Innovation and Sector Evolution White Paper Series

Non-Wires Alternatives Using Energy and Capacity Markets

MAY 2020

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Executive Summary

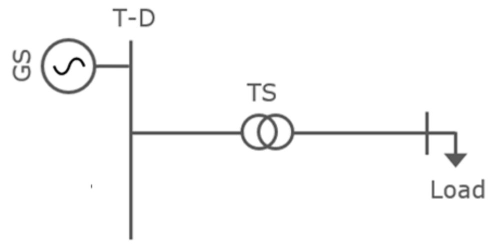
The cost and capabilities of distributed energy resources (DERs) are improving, making it more technically feasible and economically attractive to procure electricity services from them. One key emerging opportunity is the deployment of DERs as non-wires alternatives (NWAs) to traditional transmission and distribution network infrastructure, especially as identified in integrated planning processes.

DERs can provide value at both the distribution and transmission levels. Wholesale markets can compensate these resources for transmission-level services, such as capacity, energy and ancillary services, especially as DERs' access to these markets is improved with new and enhanced participation models. DERs can be deployed in a locationally targeted manner, sited close to load and used as NWAs to provide local energy and capacity services. This paper explores how the standard capacity and energy market constructs used at the transmission level in restructured jurisdictions could be used to secure services from DERs. Specifically, this paper investigates the "use case" where dispatchable DERs are employed as NWAs to distribution network infrastructure in order to help illustrate potential coordination process steps and market transactions.

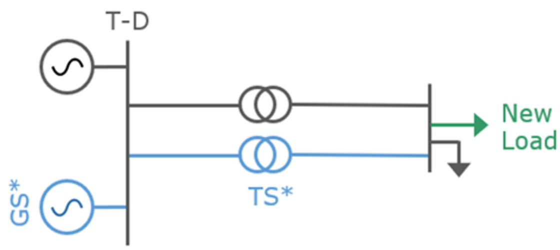
To fully enable DERs to provide services, the distribution network needs to be modelled to some degree to ensure that the dispatch of DERs does not violate any limits. In concept, an independent system operator (ISO) could extend existing transmission-level market and system operations to the distribution level and optimally dispatch many small, dispersed DERs along with transmission-connected resources. However, managing the electricity system at significantly greater granularity than today may be computationally challenging for an ISO, given current optimization techniques and technology. One approach to address this challenge in a high-DER environment could be establishing distribution system operators (DSOs) to partition the management of the full electricity system and to provide a simplified representation of the distribution system to a transmission system operator (TSO).

In an environment with DSOs and a TSO, rigorous market and system operation coordination processes would be required to ensure operational reliability, resource adequacy and economically efficient market outcomes. A lack of effective coordination could, for example, lead to conflicting instructions to DERs or unanticipated power flows, which at higher DER penetrations could result in increased costs or even reliability risks. Coordination between distribution- and transmission-level services will be necessary to take advantage of the full value that DERs could provide, while avoiding duplicative or inappropriate compensation. This paper examines how payments from distribution-level energy and capacity markets facilitated by DSOs could be combined or "stacked" with payments from transmission-level energy and capacity markets.

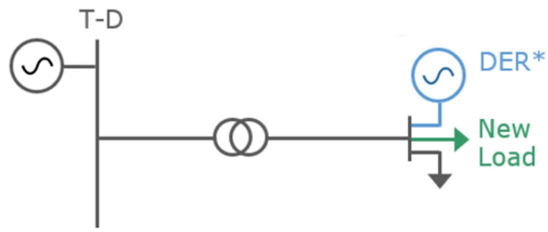
In wholesale capacity markets, capacity zones typically represent an area of the grid bounded by transmission limitations. To ensure that each capacity zone meets its resource adequacy needs, zones have specific requirements for the minimum and maximum amount of resource capacity secured in the market. In other words, the addition of resource capacity may be restricted or required in a capacity zone. Additionally, capacity markets generate specific prices for zones, which can signal market participants to focus their efforts in high-priced, high-value capacity zones. The concepts of capacity zones and zonal capacity prices can be applied at the distribution level to support NWAs to distribution system infrastructure and can inform how capacity payments at the distribution and transmission levels could be stacked.



1a. Existing generating station (GS), transformer station (TS), load



1b. Growth met with new TS and new GS



1c. Growth met with DERs

Figure 1: Demand growth can be met with traditional infrastructure or DERs

Figure 1 illustrates a scenario faced by planners when forecasted load growth in an existing area (1a) can be addressed through investment in either (1b) network infrastructure and centralized, transmission-connected resources or (1c) DERs. In the investment time frame, DERs that are technically able to provide capacity service and can be relied upon to meet this need can be used as an alternative to *both* the network infrastructure and the transmission-connected resource – reasoning that suggests that DERs could stack the two value components. To enable DERs to provide capacity value in this manner, a distribution-level capacity zone could be defined to indicate that the zone will require a certain DER capacity to meet resource adequacy needs and that a specific zonal capacity price will be established. As further detailed in section 4 of this paper, depending on the TSO-DSO model considered, DERs would either receive compensation for their full capacity value from the DSO or they would receive compensation for their distribution-level capacity value from the DSO and their transmission-level capacity value from the TSO.

In the operational time frame, if DERs are used as NWAs to distribution network infrastructure, there will be instances when the loading in the capacity zone will exceed the limits of the network unless DERs are operated and net loading in the zone is reduced. The need can be met with passive DERs, such as solar photovoltaics, if they are technically capable of providing the capacity service (i.e., if their output aligns with the need, taking intermittency into account). The need can also be met with active or dispatchable DERs, such as battery storage and demand response, provided they are actively managed by the DSO and dispatched when the need is expected. In North American wholesale markets, resources are paid the locational marginal price (LMP) of energy when dispatched. LMP reflects the marginal cost of energy at different locations on the grid, considering the cost of producing the energy, the impact of losses and transmission network congestion. Similarly, DERs dispatched for distribution-level needs can be compensated at the distribution locational marginal price (DLMP). As further detailed in section 5 of this paper, depending on the TSO-DSO model considered, DERs would either receive compensation for their full energy value from the DSO or they would receive compensation for their distribution-level energy value from the DSO and their transmission-level energy value from the TSO.

If capacity and energy markets are used to secure and operate DERs used as NWAs, there would be no need to define a service specifically for using NWAs. As described in further detail in this paper, capacity and energy services are sufficient to drive the investment and operation needed to use DERs as NWAs. Using energy and capacity markets in this manner contrasts with an approach where utility-owned DERs are supported by regulated payments, as well as market payments. The approach discussed in this paper illustrates how transmission- and distribution-level energy and capacity markets can enable independent developers and customer-owned DERs to provide services as NWAs and to the system more broadly.

In addition to outlining relevant concepts and illustrating potential energy and capacity market coordination processes, the paper also touches on other considerations, such as market power, reserve requirements and cost allocation. Some areas for potential future investigation are noted as well. Finally, while using DERs as NWAs is still a novel and emerging concept, incremental steps can be taken to advance concepts, gain experience and mature mechanisms.

1. Introduction

1.1 Motivation and Objective

A major trend in the power and utilities industry in recent years is the significant cost decline, capability improvement and adoption of DERs, such as solar photovoltaics, energy storage and demand response. In parallel, innovations in information and communication technologies (ICT) are making it possible to have greater visibility and control of the distribution system and DERs, similar to the visibility and control present at the transmission level. Together these two evolutionary drivers are making it more technically feasible and economically attractive to take advantage of many small, dispersed DERs to procure electricity services and more actively manage the distribution system to provide value both locally and to the broader system.

The ability to provide value at both the distribution and transmission levels of the system gives DERs a natural advantage over centralized, transmission-connected resources that are unable to provide distribution-level value as NWAs. In many restructured jurisdictions[1] with wholesale markets, DERs above a certain capacity size threshold can participate directly in the wholesale market and smaller DERs can often participate as part of an aggregation. Wholesale markets can compensate DERs for the value of transmission-level capacity, energy and ancillary services, especially as DER access to these markets is improved with enhanced participation models. DERs (particularly demand response aggregations) have had some success in North American wholesale markets; however, when competing to provide only transmission-level value, DERs are generally up against larger, transmission-connected, centralized resources that benefit from economies of scale. That said, the potential economic attractiveness of DERs resides in their unique and defining characteristic – they are modular and can be deployed in a locationally targeted manner and sited close to load. In particular, using DERs as NWAs to provide energy when local demand peaks can help decrease net loading on the existing distribution network infrastructure and may help avoid or defer the need for new or upgraded transformer stations and lines. From a system cost perspective, when new DERs can be used as an alternative to both new centralized resource and distribution network capacity, the local benefits they provide may outweigh the economies of scale that have traditionally given centralized resources a competitive edge.

Today, many jurisdictions are exploring the use of NWAs. In New York, the Brooklyn/Queens Demand Management program is a major NWA initiative [1], and in Ontario, NWA initiatives include Toronto Hydro's Cecil TS Local DR Pilot [2] and the IESO York Region NWA Demonstration project. Navigant Research, an energy market research and advisory firm, estimates that NWA expenditures in 2017 were $63 million and forecasts that this spending will grow to $580 million annually by 2026, with North America representing about half of this amount [3]. As the use of DERs as NWAs becomes an increasingly attractive proposition, planning methodologies, electricity service definitions and market mechanisms may need to be further refined to allow DERs to compete on a level playing field with traditional generation and network infrastructure.

[1] Restructured jurisdictions are those that have re-organized from vertically integrated monopoly utilities to a structure that allows greater competition, including among independent power producers that compete to serve load.

This paper has two major objectives. First, it aims to describe the economic potential of NWAs and explore the appropriate payments and incentives needed from market mechanisms. Second, it investigates potential energy and capacity market processes that coordinate DERs, distribution system operators (DSOs), and the transmission system operator (TSO), with a focus on operational reliability and resource adequacy, as well as how services and payments can be combined (or "stacked"). DERs employed as NWAs to distribution network infrastructure will be the central use case throughout this analysis to help identify coordination process steps and detail market transactions among the parties.

Toronto Hydro's Local DR Program

In 2015, the IESO's Grid Innovation Fund (formerly the Conservation Fund) provided support to Toronto Hydro to evaluate the potential for localized demand response (DR) in place of distribution system infrastructure investments in constrained areas [4]. Toronto Hydro subsequently received approval from the Ontario Energy Board to undertake a $4.1 million local DR program [5] to provide load relief in the Cecil Transformer Station service territory, where peak load is expected to approach the transformer's capacity limit in the medium term. Leveraging primarily new and existing DR resources to reduce approximately 9.5 MVA of peak demand over the course of the investment, Toronto Hydro is expected to be able to extend the planning and implementation timelines associated with future system upgrade projects.

ConEd's BQDM Program

In 2014, the Consolidated Edison Company of New York (ConEd) received approval from the New York Public Service Commission to undertake the Brooklyn/Queens Demand Management (BQDM) program [6]. The program is designed to address a forecasted overload condition of the sub-transmission feeders serving their Brownsville No. 1 and 2 substations. With a $200 million operating budget, the program sought load relief using 17 MW of demand reduction from traditional utility-side solutions and 52 MW from non-traditional customer- and utility-side solutions by the summer of 2018. The portfolio of solutions that ConEd has developed for the BQDM includes demand response secured through an auction process. The BQDM has since been extended [6] and ConEd and other utilities in New York State are pursuing a series of non-wires solution projects [7].

1.2 Scope and Approach

To provide more in-depth analysis, the scope of this paper focuses primarily on energy and capacity services from DERs, which represent a significant portion of the value that they offer. Other potential services, such as voltage management and resilience, are beyond the scope of this report, but are recognized as additional value that DERs can provide. This paper draws extensively on concepts and practices from wholesale market design and transmission system operations. The discussion often starts with mechanisms used at the transmission level, before considering how these could be applied at the distribution level to coordinate DERs, DSOs and the TSO. The goal of the paper is to provide exploratory analysis and contribute to the broader sector discussion on DERs taking place in Ontario and internationally.

While this paper is intended to be generally applicable to international jurisdictions that have restructured power systems with independent system operators (ISOs) and a "standard market design" [8], the discussion is grounded in the context of Ontario and the Independent Electricity System Operator (IESO). To provide clarity on the specific roles and responsibilities of system entities, the term TSO used throughout the paper refers to a system operator that manages the high-voltage transmission system and administers a wholesale market, as is often the practice with ISOs in North America.[2] DSOs, in turn, are system operators that manage the low-voltage distribution system and represent a potential new type of entity or function that is distinct from, but has many parallels with the TSO. The paper also focuses on resources, services and the "sell-side" of the market. The demand and "buy-side" of the market is not discussed in detail. That said, the sell-side discussion applies to a range of buy-side arrangements, including the model used currently in Ontario, where market costs are passed through to large load customers and recovered through regulated rates from smaller customers.

The remainder of section 1 positions the paper among the IESO's many DER-related initiatives, and maps the topics investigated within the broader scope of the methods that are being proposed to secure services from DERs. Section 2 discusses the economic potential of DERs with a focus on using them as NWAs. Section 3 provides background on electricity markets and services, as well as a summarized framework for potential TSO-DSO coordination models. Sections 4 and 5 use three different TSO-DSO models to illustrate energy and capacity market coordination processes. Section 6 briefly explores additional topics, including market power, operating reserves and cost allocation, and notes several areas that deserve more detailed investigation. Finally, section 7 provides concluding commentary.

1.3 Methods to Secure NWAs

The "three Ps" – pricing, programs and procurements – are often offered as the broad set of potential methods for securing services from DERs. In its *Non-Wires Solutions Implementation Playbook*, Rocky Mountain Institute acknowledges that in practice these options often overlap and can be used alongside each other [9].

Programs and procurements can both be used to secure services from third-party DER owner/operators, but each lends itself to certain contexts. For example, programs are especially useful when targeting many small and relatively uniform participants, where the objective is to keep the method of securing services simple and transaction costs low. Pricing, on the other hand, is complementary to programs and procurements and an effect of them. Once services are procured, charges to customers can be designed to reflect costs and incentivize customers (or buyers of the services) to appropriately manage consumption and costs. This could involve customers using DERs to self-supply instead of consuming services from the system. In designing charges, the aim is generally to reflect the costs to the system as granularly as practical, including costs incurred to secure and receive electricity services from resources. Table 1 briefly describes the three Ps from these perspectives.

[2] In this paper the TSO is understood to include the entity that is accountable for two functions that in practice are performed by separate entities in some jurisdictions: the transmission system operation function, which includes provision of transmission service and real-time system balancing, and the wholesale market operation function. In North American ISOs/RTOs, and in Australia, the TSO includes both functions; in the UK and Europe, the market operator is separate from the TSO. In both cases the matter of TSO-DSO operational coordination must be addressed to ensure reliability.

Table 1: Description of the three Ps

Method	Description
Programs	Programs often provide standard offers for services from electricity resources and do not usually involve competition. Examples include feed-in tariffs, net-metering and energy-efficiency programs. Programs can standardize remuneration and simplify the process for securing electricity services, improving access and increasing participation. Transaction costs can be reduced, especially when anticipating many small participants. Programs are sometimes used for securing services from nascent and novel technologies, ahead of moving to more competitive processes when technologies mature. As well, programs can be used when electricity services are dispersed and highly localized in nature, limiting competition needed for procurements.
Procurements	Procurements are competitive processes used to secure electricity services, often involving a request for proposals (RFP) that awards contracts or an auction mechanism with rules for cleared resources. In wholesale markets, auctions are often used to secure energy and operating reserve services. RFPs and contracts are sometimes used to secure certain transmission-level ancillary services. Generally, resource capacity can be procured with RFPs or capacity auctions and both are employed in jurisdictions across North America and internationally. Both RFPs and auction processes are being used to procure services from DERs used as NWAs, but RFPs are more typical today [9].
Pricing	Cost-reflective charges signal the cost of consumption decisions to customers, driving them to reduce consumption when the cost is high and increase consumption when the cost is low. Charges can be cost-reflective by designing them granularly to be time-varying, service-specific and locational. For instance, time-of-use rates and dynamic rates often reflect the difference in cost in a wholesale energy market during different times of day and throughout a year. Coincident peak demand charges and critical peak prices are often based on the cost of capacity service from resources.

This paper explores how services can be secured from independent DER developers and customer-owned DERs, focusing on the use of energy and capacity market auction process to compensate DERs for their value as NWAs. This approach differs from some that have been proposed and are being explored in Ontario and other jurisdictions. For example, one approach involves the distributor treating DERs used as NWAs effectively as "wires" assets, owning and operating them, and seeking recovery of the associated cost through the traditional regulatory mechanisms used for network infrastructure today. However, this poses a number of questions. Could the utility-owned DERs be used to their full potential and participate fairly in the wholesale markets? How would the regulatory cost-recovery methodology account for market revenues? How would customer-owned DERs be used to provide services? Enabling independent and customer-owned DERs to compete to provide services is consistent with deregulation efforts in restructured jurisdictions.

Sections 4 and 5 outline illustrative coordination processes for different TSO-DSO models where market auction mechanisms are employed at both the transmission and distribution levels. Section 6 discusses similarities and differences between auction and RFP approaches, as well as considerations for cost-recovery and rate-setting.

1.4 Related IESO Initiatives

The IESO is conducting a series of projects and initiatives that are related to the concepts explored in this paper. Table 2 highlights some of the major undertakings that are particularly relevant and can provide further background.

Table 2: Description of relevant IESO initiatives

Initiative	Description
Market Renewal	The Market Renewal Program is introducing fundamental reforms to the IESO's energy market by establishing locational marginal prices, a day-ahead market, and an enhanced unit commitment process.
Capacity Auction	The IESO's capacity auction will evolve the existing demand response auction to enable additional resource types to compete to provide capacity service.
Innovation Roadmap	The Innovation Roadmap sets out the IESO's approach to innovation, positioning the IESO to act on priorities that enable it to deliver on its mandate, while undertaking, supporting or participating in projects that will benefit the sector overall.
Grid-LDC Interoperability Committee	The Grid-LDC Interoperability Standing Committee is a forum where the IESO and local distribution companies engage on matters relating to interoperability and operational issues in order to enhance the reliability and efficiency of Ontario's electricity grid.
White Paper Series	The Innovation and Sector Evolution White Paper Series is focused on emerging issues that may have a significant future impact on the electricity system, with several papers focused on DERs.
York Region NWA Demonstration	The demonstration project in York Region will test a market mechanism to secure services from DERs to provide both transmission- and distribution-level value, with a focus on the transmission-distribution interface.
Regional Planning Review	The review examines how the existing regional planning process coordinates with related processes, such as bulk system and community energy planning, including a review of barriers to NWAs.

This paper is part of the IESO's Innovation and Sector Evolution White Paper Series and is included in the Innovation Roadmap. The findings will inform the design of the York Region NWA demonstration project [10], which, in turn, is expected to provide input into evolving regional planning processes and potentially wholesale market processes in the future.

1.5 Regional Planning and Barriers to NWAs

Through the regional planning process, the IESO works with distributors and transmitters to assess Ontario's regional electricity needs, and engages with local municipalities, Indigenous communities, businesses, consumer advocates and other stakeholders. The process bridges bulk system and distribution network planning to produce a 20-year outlook for a regional area. The regional plan supports the regulatory process for new network infrastructure and indirectly informs the target capacity in capacity auction processes for new resources. An integrated planning approach is taken in Ontario, where a combination of potential solutions is considered to meet identified needs, including energy efficiency, generation, storage, DERs and transmission and distribution network infrastructure.

As part of a broader review of the regional planning process, the IESO is currently exploring planning methods to more comprehensively and formally identify NWA opportunities. The scope of the initiative also includes identifying barriers to the implementation of cost-effective NWAs and providing options to address them. While this work is still ongoing, the IESO has developed a draft inventory of barriers, which include technology, system value, resource market, process understanding, tools and data, regulation, procurement, connection and operations barriers [11]. The work on addressing NWA barriers is particularly relevant to the topics explored in this paper, which focuses specifically on some of the resource market barriers.

2. Economics of NWAs

2.1 NWA Definition

Non-wires alternatives (NWAs) are resources, such as generation, storage, demand response and energy efficiency, that provide electricity service as alternatives to transmission and distribution (T&D) or traditional "poles and wires" solutions, such as transformer stations and lines. Through the use of NWAs, investments in major T&D solutions can be avoided or deferred, which can reduce system costs when NWAs are the more cost-effective solution. NWAs can be used in lieu of transmission- or distribution-level network infrastructure. When the opportunity to employ NWAs is at the transmission level, both centralized, transmission-connected resources and DERs that are located in the associated transmission zone can be used as non-transmission alternatives. When seeking NWAs to distribution infrastructure, only DERs that are located in the associated distribution zone can be used to meet the need. As well, it should be noted that NWAs are not a resource class per se, but rather represent a way DERs can be used. DERs that are used as NWAs may also be technically capable of providing services to defer or avoid investment in centralized, transmission-connected resources and ancillary services.

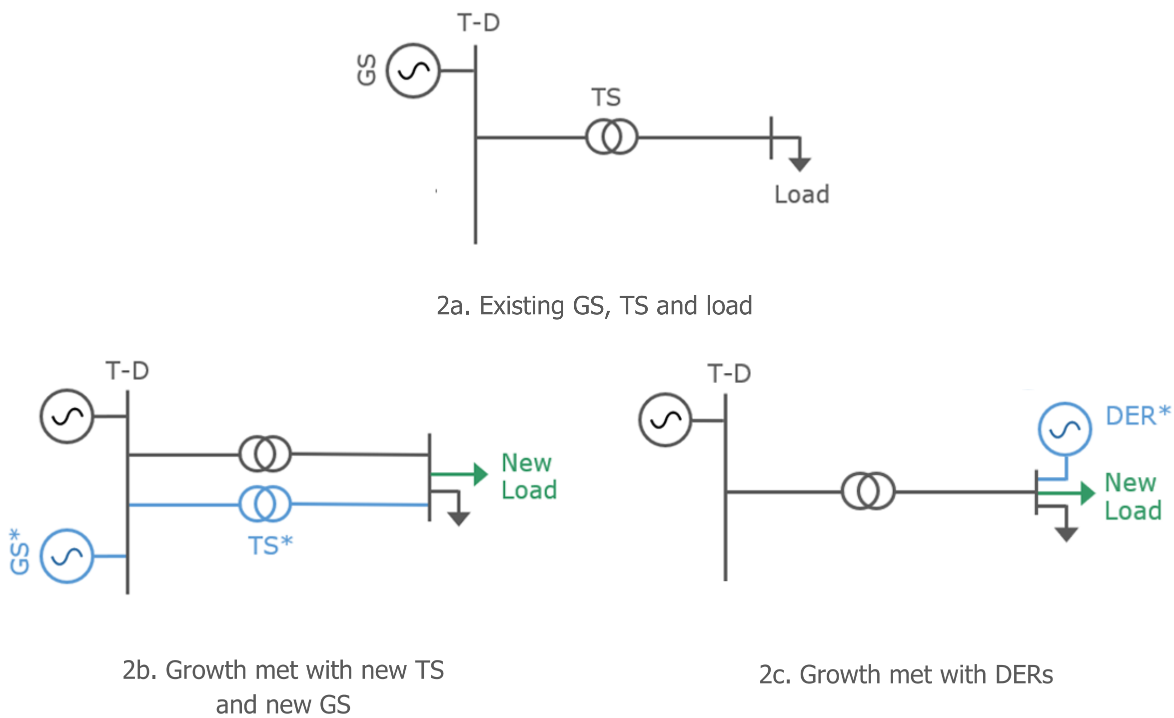
While NWAs have emerged in recent years as a focus in the power and utilities sector, the concept is not new, especially at the transmission level. Bonneville Power Administration first started exploring NWA opportunities in the U.S. Pacific Northwest in the late 1980s, and Pacific Gas and Electric in California started doing so in the early 1990s [12]. The U.S. Federal Energy Regulatory Commission (FERC) addressed NWAs in Orders 890 and 1000 in 2007 and 2011 respectively. These orders require open and transparent regional transmission planning processes that evaluate whether non-transmission alternative solutions might meet system needs more cost-effectively [13], [14]. The interest in NWAs today is driven, in large part, by the material deployment of DERs in many jurisdictions in recent years, and by the anticipation of ongoing growth, as the cost and capabilities of DERs continue to improve. While sections 4 and 5 are focused on NWAs to distribution network infrastructure, where TSO-DSO coordination processes are especially challenging, the analysis will leverage transmission-level concepts and experience.

2.2 A Motivating Example

An example will illustrate the potential for NWAs to reduce system costs and help frame the economic opportunity that DERs as NWAs may present. Generally, local resources can be an alternative or substitute to additional network infrastructure and more remote, centralized resources. In other words, load customers' demand can be met either with smaller resources located close to the point of consumption or with transmission-connected resources sited further away and delivered through the T&D network infrastructure. DERs can serve as an alternative to *both* centralized resources and T&D infrastructure, and when used in this integrated manner may generate even greater savings than if they were only serving as an alternative to one of those infrastructure investment categories.

Aging and retiring infrastructure, as well as electrification of heating and transportation, may drive significant need for new centralized resources and T&D infrastructure in the future. However, if DER costs continue to decline, and planning, market and operations processes continue to evolve, opportunities for DERs to meet these growing needs may increase. As explored in section 4, jurisdictions with wholesale capacity markets secure resource capacity through technology-neutral,[3] rule-based market transactions. The open and periodic nature of capacity markets may be particularly helpful for coordinating the investment in DERs. In contrast to capacity markets, RFP processes that award long-term contracts lock resources into service provision terms and conditions that may limit opportunities for lower-cost DERs to enter the market and provide the full range of services they are technically capable of providing.

As noted by Krishnan et al. in *Co-optimization of electricity transmission and generation resources for planning and policy analysis: review of concepts and modeling approaches* [15], historically, planning for needed generation was conducted before planning the T&D network to deliver the electricity to customers. Today, capturing the more complete economic problem by co-optimizing network and resource investments, and assessing them simultaneously to identify the lowest-cost strategy is considered a best practice.[4] Assessing these solutions separately on only a network or resource planning basis could result in lower-cost solutions being overlooked [15].



2a. Existing GS, TS and load

2b. Growth met with new TS and new GS

2c. Growth met with DERs

Figure 2: Demand growth can be met with traditional infrastructure or DERs

[3] In capacity markets, capacity service is intended to be non-discriminatory and as technology-neutral as possible in order to "commoditize" the service and enable competition from different resource types on a level playing field. Unforced capacity (UCAP) is often used as a measure that reflects the level at which a resource can be expected to consistently produce energy during peak system demand periods. For example, a resource's UCAP can be assessed by determining its effective load carrying capability (ELCC), where its ability to contribute toward meeting resource adequacy needs is calculated using probabilistic reliability modeling.
[4] As noted in section 1.5, Regional Planning and Barriers to NWAs, and discussed in section 2.3, NWAs in Integrated Planning, Ontario has a long-standing practice of using integrated planning processes.

Figure 2 illustrates a highly simplified example of NWAs at the distribution level. In 1a, the existing system is shown, with a centralized generation station (GS), the transmission-distribution interface, a transformer station (TS) and distribution-connected load. In this example, the existing transmission-connected GS and the TS are at their maximum capability to generate and deliver electricity. Any growth in demand will drive new infrastructure investment. In 1b, new load growth (highlighted in green) will drive the need for new infrastructure in the form of a new centralized GS and a new TS (highlighted in blue). In 1c, DER is highlighted as an alternative to investing in a new centralized GS and TS.

Table 3: Cost comparison for Figure 2 – DERs versus centralized infrastructure solutions

Infrastructure	Variable O&M Cost ($/MWh)	Investment Cost ($/MW/year)	Total Annual Cost ($/MW/year given capacity factor=30%)
Option 1: DERs			
DER*	$20	$150,000	$202,560
Option 2: GS + TS			
GS*	$30	$100,000	$178,840
TS*	$0	$70,000	$70,000

Table 3 provides illustrative cost data (on a per-megawatt-per-year basis) for the two infrastructure options highlighted in blue in Figure 2. This example assumes that the resource selected (centralized GS or DER) will operate at a capacity factor of 30%. If decoupled assessments are conducted, the DER solution will not be selected, since it will appear to be costlier than the centralized GS and TS on a stand-alone basis. However, if T&D network and resource investments are considered on an integrated basis, then the DER solution is selected because it is less expensive than building both the centralized GS and the TS (i.e., $202,560 < $178,840 + $70,000).[5]

Of course, this example is highly simplified for illustration purposes. For instance, numbers are provided on an annualized basis and it does not capture a full planning horizon – with potentially changing year-over-year costs, different capacity factors, facility lives and investment time frames. Energy loss reductions and the associated cost savings when using DERs are also ignored. The cost categories used (i.e., variable operations and maintenance costs, and investment costs) are from the perspective of the resource owner/operator and reflect traditional planning approaches. In a market environment, the system cost metrics would be energy costs and capacity costs based on market prices.

[5] In the scenario described, both a GS and a TS are needed to meet new load. However, there are situations in which either the GS or TS is needed, but not necessarily both. DERs may be able to compete on a one-to-one basis with transmission-connected generation and network infrastructure, but their economics improve when they can provide services as an alternative to both categories. As mentioned previously, capacity markets can help coordinate more complex DER participation, given the open, periodic auction process.

2.3 NWAs in Integrated Planning

Ontario has a long-standing practice of using integrated planning for electricity infrastructure. The best practice today is to explore NWAs through integrated planning processes, where a combination of potential solutions, including T&D, centralized resources and DERs, are modelled over the planning horizon and assessed to identify the lowest-cost options. As detailed by Burger et al. in *Why Distributed? A Critical Review of the Tradeoffs Between Centralized and Decentralized Resources* [16], while centralized resources have the advantage of economies of scale, DERs may be the lower-cost solution, considering that they can uniquely be deployed in a locationally targeted manner and sited close to load, for instance in dense urban environments.

As illustrated in the example, DERs can help avoid or defer the need for both T&D infrastructure and centralized resources, reducing overall system costs. The "lumpy" nature of T&D infrastructure investment is also a dynamic that favours DERs, which are more modular and can be invested in and deployed over time [16]. While hard to quantify, the smaller, staggered and shorter-term investment in DERs provides option value, permitting planners to observe how technology costs and demand growth trends unfold before making further investments [17]. This approach contrasts with the longer-term, upfront commitments made with larger, centralized infrastructure. DERs may also reduce system energy losses, which can be material at the lower-voltage distribution level, especially during peak demand [18]. Without locational value, DERs would be competing directly with centralized solutions that enjoy economies of scale without providing other value [16].

The need for new resource capacity and T&D solutions is generally driven by peak load on system infrastructure. When DERs are used as NWAs, the relevant peak load is that of the local load customers serviced by the T&D infrastructure that is reaching its limits. However, for centralized, transmission-connected resources, the relevant peak load is more system wide, often regional or zonal in nature. As shown in the motivating example, the economic case for DERs becomes more attractive when the existing T&D infrastructure and resource fleet are at or near their capacity limits and DERs can be used as an alternative to both. In other words, when ample T&D or resource capacity exists, the incremental, near-term value of DER deployment to the system is lower. To provide significant value as NWAs, DERs need to be located and operated where and when the local gross peak load is expected to exceed the limits of the upstream T&D network capacity. In such hours, DERs located downstream of the limits must be operated and relied upon to serve the portion of load that the broader system cannot, reducing the net loading on the local network infrastructure. To capture value in this manner, DERs must be capable of reliably providing electricity services to lower the net loading on the network infrastructure to below the limits.

Both active DERs that respond to dispatch signals and passive DERs that behave predictably can be used as alternatives to centralized infrastructure and contribute to meeting system needs. Some passive DERs, such as combined heat and power, are generally more predictable. Others are intermittent, such as solar photovoltaic installations, and may have less local value. Regardless, the extent to which the output from passive DERs aligns with the NWA need and the associated value can be assessed upfront when securing resource capacity. In the operational time frame, passive resources do not need much active management and will provide value, as long as they are available. However, to provide significant value, dispatchable DERs, such as demand response and energy storage, must be managed actively. Dispatchable DERs intended to be used as NWAs need to be responsive to changing grid conditions and operate when local demand is high and the limits of upstream infrastructure are expected to be exceeded. Without active management, these DERs may sit idle when needed. To derive value from these DERs, a system operator would generally send a dispatch signal to resources, which in turn would follow dispatch instructions.

3. Market Design Considerations

3.1 Wholesale Markets

As part of electricity sector restructuring, many jurisdictions globally have introduced wholesale markets that enable resources to compete to serve load. Wholesale markets allow independent developers to make private investments and provide services in a competitive market, resulting in efficiencies and innovation, while reducing overall costs. In these market designs, ISOs facilitate non-discriminatory access to the transmission grid and provide coordination services to ensure reliable operations by using day-ahead, intra-day, real-time and ancillary services markets that schedule and dispatch resources. ISOs are neutral market facilitators and system operators, given that they are not-for-profit, independent organizations that do not own resources or network infrastructure assets.

In some jurisdictions, ISOs have also introduced capacity markets to ensure resource adequacy, often procuring this capacity years in advance of when the associated operational obligations in the energy market commence. In capacity markets, eligible resources compete with each other on a level playing field (i.e., regardless of technology type) in periodic auctions. To facilitate technology-neutral competition, resources typically undergo a qualification process before each capacity auction to determine the contribution they are technically capable of providing to meet resource adequacy needs. Resources that clear in the capacity market are required to participate in the energy market during a defined commitment period and be available to meet resource adequacy needs. Capacity markets provide capacity payments that are in addition to those received for any energy and ancillary services. In some jurisdictions, such as California the capacity requirement is met through bilateral contracts between suppliers and buyers rather than through a central capacity market. Nevertheless, the suppliers of capacity are still compensated with capacity payments and have obligations to participate in the ISO energy market and support real-time operations.

In market designs that include both a capacity market and an energy market, the two mechanisms are intended to give resource-owners the opportunity to recover variable and fixed costs, including a return commensurate with the risk associated with the investment in the resource. Energy market prices in North American ISOs are typically set at the locational marginal price (LMP), which in competitive markets reflects the marginal cost of energy at different locations on the grid, considering the cost of producing the energy, impact of losses and transmission network congestion.[6] Resources are dispatched in the energy market when their offer to produce energy, which generally reflects their short-run (or variable) operating cost, is at or lower than the LMP. When the LMP is higher than a resource's short-run costs, the resource earns margins in the energy market. While resources earn margins in the energy market, they may be insufficient to recover their full fixed costs, particularly in the context of declining energy market prices due to increased penetration of zero-marginal cost resources (e.g., wind and solar) and low natural gas prices. The economic theory of capacity payments is that they will provide additional payments that in the long run, on average, compensate resources at the long-run marginal cost of supply [19]. For resource owners, capacity payments provide the price stability and revenue certainty to

[6] The locations of LMP pricing nodes in energy markets consist of transmission-distribution interface substations, where power is withdrawn from the transmission system to serve load on the distribution system, as well as transmission-connected generator locations and interties with adjacent balancing areas.

incentivize them to make capacity available [19]. For system operators, capacity payments help ensure that the required resources are available to meet adequacy needs at competitive prices.

One way to secure electricity services at the distribution level is to extend the concepts of energy and capacity markets to the full grid, including the distribution system. Sections 4 and 5 explore this approach in detail.

3.2 Electricity Services

A set of core physical electricity services that are necessary for a power system to function reliably can be defined [20]. Table 4 outlines a proposed high-level categorization of core electricity services for the purposes of this paper. To permit the contributions of all technology types to be recognized and assessed in integrated planning analyses and market mechanisms, core services should be defined in a technology-neutral manner. In concept, these services are all locational in nature and can be defined granularly across time and locations on the system. However, in practice, electricity service prices are often the same across many locations. For instance, if there is ample T&D network capacity in a region and no transmission constraints, the value of resource capacity is effectively uniform throughout the region.

Table 4: Categories of core electricity services

Energy Service (Operational Time Frame)	Capacity Service (Investment Time Frame)
Real energy	Resource capacity
Reactive energy	Network capacity
Reserve energy	

In the operational time frame,[7] the energy services of real, reactive and reserve energy in Table 4 are consistent with other similar listings of core electricity services, such as those in the *White Paper on Developing Competitive Electricity Markets and Pricing Structures* by Tabors et al. [21]. In wholesale markets, energy services are sometimes categorized as energy, operating reserves and ancillary services. The proposed categorization in Table 4 is also consistent with this, but more prominently highlights reactive energy service. In jurisdictions with wholesale markets, real energy and reserves are secured through auction mechanisms, and are usually co-optimized, with a single market and optimization process clearing the lowest-cost set of resources to provide both electricity services. Real energy and reserve energy are transacted in real-time in wholesale markets and are also typically coordinated on a day-ahead basis, often through day-ahead market transactions. In wholesale markets, there are usually different energy reserves sub-categories with different levels of "readiness" to respond to contingencies, shortages, and, increasingly, operability needs with flexibility. Broadly defined, energy reserves include primary, secondary and tertiary reserves, provided by governor action, automatic generation control (AGC) and operating reserves. Reactive energy – which is related to voltage management and Volt/VAR

[7] In the operational time frame, the goal of electricity market designs is "short-run efficiency – making the best use of the existing resources" [4].

control – is generally not transacted dynamically in wholesale markets. Today, there is increasing interest in expanding opportunities for the provision of reactive energy, especially at the distribution level.

In the investment time frame,[8] capacity service is proposed to involve the capability to deliver real, reserve and reactive energy to load when needed in the operational time frame. Capacity service could involve the use of:

- Resource capacity co-located with load with no use of network capacity
- Resource capacity located close to load and delivered using existing network capacity
- Remote resource capacity delivered to load through new network capacity

This framing of capacity service better identifies the opportunity to co-optimize resource and network capacity to provide the service. Network capacity is generally provided by transmission and distribution system owners/operators that receive payment through regulatory processes. In jurisdictions with capacity markets, resource capacity is secured through auction mechanisms on a forward basis (e.g., one to three years). Resources that clear the auctions receive capacity payments for providing the service during the delivery or commitment period. Framing capacity service in a general way also demonstrates that from a system perspective, it may be more cost-effective to pay more for new resource capacity but forgo paying for new network capacity.

Lists of electricity services are usually longer than the five services discussed above, but they often contain components that can be reduced to the five in Table 4. For instance, market designs that do not employ LMP for pricing energy may use separate mechanisms to manage network congestion and reduce losses. However, in North American wholesale markets, LMP reflects and internalizes both these elements. The categories in Table 4 do not include a service specifically for NWAs. This paper proposes that energy and capacity services are sufficient to drive the investment and operation needed to use resources as NWAs. Furthermore, some lists of electricity services describe those that DERs can provide, which include behind-the-meter installations that permit customers to self-supply in lieu of buying services from the electricity system. However, these self-supply services are not included in the services described above, as Table 4 only captures services required to operate the electricity system.

3.3 Multi-Service Participation

Many resource technology types are capable of providing more than one type of electricity service. For instance, battery storage DERs are modular and highly controllable, giving them the potential to provide several different services. In general, the electricity sector today is seeking to refine and clarify how different DERs can provide multiple services, especially if the services are defined, valued and acquired at both the distribution and transmission levels. The aspiration is to develop a comprehensive multi-service framework that would allow resources to provide all electricity services that they are technically capable of providing, potentially enabling resources to generate more value while reducing system costs. A multi-service framework would also preserve system reliability by developing operational coordination processes that mediate potentially conflicting services and avoid duplicate compensation of DERs for providing the same service. Based on analysis from a California Public Utilities Commission (CPUC) proceeding on multiple-use energy storage applications [22], Table 5 outlines three ways in which

[8] In the investment time frame, the goal of electricity market designs is "long-run efficiency – promoting efficient investment in new resources" [4].

multiple services can be provided: on a capacity-differentiated, time-differentiated and simultaneous basis.

Table 5: Three ways to provide multiple services

Multi-Service Type	Description
Capacity-differentiated	Committing a portion of a resource's capacity to a certain service in the same time interval, e.g., committing 0.5 MW of a 1 MW battery storage's capacity to one service and the other 0.5 MW to another service in the same time interval.
Time-differentiated	Committing certain capacity to different services in different time intervals, e.g., a battery storage device with 1 MW of capacity is committed to one service in one time interval and to another service in the following time interval.
Simultaneous	Committing certain capacity to more than one service in the same time interval and providing multiple services simultaneously, e.g., a battery storage device with 1 MW of capacity is fully committed to providing more than one service in the same time interval.

In the wholesale market at the transmission level, a framework already exists for specific use cases. For instance, energy and operating reserves can be provided on a capacity-differentiated and time-differentiated basis, but not simultaneously. In other words, in a given time interval, a generator can provide energy with a portion of its capacity and operating reserve with its remaining capacity. In a future time interval, the portions used for energy and operating reserve could change. However, the generator cannot simultaneously provide energy and operating reserve with its full capacity. In wholesale markets, the energy and operating reserve services are usually co-optimized and secured as part of one, integrated energy market process.

In a potential high-DER future, where electricity services are defined and transacted at the distribution and wholesale levels, a comprehensive multi-service framework will be required to coordinate market and system operations between the TSO and DSOs. Uncoordinated market and system operations may work at low penetrations of DERs, but at high penetrations, additional coordination will be required to preserve reliability. Coordination between the TSO and DSOs will be required in both the operational time frame for real, reserve and reactive energy and in the investment time frame for capacity service – both resource and network capacity.

Sections 4 and 5 discuss and illustrate how distribution- and transmission-level energy and capacity markets can be coordinated with the aim of allowing DERs to appropriately stack services.

3.4 TSO-DSO Coordination

In the report *Distribution Systems in a High DER Future* [23], De Martini and Kristov outline a spectrum of potential transmission-distribution coordination arrangements that could be used in a high-DER future – from a Total TSO Model on one end, to a Total DSO Model on the other. In the Total TSO Model, fully integrated market and system operation is conducted by a central system operator, the Total TSO, at both the transmission and distribution levels. At the other end is the Total DSO Model, where fully bi-level market and system operations is conducted by DSOs at the distribution level and by a central TSO at the transmission level. Between these lies a spectrum of possible Hybrid DSO models with varying functional responsibilities shared between the TSO and DSOs.

ISOs today can be characterized as TSOs. The potential for existing distribution owners/operators to evolve and assume the DSO function or for a new entity to be introduced to take on the DSO function is the subject of ongoing discussions globally. While DERs (or aggregations of DERs) can directly participate in ISO wholesale markets, ISOs have limited visibility into the distribution system. As such, the dispatch signals and market prices generated by the wholesale market are based only on transmission-level supply-demand balancing and transmission-level network limits and losses. Figure 3 depicts the TSO-DSO models.

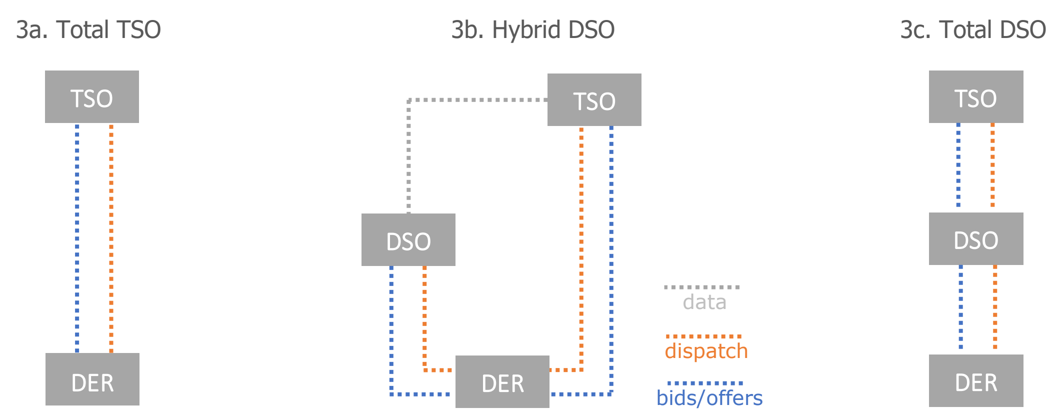


Figure 3: TSO-DSO coordination models[9]

In the Total TSO Model, the central system operator's visibility, control and markets would be extended to include the distribution system. The distribution system's topology would be modelled in a full-system network representation, including more exact mapping of the location of DERs on the system. As well, the Total TSO would receive distribution system telemetry,[10] which would feed into forecasting and other system operations tools. The Total TSO would also receive bids and offers from DERs in addition to transmission-connected resources and conduct an optimization that includes network constraints and losses at the distribution level. With this additional data and expanded operations, the Total TSO could

[9] Figure 3 is a highly simplified representation that shows coordination relationships, but does not depict multiple DERs, multiple DSOs or transmission-connected resources.

[10] Telemetry is the automatic recording and transmission of data from remote locations to permit monitoring, analysis and operator actions.

produce granular dispatch signals and market prices to reliably operate the full system. In this model, the TSO's relationship with the distribution system owner would in concept be analogous with the current relationship between ISOs and transmission system owners, except that interactions may be more involved given the complexity of distribution system operations. Because of this, the Total TSO Model would include a "minimal" DSO that is sufficiently enhanced compared to today's distributors to be able to maintain reliable performance of the distribution network without taking on any major new functions, such as optimizing DER dispatch or operating a distribution-level market. However, as the penetration of DERs grows significantly, the Total TSO Model may face scalability challenges when it comes to obtaining the visibility into and control of the full system required to optimize, dispatch and generate prices in one centralized process. This could represent a major technical barrier, given the technology available today.

In a Total DSO Model, the DSOs would have visibility into and control of the distribution system downstream of T-D interfaces across the transmission system. While there can only be one DSO for each T-D interface, the same entity may be the DSO for multiple T-D interfaces. As for the TSO, its visibility and modeling of the distribution system would stop at the T-D interface. DER provision of wholesale market services would no longer involve a direct interface with the TSO. Instead, the DER owner or DER aggregator would submit its bids or offers into the local market operated by the DSO for the relevant T-D interface. The DSO would then aggregate the bids and offers into a single aggregated offer (potentially with granular price-quantity pairs) into the TSO's market at the T-D interface. The offer would reflect the availabilities and capabilities of DERs to provide wholesale market services given current distribution system conditions and supply-demand balance within the local area.

The TSO would subsequently conduct a centralized optimization and market process, and dispatch transmission-connected resources and DSOs (representing all DERs and aggregations below an individual T-D interface) that are economical, clearing the TSO's market. The TSO's central process is still needed, so that DERs (represented by DSOs) and transmission-connected resources can compete to provide transmission-level services. This would include opportunities for DSOs clearing the TSO's market to provide services to transmission-connected load customers or load customers located in other DSO service territories. The Total DSO Model represents a simplification of overall system operations for the TSO, considering that the TSO only needs to concern itself with the aggregated data that is an output of the processes and activities undertaken by the DSOs.

A major consideration with DSO models is the transparency and fairness of the market. For example, consideration would need to be given to how a Total DSO aggregates DER bids and offers submitted into the TSO's market and how it subsequently disaggregates the TSO's dispatch among the DERs. Legislative and regulatory frameworks, transparent DSO market rules and other governance mechanisms could be used to ensure that DERs can participate in the market in an open, non-discriminatory manner. As well, to avoid actual or perceived conflicts of interest, DSOs will require a necessary degree of independence from other distribution system functions, such as DER ownership, as well as from any other profit motives associated with operating the market.[11] These independent DSOs (IDSOs) would serve as neutral market

[11] A challenge for implementing DSO models is emerging in jurisdictions where distributors have begun to establish business models that include DER ownership and operation. Forays into this business model could make sector evolution more challenging and even limit the options for determining which entities could operate a distribution-level market. Some parallels can be drawn with sector-restructuring efforts undertaken in North America in the 1990s and 2000s, when vertically integrated utilities were separated into transmission provider and generation supplier businesses, some divestitures were required and independent system operators were introduced.

facilitators, giving DER participants an opportunity to be compensated transparently and fairly in relation to the value they provide to the system.

In between the Total TSO and Total DSO models, where DER participants have a single market and system operation interface with either the TSO or DSO, a range of Hybrid DSO models are possible. In these models, a DER could interface with the TSO, DSO or both, depending on the size of the DER, the service in question and/or the time periods considered. Unlike the Total DSO Model where there is a simpler TSO-DSO interface, a Hybrid model may involve additional complexity and cost in the coordination processes among the TSO, DSOs and DERs that are needed to preserve reliability.

The analysis in sections 4 and 5 explores a specific Hybrid DSO model (the Explored Hybrid Model) that has been identified from a system and market operations perspective. In this construct, only the DSO models the distribution network and receives telemetry from it. The DSO would dispatch DERs and generate prices for services based on the distribution-level needs that it has visibility into and can identify. The TSO would similarly dispatch DERs and generate prices on the basis of available information and needs at the transmission level. In short, this model would involve DERs participating in distribution-level energy and capacity markets operated by a DSO and separately participating in transmission-level energy and capacity markets operated by the TSO.

While a rigorous DSO-TSO coordination approach has not yet been fully implemented, many jurisdictions, including Australia [24], the United Kingdom [25], New York [26] and California [27], are undertaking major initiatives to achieve this goal. Many complex technical and policy considerations apply when assessing different TSO-DSO models. In the IESO-commissioned report, *Development of a Wholesale-Distribution Interoperability Framework* [28], ICF Canada provides a comprehensive and detailed exploration of system architecture and potential TSO-DSO coordination models.

A major challenge with implementing DSO models is that the standards that define the reliability requirements for planning and operating the electricity system were not developed to explicitly contemplate a high-DER future, especially not with DSOs that would operate the distribution system in the very active and complex manner being considered in some system evolution discussions today. As part of its System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG), the North American Electric Reliability Corporation (NERC) is developing a reliability guideline for communication and coordination strategies for transmission and distribution entities regarding DERs [29]. Additionally, the Electric Power Research Institute (EPRI) and Argonne National Laboratory (ANL) are undertaking a project to model and investigate TSO-DSO coordination, including a review of potentially impacted NERC reliability standards [30]. EPRI and ANL note that an actively managed distribution system and significant DER penetration may give rise to (a) new methods or approaches to comply with a standard, (b) the need for new data exchanges to facilitate standard compliance, and (c) the need to examine a standard's provisions due to an emerging risk not covered by existing metrics or requirements [31]. Prior to a potential full implementation of DSOs, some reliability standards may have to be amended and compliance processes put into place.

In order to provide more in-depth analysis, the following sections are narrow in scope, focusing on coordination processes when energy and capacity markets are employed under the Total TSO, Total DSO and the Explored Hybrid models. This analysis is based on the principle that a DER's energy and capacity payments should be based on its value to the system and be independent of the coordination model adopted among the TSO, DSOs and DERs.

4. NWAs in Capacity Markets

4.1 Applying Capacity Zones to NWAs

Jurisdictions with capacity markets typically define capacity zones that reflect major transmission limitations in order to set locational capacity requirements and ensure that resource adequacy needs within the capacity zones are met. Capacity markets generate zonal capacity price signals, which incentivize market participants to focus their efforts in high-priced, high-value capacity zones.

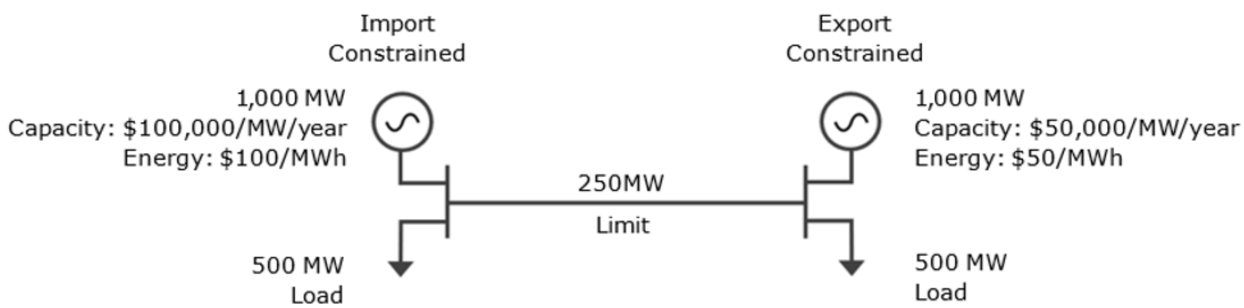


Figure 4: Illustration of import- and export-constrained zones[12]

A capacity zone is an area of the grid bounded by transmission limitations where the addition of resource capacity may either be restricted or required. To meet capacity needs in an "import-constrained" capacity zone, a minimum amount of resource capacity must be secured in the capacity auction from within the zone to meet adequacy needs, because transmission constraints limit how much energy can be delivered from outside the zone. If a capacity zone is "export-constrained," a maximum amount of resource capacity is permitted to clear, because transmission constraints limit how much energy can be delivered outside the zone. Clearing additional resource capacity within an export-constrained zone would not contribute to meeting system resource adequacy needs. In short, the specific amounts of capacity that must be secured in the capacity market in each zone reflect transmission limitations.

Capacity zones result in separation of capacity market clearing prices across the zones. For example, to secure the minimum resource capacity needed from within an import-constrained zone, market offers submitted from within the zone may clear even if they are more expensive than offers from elsewhere on the system. Zonal prices send price signals for the value of capacity in specific areas, which may be higher or lower than the average system-wide capacity price. However, if major transmission limitations do not exist, the value and price of resource capacity is effectively uniform throughout the zone. In other

[12] The diagram depicts two areas connected through a line that is limited to 250 MW of capacity. In the area on the right-hand side of the diagram, load benefits from relatively inexpensive generation. The area also has 500 MW of excess capacity – enough to fully serve the load connected at the other end of the line. However, given the 250-MW limit of the line, only 250 MW of the inexpensive capacity from the export-constrained area can be used to meet area needs shown on the left-hand side of the diagram. The 250 MW of more expensive generation located in the left-hand area of the diagram is required to meet the need in the import-constrained area.

words, within a zone, resource capacity is generally deliverable to anywhere else in that zone. In this manner, capacity zones can indicate the locational value of resource capacity to the market and drive resource investment and deployment.

The concepts of capacity zones and zonal prices can be applied to NWAs within the distribution system infrastructure. While capacity zones at the wholesale level often reflect major existing transmission limitations, more granular capacity zones can, in concept, be defined at the distribution level to reflect more localized constraints driven by new or emerging needs.[13] This approach would drive separation of capacity prices of distribution-level zones from capacity prices on the rest of the system and can indicate the relative higher value of siting DERs in a particular zone.

4.2 Illustrative Capacity Market Coordination

The following analysis illustrates how DERs used as NWAs to distribution network infrastructure could be secured in the investment time frame using capacity markets under three TSO-DSO models: Total TSO, Explored Hybrid DSO and Total DSO. As discussed, a key principle of the analysis is that the total capacity market opportunity for DERs should be the same, regardless of the TSO-DSO model employed. The capacity value of the DER to the system is independent of the model considered. At the same time, the TSO-DSO model adopted for the capacity market could be different than the one adopted for the energy market (which will be discussed in section 5). For instance, there could be merit to an approach where a TSO administers a capacity market encompassing the whole electricity system (i.e., on a Total TSO basis), but either a Total DSO Model or Hybrid DSO Model, with greater responsibilities for the DSO, is employed in the operational time frame.

Figure 5: Illustrative stages in the planning, investment and operational time frames

To help illustrate how coordination processes could be structured and how market payments could be made under each of the TSO-DSO models, the following example will use the high-level approach depicted in Figure 5. Consider a jurisdiction where energy markets and resource capacity markets are used to secure and operate resources. In the planning time frame, an integrated planning process identifies the use of DERs as NWAs to distribution network infrastructure in a specific geographic area as the more economical option to meeting growing local demand. Subsequently, in the investment time frame, a capacity market process is conducted to support investment in DERs and ensure that adequate resource capacity is secured within the distribution-level capacity zone to operate the distribution system

[13] Situations may arise where it is challenging to simply define capacity prices in a distribution-level capacity zone, e.g., in a distribution area that is fed through several connections to the transmission system and one of the connection points is reaching its limits. In such cases, it may be necessary to assess the DER's individual "qualified" capacity contribution to the NWA opportunity and clear the capacity auction on this basis.

reliably.[14] The capacity market process takes place in advance of a commitment period, when cleared non-dispatchable DERs must be available and dispatchable DERs will be subject to dispatch. In the operational time frame, during the commitment period, dispatchable DERs participate in the energy market and get dispatched when needed, for instance when local demand is expected to be high and distribution limits would be exceeded if they were not dispatched.

Table 6: Illustrative annual payments to DERs for integrated planning options

	Energy Payment ($/MW/year)	Resource Capacity Payment ($/MW/year)	Network Capacity Payment ($/MW/year)
Option 1: DERs			
DERs	$80,000	$140,000	N/A
Option 2: GS + TS			
GS	$70,000	$100,000	N/A
TS	N/A	N/A	$70,000

Table 6 outlines two planning options: one where DERs are used as resource capacity and one where a transmission-connected generating station is used and its resource capacity is delivered through network capacity. The table shows energy and resource capacity payments as part of market processes and network capacity payment to the utility to recover its costs.[15] The payments represent the revenue that resource and network assets receive, as well as the cost of the system for load. While the example is generally consistent with the motivating example presented in section 2, the values in the table do not perfectly align with it. The amounts in Table 6 are intended to show market payments received, while the motivating example, as previously noted, provided traditional planning types of cost categories. As was the case with the motivating example, the DER option is pursued because it is the lower-cost solution.

This paper explores the use of energy and capacity markets at the distribution and transmission levels to secure services from DERs, including as NWAs to distribution network infrastructure. As illustrated in the next three subsections, the manner in which DERs receive energy and capacity payments depends on the TSO-DSO model considered. The remainder of section 4 illustrates coordination processes for the capacity market, while section 5 does the same for the energy market.

The following discussion of coordination processes assumes that the system operators are independent, operating electricity markets without any profit motive and acting as neutral market facilitators that pass costs through to loads, and revenues through to resources. This approach is consistent with how wholesale markets are managed today. At the distribution level, an IDSO would facilitate DER participation in the distribution-level market and (depending on the model) in the wholesale market in a transparent manner without mark-up or distortion. This approach would enable DER participants to be compensated for the value they provide to the system.

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[14] Another conceivable approach involves the planning process identifying the need, but not whether it is more economical to use DERs as NWAs or new network infrastructure and centralized generation. Instead, the capacity market process would allow the various solutions to compete. While that approach is interesting and has some appeal, it is not explored further in this analysis.

[15] In Table 6, payment to the utility for the network is represented in capacity cost terms (with units of $/MW/year) to simplify comparison of the options. The network capacity payment reflects the annualized investment cost and fixed operation and maintenance cost. For simplicity, it is also assumed that the variable cost of operating the network is zero.

4.2.1 Total TSO Model

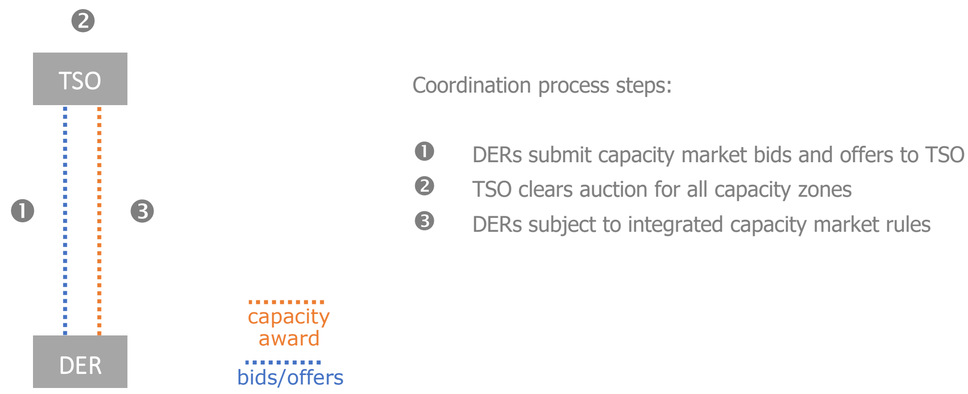


Figure 6: Illustrative coordination process for capacity procurement in the Total TSO Model

In the Total TSO Model, the TSO administers the capacity markets, both at the wholesale and distribution levels. In other words, the Total TSO administers one integrated capacity market for the full system, which would granularly indicate the capacity value of resources, including as alternatives to distribution network infrastructure as indicated by the capacity prices of distribution-level capacity zones.

Table 7: TSO capacity payment to DERs

Transacting Parties	Capacity Payment ($/MW/year)
To DERs from TSO	$140,000

As shown in Table 7, the distribution-level capacity zone clears at $140,000/MW/year in the example. This payment would compensate DERs for the combined value they provide as an alternative to resource capacity at the transmission level and as NWAs to distribution network infrastructure. In other words, at the transmission level, the capacity payments to transmission-connected resources in this market would be expected to be less than those provided to DERs at the distribution level, because the capacity value at the transmission level would not include the value of distribution NWAs.

Similar to the performance obligation in wholesale capacity markets, dispatchable DERs would be required to participate in the energy market and make their capacity available to meet resource adequacy needs. In an import-constrained distribution-level capacity zone where DERs are being used as NWAs, resource adequacy needs would be driven by periods when:

1. Distribution network capacity is limited or scarce, and there is ample resource capacity outside the zone
2. Resource capacity is limited or scarce outside the zone, and there is ample distribution network capacity

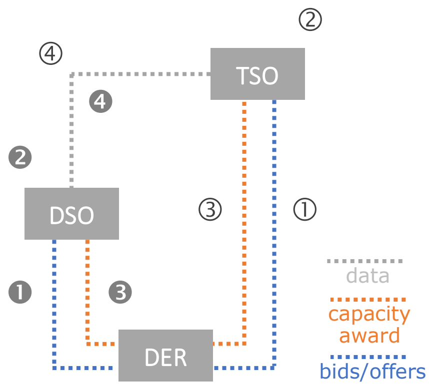
These two events can also occur simultaneously; distribution network capacity and resource capacity outside the zone can be limited at the same time. In such cases, DERs simultaneously meet both needs and should be compensated for their full capacity value.[16] In other words, the DERs are effectively being used by local customers simultaneously as an alternative to resource capacity outside the zone and as network capacity to deliver the resource's output into the zone. However, if the two types of events do not coincide, DERs would need to be capable of providing energy during both types of periods to receive the full $140,000/MW/year capacity value shown in the example.

The ability of different DERs to meet this resource adequacy requirement varies and can sometimes be limited, given for instance the energy-limited nature of energy storage and the specific energy output profile of solar PV. The requirement will also become more challenging as the local need grows and the distribution network capacity becomes limited during more hours of the year. To determine the contribution that they can provide, resources would generally go through a qualification process prior to each auction in the capacity market. Also, capacity markets generally have a single capacity service definition (or "product"), which is consistent with the approach described above. However, the two drivers of the full resource adequacy requirement are distinct. As such, two separate capacity service products could be procured for the two resource adequacy needs: one using DERs as NWAs to distribution infrastructure and another using DERs as system resources at the transmission level. One benefit of splitting the two products is that DERs that are capable of providing one service but not the other can more readily participate in the market. This approach is described further in the next section, which illustrates coordination processes under the Explored Hybrid DSO Model.

To facilitate this model, the TSO would need some inputs from distribution-level planning data, including the value of deferring or avoiding distribution network infrastructure to inform the capacity market parameters. From a DER provider's perspective, the TSO would represent the single interface and counterparty seeking to secure capacity services for the system. This simplicity is a major benefit of the Total TSO Model, as it reduces both the administrative cost and the risk of market participation for DERs (as discussed further in the next section). In this model, the TSO's market would also provide an integrated platform for participation across all transmission and distribution areas, permitting DER developers, aggregators and other participants to more easily identify investment opportunities, reducing search cost, increasing competition, and, in a sense, making the market more liquid.

[16] It is sometimes argued that DERs do not have transmission-level capacity value when a distribution constraint is binding, because their capacity is not available to the transmission system. However, this reasoning only applies to export-constrained zones. Import-constrained zones using DERs as NWAs should compensate DERs for their transmission level capacity value if they are available when there is limited (or scarce) resource capacity at the transmission level.

4.2.2 Explored Hybrid DSO Model



DSO process steps:

❶ DERs submit capacity market bids and offers to DSO
❷ DSO clears auction for its distribution-level capacity zones
❸ DERs subject to distribution capacity market rules
❹ DSO notifies TSO of DERs and capacity cleared

TSO process steps:

① Participants submit capacity market bids and offers to TSO
② TSO clears auction for all transmission-level capacity zones
③ DERs subject to wholesale capacity market rules
④ TSO notifies DSOs of DERs cleared

Figure 7: Illustrative coordination process for capacity procurement in Hybrid DSO Model

In the Explored Hybrid DSO Model shown, the TSO administers the capacity market at the wholesale level and the DSOs administer the capacity market at the distribution level.

The distribution-level capacity market would only reflect the value of using DERs as NWAs to distribution infrastructure, as only the DSOs would have visibility into distribution-level needs and secure DERs for these needs. Similarly, the TSO, which models and has visibility into transmission-level needs, would secure DERs and other resources to meet those needs. In this model, the DSO does not aggregate DERs' bids/offers and submit them to the TSO's energy market – the DERs participate directly and separately in both markets. As well, with this approach, the single capacity service definition described in the previous section for the Total TSO Model is split into two capacity service products. Consistent with the resource adequacy and capacity service definitions for the Total TSO Model, the distribution and transmission level capacity markets could be stackable, with rules and processes allowing DERs to simultaneously provide services and receive payments in both.

As summarized in Table 8, the total payments to DERs would, in theory, be the same under the Explored Hybrid DSO Model as under a Total DSO Model. As is the case with the Total TSO Model, to receive the full capacity value, DERs must make their capacity available to meet resource adequacy needs when (1) the distribution network capacity is limited, and when (2) resource capacity outside the zone, at the transmission level, is limited. The TSO capacity market payments to DERs would reflect the price and value of "system resources" at the transmission level, while the DSO capacity payments would reflect the price and value of the DERs as NWAs. To enable this model, capacity service and non-performance charges would have to be carefully defined to ensure DERs receive compensation for their full value, while ensuring reliability and appropriate payments for the services provided. Table 8 shows that the two payments combined align with the payment in Table 7 for the Total TSO Model.

Table 8: TSO and DSO capacity payments to DERs[17]

Transacting Parties	Capacity Payment ($/MW/year)
To DERs from TSO	$100,000
To DERs from DSO	$40,000

Where possible, aligning and simplifying the processes in the two capacity markets would lower the transaction cost and risk to market participation for the DERs, and perhaps, most importantly, reduce the possibility of one market creating inefficiencies and distortions for the other. For example, if capacity market rules were standardized (to the extent possible), participants could avoid having to review and understand two different sets of terms and conditions. Another risk associated with separate capacity market processes is that a DER provider counting on payments from the capacity auctions at both levels could only clear one of the auctions but not the other. While the payments to DERs under this model (shown in Table 8) would, in concept, be the same as under the Total TSO Model, this reasoning is only intended to facilitate the coordination-related analysis above (i.e., to identify parties and direction of transactions), but does not account for the difference in cost to the parties due to the coordination models themselves. If material risk and transaction costs are associated with DER market participation under the Explored Hybrid Model, payments would not be the same as those in the Total TSO Model. In such cases, DER participants' bids and offers into the capacity markets would reflect premiums, driving the total cost in Table 8 up.

4.2.3 Total DSO Model

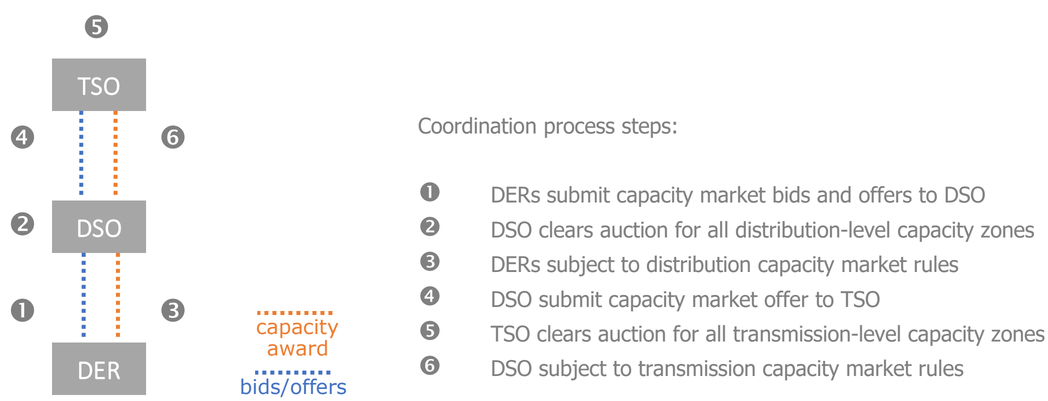


Figure 8: Illustrative coordination process for capacity procurement in Total DSO Model

[17] The split of the full capacity payment in the example into the transmission-level $100,000/MW/year and the distribution-level $40,000/MW/year is arbitrary. The intent is to show how these payments are transacted among the parties across the different TSO-DSO models. The specific amounts do not have any bearing on the concepts being illustrated.

In a Total DSO Model, DERs would only participate in the capacity market administered by the DSO in the territory where they are located, which would reflect the combined capacity value of both distribution- and transmission-level needs. DSOs, in turn, would participate in the TSO's capacity market, which only reflects transmission-level value. In this model, DERs cannot participate directly in the TSO's transmission-level capacity market. Instead, the DSOs submit aggregated capacity offers at the T-D interfaces to the TSO's capacity market. As discussed above, an IDSO would conduct this in a transparent pass-through manner, reflecting DER capacity bids and offers in its aggregated capacity offer into the TSO's capacity market. Similarly, capacity payments the IDSO receives from the TSO's market would pass directly to DERs, ensuring these resources are fairly compensated for the value they provide to the system. As summarized in Table 9, total payments to DERs would, in theory (neglecting differences in participant risk and administrative costs), be the same under a Total DSO Model as under the other two coordination models. As well, the cost borne by the DSO would be the same as under the Explored Hybrid Model, considering that the DSO would recover the value of DERs as "system resources" at the transmission-level from the TSO.

Table 9: TSO and DSO capacity payments

Transacting Parties	Capacity Payment ($/MW/year)
To DERs from TSO	$0
To DERs from DSO	$140,000
To DSO from TSO	$100,000

A major benefit of the Total DSO Model is that DERs participate in a single capacity auction that integrates distribution and transmission needs and value, reducing the risk of market participation and some administrative cost for the DER provider. That said, transaction costs would be higher than under the Total TSO Model, as DER developers, aggregators and other participants may search for opportunities and participate in different DSO markets with different market rules, processes and interfaces. This model also introduces some risk to be managed by the DSO, which may have to forecast the TSO's capacity auction clearing price when conducting its distribution-level capacity auction. In administering the distribution-level capacity auction in the above example, the DSO would accept the $140,000/MW/year clearing price based on the forecasted and anticipated clearing price of the TSO capacity market. When the TSO conducts its auction, the DSO would participate as a price taker, having already committed the expected transmission-level payment to the DERs. The risk to the DSO is that the TSO's clearing price would differ from the expected clearing price. Even an IDSO that simply passes costs through to load has to manage the risk with the aim of reducing its impact. To manage this risk, the DSO could employ an alternative capacity auction process where (1) the DSO opens the distribution-level capacity auction prior to the TSO's centralized auction, (2) the DSO receives capacity bids and offers from DERs, (3) the DSO aggregates the DER bids/offers and submits to the TSO's auction when it is opened, (4) the TSO clears the centralized auction and provides capacity awards to the DSOs, (5) the DSO clears the distribution-level capacity auction and provides capacity awards to the DERs. With this approach, the DSO only makes commitments to DERs once the TSO market's clearing price and capacity awards are known, reducing or even eliminating the risk. This coordination process is similar to the process explored for the energy market under the Total DSO Model described below.

5. NWAs in Energy Markets

5.1 Active Management of DERs

Traditionally, distribution network planning involved forecasting the peak customer demand over the planning horizon and investing in distribution network assets to accommodate the peak gross loading on the system [18]. In this “fit-and-forget” approach, sufficient distribution network capacity was installed to ensure that network constraints would not be violated, which in turn meant that limited monitoring and control was required [18]. Given that, historically, demand responsiveness was low and DERs were much more expensive, the ability to create value with local market opportunities was limited. However, as the electricity sector evolves, active management of the distribution network and DERs may be needed to capture the full value of technological advancements. In particular, dispatchable resources, such as demand response, energy storage and gas engines, need to receive a signal from system operators to operate when demand for energy and loading on the network is high. As set out in Table 10, a range of approaches to compensating DERs for dispatch is possible in concept, but LMP is the most granular and allows DER participants to better manage certain risks.

Table 10: Description of some approaches to compensating active DERs

Approach	Description
No operating payment	System operators use local “threshold control” to dispatch DERs,[18] but DERs do not receive a payment when dispatched. If the DER participant incurs a cost when dispatched, this approach could entail significant risk that would need to be managed, e.g., by including forecasted operating costs and risk premiums in capacity offers.
Standard operating payment	Perhaps as part of a standard offer program, a standard dollar per megawatt-hour ($/MWh) operating payment could be provided to all participating DERs when dispatched. While helpful, a standard payment would not reflect DER-specific underlying cost, so a risk is still present.
DER-specific operating payment	Perhaps as part of an RFP and contract procurement model, operating payments could reflect DER-specific costs, reducing risk. However, with this approach it is challenging to capture DERs’ fuel and opportunity costs that may change on a regular basis.
Locational marginal prices	LMP is typically determined in an energy market, permitting bids and offers to be updated to reflect changing fuel and opportunity costs. Payments would be at or above dispatched DERs’ operating cost and provided on a local marginal cost, clearing price basis. While LMP is the most economically efficient approach, it is complex to implement.

[18] In threshold control, the operator forecasts and observes the physical loading on the network infrastructure and dispatches DERs when the loading is expected to exceed its limit or the threshold.

5.2 LMP at the Distribution Level

Locational marginal price (LMP) is used across organized markets throughout North America and will be introduced to Ontario as part of the IESO's Market Renewal Program (MRP). LMP is well-established as the economically efficient means of pricing energy in electricity systems. It reflects the fact that the energy price varies by location and time due to differing production costs, energy losses and limits on the transmission network. The LMP at any particular pricing node is the marginal price of providing one additional megawatt-hour of energy. LMP yields economically efficient prices because it minimizes resources' cost of producing energy and maximizes the value of consuming the energy (referred to as total surplus in microeconomics) [32].

The effect of transmission limits in the energy market is very similar to the discussion of capacity zones and price separation in section 4. However, in the energy market, whether loading on the system exceeds the transmission limit depends on the time period in question. When a limit is expected to be exceeded, the constraint is binding, driving price separation in LMP across transmission nodes. An area could, for instance, be import-constrained, necessitating the use of resources that are more expensive to operate. Conversely, an area could be export-constrained, with resources that are less expensive to operate but that are bottled in – in other words, that cannot produce and export energy because of transmission constraints. LMP reflects and internalizes the cost of congestion due to constraints and the cost of losses, as captured in the notional equation [33]:

LMP = Energy Reference Price + Energy Price Congestion Component + Energy Price Loss Component

Employing dispatchable DERs as NWAs to defer or avoid building distribution network infrastructure involves the purposeful management of binding constraints in the distribution system in hours when loading[19] on the distribution network is expected to exceed limits. To manage dispatchable DERs, the energy market could be extended to include limits and losses at both the distribution and transmission levels. This approach would also extend LMP to the distribution system, producing distribution locational marginal prices (DLMP) that reflect the cost of marginal losses (which could be material at lower voltage levels and at times of high demand), as well as any constraints in the distribution system. In other words, with a distribution-level energy market and DLMP, the appropriate dispatch and price signals are provided to DERs that are used as NWAs when they are needed to operate. When dispatchable DERs are needed as NWAs due to a binding distribution-level constraint, DLMP would rise to reflect the cost of the marginal DER (i.e., the cost of the next MWh of DER output) that is dispatched at the node. DLMP, like LMP, is a clearing price, so all DERs at the same pricing node that are dispatched for distribution-level energy needs would receive it.

[19] Specifically, the loading on the distribution network referred to is net of any passive resources, such as zero-marginal cost solar photovoltaics or self-scheduling, price-taking combined heat and power. The loading referred to is gross of active, dispatchable DERs intended to be used as NWAs.

5.3 Illustrative Energy Market Coordination

In concept, it is possible to generate DLMP under different TSO-DSO coordination models. The following discussion will explore illustrative coordination processes for how DERs as NWAs to distribution network infrastructure could be operated using energy markets in a manner that could support reliability. Dispatch is illustrated under three TSO-DSO models: Total TSO, Explored Hybrid DSO and Total DSO. The total energy market opportunity for DERs should, in concept, be the same, given that the value of DERs to the system is the same, regardless of the TSO-DSO model considered.

Again, the TSO-DSO model adopted for the energy market could be different than the one adopted for the capacity market (discussed in section 4). For instance, there could be merit to an approach where a TSO administers a capacity market that encompasses the whole electricity system (i.e., on a Total TSO basis), but in the operational time frame, either a Total DSO or Hybrid DSO Model is employed and the DSO has greater responsibilities.

5.3.1 Total TSO Model

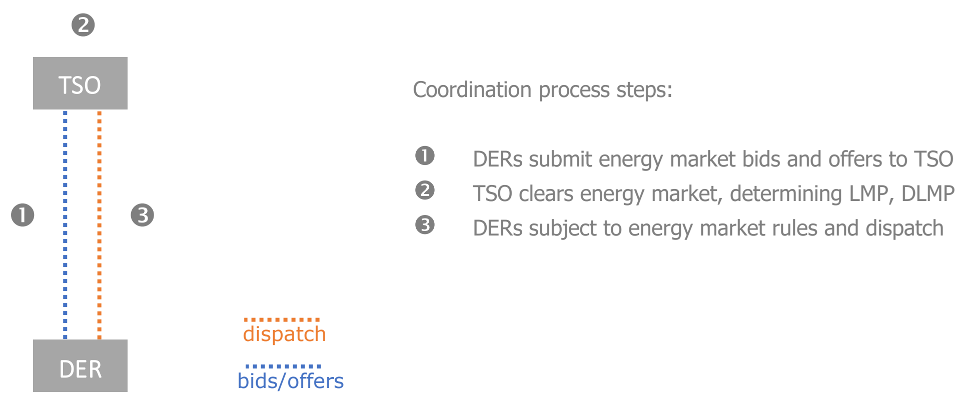


Figure 9: Illustrative coordination process for energy market in Total TSO Model

In the Total TSO Model, the TSO administers the energy market, both at the wholesale and distribution levels. In other words, DERs would participate in an integrated energy market. As illustrated in Table 11, the energy market payment to DERs would be at DLMP, reflecting the energy value considering losses and constraints at both the transmission and distribution levels. This payment would be higher for a DER used as an NWA than a resource (with the same bids and offers in the energy market) connected further upstream at the transmission level because the DER would capture additional value for addressing binding distribution constraints. Resources connected at the transmission level would receive LMP, while DERs would receive DLMP, which may be higher in import-constrained zones.[20] Importantly, DERs that cleared in the capacity market would receive a full capacity payment, provided they are available for

[20] Export-constrained DERs do not have local value. They would not be dispatched on or would be curtailed off because DER energy output in the area is in excess of what the network infrastructure can deliver out of the export-constrained area.

dispatch in the Total TSO's energy market. The capacity payment would be provided regardless of whether the DER's dispatch in the energy market is driven by distribution- or transmission-level needs.

Table 11: TSO energy payment to DERs

Transacting Parties	Energy Payment ($/MW/year)
To DERs from TSO	$80,000

Today, ISOs do not compute DLMP, as their network models do not generally extend into the distribution system and they do not receive telemetry and other data from the distribution system sufficient to determine DLMP. Also, ISOs do not have the operational control at the distribution level (e.g., to operate switches and capacitor banks) to actively manage the distribution system. This lack of visibility and control contrasts with the wholesale level, where the ISO has access to all of the necessary data and can direct the operation of the transmission network. In theory, if access to data is provided and ISO network models and operations are expanded into the distribution system, then ISOs could determine DLMP and dispatch DERs. However, considering current optimization techniques and technology, determining DLMP at scale (i.e., granularly for large portions of the distribution system) may be computationally challenging or infeasible. Models for determining DLMP that involve DSOs may reduce the computational burden on the TSO, in effect dividing it between a TSO that models the transmission system and generates LMP and DSOs that model the distribution system and generate DLMPs.

5.3.2 Explored Hybrid DSO Model

In the Explored Hybrid DSO Model, the TSO administers the energy market at the transmission level and DSOs administer energy markets at the distribution level. A DER that has capacity obligations in both the transmission- and distribution-level capacity markets would participate in both the TSO's and applicable DSO's energy markets, and be dispatched by either. With this approach, the DSO does not aggregate DERs and offer them into the TSO's energy market – DERs participate directly. In the Hybrid DSO models, processes must be carefully designed and aligned across the TSO, DSOs and DERs, to ensure resource dispatch can be conducted in a manner that maintains electricity system reliability".

DER participation in the transmission-level energy market is beneficial in several ways. First, DERs that do not provide distribution-level value still have value to the system. Transmission-level market participation is a major pathway to realize the value of cost-effective DERs. Without market participation and its associated visibility, the output of DERs and their active response to prices would need to be estimated and forecasted by system operators as part of net load (i.e., gross load minus DER output) at transmission-distribution nodes. Without sufficient data to model non-market-participating DERs accurately, forecast errors can increase, especially in a potential high-DER future. This dynamic could drive up the need for more "flexible" resources and "flexibility" services, such as operating reserves that are used to balance the system when conditions change unexpectedly and abruptly.

DERs participating in the transmission-level energy market are also beneficial when providing services as NWAs to distribution network infrastructure. In the Explored Hybrid DSO Model, DSOs have visibility into the distribution system and dispatch DERs as NWAs when there are binding constraints at the distribution level. However, this may only occur on a limited basis each year during high-demand days. While DERs as NWAs potentially have significant capacity value, they may only be dispatched for this need occasionally. The rest of the time, when distribution-level constraints are not binding, DERs can provide energy value to the broader system. Transmission-level energy market participation facilitates this by considering DERs, transmission-connected generation, the transmission network and system-wide demand as part of the market process. In other words, DERs can increase operating efficiency, displacing energy from more expensive transmission-connected resources. As well, participation in the transmission-level energy market enables DERs to provide capacity value at the transmission level, as further detailed in Table 12. In fact, as discussed, a major obligation of capacity markets is for the participant to make the resource capacity available to dispatch by participating in the energy market. Similar to the outcome under the Total TSO Model, DERs used as NWAs that cleared in the capacity market would receive a full capacity payment, provided they are available for dispatch in the energy market, regardless of whether it is driven by distribution- or transmission-level needs.

Table 12: The two operational scenarios of distribution and transmission peaks

Scenario 1: Coincident Distribution and Transmission Peaks	Scenario 2: Non-Coincident Distribution and Transmission Peaks
DERs are secured as NWAs to distribution network infrastructure. In scenario 1, the relevant distribution area's load peaks at exactly the same time the transmission system load peaks. The DSO, which has visibility into the distribution system, would dispatch the DERs as NWAs (and TSO dispatch is not required). In scenario 1, DERs are providing transmission-level value in the sense that distribution network infrastructure and transmission-connected resources would have been needed without them.	DERs are secured as NWAs to distribution network infrastructure. In scenario 2, the relevant distribution area's load peaks at different times than the transmission system.[21] To have transmission level capacity value, the DERs need to operate when the transmission system peaks – which is visible to the TSO. To have distribution-level capacity value, the DERs need to operate when the distribution system peaks, which is visible to the DSO. For DERs to provide their full value, both TSO and DSO dispatch is needed.

In the Explored Hybrid DSO Model, both the applicable DSO and the TSO can dispatch DERs. To enable this dual participation, the two system operators need to know the operational status of the DERs. For instance, when a TSO dispatches a DER in its energy market, the TSO anticipates that the loading at the transmission-distribution node will decrease when the DER starts operating. However, if the DER is already being used as an NWA in an import-constrained distribution area, the TSO's dispatch of the DER will not have the anticipated incremental impact at the transmission level. To address this and similar situations, the TSO and DSOs need to coordinate their operations and keep their systems updated with the operational status of the DERs participating in their respective markets, reflecting the scheduling and dispatch instructions received from the other system operator.

[21] May be driven by the difference between the load profile of distribution-level residential customers and the load profile at the transmission level, reflecting commercial and industrial customers' patterns as well.

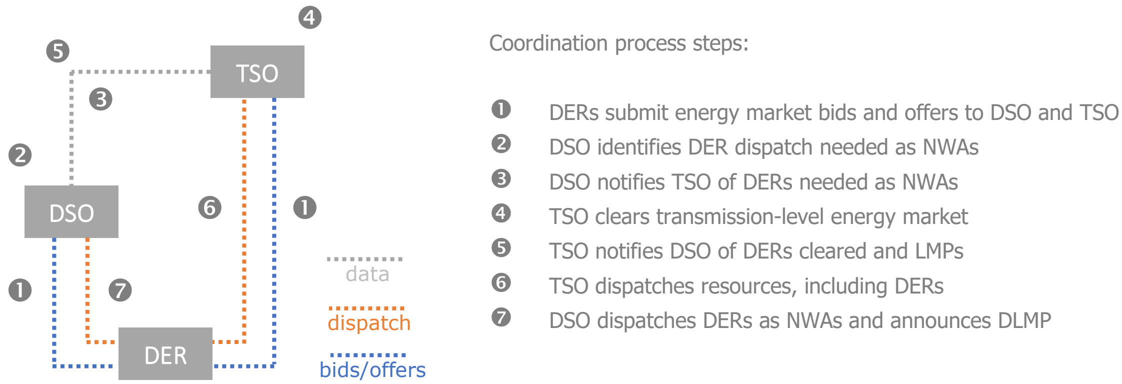


Figure 10: Illustrative coordination process for the energy market in the Hybrid DSO Model

As illustrated in Figure 10, DSOs and the TSO must conduct their respective energy market processes in order, starting at the distribution level. This process flow ensures the TSO knows which DERs are available and unavailable to the transmission-system, as it clears the bids and offers from DERs and transmission-connected resources and loads. In conducting part of their process first, the DSOs identify any DERs needed as NWAs and notify the TSO. The TSO then conducts its transmission-level optimization, determines LMP, sends dispatch instructions, and notifies the DSOs of DERs dispatched and the LMPs at the transmission-distribution nodes. At this point, the DSOs have the information needed to conclude their energy market process, sending additional dispatch instructions to DERs as NWAs and announcing DLMP. The process described and illustrated in Figure 9 involves the applicable DSO and TSO directly notifying each other of DER dispatch based on their respective networks and needs. An alternative communication path, currently being explored in New York, involves DER participants being notified by the DSO and relaying that notice to the TSO (and vice versa).

Table 13: TSO and DSO energy payments to DERs[22]

Transacting Parties	Energy Payment ($/MW/year)
To DERs from TSO	$60,000
To DERs from DSO	$20,000

As summarized in Table 13, providing service to the distribution- and transmission-level energy markets would be stackable, with rules and processes allowing DERs to combine payments. In the example, the $60,000/MW/year payment represents LMP multiplied by the energy dispatch of the TSO. The $20,000/MW/year payment represents DLMP multiplied by the energy dispatch of the DSO. Combined, the DER receives $80,000/MW/year, consistent with the payment received under the Total TSO Model. In the Explored Hybrid DSO Model, these payments would be stackable on a time-differentiated basis, with

[22] The split of the full energy payment into the transmission-level $60,000/MW/year and the distribution-level $20,000/MW/year is arbitrary. The intent is to show how these payments are transacted among the parties across the different TSO-DSO models. The payment amounts do not have any bearing on the concepts being illustrated.

the DERs being dispatched and paid by the TSO and applicable DSO at different times, depending on which of the two has visibility into the need and dispatches the DER.

In the Explored Hybrid DSO approach, only the DSO would have visibility into distribution-level needs and would dispatch and pay DERs used as NWAs in its energy market. Similarly, the TSO would dispatch and pay DERs for meeting transmission-level needs. Adhering to the above coordination process (or a similar one) should help prevent situations where a DER receives conflicting instructions from the DSO and TSO. In other words, when it has information about which DERs will already be operating to meet distribution-level needs, the TSO will not dispatch these DERs and will appropriately account for them in its energy market process.[23] As discussed in section 4.2.1, DERs obligated to provide capacity service to the TSO should not be penalized when they are dispatched by the DSO for use as NWAs to distribution infrastructure.

A major disadvantage of the Explored Hybrid DSO approach to the energy market is that the coordination process is complex and, if not designed carefully, could undermine system reliability. As discussed above, incorrect information about the state of DERs and dispatch instructions could affect reliability, especially at high penetrations of DERs. In defining stacking rules and non-performance charges, care is needed to ensure correct economic signals and market outcomes. As well, participating in two separate energy markets, each potentially with its own set of rules and processes, would result in additional transaction costs for DERs, which would be reflected in participant bids and offers in the market.

5.3.3 Total DSO Model

Figure 11: Illustrative coordination process for the energy market in the Total DSO Model

In a Total DSO Model, DERs only participate in an energy market administered by the DSO, which would reflect the energy value with losses and constraints at both the distribution and transmission levels. The DSO, in turn, participates in the TSO's energy market and is dispatched by the TSO. In this model, DERs cannot participate directly in the TSO's energy market, regardless of whether they are NWAs to

[23] With respect to TSO-DSO coordination, a common query is whether the TSO's or the DSO's dispatch would take precedence in the event of a conflict. With this approach, conflicting dispatch would not arise.

distribution network infrastructure or only providing transmission-level value. As discussed above, it is assumed that an IDSO conducts this aggregation in a transparent pass-through manner, reflecting DER energy bids and offers directly in the aggregated energy offer into the TSO's energy market. As well, the energy payments the DSO receives from the TSO's market would pass through directly to the DERs, compensating them fairly for the value their services provide to the system. As summarized in Table 14, the total energy payments to DERs would, in concept, be the same under the other two models. The DSO would provide the DERs with their total payments, but in turn would receive payment from the TSO for the DERs' transmission-level value. In other words, the DSO's net position would be $60,000/MW/year, consistent with the payments under the Total TSO and Explored Hybrid DSO Models.

Table 14: TSO and DSO energy payments

Transacting Parties	Energy Payment ($/MW/year)
To DERs from TSO	$0
To DERs from DSO	$80,000
To DSO from TSO	$20,000

Figure 11 illustrates the coordination process for the Total DSO Model. First, the DSO receives bids and offers from DERs, adjusts the bids and offers to reflect distribution-level constraints, and submits an aggregated offer to the TSO. Second, the TSO, having received the DSOs' aggregated offers, conducts its energy market processes, determining transmission-level LMP and dispatch of centralized, transmission-connected resources and DSOs. Based on the dispatch received from the TSO, DSOs identify DERs that are economic to operate given transmission-level conditions – these are in addition to the DERs already identified as needed to operate given any binding distribution-level constraints. In other words, following the TSO's dispatch of the DSOs, the DSOs would dispatch the DERs, partly relaying the TSO's (full) dispatch and partly layering in distribution-level dispatch based on distribution needs not visible to the TSO. Similar to the approach under the Total TSO Model, DERs used as NWAs that cleared in the capacity market would receive a full capacity payment, provided they are available for dispatch, regardless of whether that dispatch is driven by distribution- or transmission-level needs.

A major benefit of the Total DSO Model is that DER providers incur a lower administrative cost for participating in an integrated energy market. However, DER developers and aggregators that participate in several different DSO markets would be exposed to different market rules, processes and interfaces, increasing their transaction costs.[24]

[24] The description of the capacity market coordination process for the Total DSO Model in section 4.2.3 notes that the DSO takes on a risk in forecasting the TSO's expected capacity auction clearing price when conducting its distribution-level capacity auction. A similar situation occurs in the energy market, if the DSO forecasts LMP and dispatches DERs prior to the TSO's energy market dispatch and LMP announcement. However, this section describes a more integrated coordination process that has the DSO participating in the TSO's market before it dispatches the DERs. In this manner, the TSO's dispatch and LMP are known to the DSO when it dispatches the DERs. Some energy market coordination processes also contemplate the DSO conducting a "re-optimization" following the TSO's dispatch – but prior to DERs being dispatched by it – if conditions have changed (e.g., a network topology change due to a fault) between the time the DSO submitted the aggregated offer to the TSO's energy market and the time the DSO is dispatched by the TSO.

6. Implementing NWAs

6.1 Day-Ahead and Real-Time Energy Markets

The TSO-DSO energy market coordination processes illustrated in section 5 can be applied in both the day-ahead and real-time time frames and markets. Both time frames require coordination between the TSO and DSOs, given the lack of visibility into each other's respective market and system. The day-ahead market is a standard component of electricity market design, providing financially binding schedules for participating resources a day in advance of operation. It provides a high degree of financial and operational certainty to market participants and system operators, enabling participants to manage their risks and costs. For instance, the day-ahead market could permit natural-gas fired generators to better secure fuel and for demand response participants to better plan load curtailments. The day-ahead market also enables system operators to schedule cost-effective and reliable supply by better capturing resource start-up costs, ramp rates, minimum output and other technical specifications.

Typically, in wholesale markets, most of the system's resource capacity is scheduled in the day-ahead market based on day-ahead forecasts, while the real-time market is used effectively to balance any deviations that occur between the day-ahead and real-time. However, with increasing levels of intermittent renewable resources, behind-the-meter DERs that are not visible to system operators, and customers that are more responsive to time-varying retail rates, accurate forecasting may become more challenging in the future due to greater variability in net loading in real-time. This challenge may require more adjustments to day-ahead resource schedules in the intra-day time frame and a greater reliance on the real-time energy market and operating reserves.

In future work, it would be worthwhile to assess the viability of relying on either a day-ahead or real-time market solely when introducing distribution market designs to reduce initial cost and complexity. For instance, it may be possible to use conservative day-ahead forecasts to anticipate when local gross load is expected to be high and local constraints will bind in order to schedule sufficient DERs as NWAs to operate the distribution system reliably.

6.2 Reserve Margin and Operating Reserve

Reliability standards for the transmission and distribution systems vary due to differences in the engineering design of the systems and the way they have traditionally been planned and operated. System reliability indices applied to the distribution system measure the frequency and duration of interruptions to electricity service to end-use customers, for instance using the system average interruption frequency index (SAIFI) and the system average interruption duration index (SAIDI). At the distribution level, reliability performance is largely dependent on timely installation of new network infrastructure and maintenance of distribution system assets, as well as resilience in the face of severe conditions and restoration time when interruptions happen. On the other hand, at the transmission level, reliability standards focus on resource adequacy and operational reliability, which capture resources' impact on reliability in addition to the transmission network infrastructure.

Section 4 described capacity auction mechanisms for securing DERs as NWAs and for meeting resource adequacy needs. The exact quantity of resource capacity that is secured, determined by resource adequacy requirements, is a fundamental element of reliability. In Ontario, the relevant reliability standard at the transmission level is established by the Northeast Power Coordinating Council (NPCC) – one of nine regional electric reliability councils under the authority of the North American Electric Reliability Corporation (NERC). NPCC's resource adequacy design criterion requires that the IESO "…probabilistically evaluate resource adequacy" of the bulk power system "to demonstrate that the loss of load expectation (LOLE) of disconnecting from load due to resource deficiencies is, on average, no more than 0.1 days per year" [34]. It further requires the IESO to "make due allowances for demand uncertainty, scheduled outages and deratings, forced outages and deratings" [34]. To assess resource adequacy, a range of detailed inputs are modelled, including load forecast uncertainty, planned outages, forced outage rates, weather variability, major transmission network constraints and resource limitations. The output of the assessment produces planning reserve margins, i.e., capacity that needs to be secured in excess of the expected peak requirement in order to meet the reliability standard. In addition, the process establishes the quantity of resource capacity that must be located within transmission-constrained zones.

While section 5 described energy market mechanisms for operating DERs as NWAs to distribution network infrastructure, the descriptions did not consider the need for operating reserves to reliably operate the system. Reliability is based on adequacy, which involves having the necessary resource capacity and network capacity, and on operating reliability, which involves the ability to balance the system under forecasted and contingency conditions. At the transmission level in Ontario, the operating reserve requirement is based both on NERC reliability standards and reliability criteria established by NPCC. The IESO currently administers three different classes of operating reserve products[25] that are secured in the wholesale energy market, co-optimized with energy and simultaneously scheduled. The classes of operating reserve have varying degrees of readiness to respond to contingencies and, together cover the largest single contingency plus half of the second-largest contingency that may occur. Typically, this means the loss of Ontario's one and a half largest generators. In addition, operating reserve areas are defined to ensure that operating reserve is distributed appropriately across the system. The boundaries for these reserve areas are defined by transmission network limits. The growth in penetration of intermittent renewable resources and DERs has also increased the potential for errors in operational forecasting and increased ramping needs, resulting in the need for resources with flexibility. To increase the availability of flexible resources, the IESO recently amended its market rules to allow increases to 30-minute operating reserve to cover for uncertainty (in addition to contingency) in specific situations [35].

To prepare for an environment where DSOs operate DERs, future work could explore additional reliability standards and how these could be applied through legislation and regulations. Reliability standards at the transmission level provide a starting point; however, these may need to be modified to reflect differences between the transmission and distribution systems. Additionally, reliability standards may need to specify the TSO-DSO operational process required at the transmission-distribution interface to reliably operate the system.

[25] The three types of operating reserve classes that can be offered by dispatchable generators and dispatchable loads are: 10-minute synchronized (spinning) reserve; 10-minute non-synchronized (non-spinning) reserve; and 30-minute reserve (non-synchronized).

6.3 Market Power

If there are sufficient conditions for competition, market mechanisms can effectively be used to secure electricity services in an economically efficient manner. However, when conditions are insufficient for competition, participants can potentially exercise market power through either physical withholding (i.e., reducing the output offered into the market) or economic withholding (i.e., increasing the price offered into the market) to profitably alter prices away from competitive levels [32]. Market power can be local in nature; for instance, transmission-level constraints may effectively create isolated zones where competition is limited. However, at the transmission level, these segmented areas are generally large zones of the system where energy, reserve and capacity services can still be competitively secured.

Market operators and regulators use a range of methods to detect market power [36], which is of particular concern in the operational time frame, when in the short run, provision of energy and reserve services is limited to existing, installed resources. In the investment time frame, capacity markets generally receive sufficient competition from existing participants and participants seeking to enter with new resource capacity, provided the capacity zones defined for the auction are sizeable. If detected, market power can be mitigated in a number of ways, including market-wide price caps, resource-specific offer caps and longer-term contracts that reflect the resource's costs [36].

Market power concerns are heightened when securing services with distribution-level markets, given that their smaller, local nature may limit competition. However, the ability of many smaller DERs to participate in distribution-level markets could act as a balancing dynamic that alleviates those concerns. Some jurisdictions are using suitability criteria to identify distribution-level NWA opportunities. While not directly related to market power, these criteria, which include size and cost thresholds, can to some extent remove NWA opportunities that are small and have limited competition. In future work, it would be useful to assess the conditions that would permit competition for distribution-level services and the use of market mechanisms, and those under which other mechanisms, such as programs, RFPs and contracts, would be better suited for securing services.

6.4 Competitive RFPs and Contracts

A DSO could use request for proposal (RFP) processes to secure services from DERs instead of capacity auction processes, such as those described in section 4. Often RFPs for resources award contracts that outline terms, including performance requirements, settlement provisions and non-performance charges. Capacity auctions, on the other hand, clear market offers for provision of resource capacity, making them subject to market rules that also outline performance requirements and settlement provisions, among other rules.

Many considerations apply to both approaches. For instance, in the Rocky Mountain Institute's *Non-Wires Solutions Implementation Playbook* [9], the best practices recommended for RFPs and contracting are also important for capacity auctions and market approaches. These include:

- Describing performance requirements for NWA solutions instead of specifying technology outcomes, permitting technology-agnostic competition
- Engaging with stakeholders in developing requirements and processes, and providing sufficient data for third parties to design NWA solutions

- Outlining availability and other requirements to foster confidence that NWAs will deliver reliably, without placing undue risk and cost on third-party participants
- Specifying the rules for participation across opportunities to provide electricity services, ensuring that resources are not double-counted and will perform reliably

While both procurement approaches facilitate competition among resource developers, aggregators, independent power producers and other third-party electricity service providers, they also differ in important ways. Capacity auction processes are designed specifically to work in parallel with energy markets, while contract settlement provisions may create economically inefficient operational incentives if not carefully crafted. RFP processes can include considerations for qualitative criteria, such as development experience and financial wherewithal. On the other hand, capacity auction clearing is based on price alone, permitting more open and potentially more innovative participation, in addition to clear evaluation of offers. The clearing price for capacity auction processes is also transparently published, while contract prices are often not disclosed. Contracts awarded as part of RFP processes are usually long term, often between five and 20 years. While capacity auction processes often provide multi-year commitments for new resources, these will usually be shorter, often between three and 10 years. In capacity auctions, existing resources often receive even shorter commitments – typically six months or a year.

A major benefit of capacity markets is that they are more periodic, incremental, flexible and algorithmic than RFP processes. RFPs often procure services on a chunky, long-term basis, with larger quantities being secured with longer-term commitments. However, capacity auctions take place on a fixed, periodic – often annual – basis permitting procurement of services, in-step with the growth of local load year-over-year for instance. The more open and flexible aspect of capacity auctions may also facilitate easier coordination between DSOs and a TSO. That said, in a scenario where both DSO and TSO procurement of services is on an RFP and contract basis, lack of timing and process coordination may result in missed opportunities to take advantage of lower-cost NWA solutions. While an upfront investment is needed to design a distribution-level capacity auction process and for participants to evaluate and familiarize themselves with the rules, a consistent, periodic process will lower transaction costs in the long run. On the other hand, RFP processes are often tailored, with each potentially having its own unique set of processes and contract terms that may increase the cost of the procurement, and potentially reduce access to smaller, less sophisticated participants. A simple and consistent capacity auction process lends itself to a more transactive energy approach, with potentially automated devices participating in an algorithmic manner in the market.

6.5 Cost Allocation and Rates

Sections 4 and 5 described potential energy and capacity market interactions among DERs, DSOs and a TSO under three different TSO-DSO coordination arrangements, presenting illustrative transactions that would take place among the parties. However, these descriptions consider only the supply- or resource-side provision and sale of electricity service, but not the purchase of electricity services, including how charges to load customers could be structured and how "buy-side" competition would be enabled.
In the context of a potential high-DER future and DERs' improving capability to provide services locally, allocating the associated costs on a more granular locational basis would also be appropriate. Granular cost allocation would be consistent with the "beneficiary pays" and "cost-causation" principles of ratemaking. This type of approach could be thought of as local customers paying for new DERs instead of

paying for new network infrastructure and centralized resources, where integrated planning has shown that DERs would be the lower-cost solution.

In future work, a detailed exploration of more granular cost-recovery methods under different TSO-DSO models and further consideration of potential "buy-side" entities would be useful to better understand the full picture of potential challenges and opportunities of TSO-DSO coordination in a high-DER future.

7. Conclusions

Taking advantage of DERs as NWAs at scale, by actively managing the distribution system and introducing DSOs, may require fundamental changes to legislation, regulations, planning methods, market rules and system operations. As noted throughout the paper, while low penetrations of DERs can be managed with existing market and system operation tools and mechanisms, these will be challenged in a potential high-DER future. While the concepts explored in this paper support the use of market constructs to secure and operate DERs as NWAs, they require further investigation and understanding, particularly given the potential reliability risks associated with prematurely introducing changes to an already complex electricity system. That said, complexity and reliability concerns should be balanced against opportunities to evolve the system to reduce costs and improve electricity service. At the most fundamental level, there will be a need to determine the information, analysis and/or modelling required to provide reassurance that the TSO-DSO coordination models being considered will maintain reliability in a high-DER future and are sufficiently mature to be implemented.

Steps can be taken to advance NWA concepts and incrementally introduce NWA opportunities. For instance, large and high-value opportunities to use DERs as NWAs to distribution network infrastructure can be pursued without the need for highly granular prices throughout the distribution system. It is conceivable that in the near to medium term, distribution-level markets and prices may be introduced for a few specific zones in the distribution system where there is a need, signaling to potential participants where there is material value in deploying and operating DERs. These zones could grow in number over time as load growth and infrastructure retirements create additional NWA opportunities. The zones can also become incrementally more granular, as mechanisms mature to enable smaller NWA opportunities to be pursued. A gradual approach would also present an opportunity to test, collect data, and refine methodologies. Ultimately, once concepts and mechanisms mature, full-scale changes to regulations, operational tools and market rules may need to be implemented. During that process, Ontario will also have to consider the level of standardization in processes and commercial terms required across the service territories of the dozens of local distribution companies that currently exist in the province. From the perspective of DER participants, a standard approach will reduce transaction costs and other barriers to participation in the broader Ontario electricity marketplace.

Today there is significant focus and effort throughout the power and utilities sector on the emerging need to more actively manage the distribution system and provide opportunities for DERs to more fully participate in the wholesale markets. Exploring the use case of DERs that are employed as NWAs to distribution network infrastructure provides insight in analyzing the coordination of TSO-DSO market and system operations. In particular, the use case identifies critical process steps that may be needed to ensure operational reliability, resource adequacy and economically efficient market outcomes. As well, while the requirements of distribution-level market and system operations are different than at the transmission-level, concepts, processes, mechanisms, and experiences can be drawn from and applied at the distribution level, including the use of energy and capacity markets.

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