TECHNICAL BRIEF

# Procuring Services from Distributed Energy Resources

## Part 1 – Foundational Topics: Grid Services, Coordination Frameworks, Value Stacking Scenarios

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## THE EMERGENCE OF GRID SERVICES PROVIDED BY DISTRIBUTED ENERGY RESOURCES

Distributed energy resources[1] (DER) connected to the distribution system are increasingly being considered for their capabilities to provide *grid services*[2] to the electric utility operating the distribution system, and/or to the wholesale market operator managing the bulk transmission system.[3] In practice, DER voluntarily entering a contract to provide grid services are financially compensated to adjust their power output (active and/or reactive) in response to system needs. DER can provide grid services as standalone assets or via DER aggregators[4] (DERA); they may also consider providing multiple services across the distribution and/or bulk system domains, a strategy known as *value stacking*.

DER-provided grid services have the potential to cost-efficiently defer (or enhance) conventional resources, network reinforcements, or solutions otherwise required to maintain reliable operations. For this reason, electric regulators in several jurisdictions are now encouraging (and sometimes requiring) distribution utilities to fully consider DER-provided *distribution services* as part of their standard planning practices, along with traditional capital investments. In parallel, several recent regulatory initiatives, including the Federal Energy Regulatory Commission’s (FERC) Order No. 2222 in the U.S., require that wholesale market operators allow and enable DER to provide *bulk system services* in the wholesale electricity markets, including energy, capacity, and ancillary services.

1 This paper series intentionally adopts a broad working definition of DER, which includes solar PV, other form of distributed generation, battery storage, demand response, electric vehicles and their supply equipment, and other types of distribution-connected technologies. This approach is consistent with the recent Framework for Energy Innovation (FEI) developed by the Ontario Energy Board (OEB), which states that the definition of DER “is context specific and different definitions may be warranted in different regulatory instruments serving different purposes.”

2 In Europe, the term “flexibility services” is sometimes used to refer to grid services provided by DER.

3 While DER can also provide economic or reliability services to the *customer*, the scope of this paper series is limited to services DER provide to the *grid*.

4 For brevity, throughout this paper series, the acronym “DER” can either refer to an individual DER, or a portfolio of DER managed as a group by a DERA.

The industry has different levels of experience with distribution and bulk system grid services. Jurisdictions where organized wholesale markets exist have had well-defined service products in place to address bulk system grid needs, with established service definitions, performance requirements, participation models, bidding procedures, metering and telemetry requirements, and settlement mechanisms. In contrast, distribution services are less clearly defined, with a limited number of early-adopter utilities already procuring these services from DER as part of their standard planning and operational practices.

EPRI recently explored some of the opportunities and challenges related to DER-provided grid services in the context of the Ontario power system, along with some of the coordination processes required to enable grid service delivery.[5] This technical brief, the first of a series of three companion papers, introduces several foundational topics including the specific grid services considered in this research effort, a range of value stacking scenarios, and two coordination frameworks between grid actors. This document does not intend to make policy or market design recommendations; rather, the goal is to equip stakeholders with a robust understanding of the key concepts necessary to assimilate the results presented in the two subsequent papers.

5 This research effort did not assess the incentives potentially motivating DER to provide grid services, but rather focused on assessing aspects related to technical feasibility and operational coordination, should these incentives exist.

## TERMINOLOGY USED TO REFER TO SERVICE REQUESTING ENTITIES

In the distribution domain, while the term *distribution system operator* (DSO) is often used in ongoing discussions related to grid modernization, the utility industry has not yet converged to a universally accepted definition. To the contrary, "DSO" often has multiple meanings, depending on context and stakeholders. This research does not intend to set a formal definition of DSO. Instead, the term is used broadly to refer to a traditional *distribution utility* (called, in the Ontario context, a *local distribution company* or *LDC*) that has implemented new functional capabilities to manage high levels of DER penetration and enable DER to provide grid services. In the bulk system domain, this paper developed in a North America context uses the terms *independent system operator* (ISO) and *wholesale market operator* interchangeably. In Europe, the term *transmission system operator* (TSO) is also used.

## BULK SYSTEM SERVICES

Historically, bulk system services[6] have been mostly provided by large, transmission-connected power plants to the bulk system balancing area authority through a range of market products, arrangements, and/or standards. In areas where organized markets exist, service products are purchased by the ISO and sold by different wholesale market participants. In Ontario, the Independent Electricity System Operator (IESO) is the ISO operating the bulk system and administering the wholesale electricity markets.

Under current market rules, wholesale market participants in Ontario are classified into two main categories: *dispatchable* and *non-dispatchable*. Dispatchable market participants bid into IESO's wholesale markets and receive dispatch instructions every five minutes to reach a specified level of generation or consumption. Examples of dispatchable participants include generators, storage, or large industrial loads. Non-dispatchable market participants[7] are price takers; they produce or consume power in real-time and get paid (or are charged) at the hourly energy price. Today, most of the loads in Ontario are non-dispatchable while most of the generators are dispatchable. Further, the resources from the five neighboring zones interconnected with Ontario can also import or export power as market participants.

This technical brief focuses on three bulk system services, each having corresponding auctions in which they are procured: *energy*, *operating reserves*, and *capacity*.[8] Regulators are envisioning that DER may increasingly participate and compete with traditional, transmission-connected resources to provide these services.[9] The rest of this section further describes these services in the context of Ontario,

6 For simplicity, this paper series uses the terms bulk system services and wholesale market services interchangeably since organized wholesale markets exist in Ontario. We acknowledge that in general, these two terms are not necessarily synonyms.

7 These participants are *currently* non-dispatchable, and their demand is forecasted by IESO. However, in the future, they *could* become dispatchable through some of the service products examined in this paper.

8 *Energy* is provided at specific locations (for specific time intervals); by contrast, *operating reserves* and *capacity* can generally be provided anywhere on the system (with the possible exception of import constrained areas).

9 Other bulk system services not considered in this research effort, for example frequency regulation, could also be provided by distribution-connected DER.

as well as the wholesale market auctions used to procure those services when relevant.

## Energy (At Time and Location)

Energy is the core service provided to consumers, and is traditionally provided as a product from suppliers that is delivered across the transmission to distribution system to end-use consumers. Following MRP implementation, IESO will operate both a day-ahead energy market (DAM) and real-time energy market (RTM) for buyers and sellers to transact energy across the grid. Based on the supply and demand bids (for specific locations and time intervals) received from the market participants, IESO will determine the least-cost solution of all suppliers to deliver energy to where it is consumed subject to the constraints of the transmission system and other physical constraints.

The DAM will be cleared for every hour of the following day whereas the RTM is cleared every five minutes. In addition, energy prices for both RTM and DAM will be calculated for different locations across the grid including individual generator locations and substations. By pricing energy for each time point and location, it is said to be converting energy into a commodity that is fungible (a consumer is indifferent to where it came from and who has provided it). The service of providing energy is also thus the service of providing it at the most valuable locations and times.

### ONTARIO'S MARKET RENEWAL PROGRAM

The Market Renewal Program[10] (MRP) is an initiative conducted by IESO to modernize Ontario's electricity markets. The MRP has been designed and is currently being implemented with an anticipated go-live date of 2025. In particular, the MRP will include a change to energy pricing with the use of locational marginal prices (i.e., single schedule prices), a day-ahead market (DAM), and an enhanced real-time unit commitment, among other features. These changes may have an impact on how these services are procured, but not a significant impact on the services themselves. In general, this paper emphasizes post-MRP features, but may call out existing features when useful for the reader.

10 Additional information can be found at: https://www.ieso.ca/en/Market-Renewal.

Energy providers can help manage transmission congestion by providing more energy in locations on the receiving end of congested transmission paths and providing less energy at the sending end of these paths. Providers can also support the balancing of energy by providing more or less energy during the times when there is greater or lesser need, respectively, as reflected in market prices. This ability to adjust energy up and down based on the needs at location and times enables these resources to also provide flexibility that can allow for the system to better accommodate changes in conditions from time to time and location to location.

## Operating Reserve

Operating reserves are procured to balance supply and demand in the event of a contingency, such as a generator or transmission line outage. In Ontario, three types of operating reserves are procured by IESO through the operating reserve market:

- 10-minute synchronized reserve (also called: 10-minute spinning reserve)
- 10-minute non-synchronized reserve (also called: 10-minute non-spinning reserve)
- 30- minute non-synchronized reserve

Reserve allows for the system to reduce the balancing error of the IESO system and the potential resulting frequency error of the Eastern Interconnection. When the contingency occurs, either all or a subset of the reserve providers are asked to respond by increasing power (or decreasing consumption if a demand-side technology). Synchronized reserve service must be provided by resources that are online and operating and can provide the allocated quantity of reserve within the timeframe specified by the product definition (e.g., 10 minutes). Non-synchronized reserve can be provided by either online resources or offline resources that can be switched online within the timeframe specified by the product (e.g., 10 or 30 minutes).

The reserve markets are cleared simultaneously with energy in the RTM. The resources are paid per MW-h for the capacity they allocate to that reserve. Further, if called to deploy, the resources are paid for the energy they deliver. Under current market rules, each offer to provide operating reserve must be accompanied by a corresponding energy offer that covers the same MW range. Further, participants cleared for providing reserve are expected to respond for energy dispatch if called. A lack of response, or a partial response, may lead to penalties.

## Capacity

Capacity is the total capability of a resource to deliver and make itself available to the IESO for critical time periods. Sufficient amount of capacity is necessary to meet resource adequacy criteria, such as less than one day of involuntary load shedding over a 10-year time span. Capacity as a service is independent of how often it is used.

In Ontario, a capacity auction is run annually in December (of Year X) for a commitment period of one year starting May 1st (of Year X+1) to April 30th (of Year X+2). This one-year commitment period is further divided into two six-month obligation periods: Summer (May to October) and Winter (November to April). Capacity accreditation and capacity needs may be different for those two periods.

All participants cleared in the capacity market are expected to meet their capacity obligations by participating in the energy market. To that end, participants cleared in the capacity market are required to submit market bids and offers for all hours of the "availability window" in the DAM and RTM. The availability window is 12:00 to 21:00 EST for the Summer period, and 16:00 to 21:00 EST, for the Winter period.

# WHOLESALE MARKET OPERATION TIMELINES

Market operation timelines are an important factor to consider when assessing the participation of distribution-connected DER in IESO's markets, and the potential compatibility with a simultaneous participation in distribution service products managed by the distribution utility.

## Day-Ahead Market (DAM)

IESO currently uses a day-ahead commitment process (DACP) which provides a dependable view of the next day's available supply and anticipated demand across Ontario. The DACP is very similar to the DAM in other jurisdictions, except that DACP schedules and prices are not financially binding. Post-MRP implementation, the DAM will replace the DACP and day-ahead schedules will become financially binding. Figure 1 illustrates the applicable timeline for day-ahead operations; this timeline is applicable to the future DAM (post-MRP), which is similar to the existing DACP (pre-MRP).

Dispatchable generators or loads interested in submitting day-ahead offers must send their operational data to IESO by 10:00 AM on the prior day of dispatch. Offers include data on hours of availability, amount of energy when relevant, and capacity limits. Once day-ahead offers are received, the DAM calculation engine is used to determine DAM schedules, which optimally manage resources by committing them on or off for the next 24-hour period in the unit commitment process. The final schedule is posted by 13:30.

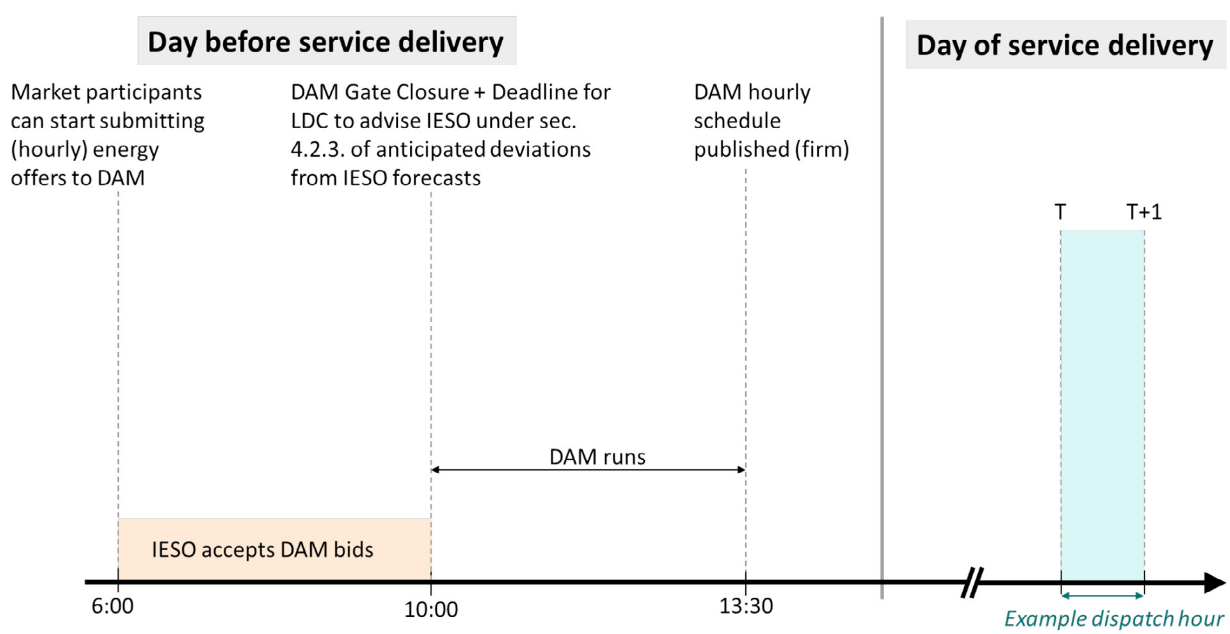


*Figure 1. Timeline for future day-ahead market*

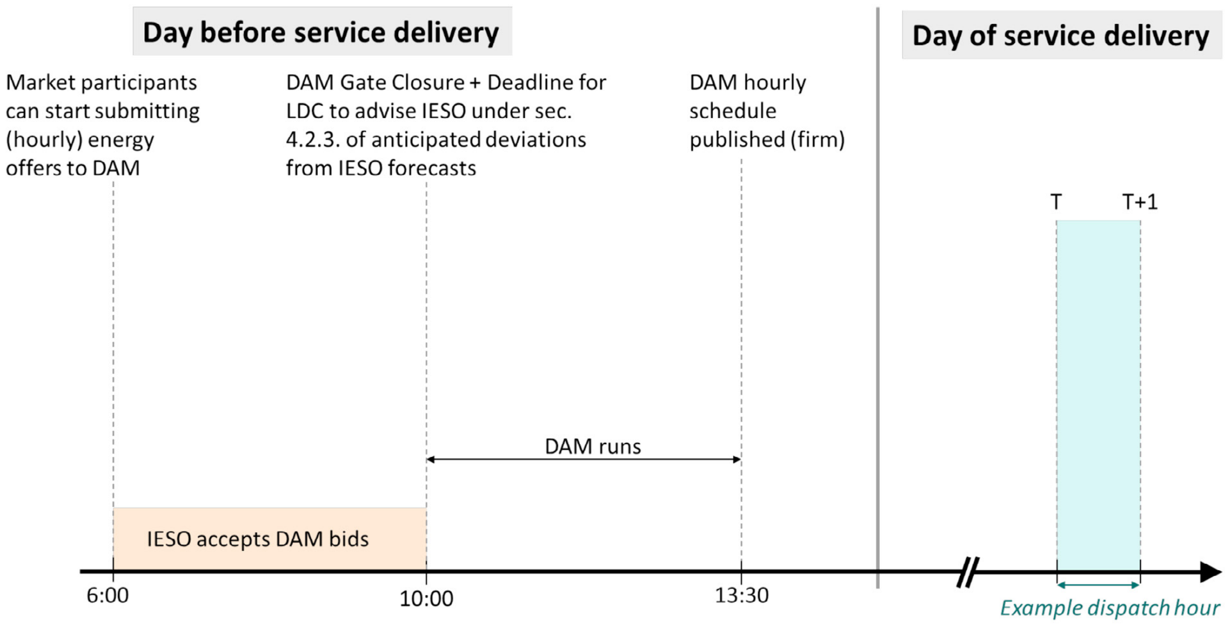


***Figure 2.*** *Timeline for real-time market*

## Pre-Dispatch (PD) and Real-Time Market (RTM)

In the real-time timeframe, schedules reflect the optimization of actual generation, reserve allocation and physical demand within the RTM. IESO issues dispatch instructions to the participants according to the real-time schedules. IESO runs market clearing software every five minutes to determine prices, and schedules for each five-minute interval. In Figure 2, the RTM Gate Closure (where offers must be submitted prior to) corresponds to IESO's "Mandatory Window", which is the time interval starting two hours before the dispatch hour, up until ten minutes before dispatch. Prior to the five-minute RTM, pre-dispatch schedules are provided to resources as advisory results.

## DISTRIBUTION SERVICES

Distribution services provided by DER to distribution utilities are less clearly defined than bulk system services, with a limited number of early-adopter utilities worldwide already procuring these services as part of their standard planning and operational practices. In Ontario, and similar to most jurisdictions, distribution utilities are in the process of developing distribution service products, building on the foundations of IESO's well-established bulk system service products described above.

### DISTRIBUTION SERVICES VS. NON-WIRES ALTERNATIVES

The concepts of *distribution services* and *non-wires alternatives* (NWA) are closely related. NWAs are utility-driven solutions that defer or eliminate the need for conventional system upgrades to address network constraints. Such need may arise from a range of factors, including load growth and increased DER penetration. The technical requirements for DER-based NWAs can be decomposed and packaged into one or several distribution services, such as the ones introduced in this section, based on the specific system needs identified by the distribution utility.

## Capacity Deferral and Local Reserve

Distribution utilities experimenting with DER-provided distribution services tend to develop a suite of distribution service products. Each product is typically designed to address distribution constraints occurring in *specific* system conditions. Certain products are designed to help address distribution needs arising in normal (i.e., "ordinary") system conditions; other products are intended to be activated less frequently, to address needs occurring in abnormal (i.e., "altrnate" or "emergency") system conditions.

Thus, two broad categories of distribution conditions can be recognized. First, *planned conditions*,[11] which comprise normal conditions (including nominal and peaking conditions) and planned alternate conditions (e.g., resulting from construction work). And second, *unplanned conditions*,[12] triggered by a contingency event, and which may require real-time corrective response (as opposed to pro-active or preventative changes).

For this paper series, two distribution service products are defined, termed *capacity deferral* and *local reserve*:[13]

- *Capacity deferral* is a distribution service intended to be activated by the distribution utility to address distribution constraints arising in planned system conditions.
- *Local reserve* is a distribution service intended to be activated by the distribution utility to address distribution constraints arising in unplanned system conditions. Such conditions may result from a range of contingency events, including distribution equipment failures, or from service providers contracted to provide capacity deferral that fail to meet their obligations.

While this research effort was limited to the two distribution service products defined above, other distribution services can be defined.

## Distribution Services: With or Without Capacity Reservation?

Most of the early-adopter distribution utilities have been experimenting with at least one service product similar to the *capacity deferral* product defined above. These early adopters typically combine capacity (MW) and energy (MWh) requirements into the same service product. Further, DER providing this service are paid to "book" the appropriate capacity and energy required, regardless of whether the service ends up being activated. For this reason, this first family of distribution service products, to be used in planned conditions, is sometimes said to be "with capacity reservation."

11 The term *planned* refers to a system need, condition, or state which is *known* (or *forecasted*) in advance of its occurrence. For example, a planned DER outage, or a planned alternate network configuration.

12 The term *unplanned* refers to a system need, condition, or state which is not expected, emerges in real time, and typically triggers a corrective response by one or multiple stakeholders.

13 The terms *capacity deferral* and local reserve are naming conventions which can be changed without affecting the validity of the content presented in this paper series.

By contrast, many early adopters also experimenting with service products similar to the *local reserve* product defined above do not require DER to reserve any capacity or energy: when a contingency occurs, DER may *choose* to respond to a service activation request. For this reason, this second family of service products, to be used in unplanned conditions, is sometimes said to be "without capacity reservation". Naturally, a distribution utility could also choose to offer a local reserve product with capacity reservation.

The notion of capacity (and energy) reservation described above is an important consideration when specifying distribution service products. However, the content presented in this paper series is largely agnostic of that design feature.

# VALUE STACKING SCENARIOS: PROVIDING MULTIPLE GRID SERVICES

## Scenarios Considered

Value stacking scenarios refer to combinations of grid services DER can provide to the distribution utility and/or wholesale market operator. The term value stacking is used to reflect that a given DER intends to "stack" revenues from multiple grid services. This research effort explored seven different scenarios, numbered 1, 2, 3a, 3b, 4a, 4b, and 5 (see Table 1).[14] The two subsequent briefs in this paper series further discuss coordination needs and simulation results in the context of these scenarios.

*Scenario 1* investigates the participation of distribution-connected DER in the wholesale energy market. Distribution congestion is not considered for this first scenario.

*Scenario 2* also investigates the participation of DER in the wholesale energy market, but this time including consideration for potential distribution congestion.

*Scenario 3a* focuses on DER providing distribution capacity to defer conventional distribution upgrades, while Scenario 3b investigates a value stacking case where DER also pursue participation in the wholesale energy market.

*Scenarios 4a* and *4b* investigate DER-provided operating reserves during contingencies. Scenario 4a focuses on distribution applications like unplanned distribution outages. Scenario 4b considers a combined service offering of DER

14 Other combinations of services, beyond the seven scenarios considered in this research effort, may also be possible.

***Table 1.*** *Scenarios considered for DER-provided services*

| SCENARIOS | WHOLESALE DOMAIN: ENERGY | WHOLESALE DOMAIN: CAPACITY | DISTRIBUTION DOMAIN: RESERVE | DISTRIBUTION DOMAIN: CAPACITY DEFERRAL | DISTRIBUTION DOMAIN: LOCAL RESERVE | VALUE STACKING |
|---|---|---|---|---|---|---|
| 1 | ● | | | | | |
| 2 | ● | | | | | |
| 3a | | | | ● | | |
| 3b | ● | | | ● | | ♦ |
| 4a | | | | | ● | |
| 4b | ○ | | ● | | ● | ♦ |
| 5 | ○ | ● | | ● | | ♦ |

**Table Notes:**

- ● Indicates the primary service(s) considered
- ○ Indicates a service implicitly required by participation in a primary service
- ♦ Indicates scenarios considering value stacking strategies.

providing both distribution and wholesale operating reserve[15] for bulk system applications, such as the loss of a large generator. Implicitly, *Scenario 4b* assumes that a resource providing wholesale operating reserve may be called to dispatch that reserve; when that's the case, the resource is effectively providing a wholesale energy service.

*Scenario 5* is an extension of Scenario 3a, where DER providing distribution capacity also pursue capacity products in the wholesale market as part of a value stacking strategy. Implicitly, Scenario 5 assumes that a resource providing wholesale capacity will submit wholesale energy offers, as required by the terms of the wholesale capacity product.[16]

## Notion of "Priority" When Delivering Multiple Services

System operators expect DER to deliver on their service commitments, whether they provide distribution services, wholesale services, or a combination of both. For distribution utilities, the reliability of DER service commitments is essential considering that the pool of alternative service providers is structurally smaller compared to what is available at the wholesale market level. In the context of the bulk system, DER service commitments are critical for ensuring resource adequacy and maintaining the overall reliability of the system. As a result, system operators may seek to design participation rules that focus on/cater to a singular service or entity, and do not contemplate service providers pursuing value stacking strategies. Alternatively, when value stacking is permitted, participation rules should discourage service providers from *knowingly* or *willingly* defaulting on service commitments with one system operator to provide services to another operator as part of profit maximization strategies.

Accordingly, when a given DER commits to provide multiple grid services, this paper assumes that the "priority order" for delivering these services reflects the associated commitment sequence: DER should ensure *before* committing to provide an additional service N+1 that the associated performance requirements are compatible with any services 1 through N already committed.[17] Verification could be left to the service providers themselves; for this first approach to be viable, providers should be sufficiently informed and trained, and the potential loss in revenues and/or financial penalties in case of underperformance should provide sufficient "deterrence." Another approach could also involve other parties, for example, the service requesting entities themselves. In any case, new tools may be required to facilitate the compatibility verification process.

15 While this paper references "the" wholesale reserve product for Scenario 4-b, it is assumed that DER participates in one or several of the wholesale reserve products previously introduced.

16 This assumption reflects the way IESO's capacity market operates today.

17 Accordingly, the term "priority order" as used in this paper does not intend to position the importance of one service domain (i.e., distribution, wholesale) over the other. Further, the term "priority order" does not suggest that DER should at times find themselves unable to meet the demands of both service requesting entities, and one entity would somehow get "priority" over the other in terms of using the resource.

For the scenarios introduced in Table 1, Scenarios 1 and 2 involve bulk system services only. By design, delivering services to a *single* system operator prevents providers from over-committing (and thus, potentially failing) to deliver services to multiple operators. Similarly, Scenarios 3a and 4a involve distribution services *only*, avoiding that same issue by design.[18]

By contrast, Scenarios 3b and 4b evaluate DER providing both distribution and *bulk* system services. These scenarios assume a commitment sequence where DER *first* commit to providing a distribution service, and *then* may commit to a wholesale service in a way that is compatible (from a performance requirements standpoint) with their prior distribution service commitments.[19]

Finally, Scenario 5 presents similarities with Scenario 3b, but a different priority order is assumed. In Scenario 5, the commitment to provide wholesale capacity is assumed to come first, since the capacity market clears several months in advance. Participation in this wholesale product creates a requirement to participate in wholesale electricity markets, as described earlier. Therefore, it is assumed that DER in Scenario 5 effectively commit first to reserve capacity (in order to submit energy offers), and then may commit to provide a distribution service (specifically, *capacity deferral* is considered in Scenario 5) in a way in that is compatible with their prior wholesale market commitments.[20]

## TWO COORDINATION FRAMEWORKS BETWEEN DSO, ISO AND DER

Grid services provided by DER require new forms of coordination between the DSO, ISO and DER to enable successful service delivery while maintaining system reliability. One coordination aspect relates to whether DER intending to provide wholesale market services can submit service offers *directly to the ISO*, or must submit their offers *through the DSO*. In the latter case, the DSO could take a range of roles and responsibilities:

- At minimum, the DSO would have the capacity to check the technical feasibility of all offers prior to submittal to the ISO. Further, the DSO could seek to actively optimize the distribution grid configuration to maximize wholesale market participation opportunities for DER, based on the offers received.
- Another aspect relates to the way the DSO would "package" the DER offers before passing them to the ISO. For example, the DSO could simply pass the individual DER offers "as is" to the ISO, provided that they are technically feasible; alternatively, the DSO could first aggregate all feasible offers received into a single aggregated offer, and then pass that consolidated set of price/quantity pairs to the ISO.
- The role played by the DSO with respect to the wholesale market also merits consideration. For example, the DSO could act as a neutral agent, simply vetting DER offers on technical terms before passing them to the ISO; in this first approach, all DER whose offers are passed to the ISO would be considered as market participants and held individually responsible in case of under-performance. Alternatively, the DSO could act as DER aggregator participating in the wholesale market; this second approach would require contractual agreements between the DSO and individual DER, such that while the DSO would be responsible to the ISO in case of under-performance, the DER would in turn be responsible to the DSO.

Among the range of possible coordination frameworks, this paper series focuses on two examples of coordination framework models, termed *Total DSO* and *Dual Participation* and illustrated in Figure 3. This focus should not be construed as a policy or market design recommendation, but rather as an attempt to explore the implications of two particular examples of coordination models.

18 It is understood that distribution services can still have some indirect impact on wholesale energy market conditions, even if a DER is not actively participating in the wholesale market.

19 Scenarios 3b and 4b assume that DER commit to distribution services first, before committing any remaining capacity available to wholesale services. This working assumption is not prescriptive, and DER could conceivably commit to wholesale services first, before considering participation in distribution services with any remaining capacity available.

20 Similarly to Scenarios 3b and 4b, the commitment sequence assumed in Scenario 5 is a working assumption and is not prescriptive. DER could conceivably commit to distribution services first, before considering participation in wholesale capacity services with any remaining capacity available.

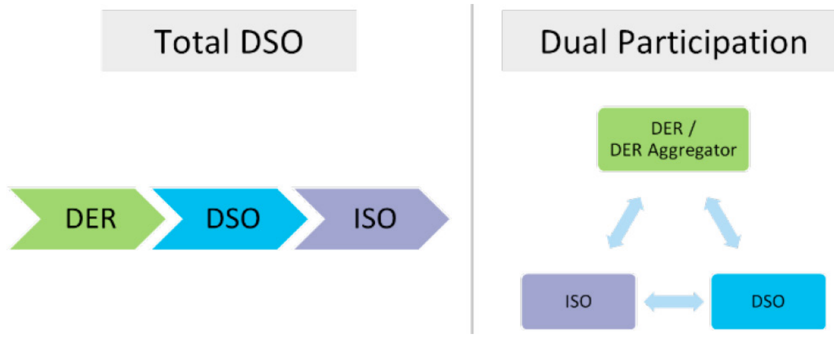


***Figure 3.*** *Total DSO vs. dual participation frameworks*

This paper series defines the *Total DSO* and *Dual Participation* frameworks as follows:

- Under the *Total DSO* framework,[21] DER seeking to participate in the wholesale electricity markets cannot submit their offers directly to the ISO. Instead, DER must submit wholesale offers to the DSO, which aggregates all offers received and submits a consolidated set of price/quantity pairs to the ISO.[22] Additionally, DER seeking to provide distribution services submit these offers to the DSO.

21 This framework was previously introduced in: L. Kristov, P. De Martini and J. D. Taft, "A Tale of Two Visions: Designing a Decentralized Transactive Electric System," in *IEEE Power and Energy Magazine*, Vol. 14, No. 3, pp. 63–69, May–June 2016, doi: 10.1109/MPE.2016.2524964.

22 For the rest of this paper series, no assumptions are made on whether the DSO would act as a neutral bid-vetting operator, or as a DER aggregator acting as wholesale market participant, as the coordination implications considered in this work are largely independent of that aspect.

## ENERGY SETTLEMENT PROCESS: WORKING ASSUMPTIONS FOR THE COORDINATION FRAMEWORKS CONSIDERED

Regardless of the coordination model considered, DER must be settled for the energy they exchange with the grid, whether this energy is exchanged while performing grid services or otherwise. This paper series makes the working assumptions that DER providing grid services are settled for energy by the ISO under the Dual Participation model, and by the DSO under the Total DSO model.

However, other constructs are possible. Notably, under the Total DSO framework, if the DSO was to act as a neutral agent (simply vetting DER offers on technical terms before passing them to the ISO), DER could conceivably be settled for energy directly by the ISO.

- Under the *Dual Participation* coordination framework, DER seeking to participate in the wholesale electricity markets may submit their offers directly to the ISO, while staying within the limits established by the DSO as part of the DER interconnection agreement or otherwise. Separately, DER seeking to provide distribution services submit these offers to the DSO, and they may be required to further notify the ISO.

The second brief in this three-paper series will further examine coordination needs between the DSO, ISO and DER in the context of the two frameworks above.

## KEY TAKEAWAYS

This technical brief, the first of a series of three companion papers, introduces several foundational concepts. This document does not intend to make policy or market design recommendations; rather, the goal is to inform grid stakeholders in Ontario (and beyond) tasked with assessing the potential development of DER-provided grid services.

First, services in two grid domains are introduced. At the bulk system level, this includes t***hree wholesale services*** currently offered by IESO: ***energy***, ***reserve***, and ***capacity***. At the distribution level, distribution utilities in Ontario are still in the process of developing distribution service products. For the purpose of this research effort, ***two distribution services*** were defined: ***capacity deferral***, designed to address distribution constraints arising in planned system conditions, and ***local reserve***, designed to address distribution constraints arising in in unplanned system conditions.

Second, ***seven value stacking scenarios*** are defined, describing combinations of grid services DER can provide to the distribution utility and/or wholesale market operator. The two subsequent briefs in this paper series further discuss coordination needs and simulation results in the context of these scenarios. The concept of priority order based on the service commitment sequence can be used to ensure that DER do not willingly "over-commit" themselves, which could potentially lead them to fail to deliver on part or all of their service commitments.

Finally, ***two coordination frameworks*** are considered, reflecting two examples of coordination approaches between the DSO, ISO and DER with respect to DER participation in wholesale electricity markets. Under the ***Total DSO*** framework, DER seeking to provide wholesale service must submit their wholesale offers through the DSO. By contrast, under the ***Dual Participation*** framework, DER can submit wholesale offers directly to the ISO, while staying within the limits established by the DSO as part of the DER interconnection agreement or otherwise.

The two subsequent briefs in this paper series apply the concepts introduced in this first paper to explore the opportunities and challenges related to DER-provided grid services in the context of the Ontario power system.

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**EPRI CONTACTS**

**STEPHEN KERR**, *Technical Leader II*
650.855.8503, skerr@epri.com

**TANGUY HUBERT**, *Technical Leader IV*
650.855.8790, thubert@epri.com

**ERIK ELA**, *Program Manager*
720.239.3714, eela@epri.com

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3420 Hillview Avenue, Palo Alto, California 94304-1338 USA • 650.855.2121 • www.epri.com