aggregation is 100 kW.

RDR is similarly bid into the market by a scheduling coordinator, but it is economically dispatched in day-ahead energy markets and deployed for reliability purposes in real-time markets. The minimum aggregation size is 500 kW for reliability DR. Customers and their registration are tracked as part of an aggregation to prevent simultaneous participation in multiple DR programs.

California has a system of obligations in place for capacity requirements associated with each LSE, in place of a capacity market. To this end, LSEs may procure the capacity contribution of demand response aggregations through a separate, bilateral demand response market between LSEs and demand response providers. More than 44 MW of DR was procured in the initial demand response auction.

Within this construct, demand response aggregations provide a demand reduction service in response to a market instruction. This can be achieved through true reduction in demand or by increasing production from DER devices so that metered load to the bulk system decreases. This has been the most popular route to market for DER to date, despite some limitations of the approach. One key limitation is the absence of a method to increase bulk system load. Demand response is currently used only to reduce bulk system load and not to increase it. This is under review at present and may be extended to include the potential for load shifting in the future. For DER such as battery energy storage, this ability is potentially valuable in periods for which there is excess generation.

### *Distributed Energy Resource Provider*

An alternative route to the demand response provider route is the DER provider (DERP) route that was introduced in 2016 [43]. This initiative allows DER to participate in the ISO markets either through an existing scheduling coordinator or as its own coordinator. DER may be aggregated over a set of pricing nodes within a subregion of the CAISO or from a single pricing node. Each pricing node receives its own LMP.

When load is aggregated across multiple pricing nodes, the capacity of the resource is limited to 20 MW. For aggregations at a single pricing node, the aggregate capacity may exceed the 20 MW threshold. This restriction is enforced to ensure that congestion does not occur on the transmission network when the distribution of an aggregation’s response to a dispatch signal deviates from the distribution used as part of the bidding process. Similarly, the rules allow for a mix of underlying resource types to be used. As part of the connection and activation into the market, DER must receive consent from local distribution utilities. Typically, when DER is connected to the distribution system, connection studies ensure that there is sufficient network capacity available for each resource to export to its desired rating in all studied scenarios to avoid distribution congestion.

This mechanism has been less favorable at present, with limited registration and participation in markets through this route. This has been for a variety of reasons, mainly related to generation interconnection, telemetry, and market interaction requirements that are applied to each DER resource, as opposed to the aggregation.

### *Market Integration*

Both DR and DER provider roles allow aggregations of DER to access energy and ancillary service markets, as well as capacity markets. All routes to market allow DER to take part in day-ahead scheduling processes, including the ability to set prices. These resources are not permitted to partake in regulation or spinning reserve at present, but this will be considered in the future. Resources are remunerated at the weighted LMP of the pricing nodes where the aggregation is located, rather than the single nodal price at which generation is remunerated. DER providers must declare outages of their assets to the system.

At present, generation units with a size of 1 MW or greater can be included in the CAISO market, meaning that a substantial proportion of utility-scale solar PV plants are eligible to participate in the market. Incentive structures for residential-scale solar PV do not incentivize response to market pricing or reflect operational needs of the power system at present, as the majority of PV is engaged in net metering or fixed tariff programs.

### *Metering and Telemetry*

Metering and telemetry are an integral part of market settlement. Telemetry is required for DR and DER provider aggregations of 10 MW or greater, or those aggregations that provide ancillary services. When telemetry is required for a resource, the scan rate is dependent on the services rendered, but it may be as frequent as a 4-second refresh resolution depending on the ancillary services and energy markets in which the resources participate. Additional information on telemetry requirements is provided in Section 5.

DER providers must provide settlement-quality meter data at market resolution from each DER that is a part of the aggregation to the CAISO. The scheduling coordinators must conduct audit checks of the metering arrangement each year, and the ISO can conduct checks at their discretion. Service is deemed to have been delivered in the case of DR when the dispatch instruction can be observed when compared to the consumption in the same interval for the 10 previous non-emergency working days.

### *Relevance for Australian Systems*

When drawing comparisons between Australia and the CAISO system, there are both strong similarities and key differences. Both areas are experiencing substantial deployment to date, which gives urgency to act to bring DER into the marketplace. Both the NEM and the CAISO operate a pool market with three-part bids, with the CAISO clearing demand on a zonal basis and generation at a nodal basis, and the NEM clearing both demand and generation on a zonal basis. Both operate day-ahead and intraday markets and have transmission constraints between zones that regularly bind. As a result, both systems may face the need to access a greater set of resources that respond to market signals to avoid substantial out-of-market actions to maintain system reliability in the future.

As a part of the Western Interconnection in the United States, which is a synchronous area encompassing balancing areas west of the Rocky Mountains, from California and New Mexico in the south to British Columbia in the north, with a system-wide peak demand of 150 GW in 2015. Therefore, the scope for leveraging neighboring systems to resolve variability or uncertainty related challenges is greater that in the NEM, as evidenced by the growth of the Energy Imbalance Market between several balancing areas in the Western Interconnection.

Evidence from the options available to DER to participate in the CAISO market to date suggests that the potential for DER such as backup generators or energy storage to act as part of demand response programs is the preferred route to market. The principal reason stated for this approach over the DERP approach is the additional complexity, duration, and cost for smaller-scale DER to implement the telemetry and market information requirements needed for market participation through a DERP when compared with the demand response route. This situation may mature in the coming years as the generation mix in California continues to mature and the value to direct market participation increases.

### Midcontinent Independent System Operator

#### *Regional Context*

MISO has an installed generation capacity of about 176 GW from more than 1300 units, with a system-wide peak demand of about 127 GW. MISO currently has about 18 GW of installed wind capacity, which is mostly located in the northern region, and less than 1 GW of installed solar capacity.

#### *Program Overview and Market Integration*

Presently, approximately 2.7 GW of installed capacity is from pumped storage hydro resources. MISO allows for use-limited or energy-limited generation schedules in their day-ahead market. Pumped storage hydro resources can participate as generating resources. In addition, to reflect their pumping or charging schedules in the day-ahead market, the pumped storage hydro resources are allowed to submit self-schedules or virtual schedules. With respect to the capacity markets, MISO imposes a 4-hour duration requirement. In other words, in accordance with MISO's capacity rules, a capacity storage resource should be able to provide a sustained power output for at least 4 hours.

Short-term storage energy resources (referred to as *type I*) such as batteries and flywheels, with a duration of less than one hour, are allowed to participate only in the ancillary services market (specifically, the regulation reserve market). The deployment logic for regulation accounts for the SoC as the resource starts to approach the maximum or minimum SoC.

MISO recently introduced a new category of short-term storage energy resources (referred to as *type II*), which is proposed to include resources that have a duration of at least one hour and frequently switch between the injecting (discharging) and withdrawing (charging) modes. This was done to remove the existing entry barriers on storage. Type II resources will be allowed to participate in ancillary services, capacity, and energy markets. Presently, MISO has no registered assets under this category, but this may change soon, as MISO seeks to comply with the FERC Order. Excluding the pumped storage hydro resources, MISO currently has three grid-scale battery storage units, which are rated at 20 MW (Indianapolis Power and Light), 7.2 MW (Luverne), and 1 MW (Entergy New Orleans) respectively. In addition, MISO has 120 MW in their interconnection queue under definitive study and has recently added 475 MW to their queue in the last few months. The increase in the quantity of the queued resources is an indication of the increased interest in alternative technologies such as battery storage. Preliminary analysis by MISO suggests that storage has the potential to have considerable impacts on the efficiency of the market in the long term; therefore, MISO plans to enhance its existing participation models for storage (by allowing for the ISO to optimize the SoC of the storage resource within the market) and move to the energy storage resource (ESR) model.

MISO plans to provide the ESRs with the option to participate in the market in four different modes or configurations, as follows:

- Offline mode (unavailable or outage)
- Generating (discharge) mode with maximum and minimum discharge limits, discharge ramp rate, and minimum SoC limitations
- Charge mode with maximum and minimum charge limits, charge ramp rate, and maximum SoC limitations
- Continuous operation mode (resources that switch from charging to discharging within a specific interval) with maximum charge limit as the maximum limit, maximum discharge limit as the minimum limit, the lesser of the charge and discharge ramp rate as the ramp rate limit, and maximum and minimum SoC limitations

In MISO's proposed participation model, the ESR asset will manage its own SoC and other bid parameters, including but not restricted to charge and discharge time, charge and discharge limits, minimum and maximum SoC, and transition times between charging and discharging (when applicable). Thus, SoC management by the ESR asset will be facilitated by offer–bid parameters and the stated limits. In other words, the ESR asset will be responsible to inform MISO of its SoC through offer parameters and telemetry. MISO envisions to accommodate bid parameters in all four modes and will require the ESR asset to specify the mode for each dispatch interval. The assets will be considered as must-runs when online.

## Independent System Operator New England

### *Regional Context*

ISO New England (ISO-NE) has an installed generation capacity of about 31 GW from more than 350 dispatchable resources, with a system-wide peak demand of about 25 GW. The generation mix includes nearly 2000 MW of pumped hydro storage and 17 MW of battery storage. Furthermore, the ISO currently has about 15 GW of proposed generation, which predominantly includes wind (53%) and natural gas (32%), in their interconnection queue. Other technologies in the ISO's interconnection queue include solar (10%), battery storage (4%), and hydro, biomass, and fuel cell (1%).

### *Program Overview and Market Integration*

To enable directly metered battery storage to participate in ancillary services, capacity, and energy markets, and to use the capabilities of battery storage to the fullest extent, the ISO has been revisiting its rules. With the new participation modeling structure in ISO-NE, battery storage will be able to participate in the capacity market as a generating resource and in the energy market as dispatchable supply and dispatchable demand, with the ability to set the wholesale market-clearing price, be settled at the LMP for its supply and demand, and be eligible for make-whole payments. ISO-NE has proposed that the ISO will not manage the energy level or SoC of an electric storage resource; rather, the ISO will allow for the ESR asset owner to self-manage its SoC through offers–bids and dispatch bounds that reflect its physical limitations. In addition, the modifications will allow for the storage resource to provide 10-minute spinning reserve in real time, as both supply and demand, and participate in the forward reserve market. The ESR asset owner will also be able to participate in the regulation market as an alternative technology regulation resource using the energy-neutral signal to manage its SoC.

With regard to telemetry requirements, the ISO's enhancements necessitate that the storage asset provide two telemetry points in real time; that is, available energy (limits injection) and available storage (limits withdrawal), which will assist the ISO in discerning the asset's dispatch limitations for use in real-time markets and account for reserve appropriately. Although the ISO will allow for the storage asset to participate either as a generator, a dispatchable asset-related demand, or an alternative technology regulation resource, the asset is proposed to receive a single net dispatch instruction to avoid confusion. Finally, the ISO envisions to exempt battery storage assets from specific market costs by applying the existing cost-allocation treatment for pumped storage to all storage resources. The ISO-NE is in the process of enhancing its storage model to comply with the size limitations proposed by the FERC Order.

The existing participation models for dispatchable storage in the ISO include the following:

- Pumped storage hydro resources, which can participate in the capacity, energy, reserves, and regulation markets as dispatchable supply and dispatchable demand
- Regulation focused, which allows for a storage resource to participate only in the regulation market as an alternative technology regulation resource (allows for aggregation)
- Demand response, which allows for a behind-the-meter storage resource to participate in the capacity, energy, and reserves markets as dispatchable demand response (allows for aggregation)

A new participation model, battery storage, is proposed to be introduced by the ISO for directly metered battery storage and other similar technologies, which will allow for the resource to participate in the capacity, energy, reserves, and regulation markets as dispatchable supply and dispatchable demand.

### Distributed Flexibility Service Offerings

The term *distributed flexibility* has become increasingly relevant as the growth of DER brings a change in the assets available to maintain power system reliability. Flexibility in this sense is the ability to cost-effectively and reliably dispatch production and consumption resources across a range of set points to maintain power balance in the system, to alleviate network congestion, and to ensure that operational reliability standards are met. Availability of this flexible response from large conventional generation resources is increasingly complemented by the same provision from distributed resources. Some of these services have been well established, as is the case in France. The following subsections provide an overview of some of the technologies that are being leveraged to provide distributed flexibility.

### *Space and Water Heating and Cooling*

#### Overview

Space and water heating and cooling are the most mature demand response asset classes to provide distributed flexibility to the bulk system for active power balancing. These technologies have been leveraged in many places since the 1980s for peak shaving and frequency regulation services and are included here to demonstrate the range of capabilities that can be used by a system.

#### Air Conditioners

Many utilities around the world, including Australia, offer rebate programs to customers who enable a degree of control over their A/C to either the retailer, the utility, or a third-party energy efficiency service provider (such as building energy management), usually to reduce load during well-defined peak demand periods. Newer use cases are also emerging for A/C, such as load turn-up during low price periods to pre-cool buildings within comfort levels.

Consolidated Edison (ConEd) has offered customers a Smart A/C program since 2011, whereby customers gain a rebate for subscription of their A/C device to a control program administered either directly through ConEd's plug-in control that cycles power to the A/C by WiFi, with newer WiFi-enabled devices and older devices that are retrofitted by the consumer with WiFi-enabled controllers. Newer devices can leverage the ability to modulate demand, whereas control for older resources typically depend on an on–off control scheme. Rebates depend on the size of the A/C devices and the degree to which they can be used. ConEd projected 21,000 connected devices through the Smart A/C program as of October 2017, with substantial and sustained enrollment in the program since its inception. This is principally used for peak demand reduction at present. The company also offers a Bring Your Own Thermostat program to enable customers with a qualifying thermostat to either subscribe the device to tariff-based control schemes (such as on- and off-peak tariff) or direct control.

Similar to New York, Commonwealth Edison (ComEd) in Illinois has a long-standing demand response program to offer customers rebates on A/C control for peak demand reduction. Based on initial experience, the program has evolved into a partnership between the utility, the thermostat provider Nest, and the communications company Comcast to cost-effectively scale the programs. Many other such programs exist in the United States, Australia, Europe, and Japan at both commercial and residential scale.

#### Market Integration

Space and water heating and cooling have historically been used predominantly to mitigate peak demand by either adherence of loads to a tariff-based signal or to dynamic signals sent by utilities, based on energy market conditions. Water heater programs also offer the possibility to shift demand into other parts of the day, with similar flexibility afforded by A/C programs. This type of response can be highly flexible, particularly when a degree of thermal storage can be leveraged.

The underlying technologies' capabilities enable services that fall into the following three broad camps:

- **Peak avoidance.** Demand reduction at peak with limited or no consequences for demand later or afterward
- **Demand shifting.** Movement of demand from peak hours to periods of less stress for the system
- **Demand turn-up.** Increasing demand during periods of potential excess energy generation

## Energy Storage

### *Overview*

Battery storage is rapidly finding market application throughout the world, driven by the following four major trends:

- Policy support or mandates (such as California, New York, Japan)
- PV tariff design and supports (such as net metering policies and U.S. investment tax credits)
- Economics as peaking plant when combined with falling costs and supports
- Need for fast-acting ancillary services

As a residential-scale, distributed flexibility resource, battery storage is largely being deployed coupled with PV systems, both behind and in front of the meter. This section reviews some of deployments at the residential scale to understand how the operation of these resources may be reflected in energy markets.

### *SonnenBatterie and Tiko*

SonnenBatterie is a German lithium ion battery manufacturer, specializing in the residential-scale market. Sonnen has market presence in several countries in Europe, as well as the United States and Australia as of 2017. Sonnen operates a VPP system named sonnenFlat in certain service territories and as part of VPPs in others. One example of this is in Switzerland, where retailer Repower and communications company Swisscom created a joint venture, Swisscom Energy Solutions (SES). SES offers VPP and smart home solutions that leverage devices such as residential PV and battery systems, water heaters, and space heaters. The bundled system enabling the VPP, named *Tiko*, includes hardware interfaces to end-use devices and a DERMS controller managing data backhaul and sending commands. In the Swiss case, this is done through cellular network backhaul systems.

Sonnen batteries are offered through the retailer for outright purchase or on a monthly plan over 10 years, similar to storage offers in other countries, including Australia. Storage owners are remunerated with an annual rebate for batteries' participation in the VPP, ranging from AUD 134 to AUD 335 (see Table A-5) to allow the VPP operator to leverage the capabilities of the underlying resources in energy and ancillary service markets. This is achieved through the combination of a proprietary energy management system that interfaces with proprietary local controllers over the customer's Internet or third-generation (3G) cellular networks. The local controller acts as a three-phase meter, reading active power at up to 1-second resolution; it also interfaces with users' devices using common protocols described in Appendix B. In the case of Switzerland, more than 100 MW of assets are under control, including 10,000 heating resources since 2014. At present, these resources modulate their power output on demand and are used for energy balancing and for secondary and tertiary frequency control ancillary services. This system is also in place with DirectEnergie in France.

**Table A-5**
**Cost and rebates for battery storage example in Switzerland**

| Storage Capacity | Yearly Tiko Rebate (AUD) | One-Off Purchase (AUD) | Monthly Purchase Plan (AUD) |
|---|---|---|---|
| 2 kWh | 134 | 7370 | 1099 + 52/month |
| 4 kWh | 201 | 11,390 | 1903 + 79/month |
| 6 kWh | 201 | 14,727 | 3631 + 92/month |
| 8 kWh | 268 | 18,157 | 3846 + 119/month |
| 10 kWh | 268 | 21,574 | 4047 + 146/month |
| 12 kWh | 335 | 25,058 | 4315 + 173/month |
| 14 kWh | 335 | 28,408 | 6057 + 186/month |
| 16 kWh | 335 | 31,825 | 6258 + 213/month |

### *Market Integration*

Integration of battery storage into markets presents a range of challenges for both utility-scale and residential-scale resources. At the utility scale, this includes SoC management and conflicts between the provision of multiple services such as transmission asset deferral and capacity provision. This is further complicated at the distribution level, where local conditions and self-consumption incentives also play a part in constraining the amount of flexibility available from a given resource. In general, distribution-connected storage resources exhibit the following characteristics when participating in a market:

- **Energy-limited.** Any instruction is inherently limited by past dispatch and limits future actions to maintain a SoC within limits
- **Demand shifting.** Moves demand from periods of system stress to less stressed periods
- **Fast responding.** The lithium ion batteries currently being deployed are capable of responding quickly to input signals, making them capable of providing fast-acting ancillary services

## Electric Vehicle Charge Management

### *Overview*

As the penetration of EVs increases around world, it can impact the demand on the bulk system and also offer energy-balancing capabilities. This presents an opportunity for incentive-driven responses to provide support to bulk system operations during periods of stress by shifting or adjusting the level of charge at any one time. Unlike other resources, EV charging is dependent on the behavior of car owners to connect the underlying asset when the stress periods arise.

Work is currently under way in many systems to gain situational awareness of charging needs, in anticipation of larger needs in the future, and to leverage the capabilities from EV charging networks. Two examples are cited here.

The Spanish transmission system operator Red Electrica Espana has developed a forecasting and situational awareness tool, located in their control center, to aggregate data from public charging network operators. This tool, called *Control Centre for the Electric Vehicle (CECOVEL)*, is available to inform operators of the profile of charging in multiple zones within Spain in anticipation of an increase in the numbers of cars connecting in future and for the potential to leverage the capability to provide system services.

In the United States, EV charging network operators such as eMotorWerks and ChargePoint are at varying points in exploring options to register as demand response resources. eMotorWerks is a California-based electric charging vendor and network operator with a business model that incentivizes vehicle owners to participate in managed EV charging programs in return for credits. This controllable charging has been offered to the CAISO energy market through the PDR product described in the California Independent System Operator section of this appendix. To date, the company has offered approximately 30 MW, with 70 MWh of virtual storage operated as a demand-responsive capability to the energy market.

# B

# INTERNATIONAL PROPOSALS FOR DISTRIBUTED ENERGY RESOURCE MARKET INTEGRATION

This report has highlighted the types of initiatives and programs that are currently in practice; however, several proposals to leverage DER in electric system operations have been tabled. This appendix reviews some of these proposals.

## Texas

### *Regional Context*

The Electric Reliability Council of Texas (ERCOT) is the ISO for the significant majority of the state of Texas. The ERCOT system operates asynchronously from other U.S. interconnections. The peak demand for the system exceeds 70 GW and was set in August 2016. Although the 20 GW of wind generation and additional 1 GW of solar generation is largely either connected to the transmission system or is distribution- or sub-transmission-connected, it is significant enough scale to be included in the ERCOT market. As of 2016, ERCOT estimates that there is approximately 1100 MW of distributed generation connected at voltage levels below 60 kV and each with a capacity less than 10 MW. Of that, almost 154 MW of capacity was less than 1 MW in size, and almost 900 MW was fossil fuel generation, mainly used as backup generation [7]. The majority of Texas allows for retail competition, providing customers with an opportunity to select and switch between retailers. This is made possible through a centralized smart metering infrastructure that has been rolled out across most of the state.

In anticipation of further growth of DER, a working group was established in 2015 to establish a path to consider DER in bulk system operations. The group produced a report outlining several possibilities for DER to be integrated and evaluated the steps required to achieve each of those aims. The group also published a subsequent report in 2017, highlighting the potential reliability issues faced in bulk system operations with high penetrations of DER.

The ERCOT day-ahead and real-time energy markets clear on a nodal basis, within the region of 9000 nodes included in the model. Generators are paid according to the locational marginal price (LMP) at the bus to which they are connected, whereas loads pay the weighted average of the LMP in one of the four zones in the ERCOT market. This has given rise to some questions related to a disparity in remuneration mechanisms for demand response as compared to conventional generators to date, which was resolved through a ruling by the Public Utilities Commission of Texas.

## *Proposal Overview*

The 2015 report highlighted three options for DER to be considered in system operations: DER minimal, DER light, and DER heavy [11]. As the names suggest, these options involve increasing levels of integration within market optimization and settlement processes. However, a set of recommendations are common across these options. These common conclusions include the following:

- Static data related to the type and characteristics of the DER are required by the bulk system operator to establish the expected infeed for price-taker resource and security constraints that are used in the market-clearing process.
- The mapping of individual DER devices to nodes included in ERCOT's common information model of the network. This typically requires mapping each DER to the 60-kV bus that best represents the interface between the bulk system and the DER's output by the distribution utility.[14]
- Metering approaches should follow practices that capture the following:
  - Gross generation and discharge from DER, not net of auxiliary load related to the generation resource
  - Native demand (that is, demand from a customer's normal usage) plus demand for auxiliary generation
  - Load from charging of energy storage devices
  - Net injections onto the distribution system
  - Measurements at a resolution equivalent to the market settlement period length

These options indicate that accurate data are the key factors underpinning DER's inclusion in markets in future. Only with accurate information as a starting point can each option be differentiated based on control capability and the degree to which interaction with the market is sought. The three proposals are summarized in the following subsections.

### Distributed Energy Resource Minimal

In the DER minimal option, DER acts similarly to the way it is currently included in the market in systems with direct marketing and priority dispatch. In this option, the net injection from the DER is remunerated at the zonal price paid by load in a price-taking arrangement. In this case, only a bidirectional meter is required at the point of interconnection because load and generation are remunerated on the same basis. The forecast output of the resource is not included in the forecast injections used in the market-clearing process.

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[14] Typical distribution configurations in the United States are based on a radial feed pattern, in contrast with a more meshed approach taken elsewhere. Although nomination of a secondary node is possible for periods when outages occur and the interface between the DER and the bulk system is no longer, although the nominated bus is, the secondary bus is unlikely to be electrically distant from the primary.

### Distributed Energy Resource Light

In the DER light arrangement, a qualifying scheduling entity (QSE) is responsible for bidding the DER into the day-ahead and real-time markets, and the forecast for that resource is used in the market-clearing process. The resource is not sent dispatch set points, however, and responds as a price-taking resource. In this case, energy production from the DER is metered individually and remunerated at the corresponding node's LMP in each interval. In this option, telemetry is required to report production and consumption information needed for the settlement process, shortly after real time. DER should also have the capability to respond to an ERCOT dispatch instruction in the case of emergency in this option.

### Distributed Energy Resource Heavy

The DER heavy option most closely resembles the role of a conventional generator in energy and ancillary service market operations. The DER would be offered into the energy markets as a resource or as part of an aggregation by the QSE, with three-part cost offers. The market clears, co-optimizing the resource with others, and determines the set points for each interval in the market run. These set points are relayed to the resources for dispatch. In this case, production is once again remunerated on a nodal basis, whereas consumption is charged on a zonal basis. In this option, real-time metering and control are required to report the production output to ERCOT through a SCADA system. Resources in this category also must comply with responsibilities to schedule outages through the ERCOT outage coordinator and will also affect the allocation of congestion revenue rights or financial transmission rights in the system, given the potential impact of the DER or an aggregation to influence congestion and price convergence between nodes.

## *Metering and Telemetry*

This project found that a variety of practices are in place at present within the ERCOT footprint for metering. The group put forward three options for metering—one corresponding to DER minimal and the other two for DER light and heavy, including and excluding the treatment of energy storage as a wholesale market resource, rather than for the management of self-consumption (see Figure B-1).

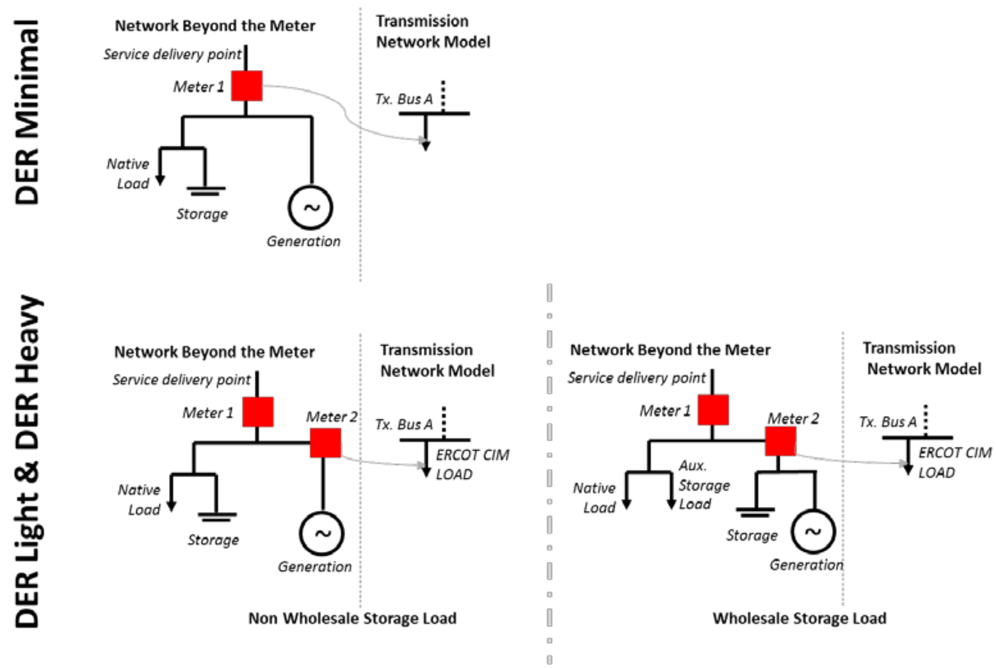


**Figure B-1**
**Proposed metering configurations in Electric Reliability Council of Texas distributed energy resource integration proposals**
*Based on "ERCOT Concept Paper on Distributed Energy Resources in the ERCOT Region" [11]*

The proposal strongly advocated for the use of dual metering in place of bidirectional metering. Dual metering separately measures cumulative export and import over a metering interval. Bidirectional meters measure the overall net position in the interval. Dual metering allows for export to be paid at one price and import to be charged at another. It also correctly records native load, which is the basis for the allocation of the costs borne by demand for system services or other actions.

The ERCOT proposals also envisage the need for telemetry from the DER back to ERCOT for emergency operations, as well as among the DER, QSE, and ERCOT. The proposal highlighted the need for further discussion on this topic but offered the possibility of using the existing ICCP protocol to interface among the parties.

### *Market Integration*

Through these proposals, DER will take either a passive role in energy markets, through the DER minimal or light approaches, or an active role in determining the price of energy and ancillary services, through DER heavy. The proposal allows for single resources or aggregations to be included for DER heavy and light, with options for settling aggregations drawn from similar experience with existing demand response and multi-unit combined cycle gas turbine models in the energy market. Concerns such as these will not apply to the same extent in zonal markets, except for cases in which redispatch actions are taken out of the market for reliability purposes, when certain resources with an aggregation may be affected more than others.

The proposals are currently under discussion in Texas. Given the relative lack of DER at present, substantial progress on the identification of the selected path forward has not materialized to any great extent to date.

### *Relevance for the Australian System*

Although it is only at proposal stage, the work conducted by ERCOT is highly relevant for any system facing substantial integration of DER resources. In particular, the 2015 proposal lays out necessary actions to enable DER integration into the market, such as mapping of DER to transmission busses, metering arrangements, and telemetry and control requirements. These are largely relevant to the NEM.

The ERCOT proposals also lay out a multi-tiered approach to DER integration, ranging from highly integrated to passive. This offers a sensible approach to engage DER in a limited way for existing resources with limited capabilities while offering a highly integrated route to market for new resources in which telemetry, metering, and control may be updated as part of the installation process.

## New York

### *Regional Context*

The New York system has more than 700 generating resources, with an installed generating capacity of approximately 43 GW, of which 1.25 GW is solar PV, 1.85 GW is wind generation, and 5.5 GW is combined heat and power (of which 2.2 GW is commercial or institutional scale). Significant build-out of renewables, including distributed resources and offshore wind, is expected in the coming years. The peak load in the New York region is approximately 30 GW. The state of New York is actively involved in improving its clean energy footprint while maintaining grid resiliency, particularly in the wake of Superstorm Sandy in 2014. This is evident from their newly introduced initiatives centered on the Reforming the Energy Vision strategy, which aims to develop an enhanced market infrastructure to engage directly with customers and a more prominent role of the distribution utilities with a goal of establishing distributed service platforms [13].

Recent announcements have established targets to build 1.5 GW of storage and more than 2 GW of offshore wind generation by 2025. With increasing penetration levels of distributed renewable energy resources, the New York ISO (NYISO) believes that ensuring adequate resource flexibility is the key to maintaining grid resiliency and managing a grid with active participation of resources from both the supply side and the demand side. DER is expected to play an enlarged role in New York, which currently has approximately 800 MW of energy storage and fuel cells in queue, which is changing rapidly. As a result, the New York ISO has developed a roadmap for the integration of DER into bulk system markets, which was released in 2017.

The roadmap establishes several additional routes to market for DER either directly or as part of load as capacity, energy, or ancillary service resources. The proposals expand on the existing emergency, demand response, and load modification programs to include direct representation of behind-the-meter and dispatchable, utility-scale DER as part of capacity, energy, and ancillary service markets (see Figure B-2).

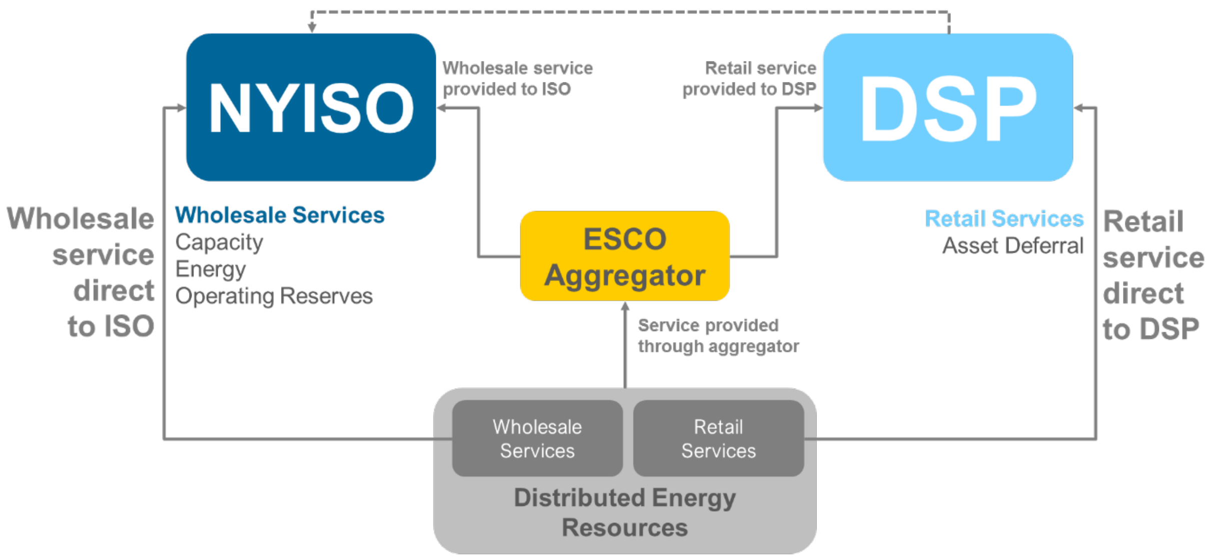


**Figure B-2**
**Schematic view of envisaged distributed energy resources participation in New York independent system operator markets**
*Based on "Distributed Energy Resources Market Design Concept Proposal" [13]*

### *Proposal Overview and Market Integration*

Following completion of the roadmap, the NYISO commenced a program to develop a market design concept proposal in 2018. The proposal is focused on DER aggregation rules and modeling, metering, and telemetry, as well as performance obligations and differentiation between wholesale and retail transactions. *DER* was defined in this case as follows:

> Resources qualified to participate in NYISO's energy, ancillary services, and/or capacity markets that are 1) capable of changing its load or 2) capable of injecting 20 MW or less onto the transmission and/or distribution system, at the NYISO's direction.

This is again split into three types of DER: dispatchable, non-dispatchable, and front-of-meter (see Figure B-3).

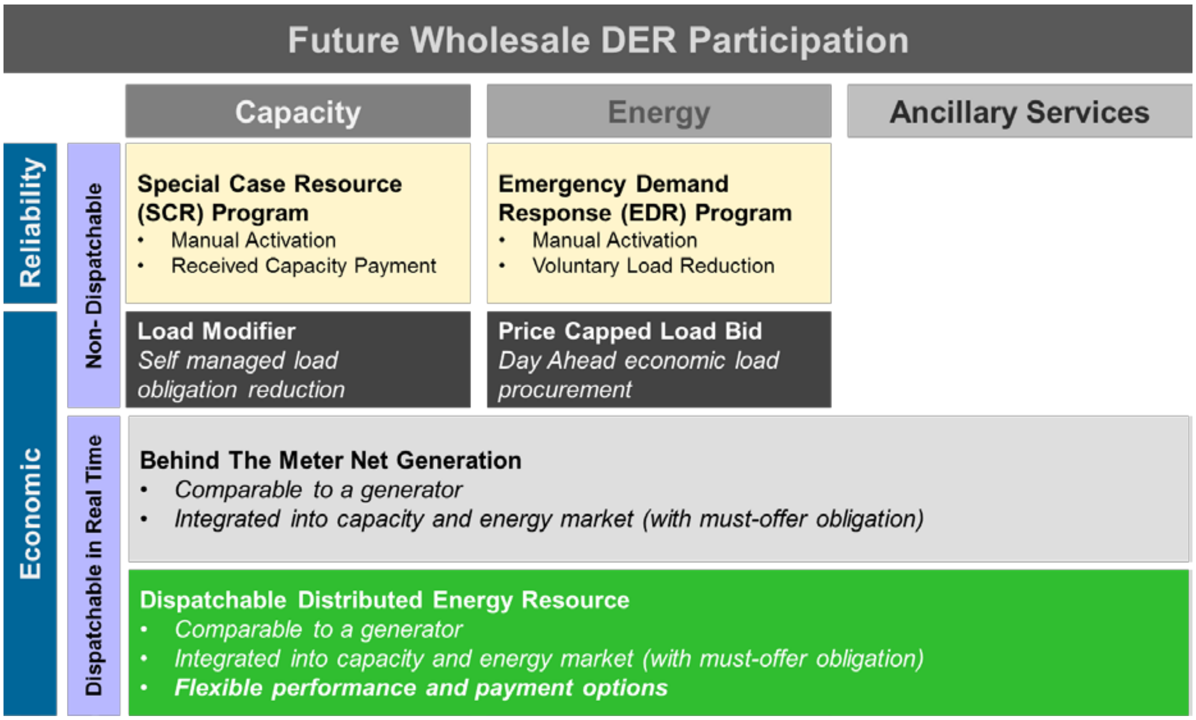


**Figure B-3**
**Distributed energy resource participation in New York independent system operator markets**
*Based on "Distributed Energy Resources Market Design Concept Proposal" [13]*

Each of the three categories of DER encompass the product offering types listed in Figure B-3. Dispatchable and front-of-meter DER will be eligible to participate in day-ahead and real-time energy and ancillary service markets, as well as capacity markets. Non-dispatchable DER will be allowed to participate in capacity and day-ahead energy markets. Front-of-meter aggregations will be assessed similarly to generator or storage resource types, depending on their constituent elements. Any participating resource can be dispatched during an emergency event.

Aggregations greater than 100 kW will be allowed to participate in capacity and energy markets, with an additional threshold of 1 MW minimum size for ancillary service markets. Aggregation will be carried out on the basis of individual transmission nodes, and the aggregator acts as the market participant with whom the NYISO interacts. This is different from the way that demand response is treated, which can be aggregated on a zonal basis. Offers from aggregators less than 1 MW in size will be aggregated at the transmission node during energy market clearing. Aggregators not offering ancillary services will also be aggregated, regardless of size. The NYISO is experimenting with the security-constrained economic dispatch engine to determine the impacts of additional small-scale resources being included in the model.

The NYISO intends to retire its present day-ahead demand response and demand-side ancillary service programs when the DER proposals enter force. One impact of this is that a net benefits test, which is used to determine when it is cost efficient to deploy demand response, will be applied to DER aggregations whose primary role is to reduce demand. Further work is being carried out to refine rule proposals surrounding DER dual participation in services.

A metering study was conducted to determine metering configurations and baselining techniques to estimate DER response when it is simultaneously providing multiple services. This study identified a need to exclude DER from energy markets when they are currently part of a net metering program and do not have an interval meter to avoid double payment for services. The report found that existing practices for baselining the output from demand resources functioned well, but they could not be extended to DER such as wind, solar, storage, and so on.

NYISO's current telemetry system operates at a 6-second scan rate, and initial proposals to extend that requirement to DER aggregations met resistance from DER providers on a cost basis. NYISO is evaluating alternate methods to gain high-resolution telemetry using existing 5-minute meter data combined with sampling or other techniques to up-sample telemetry [45].

Existing options enable DER to be leveraged by LSEs to offset the bulk system load either by direct control of the DER by the utility to manage load or by offering a price-capped offer for load (that is, a demand curve for load) into the energy market. In this way, the operation of the DER is indirectly co-optimized with the energy market, and the utility remains responsible for maintaining the load at the level cleared in each market. Deviation from day-ahead cleared level will result in potentially higher costs in real-time market runs, increased balancing charges borne by load, or both.

Demand response is already included in the New York market, with significant effort being applied to energy storage as a result of FERC Order 841. NYISO has also been heavily involved in developing energy storage rules, from both front-of-the-meter and behind-the-meter perspectives, with their stakeholders and market participants since late 2016. In NYISO, there exist two options for storage to participate in energy markets— the DER participation model and the energy storage resources (ESRs) participation model. ESRs can participate in ancillary service, capacity, and energy markets. The design of the participation model is proposed to be technology neutral to accommodate all types of storage, such as pumped storage, battery, flywheels.

In addition, to enhance the use and interaction of energy storage in a market auction model, the ISO is considering including storage in both the dispatch and scheduling models—that is, a unit commitment model. This will potentially allow for a storage resource to switch to a transition state when transitioning between the discharge and charge states. The minimum offer size for ancillary services, capacity, and energy is modified to equal 100 kW for all resources, not just energy storage (originally 1 MW). Furthermore, the schedules for both energy and ancillary services are proposed to follow the same principles that apply to conventional supply resources. While withdrawing, ESR's can provide regulation; the consumed energy is proposed to be treated as negative generation rather than load. In New York, load is charged a load-weighted zonal rate. Consequently, in contrast, the ESR would be charged a nodal rate (or LMP).

NYISO has also stated that, with the proposed design enhancements, an ESR will potentially be able to participate in both the pumping (withdrawing) and the generating (injecting) modes within a given market interval (currently unavailable). Thus, to enhance the model to accommodate novel technologies that have a fast response rate, such as lithium ion batteries, the NYISO is envisioning to accommodate an offer that ranges from full injection to full withdrawal. The ESRs are envisioned to qualify as generators under the NYISO tariff with the provision to use all the existing generator offer parameters in addition to the other operational characteristics, such as upper and lower storage limits, maximum run time, startup and no-load costs, roundtrip efficiency, state of charge (SoC), beginning energy level, maximum and minimum withdrawing time, withdrawing response rates, and so on, as recognized by FERC and NYISO. NYISO has proposed to provide the ESR participants with the option of either self-managing its energy level or having the ISO manage its energy level, potentially on a daily basis.

In the event that the ESR opts to have the ISO manage its energy level, it is up to the NYISO to ensure that the physical limitations of the ESR are not violated, including but not limited to the upper and lower storage limits, by monitoring the SoC telemetry signals when determining its schedules in the day-ahead and real-time markets. In contrast, the ESRs that choose to self-manage their energy level will need to adjust their offers to ensure that their physical limitations are met.[15]

To qualify for the provision of operating reserves, the ESR assets will need to satisfy the Northeast Power Coordinating Council (NPCC) criterion, which requires the corresponding resource to have the discharge capability of activating reserves for at least an hour. The ESR assets will need to satisfy the mandates that are set forth by the North American Electric Reliability Cooperation (NERC), NPCC, and the New York State Reliability Council to provide operating reserves analogous to other generating resources. It may be the case that DER will follow the same guidelines.[16]

## PJM Interconnection

### *Regional Context*

PJM is the system operator for 13 states and the District of Columbia. It is the largest ISO in the United States, covering 65 million people with a 2017 peak load of 165.5 GW. Wind made up 2.6% (20.7 TWh) and net-energy-metered solar made up 0.2% (1.5 TWh) of generation. Due to the mix of states in PJM, the operator must consider multiple state policies as well as federal policy and interests in operation of the grid. This can make implementing local policies across the region difficult; however, the regional diversity is also an advantage for wind and solar variability.

There is approximately 6.6 GW of non-wholesale DER, including behind-the-meter solar PV, municipal and industrial generation, and emergency backup generation. Due to local and state incentives, the majority of solar PV generation is in New Jersey and North Carolina. Offshore wind has been proposed in some PJM states, with development starting in waters off Virginia, North Carolina, and New Jersey.

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[15] With the self-managing option, it is possible that the self-monitoring ESRs receive a schedule from the ISO that is physically infeasible. The schedules for both energy and ancillary services for the ESRs will follow the same principles that apply to other generating resources; for example, the sum of the energy and the ancillary services schedules will be bounded by the economic maximum in a given interval. Furthermore, it is proposed that the SoC of an ESR will not be affected if the resource opts to provide ancillary services. In other words, for now, regulation reserve is proposed to have no impact on the SoC of an ESR in a given interval.

[16] Although the ISO will manage the ESR's energy schedules to ensure that the dispatch signals that are provided to the asset respect the resource's physical limitations, the ESR asset will be held responsible and will need to self-manage its physical SoC to ensure that it follows the dispatch signals in a manner that can enable it to continue satisfying the future desired dispatch points, failing which the asset will be subject to penalties.

### *Program Overview*

A Distributed Energy Resources Subcommittee of PJM's Markets and Reliability Committee was created in December 2017 and tasked with examining the policies and procedures associated with DERs, coordinating with states, and reviewing participation of wholesale and non-wholesale DERs. The subcommittee provides educational background on DER issues and plans to submit any necessary tariff or manual revisions as they arise.

#### Distributed Energy Resource as Demand Response

In January 2018, PJM produced a DER report documenting participation in markets through existing demand response mechanisms. The number of DERs participating as demand response in capacity markets reached a peak of 23% in the 2015–2016 delivery year, declining to 16% or 1288 MW in the 2017–2018 delivery year due to a federal court decision on emergency backup generation.[17]

Of the resources participating in capacity markets, behind-the-meter capacity is 99% diesel- and natural gas–based generation. DER capability is manifest through demand response participation in capacity markets; it also participates in smaller proportions in synchronous reserves, regulation, and economic DR programs in the energy market.

Of the economic DR energy activity, 65% of the capability came from DER in 2017. Although the total production from DER has increased in the past five years, the high percentage is primarily due to the decrease in total settled megawatt-hours of demand response. In the regulation market, 74% of the demand response came from batteries, followed by 26% from electric water heaters, and only 1% from generators.

#### Continuing Proposals

The subcommittee has been discussing alternatives for integrating DER and proposed several changes to the PJM manual. Before the official formation of the subcommittee, a strawman proposal presented 12 design components for DER integration. In the proposal, they advocated for a set of voluntary rules for DER, separate from demand response and generation, while still requiring DER to come through the PJM queue and be approved for wholesale participation. The committee split the work into the following four sections:

- Non-wholesale DER observability
- Wholesale DER (ancillary services, energy, and capacity)
- Interconnection queue process
- DER aggregation

The first two are furthest along in subcommittee discussions.

[17] A 2013 Environmental Protection Agency ruling allowed backup generators to run for 100 hours per year as part of an aggregation of customer resources bid into an energy market. In 2016, a federal court overturned that ruling, reducing the availability of backup generators to participate in capacity markets.

Proposals addressed the need to ensure that DER can deliver output to market through engineering studies and an interconnection process that includes both PJM and distribution utilities. Furthermore, consideration has been given to charging consumption at a retail rate and production at a wholesale rate and ancillary service only mechanisms. A market threshold for individual or aggregated resources was proposed at 100 kW, commensurate with DR and FERC orders for storage. A proposal was offered to apply restrictions, whereby only one DER within an aggregation larger than 100 kW can reach a total maximum capacity of 1 MW, while all within the same distribution company footprint. The proposals also include a provision requiring the market party to offer telemetry at 10-second resolution for the aggregation to PJM. This telemetry, along with the day-ahead schedules for the resources, can be shared back with the distribution company to which the aggregation is connected. These proposals will likely be revised in part as progress is made in the subcommittees.

The subcommittee has proposed and voted on non-wholesale DER manual changes for behind-the-meter generation (non-wholesale DER). The changes address communication between transmission owners and behind-the-meter generation, including information that the transmission owner is required to pass on to PJM. Some of the provisions include the need for transmission service providers to retain a list of distribution companies, municipal systems, or other cooperatives, and behind-the-meter generation greater than 1 MW in size, and to make that list available to PJM at least annually. The transmission owners are also responsible for mapping the DER to a PJM transmission substation, indicating the voltage level at which it interconnects with the PJM system, as well as other characteristics of the behind-the-meter generation unit.

Initial use of DER is provided to alleviate operational reliability issues, with provisions for PJM to issue non-binding requests to the DER through the transmission and distribution network utilities to mitigate wholesale market issues. Wholesale DER options for energy and ancillary services span many areas, including jurisdiction and metering performance. It must determine whether DER participation is under federal or state jurisdiction, which will then govern how sales, and in turn their interconnection processes, are regulated. The subcommittee produced a system to help identify whether the DER should be under federal or state jurisdiction. They also suggested two methods for measuring performance: meter either at the point of interconnection or at the DER interconnection point (submetered). Both have implications for who would be responsible for metering, either the generator owner or electric distribution company. PJM already allows for resources that are submetered to provide DR, which can allow DER to provide regulation services as DR. The subcommittee is now discussing implications for DER to provide ancillary services under both metering options.

### *Energy Storage*

Currently, the pumped storage hydro resources can participate in the capacity, energy, regulation, and reserve markets. Pumped storage hydro can participate in the energy markets either by submitting self-schedules (real-time and day-ahead), by pre-determining the hours to operate in the generating mode or the pumping mode, or by using a storage optimization model (day-ahead only) which is referred to as the *pumped hydro optimizer*. PJM uses the pumped hydro optimizer to determine the optimal mode of the pumped storage hydro resource that will lead to cost minimization. In this case, the pumped storage hydro resources are required to submit a zero-cost offer curve; therefore, costs are not considered when determining the schedules. Furthermore, the pumped hydro resources are not allowed to set prices. Other storage technologies, including batteries, are not allowed to participate in the energy markets and can only participate in the regulation market because PJM's current market structure does not allow for negative megawatts to be offered in the market. Thus, there exists a barrier for entry for other storage technologies.

PJM uses a fast-moving dynamic regulation signal—RegD—for fast resources (particularly batteries, flywheels, and hydro) that controls the faster component of the area control error, whereas the ISO uses a traditional regulation signal—RegA—for the slower component (slower resources such as thermal units) of the area control error. PJM has both regulation up and regulation down in one signal and has one product for regulation.

Splitting the DER signal into fast and slow signals occurred in recognition of the fact that faster-acting resources could support the system to quickly respond to an area control error and that conventional resources could then supplement the fast response. Initially, the fast-acting RegA signal ensured energy neutrality over the course of several periods to manage the SoC of batteries, also creating a market for battery response. This has since been relaxed, as the energy recovery process occasionally acted to counter the slower regulation signal and exacerbated area control error. This, in turn, reduced the incentive for batteries to provide the response and reduced prices in the regulation markets.

This created an opportunity for battery storage. PJM also includes another unique option to participate in the regulation market as a non-energy resource. In this context, to be considered for regulation service, a resource has the option to not provide its energy offer, which results in the resource not having any lost opportunity costs.

In the capacity markets, PJM currently imposes a 10-hour duration requirement. In other words, to contribute to capacity procurement, PJM requires that the capacity storage resources (or duration-limited resources) de-rate their installed capacity by the average power output in performance hours or that the capacity storage resources should be able to provide a sustained power output for at least 10 hours. This reduces the incentive for such resources to participate in the capacity market at present, as storage with a 1-hour duration is derated to 10% of its capacity, but proposals are underway to revamp this. PJM is currently working on developing a strawman proposal to comply with FERC Order 841.

### *Relevance for the Australian System*

PJM experience has relevance for Australia and the NEM, in particular, as it seeks to balance a set of common market rules set by federal authorities with state-based rules, incentives, and programs primarily targeted at DER. Although it is still at the proposal stage, the PJM market design closely follows that of the existing DR and generation in the market and depends to some degree on distribution congestion or export restrictions being reflected through the market interconnection process.

# C
# METERING AND TELEMETRY REQUIREMENTS

This appendix focuses on the underlying choices for metering and telemetry that enable market integration of DER. Although each region approaches these topics differently, the purpose of this appendix is to identify metering configurations, telemetry, and inverter interface protocols that are worthy of consideration.

## Options for Distributed Energy Resource Metering

Metering is critical for the settlement of DER and demand response in wholesale markets, particularly in regions with deregulated retail competition and third-party aggregators. The three main objectives in selecting a metering configuration for DER market integration are as follows:

- To record retail and wholesale transactions separately
- To record consumption and production separately
- To achieve metering objectives at least cost

### *Metering Configurations*

For existing installations, metering configurations have been determined by local distribution utilities, incentive regulations, and installers. Depending on the location, several configurations are possible. This appendix examines only active power metering, but reactive power metering faces similar issues in certain respects. For DER to be settled in the market, a set of meters can be linked with an aggregator that represents a given portfolio. Depending on the type of asset included in the portfolio and the services offered by the asset to the energy market or other such ancillary services, DER may require individual measurements of total export, battery charging demand, or resource-specific production and consumption if aggregators are restricted to a single class of resources

#### Bidirectional

Bidirectional metering is a common configuration for a customer with no DER or with net metering rules for DER. In this case, there is one meter at the customer's service connection point that increments for consumption and decrements during export to the grid (see Figure C-1). This metering configuration cannot distinguish between consumption by load and that by a storage device, nor can it deduce whether consumption was by a generator or storage. It is not possible to ascertain true demand or production from this metering configuration.

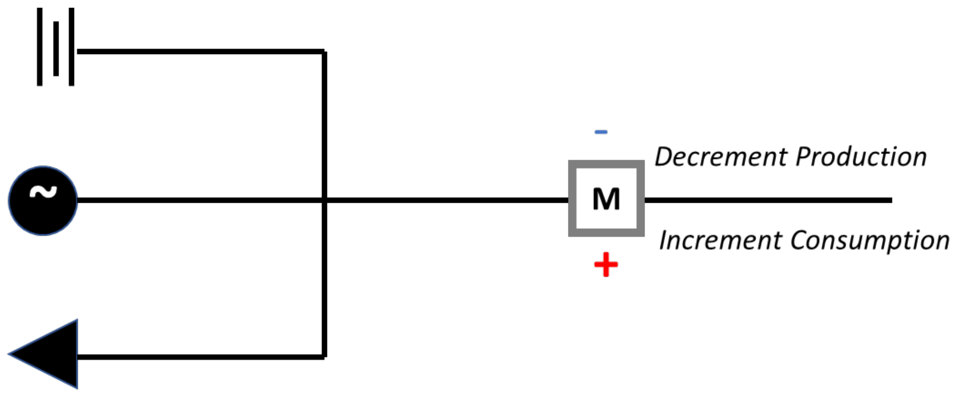


**Figure C-1**
**Bidirectional configuration**

### Two-Channel

In the two-channel configuration, production and consumption are metered separately (see Figure C-2). When netting is applied for incentive calculations, this is done by the metering operator as a post-processing calculation. In this configuration, it is still not possible to determine underlying demand or consumption, but it is more insightful than the bidirectional meter, given the separate accounting for imports and exports.

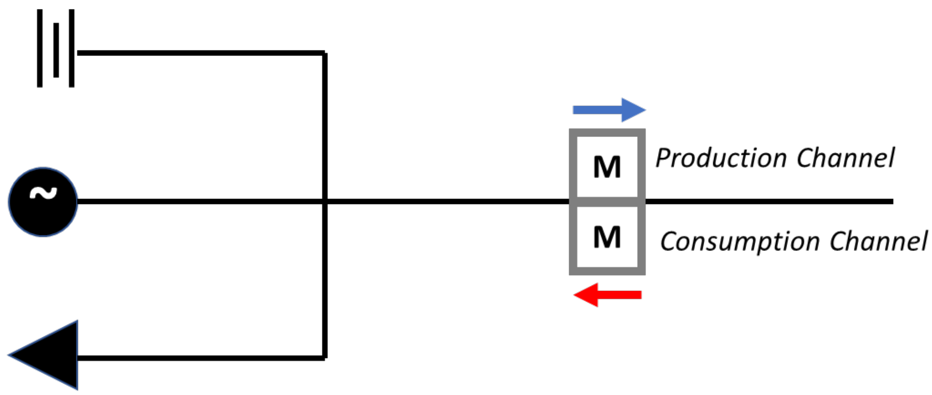


**Figure C-2**
**Two-channel configuration**

### Submeter

To ascertain the production from DER, a submeter may be installed. The location of the submeter is straightforward in cases with no storage—it is connected between the terminals of the generator and the customer's main distribution board (see Figure C-3). In this configuration, a submeter records production, and the existing bidirectional meter continues to net production from consumption. Without a storage device, demand can be calculated from this arrangement. With storage, true demand is not metered separately from storage, and this measurement cannot be determined.

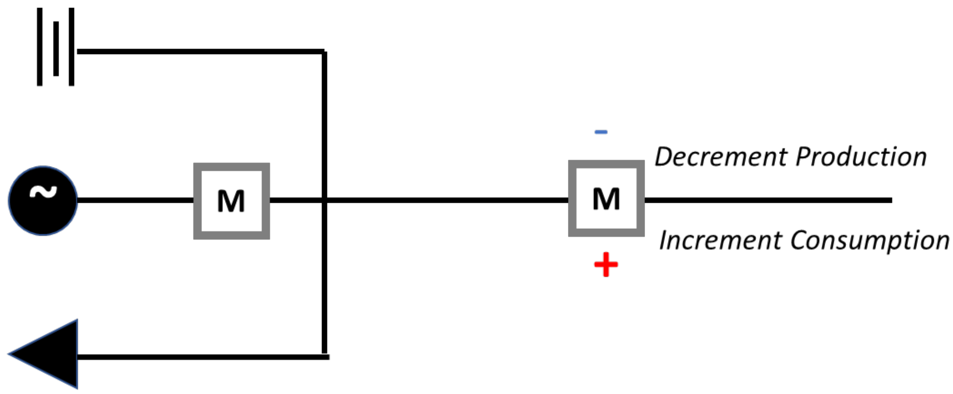


**Figure C-3**
**Submeter configuration**

### Submeter Including Storage

Adjusting the previous configuration to include storage behind the submeter (see Figure C-4), true demand can be determined when the submeter reading is netted from the main meter. The demand to charge the energy storage device and the production from either the storage resource or the distributed generator cannot be ascertained individually but can be for the combined set.

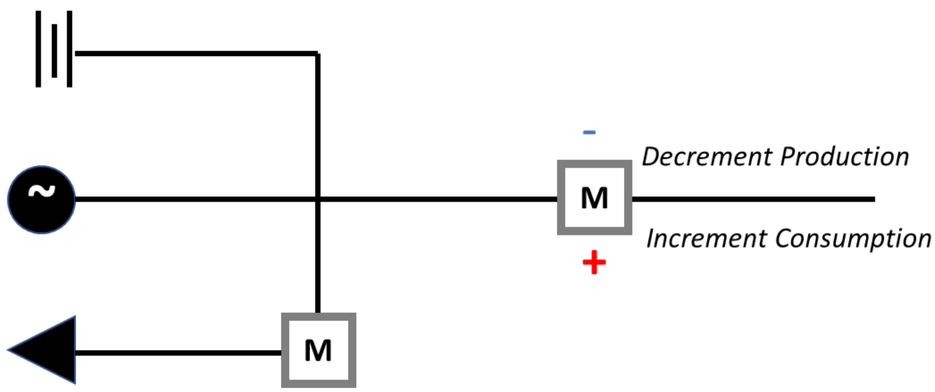


**Figure C-4**
**Submeter configuration including storage**

### Dual Two-Channel

In the dual two-channel configuration with generation and storage behind the sub-dual channel meter (see Figure C-5), a better understanding of the flows can be gained. In this setup, true demand and demand to charge the battery from the grid can be ascertained individually. Production can be determined for the combined storage and generation set.

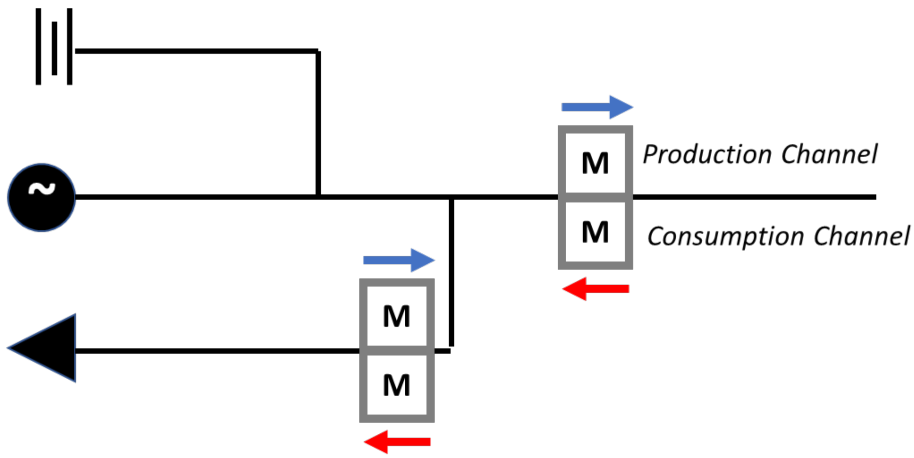


**Figure C-5**
**Dual two-channel configuration**

## Individual Submetering

In the case that individual production and consumption meter readings are required, there is little option but to install separate meters on each generator and storage resource (see Figure C-6). A growing trend is the inclusion of revenue-grade meters within DER inverters, compliant with the same measurement and accuracy standards as existing meters. Should this trend reach mainstream acceptance through certification, submetering each resource behind the meter with two-channel information may become widely available for new resources.

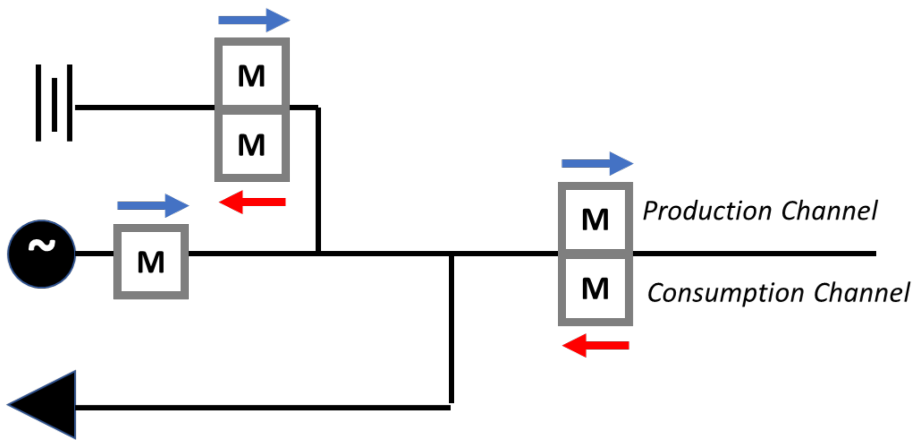


**Figure C-6**
**Individual submetering configuration**

The measurements available from each configuration are summarized in Table C-1.

**Table C-1**
**Measurements available from various metering configurations**

| Configuration | Net Import | True Demand | Generation | Storage Production | Storage Charging | Total Import | Total Export |
|---|---|---|---|---|---|---|---|
| Bidirectional | ✓ | ✗ | ✗ | ✗ | ✗ | ✗ | ✗ |
| Two-channel | ✓ | ✗ | Combined | | ✗ | ✓ | ✓ |
| Submeter | ✓ | ✗ | ✓ | ✗ | ✗ | ✗ | ✗ |
| Submeter including storage | ✓ | ✓ | ✗ | ✗ | ✗ | ✗ | ✗ |
| Dual two-channel | ✓ | ✓ | Combined | | ✓ | ✓ | ✓ |
| Individual submetering | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |

## Time Resolution

In addition to the possibilities for variables to be recorded, consideration should also be given to requirements for interval-based meter readings as opposed to older, continuous readings. Interval readings record the specified values with a certain time resolution. This time resolution may be hourly, 10 minutes, 5 minutes, and so on. In the case that DER is taking part in real-time markets, the market interval length is 5 minutes in the forthcoming NEM arrangements. Therefore, to be able to determine the settlement for the resource in that period or to apply pay-for-performance metrics, metering should be at the same time resolution as the shortest market-clearing interval or at a higher resolution.

Additional consideration should be given to participation in the frequency control ancillary service (FCAS) products, in which deployment may occur in the sub-second range. The granularity of interval meters is typically insufficient to validate the timing of fast frequency and primary reserve deployment in response to a frequency excursion. Supply of fast-acting reserve products is typically certified in commissioning and prequalification tests for large resources such as generators or utility-scale DER. When desired, fast frequency response provision can be monitored by high-resolution monitoring devices such as phasor measurement units (PMU). Although these are increasingly common devices to have alongside newer assets, they are typically used only for ex-post analysis of certain events, rather than for settling the provision of fast-acting services. For an aggregation of DER, this is likely to be the case into the future, given the higher cost of more granular measurement with PMUs. For longer-acting FCAS services, these may be deployed over several or tens of minutes, which may be measured by interval metering, depending on the specification of the meter intervals (such as 5-minute intervals).

The most likely mechanism to integrate DER provision of such services may be to certify inverter capabilities against a type prequalification test and to potentially monitor the provision of FCAS from a subset of resources in real time, together with data from PMUs located at primary substations, to attain an overall estimation of the fast frequency response services provided by DER in an area. This approach does not ensure that each resource in a given distribution network provides fast frequency response equally in response to a frequency deviation, but it may be used to trend response over time for a set of resources.

### Key Considerations

In selecting metering requirements and configurations, the targeted market design for DER should be kept in mind. For indirect participation, it may be sufficient to have a bidirectional meter at the customer's service connection point to measure net import. For direct, deep participation with homogenous resources, individual submetering may be required. For interim scenarios with heterogeneous DER aggregations, dual two-channel metering configurations may suffice. The choice of metering infrastructure will have implications for the enabling communication and information management systems. Increasing the number of measurands and the temporal resolution of each measurand increases the costs associated with the operation of metering systems. Although examination of these costs and the costs of metering configurations are beyond of the scope of this report, these costs should be borne in mind.

## Options for Distributed Energy Resource Telemetry

The *communication protocol* is the agreed method by which telemetry data (monitoring, state, or control information) is transferred between two systems. These systems may be control systems, DER, local controllers, or any other system. Metering requirements vary by market and product, driven by the time scale that the ancillary service product must be deployed, state estimator and automatic generator control refresh rates, and market scheduling intervals. Telemetry requirements vary in the United States based on the service provided—typically, energy market participation requires less detailed telemetry than that of faster ancillary services. Table C-2 outlines the telemetry requirements levied on DER when participating in ISO market services in the United States and the protocol used for telemetry systems.

Typically, the telemetry is required for the aggregate DER provided, rather than individual resources. Several systems have adopted a sampling approach whereby the telemetry at a subset of DER resources is used by a system operator to estimate the production from a wider set of resources. This sampling technique can also be used for baselining response from demand response and other compound or complex-to-measure resources.

**Table C-2**
**Telemetry requirements for select U.S. independent system operators by product as of March 2017**

| Product | ISO-NE | NYISO | PJM | MISO | ERCOT | CAISO |
|---|---|---|---|---|---|---|
| Regulation | 4 seconds for DR, same for generator | 6-second resolution (ICCP) | 2- to 4-second resolution (ICCP) | 2-second resolution (ICCP) | 2 seconds (DNP 3) | 4 seconds |
| 10-minute spin | 1 minute for DR, 10 sec for generator | 6-second resolution (ICCP) | N/A | 10-second resolution (ICCP) | 2 seconds (DNP 3) | 4 seconds |
| 10-minute non-spin | 1 minute for DR, 10 sec for generator | 6-second resolution (ICCP) | | 10- second resolution (ICCP) (Exception: for demand response resource (DRR) type I after-the-fact metering with 5-minute resolution suffices) | | 4-seconds (1-minute scan for PDR, 4-second scan for NGR) |
| 30-minute non-spin | 5 minute for DR, 10 sec for generator | 6-second resolution (ICCP) | | | 2 seconds (DNP 3) | |
| Real-time energy | 5 minutes for DR, 10 sec for generator | N/A (except for real-time energy dispatched from AS capacity as stated above) | N/A | 4- second resolution (ICCP) (Exception: For DRR type I after-the-fact metering with 1-minute resolution suffices) | N/A | 4 seconds (5-minute scan) |
| Day-ahead energy | N/A | N/A | N/A | N/A | N/A | N/A (for small resource <10 MW) |
| Capacity mechanism | N/A | N/A | N/A | N/A | | N/A |

**Note:** N/A indicates that there are no telemetry requirements to provide this service. Shaded cells indicate that the reserve service is not a product in that ISO region.

*Source: EPRI [18]*

### *Communication Protocol*

Communications to DER requires that systems from two parties support the same protocol to ensure that they are both able to interpret the information exchanged between them. This includes the *application protocol,* which defines the process by which communication is conducted, and the *information model* or *semantic model*, which defines the format of the content of the information passed. The selection of an application layer protocol—such as IEEE 1815 (DNP3), IEEE 2030.5, IEC-61850, or SunSpec Modbus—ensures that two entities can successfully exchange information. The protocol defines the semantics and methods for data to be exchanged; however, it does not define the specific information to be exchanged. The information model does this.

### *Information Models*

Information models define a standard method for how information (monitoring data or control parameters) is structured. This includes naming, functional descriptions aligned with standardized data models or functional descriptions, and data syntax information. These information models vary by protocol, as follows:

- In IEEE 1815 (DNP3), it is captured in application notes such as AN-2013-001, “DNP3 Profile for Advanced Photovoltaic Generation and Storage.”
- In IEEE 2030.5, it is captured in XML schemas.
- In IEC-61850, it is captured in the IEC-61850-7-420 document.
- In Modbus, it is captured in the SunSpec specification.

All these protocols can use custom information models; however, the use of standardized models simplifies connectivity and may reduce cost through interoperability.

### *Architectural Applicability*

Every protocol has a place within the greater control architecture. Protocols can be implemented at any level; however, various traits of the protocols make some more suitable in one area than another. These traits may include functionality, common use, grid code requirements, and others. The functionality included in the information models of a protocol may limit its applicability outside its domain; for example, a protocol may not support the messages to convey the information needed in communications between a TSO and DSO but may include the information needed to communicate between individual DER. Another trait, common use, covers where a protocol is most commonly used in the industry. An example is that Modbus is most commonly used for communication between DER or DER components; some deployments have applied it at higher levels in the architecture, but it is not common. Grid codes also play a large role. Requirements to use protocols in a specific domain can increase use in that area.

### *Smart Inverter Protocols*

In the smart inverter domain— which primarily includes solar and storage systems—four open protocols are used: IEEE 2030.5, IEEE 1815, SunSpec Modbus, and IEC-61850. In IEEE 1547, the standard that North American grid codes are based on, at least one of three standard protocols must be used—IEEE 2030.5, IEEE 1815, or SunSpec Modbus. Outside North America, these three protocols are also used; however, IEC-61850 is more common, with some countries, such as France, mandating its use.

### IEEE Standard 1815 (DNP3, AN 2013-001)

DNP3 is commonly used in utility SCADA networks to control distribution monitoring and control devices and substation equipment. DNP application note AN 2013-001 provides a specific point list to achieve interoperability of solar and storage DER. Accordingly, DNP3 is of particular interest to stakeholders—particularly for commercial, industrial, and utility-scale DER—and has been implemented in a number of commercial DER devices. An updated application note is expected.

DNP3 is commonly used for SCADA, including various utility assets, and includes application layer security. Depending on the configuration of the DER, DNP3 may be used direct to the DER or to a site-level management system that manages multiple DER and other assets. It is commonly used for utility-owned systems because the systems can be easily integrated into existing communications networks. Figure C-7 shows DNP3 communications interfaces.

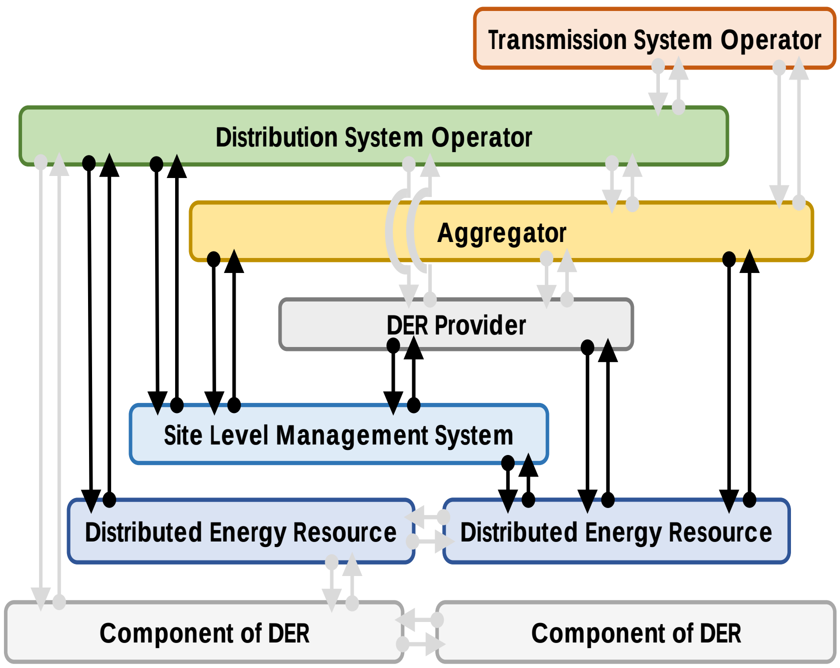


**Figure C-7**
**IEEE standard 1815 (DNP3) communications interfaces (black) as part of network operator–distributed energy resource communication infrastructure**

### IEEE Standard 2030.5

IEEE 2030.5 was identified for use with DER in the recently updated California Rule 21. It was originally developed by the ZigBee Alliance as a home area network protocol. It is unclear whether California applications will use it in the DER or in the networks terminating at a gateway device at the DER. The protocol relies on transport layer security protocols to provide cyber security. IEEE 2030.5 has not been implemented natively in a DER at this time.

In the diagram in Figure C-8, IEEE 2030.5 is not listed as a protocol between utilities and aggregators because IEEE 2030.5 does not currently support management of DER groups (aggregate control of DER); rather, it supports only pass-through messaging from one point to another.

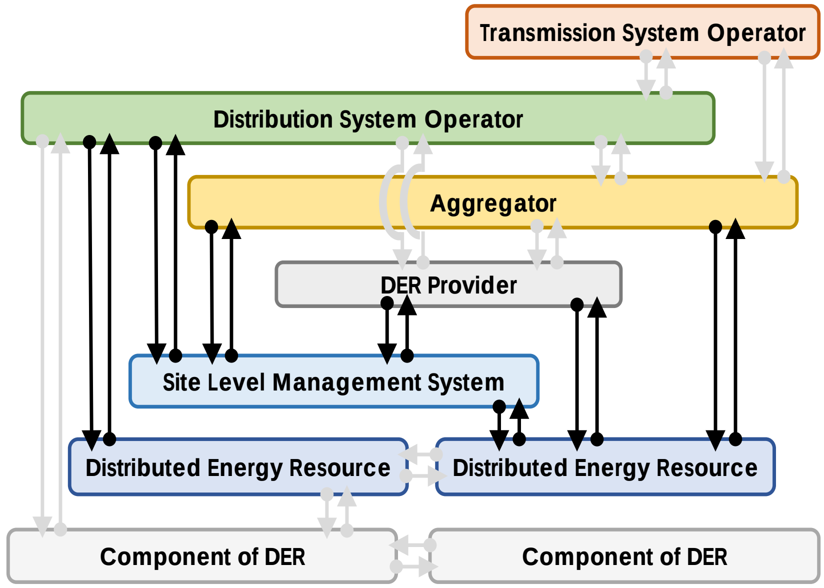


**Figure C-8**
**IEEE standard 2030.5 communications interfaces (black) as part of network operator–distributed energy resource communication infrastructure**

## SunSpec Modbus

SunSpec Modbus is a specific version of the Modbus protocol that is managed by the SunSpec Alliance for communicating between smart inverters and a site controller. Modbus has been adopted almost universally by DER manufacturers, and there is broad support among these manufacturers to adopt the SunSpec point mapping. Modbus does not include application layer cybersecurity, but some utilities are using it over virtual private networks or other secured connections (such as transport layer security protocol) or locally between inverters and network gateways.

SunSpec Modbus is commonly used to connect components of DER (meters, inverters, controllers, and battery management systems) and DER (solar, storage, or generator). The information models include detailed DER internal information (battery information, cell voltage, and so on) and also include higher-level grid controls to allow a site management system, owner, or utility to manage the system as a single DER. Figure C-9 shows SunSpec Modbus communications interfaces.

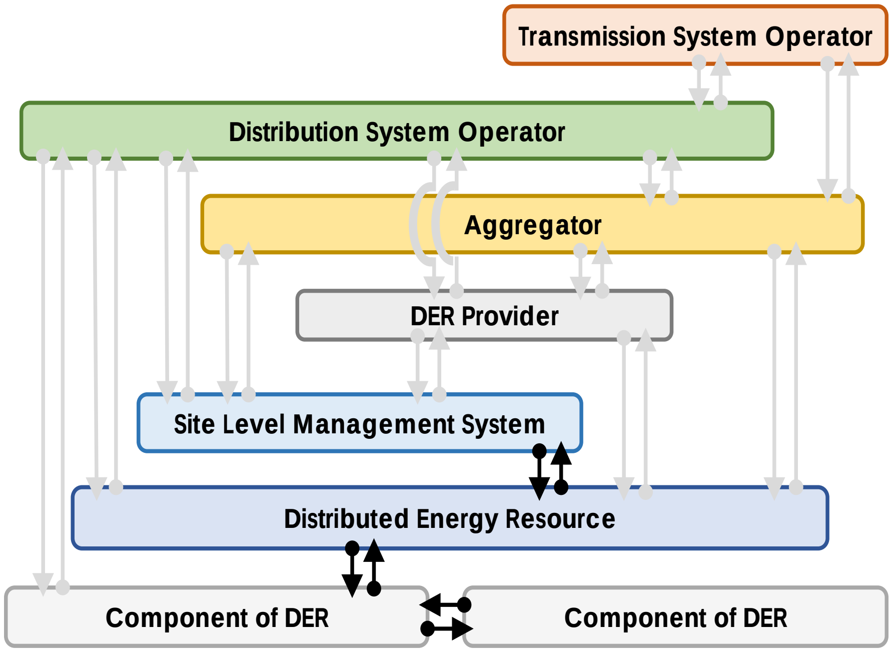


**Figure C-9**
**SunSpec Modbus communications interfaces (black) as part of network operator–distributed energy resource communication infrastructure**

## International Electrotechnical Commission Standard 61850

The IEC 61850 standard contains a number of different information models that can be used for different applications. IEC 61850-7-420 defines the information models to be used for DER. These information models have been influential in all other smart inverter communications protocols.

IEC 61850 uses an abstract communication service layer, which has allowed it to be mapped to other messaging protocols, including both Manufacturing Message Specification (MMS) defined in ISO/IEC 9506 and Distributed Network Protocol (DNP3) defined in IEEE 1815. Furthermore, by replacing the transport layers—Generic Object Oriented Substation Events (GOOSE) or Ethernet—with standard Transmission Control Protocol/Internet Protocol (TCP/IP) protocols, native IEC 61850 messages have become fully routable for use in wide area networks. With these options available, IEC 61850 has moved from the localized substation domain into the realm of SCADA systems and control centers. Figure C-10 shows IEC 61850 communications interfaces.

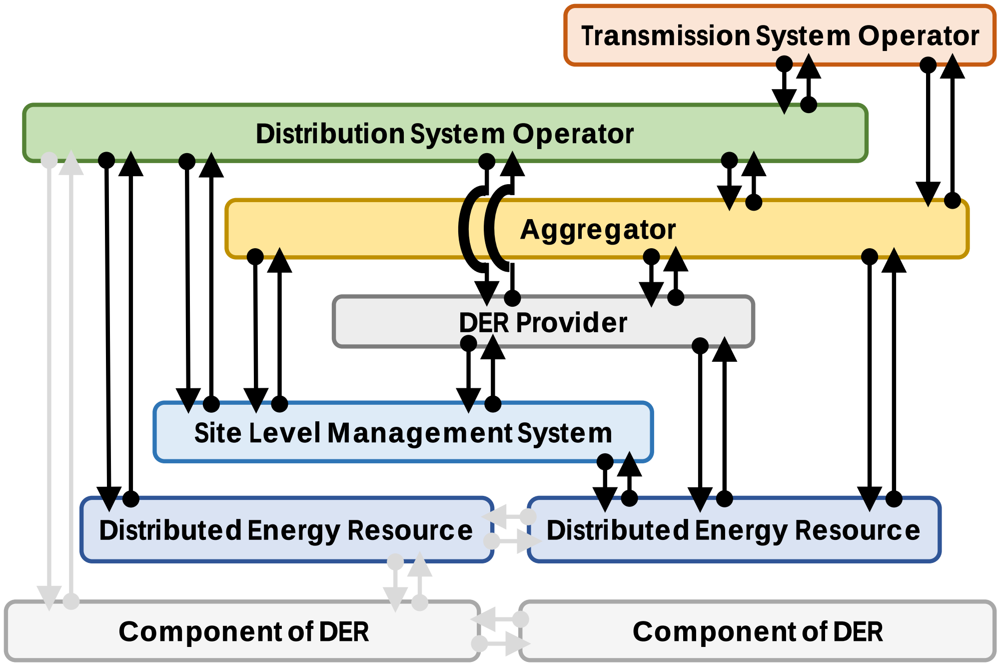


**Figure C-10**
**International Electrotechnical Commission standard 61850 communications interfaces (black) as part of network operator–distributed energy resource communication infrastructure**

### Criteria for Protocol Selection

In an ideal scenario, a utility would have the freedom to select protocols and communication networks freely to match their use case; however, near-term applications often require the use of existing systems and must work around constraints. Therefore, utilities sometimes use protocols that they have already deployed for dispatch of customer or distribution system resources or develop plans to scale their networks. Leveraging existing infrastructure can help work within time or cost constraints. However, as utilities are planning their grid modernization roadmaps, it is important to consider other protocols and implement them as appropriate. When considering a protocol, several criteria often drive decision making. A few of these criteria may change over time, so it is important to consider both current state and estimated future states. The criteria currently include the following:

- **Adoption.** How widely the protocol is used, including the number of products on the market today, including use in products from individual DER to control systems
- **Governance and maintenance.** Who manages the standards and reviews potential changes, the process to update this standard, and information about past, present, or future revisions
- **Devices and technologies.** The types of devices supported by the protocol and the type of functions the protocol supports (direct control or inform and motivate)
- **Implementation.** How the protocol works, its complexity, and general requirements for implementation

- **Test tools and certification.** Test tools and certification processes to help ensure that protocols are implemented properly
- **Cybersecurity.** Security requirements for this protocol and whether security is included in protocol conformance testing
- **Regulatory framework.** Whether the protocol is required or suggested as part of grid codes or other regulations

# D
# ABBREVIATIONS AND ACRONYMS

The following abbreviations and acronyms are used in this report:

| | |
|---|---|
| A/C | air conditioning |
| AEMO | Australian Energy Market Operator |
| AUD | Australian dollars |
| CAISO | California independent system operator |
| CGS+ | Customer Grid-Supply Plus (Hawaiian Electric Company) |
| CHP | combined heat and power |
| ComEd | Commonwealth Edison |
| ConEd | Consolidated Edison Company of New York |
| DER | distributed energy resources |
| DERMS | distributed energy resource management system |
| DERP | distributed energy resource provider |
| DNO | distribution network operator |
| DR | demand response |
| DSO | distribution system operator |
| ERCOT | Electric Reliability Council of Texas |
| ESR | energy storage resource |
| ETPA | Energy Trading Platform Amsterdam |
| FCAS | frequency control ancillary services |
| FERC | Federal Energy Regulatory Commission |
| FRAC-MOO | flexible resource adequacy criteria—must-offer obligation (CAISO) |
| GMP | Green Mountain Power |
| GRE | Great River Energy |
| HECO | Hawaiian Electric Company |
| ICCP | inter-control center protocol |

| | |
|---|---|
| IEC | International Electrotechnical Commission |
| IMSys | intelligent metering system (Germany) |
| ISO/RTO | independent system operator/regional transmission organization |
| LMP | locational marginal prices |
| LSE | load-serving entities |
| MISO | Midcontinent ISO |
| NEM | national energy market |
| NERC | North American Electric Reliability Cooperation |
| NYISO | New York ISO |
| PDR | proxy demand response (CAISO) |
| PJM | Pennsylvania Jersey Maryland (ISO) |
| PMU | phasor measurement units |
| QSE | qualifying scheduling entity |
| RDR | reliability demand response (CAISO) |
| Reg | regulation (reserve) |
| RTU | remote terminal units |
| SCADA | supervisory control and data acquisition |
| SMGw | smart meter gateway (Germany) |
| SoC | state of charge |
| STOR | short-term operating reserve (United Kingdom) |
| TCP/IP | transmission control protocol/Internet protocol |
| TSO | transmission system operator |
| UKPN | United Kingdom Power Networks |
| USD | United States dollars |
| VPP | virtual power plant |

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