Development of a **Transmission-Distribution Interoperability Framework**

Prepared by ICF for the Independent Electricity System Operator

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Part of the IESO's Innovation and Sector Evolution White Paper Series, this report was commissioned by the IESO to re-examine traditional roles at the transmission and distribution levels, and assess the potential for an electricity system architecture that incrementally builds on existing capabilities, as well as the current responsibilities of transmission and distribution operators and how they interact with each other to serve the evolving and future needs of the system. The paper lays out next steps for further exploration of a model for transmission-distribution interoperability that takes a flexible approach to coordinating operations, ensures electricity system reliability and reflects the province's objectives for the grid.

The IESO's Innovation and Sector Evolution White Paper Series is designed to support the creation of a shared, fact-based understanding of emerging issues, opportunities and trends with the potential to significantly impact the future of Ontario's electricity system, the broader electricity sector and, particularly, electricity market efficiency, affordability and reliability. The white papers also aim to provide transparent, objective information to inform policy, planning and investment decisions and help overcome access-to-information barriers that can pose a challenge to participation in electricity markets. Finally, by engaging a wide range of stakeholders and interested parties in the development of the research white papers, the IESO hopes to reduce duplication of efforts by interested parties by creating a joint research and learning opportunity.

DISCLAIMER:

This report, prepared by the ICF team of Samir Succar, Mike Alter, Homaira Siddiqui, Lorenzo Kristov and Paul De Martini for the Independent Electricity System Operator (IESO), is conceptual in nature and does not represent ICF's validation or recommendation of either of the alternative transmission-distribution interoperability models analyzed. Any errors, omissions or mischaracterizations are the responsibility of the authors.

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Executive Summary

Significant technological change is transforming Ontario's electricity system. With that comes an imperative to re-examine and potentially re-create the traditional roles and responsibilities at the transmission and distribution levels, and how they work together to serve the changing and future electricity needs of the province.

In Ontario, the wholesale market administered by the Independent Electricity System Operator (IESO) coordinates the supply of services to meet the electricity needs of consumers. This role was established to serve a model where electricity was produced by large, transmission-connected power plants and then delivered to customers through transmission and distribution networks. Today, that traditional way of operating is being upended by a growing number of distributed energy resources (DERs), such as rooftop solar panels, smart thermostat-connected air conditioners, home batteries and other resources potentially capable of providing services to the system. Although regulatory reforms are underway in response to this change, one important constant is the IESO's mandate to ensure a safe, reliable and affordable power system for Ontarians.

The IESO's current visibility into the transmission system, operational systems and coordination processes have been robust enough to maintain safety and reliability. However, as the number of DERs grows and opportunities increase for these resources to participate in the wholesale market, enhanced operational coordination between the distribution and transmission systems will be required to preserve safe and reliable operation, while enabling DER value and cost-effective electricity services.

This white paper aims to provide readers with a practical understanding of how interoperability between the transmission and distribution systems could evolve to support a system with growing numbers of DERs, while realizing all of the benefits of these new technologies and maintaining safety and reliability. Central to this is how the roles and responsibilities of key players and functional capabilities could evolve to enable enhanced coordination between the transmission and distribution systems. The assignment of roles and responsibilities primarily concerns two players – the transmission system operator (TSO), which in Ontario is the IESO, and the distribution system operator (DSO). The role of the latter is currently performed by local distribution companies (LDCs), whose capabilities to support DSO functionalities are still evolving. This assignment may vary depending on the key players involved in the electricity system and the interfaces between them.

To guide these important decisions, this report provides a framework to help Ontario design a transmission-distribution (T-D) interoperability model based on a set of system objectives, the system features needed to achieve these objectives, the roles and responsibilities of and interfaces between key players and the operational systems needed to enable this coordination. This paper introduces two bookend T-D interoperability models where either the TSO or DSO takes full responsibility for distribution system operations and DER optimization, and then applies the framework to two alternative hybrid models where these responsibilities are shared.
A comparative analysis highlights the relative strengths and weaknesses of each, and includes changes that may be needed in order to achieve a desired system design given Ontario's emerging industry structure over the next five to 10 years.

Key takeaways

Ontario can design a future electricity system architecture that incrementally builds on the system's existing functional capabilities, the current roles and responsibilities of the transmission and distribution operators, and how they interact with each other. This white paper examines two potential T-D interoperability models to illustrate the types of trade-offs between alternative approaches. There are three key takeaways to guide this process.

Defining objectives for Ontario's electricity grid will help determine the most suitable T-D interoperability model

Potential system architecture options can be assessed on their ability to achieve objectives set for the province. Prioritizing the objectives can help determine where compromises can be made and how to make important decisions about changes relative to Ontario's current and emerging system. For example, if enabling third-party competition is an objective, Ontario will need to make decisions about whether LDCs should also be the entities to take on greater DSO functions, such as procuring DERs to provide distribution services and aggregating them to participate in the wholesale market. The scope and scale of changes needed to achieve these objectives – which may include regulatory reforms or market design enhancements – will determine the pace of Ontario's electricity system evolution.

These objectives will also help Ontario make a fundamental decision about whether to pursue a more centralized or layered T-D interoperability model. While a more centralized system could give DER providers greater direct access to the wholesale market, there would be greater complexity for coordination between the transmission and distribution systems. Conversely, while a more layered system has the potential to simplify coordination processes, there are concerns that DSO ownership and operation of the distribution system could hamper third-party competition.

System reliability serves as the foundation for determining the types of interactions between key players and their respective roles and responsibilities

The need to preserve safety and reliability is at the core of bulk power and distribution system operations. All planning and procurement activities must converge into reliable real-time system operation. This goal requires that operators determine the types of responses required from system assets and resources, from a second-by-second response to one required multiple months or years in advance. From this vantage, Ontario can determine the required blend of operational control, market signals, resource procurement and system planning to maintain reliability. Specifying the roles, responsibilities and interactions between transmission and distribution will shape the preferred system design.

A flexible approach to coordinating operations is necessary to address diversity between and within LDCs in the province

Ontario's LDCs vary significantly in customer base size, functional capabilities, the amount of DERs on their system and the rate at which they are growing. The number of DERs is a significant driver of required functional capabilities on the distribution system. Since the number of DERs may vary significantly among LDCs, or even within a single LDC, Ontario may prefer to develop these capabilities only for those T-D interfaces – the physical points where the transmission and distribution systems interconnect – characterized by higher numbers of DER penetration rather than for all LDC systems across Ontario.

The development of a shared platform for the IESO, LDCs and DER providers would enable Ontario to have a single interface that centralizes market and operational coordination. This would include DER providers submitting bids to the wholesale market, the IESO issuing dispatch instructions to DER providers and the LDC ensuring DER providers have information about distribution system conditions that impact DER operations. Overall, this type of platform would help reduce both complexity and costs for the IESO, LDCs and DER providers by simplifying interfaces between them and allowing LDCs greater flexibility to leverage existing operational systems and acquire other functionalities.

Next steps

This white paper lays out next steps for the province to identify, design, select and implement a preferred T-D interoperability model.

1

Define Ontario's system objectives and enable regulatory changes

A final set of objectives to guide system evolution needs to be collaboratively defined and accepted by key Ontario stakeholders, and accompanied by regulatory changes required to achieve the objectives.

2

Identify and describe T-D interoperability models of interest to Ontario and apply the Ontario-specific decision framework to choose the interoperability architecture

After fully considering a range of options, Ontario can use the decision framework that combines Ontario-specific objectives and grid architecture principles to determine the most suitable T-D interoperability model(s) for further analysis.

3

Conduct a detailed grid architecture assessment of the selected model

A detailed architectural assessment of the selected T-D interoperability model(s) applies engineering analysis and operational risk assessments to determine effective structural options, and map the functionalities to the operational system(s) that will enable them.

4

Continue efforts to integrate DERs and reflect their value in market opportunities

Examples include the York Region demonstration project, which aims to prove the value of NWAs, the IESO's efforts to identify participation models for DERs, and the IESO's plans to implement a capacity auction.

5

Facilitate collaboration between the IESO, LDCs and DER providers on operational coordination requirements and systems

Discussions in Ontario should continue about how best to structure this coordination in the near term, considering the potential for developing a shared DER lifecycle management coordination platform.

6

Design and implement pilots and demonstration projects to test key aspects of T-D interoperability

Ontario should explore additional opportunities to test critical aspects of T-D interoperability, such as the York Region demonstration project.

1 Overview

This paper provides a practical understanding of how the roles and responsibilities of key players, including transmission and distribution system operators, and functional capabilities could evolve to serve a system with a much greater number of distributed energy resources (DERs)[1] by:

- Defining the functions required to deliver a reliable and cost-effective electricity supply
- Describing the operational interfaces between entities, data exchange requirements, and information and communication technologies required to coordinate system operations
- Developing a framework for evaluating transmission-distribution (T-D) interoperability models, and applying it to two alternatives in the context of Ontario's evolving industry structure over the next five to 10 years
- Establishing findings to inform policy and regulatory efforts related to the evolution of the distribution system and resulting T-D interoperability needs in Ontario

This paper is divided into six sections. Following this overview, Section 2 introduces the key drivers of DER growth in Ontario, including ongoing efforts to integrate these resources into the wholesale electricity market and leverage them to serve as cost-effective non-wires alternatives (NWAs) to traditional transmission and distribution infrastructure investments.

Section 3 provides a framework for Ontario to make future decisions about T-D interoperability, exploring potential objectives for the system and employing grid architecture principles to illustrate which system structure might best meet these objectives. The section provides an overview of Ontario's evolving industry structure for the next five to 10 years, including the key functional entities that might exist, potential interactions between them, and operational coordination issues that could arise given prospective changes to Ontario's current electricity system. Finally, the section highlights how the enhanced distribution system functions required by the growing number of DERs will ultimately inform the evolution of the entire electricity system.

Section 4 examines potential T-D models to allocate roles and responsibilities between the two major system players: the transmission system operator (TSO) and the distribution system operator (DSO). The section describes two conceptual bookend models with either the TSO or DSO assuming full responsibility for distribution system operations and DER optimization, and then hybrid models along the spectrum between these bookends. Two alternative hybrid models are used to illustrate possible futures for Ontario's electricity system, highlighting the relative merits of each, and the changes necessary to adapt to the evolving industry structure described in Section 3.3. Also contemplated is the relationship between these alternative models and Ontario's system characteristics, including

[1] As used in this report, the term distributed energy resource (DER) includes all electricity resources (except for energy efficiency) connected to the distribution system as opposed to the IESO-controlled transmission network. DERs may be connected on a customer's premises behind the utility revenue meter, or directly to the facilities of local distribution companies (LDCs). The term is used broadly to include distributed generation, energy storage, demand response, and electric vehicle charging infrastructure, all of which will affect the electricity system and contribute to the need for robust T-D interoperability and coordination.

considerations that may be required to more explicitly guide evolution of the system to meet specific objectives.

Section 5 analyzes two potential approaches for operational coordination systems that will be needed to enable the interactions required under any system architecture:

1. An extension of the status quo where the IESO and LDCs continue investing in and implementing separate operational coordination systems, with potential duplication in functional capabilities
2. The development of a shared platform – for the IESO, LDCs and DER providers – to manage the entire DER lifecycle. Shared platforms for coordinating wholesale market participation of demand-response aggregations are already in operation in California, while Australia is actively analyzing the potential for a more comprehensive DER lifecycle management platform.

In Ontario, the second approach could significantly lower costs for all parties, reduce the complexity around communications standards and protocols, and provide greater flexibility for LDCs to integrate existing systems on an individual basis, only paying for the incremental functionalities they need. A high-level cost assessment for the province is included.

Finally, Section 6 delivers key takeaways to help policy-makers, system operators and other stakeholders identify, design and implement a preferred T-D interoperability model in Ontario.

2 Ontario's evolving electricity system

The province's electricity system is undergoing significant change, thanks, in part, to shifting policy directives and an increasingly diverse and distributed set of electricity resources. The IESO's first Annual Planning Outlook[2] studied alternative scenarios for a future Ontario electricity system, assessing how to preserve safety and reliability as the system capitalizes on opportunities provided by emerging technologies, including DERs. Feed-in tariffs have been a primary driver for solar photovoltaic growth in the province, accounting for the majority of DERs installed to date. Additionally, energy efficiency programs and rate design – including the Industrial Conservation Initiative (ICI)[3] – have contributed to the growth in DER installations, mainly energy storage and combined heat and power. While the penetration of DERs on Ontario's grid is still relatively modest, the growth rate has been significant. Over the last 10 years, more than 4,000 megawatts (MW) of DERs have been contracted or installed in Ontario.[4] The impact of DERs on markets, planning and operations will increase proportionally as they make up an increasing share of the resource mix.

The IESO's Innovation and Sector Evolution White Paper Series[5] provides research and analysis aimed at paving the way for DERs to play a greater role in the wholesale market and to provide various bulk

[2] IESO, *Annual Planning Outlook: A view of Ontario's electricity system needs*, January 2020. http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Annual-Planning-Outlook-Jan2020.pdf?la=en.
[3] IESO, *Industrial Conservation Initiative Backgrounder*, August 2019. http://www.ieso.ca/-/media/files/ieso/document-library/global-adjustment/ici-backgrounder.pdf?la=en.
[4] Energy Transformation Network of Ontario, *Structural Options for Ontario's Electricity System in a High-DER Future: Potential implications for reliability, affordability, competition and consumer choice*, June 2019. http://www.ieso.ca/-/media/files/ieso/document-library/etno/etno-structuraloptionshighderfuture-june2019.
[5] IESO, *Active Engagements: Innovation and Sector Evolution White Paper Series*. http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Innovation-and-Sector-Evolution-White-Paper-Series.

power and distribution system services. The IESO also formed the Grid-LDC Interoperability Standing Committee[6] to look at the ongoing coordination of system operations. Additionally, the IESO is collaborating with other Ontario stakeholders to identify and overcome barriers that hinder DERs from serving as NWAs for transmission and distribution deferral opportunities,[7] and plans to test some of these findings through a demonstration pilot project in York Region.[8]

Policy and market changes that open up greater opportunities for DERs in the electricity market, together with the decreasing cost of DER technologies, will determine the direction and pace of the evolution of Ontario's electricity system. These changes will be driven, in part, by the future Ontario energy marketplace, including the rate of DER adoption, the number of DER providers and aggregators participating in the wholesale market, and the growth of electrification. The potential integration pathways for DERs – the minimum-size threshold for wholesale market participation, rules for aggregating DERs and the scope of services DERs can provide to the bulk power and distribution systems, as well as how system planning accounts for DERs – will also determine how the system evolves.

With these drivers come new opportunities to meet the objectives for Ontario's electricity grid, which require proactive consideration to guide the evolution of the province's electricity system. For example, a recent study by the Energy Transformation Network of Ontario (ETNO)[9] explores a set of structural options for Ontario in a high-DER environment, including how to allocate roles and responsibilities between various industry players as DERs are integrated. This paper addresses topics similar to the ETNO study, but focuses on developing a framework to guide decisions on prospective changes to the Ontario electricity system.

3 Ontario T-D interoperability decision framework

As the drivers outlined in Section 2 shape the evolution of Ontario's power system, a T-D interoperability framework can support the objectives of the province and the safe, secure and reliable operation of the electricity grid. With higher DER volumes on the system, the core question is whether to pursue a more centralized or layered approach to operational coordination.[10]

- With a **centralized approach,** the IESO would assume a much larger share of the roles and responsibilities for planning and operating both the bulk power and distribution systems, requiring enhanced functions and capabilities.

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[6] IESO, *Grid-LDC Interoperability Standing Committee*. http://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Standing-Committees/Grid-LDC-Interoperability-Standing-Committee.

[7] IESO, *Barriers to Implementing Non-Wires Alternatives in Regional Planning*. http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/rpr/rprag-20181101-barriers.pdf?la=en.

[8] IESO, *York Region Scoping Assessment Outcome Report*, August 28, 2018, p.24. http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/York/York-Region-Scoping-Assessment-Outcome-Report-20180828.pdf?la=en.

[9] ETNO, *Structural Options for Ontario's Electricity System in a High-DER Future: Potential implications for reliability, affordability, competition and consumer choice*, June 2019. http://www.ieso.ca/-/media/files/ieso/document-library/etno/etno-structuraloptionshighderfuture-june2019.

[10] Kristov, L., De Martini, P., & Taft, J., *Two Visions of a Transactive Energy System*, April 2016. http://resnick.caltech.edu/docs/Two_Visions.pdf.

- In contrast, a **layered approach** would give a comparatively greater share of distribution-level roles and responsibilities to a distribution system operator (DSO), which would provide some analogous functions for the distribution system that an independent system operator (ISO, which is also referred to as the TSO[11]) provides for the bulk power system.

The T-D interface as the unit of analysis plays a pivotal role in this decision. The T-D interface is the physical point where the transmission and distribution systems interconnect, typically at a major sub-station that reduces the voltage level as the electric topology transitions from networked to radial. The Ontario system has many T-D interfaces, with each local distribution area (LDA) corresponding to a single T-D interface that must operate reliably and safely as an electrical unit.

By focusing on each individual T-D interface for the purposes of TSO-DSO coordination (i.e., T-D interoperability), decisions can be made about the future structure of Ontario's electricity system and the relative merits of more centralized to more layered structures. Each structural option must outline the roles and responsibilities of the players involved, identifying the functional capabilities required to fulfill these responsibilities to meet overarching objectives.

While the evolution of Ontario's electricity system toward a high-DER environment is partly driven by external developments, such as the decreasing costs of DER technologies, key decisions will also shape the evolution. These include determining the role of third parties, especially DER owner/operators in providing electricity services at the transmission and distribution levels, such as infrastructure deferral and voltage support. Also, a detailed framework should be developed for the services DERs can provide, and the rules defined for wholesale market participation by DERs and DER aggregations (DERAs). To help ensure decisions to guide system evolution are sound, the framework should reflect Ontario-specific objectives and electricity system architecture principles.

The discipline of grid architecture provides a logic and method for analyzing the T-D interoperability complexities that emerge with high numbers of DERs on the system. The first step for developing this decision framework is specifying high-level objectives for the system, from the more traditional focus on reliability, affordability and safety, to newer goals such as flexibility, resilience and environmental impacts.

These goals can be used to determine performance characteristics the system needs to achieve them. For example, a reliability goal could translate into targets for outage frequency and recovery time, while a flexibility goal could translate into the ability to integrate new grid technologies, business models and end-use devices into system operations and planning. Grid architecture then addresses the structure of the system – identifying the key players and specifying their roles and responsibilities – required to achieve the desired performance (further discussion in Section 3.2).

The structure – key players and their roles, responsibilities, capabilities and interactions – is the foundation of any T-D interoperability architecture. In Ontario, this can be determined by understanding the requirements and implications of a more centralized structure under the IESO for system operation and markets (which minimizes the need for DER-related enhancements to the functional capabilities of

[11] This report uses the term transmission system operator (TSO) to reflect the combined functions of the balancing authority (real-time supply-demand balancing and reliable system operation) and the wholesale spot market operator. This combination is common to ISOs and RTOs in North America, in contrast to the UK and Europe, where the TSO is the balancing authority and a separate entity is the wholesale market operator.

the distribution operator), versus a more layered structure where the distribution operator takes on significant new responsibilities for coordinating DER operation and market participation.

3.1 Objectives for Ontario's electricity system

Establishing specific objectives for Ontario's electricity system evolution will serve as the starting point to determine the functionalities required in the future. Both the United Kingdom[12] and Australia[13] initiated multi-year collaborative stakeholder efforts to define these objectives and chart options for system evolution. Establishing these objectives will allow Ontario regulators, system planners and operators, and other key stakeholders to evaluate the relative merits of potential future structures for Ontario.

Several efforts to outline objectives for Ontario's electricity system are already underway.

- Through a collaborative stakeholder process, the Energy Transformation Network of Ontario (ETNO) defined four objectives for a high-DER future: reliability, affordability, competition and consumer choice.[14]
- The government's 2019 Ontario budget outlined the objective of lowering the cost of energy through initiatives that make costs more transparent and affordable.[15]
- In creating a foundation for dialogue with stakeholders on utility remuneration and responding to DERs, the Ontario Energy Board (OEB) outlined four potential guiding principles: economic efficiency and performance, customer focus, stable yet evolving sector, and regulatory simplicity.[16]
- Through its Market Renewal Program, the IESO set out five principles to guide the delivery of a marketplace that meets system and participant needs at lowest cost: efficiency, competition, implementability, certainty and transparency.[17]

In attempting to achieve multiple objectives, trade-offs are nearly always required. For example, while market efficiency seeks to achieve prices and market outcomes that accurately reflect costs, it may result in less certainty for market participants due to fluctuating spot market prices that reflect changes in electricity supply and demand. Also, some objectives may take precedence over others, and their relative priority may evolve. That said, objectives provide a critical foundation for decisions that will

[12] UK ENA Open Network Project, *Open Networks Future Worlds: Developing change options to facilitate energy decarbonisation, digitization and decentralisation*, July 31, 2018. http://www.energynetworks.org/assets/files/14969_ENA_FutureWorlds_AW06_INT.pdf.

[13] AEMO and Energy Networks Australia, *Open Energy Neworks Consultation Paper*, 2018. https://www.energynetworks.com.au/sites/default/files/open_energy_networks_consultation_paper.pdf.

[14] ETNO, *Structural Options for Ontario's Electricity System in a High-DER Future: Potential implications for reliability, affordability, competition and consumer choice*, June 2019. http://www.ieso.ca/-/media/files/ieso/document-library/etno/etno-structuraloptionshighderfuture-june2019.

[15] Ontario, *2019 Ontario Budget: Protecting What Matters Most,* Minister of Finance, the Honourable Victor Fedeli, 2019. http://budget.ontario.ca/pdf/2019/2019-ontario-budget-en.pdf.

[16] OEB, *Utility Remuneration and Responding to Distributed Energy Resources Board File Numbers: EB-2018-0287 and EB-2018-0288*, July 17, 2019. https://www.oeb.ca/sites/default/files/Ltr-UR-RDER-Refreshed-Consultation-20190717.pdf.

[17] IESO, *Market Renewal: Mission and Principles.* http://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/market-renewal-mission-principles.pdf?la=en.

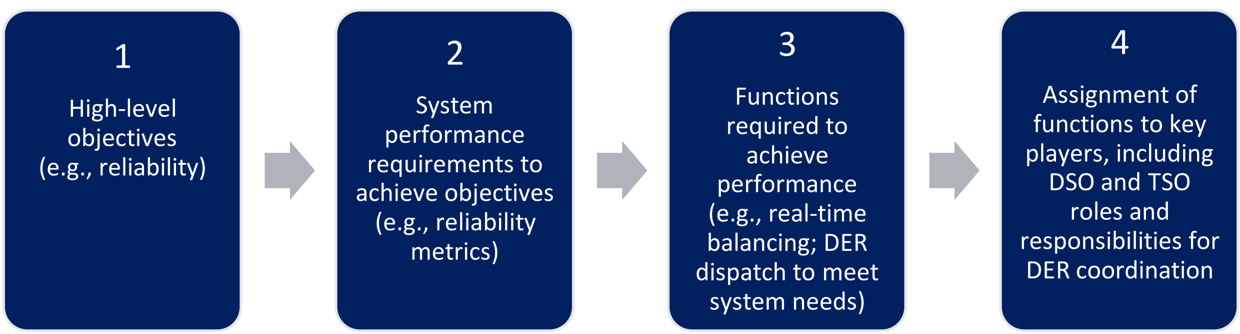
shape the evolution of Ontario's electricity system, helping ensure near-term efforts to expand opportunities for DERs and enable T-D interoperability do not conflict with each other or create barriers to achieving them.

3.2 System architecture

Establishing T-D interoperability that achieves Ontario-specific objectives requires targeted efforts from diverse stakeholders. As is the case in many jurisdictions around the world, the electricity system in Ontario comprises a number of distinct players. These include the IESO, generators, transmitters, LDCs, DER providers, and prosumers, most of which have historically had limited interaction with each other. However, with the potential for more DERs to provide services across the T-D interface, grid operators are evaluating how to structure roles and responsibilities regarding T-D interoperability to realize the greatest value. This involves answering fundamental questions about what coordination should look like, the players involved, and the time frame for making changes to most effectively preserve system safety and reliability.

Figure 1 illustrates the logic of grid architecture.[18] The high-level objectives for the power system determine the necessary properties, behaviour and performance of the grid. These performance requirements translate into functions, which, in turn, become decisions about the structure of the system and the roles and responsibilities, interfaces and interactions among the key players.

Figure 1: How grid architecture builds on system objectives



[18] Basic Terms and Principles page of the Grid Architecture website at http://gridarchitecture.pnnl.gov/

Table 1 outlines seven principles for applying grid architecture to T-D interoperability.[19]

The first principle – observability – relates to the level of operational visibility required by the DSO and TSO to ensure safe and reliable operation while effectively using DER services. Under Ontario's current structure, the IESO (as the TSO) has limited visibility into the distribution system and the DERs connected to it, i.e., those that don't participate in the IESO's wholesale market and distribution-connected variable generators smaller than 5 MW. As Ontario considers options for future grid architectures, it will be critical to determine whether the limits of the IESO's current observability of the distribution system and DERs will enable the system to maximize the value of DERs while maintaining system safety and reliability. The discipline of grid architecture confirms that observability needs of the key players, mainly the DSO and TSO, will depend on the functional responsibilities assigned to them.

Another principle that becomes increasingly important in an electricity system with an organized wholesale market is tier bypassing – the ability of some market transactions to skip a physical tier of the system (e.g., the distribution system). For example, a DER that participates directly in the IESO's wholesale market would submit bids/offers directly to the TSO and receive a schedule or dispatch instruction from the TSO, bypassing the distribution system. This scenario is problematic because the DER's response to the TSO dispatch may be constrained by current distribution system conditions. For example, if a reconfigured distribution circuit creates a situation where there is not enough capacity on the distribution system to support DER injections, the DER would be unavailable to meet the TSO's dispatch during the time the distribution circuit is in a reconfigured state (i.e., assuming the dispatch calls for the DER to inject onto the system).

Hidden coupling is another grid architecture concern. If a DER participates in the wholesale market and provides distribution grid services to the DSO, a potential problem arises when the DSO and TSO each issue conflicting operating instructions to the DER based on the needs of their own systems. To mitigate the potential for tier bypassing and hidden coupling, coordination measures must be included when functional responsibilities are assigned to the DSO and TSO.

Along with the objectives outlined in Section 3.1, the grid architecture principles in Table 1 form a foundation for analyzing two potential alternative system structures (Section 4) and identifying the operational coordination systems that will be required to preserve system safety and reliability under those models (Section 5).

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[19] Taft, Jeff, *Grid Architecture 2*, Pacific Northwest National Laboratory, 2016. https://gridmod.labworks.org/sites/default/files/resources/Grid%20Architecture%202%20final_GMLC.pdf.

Table 1: Summary of key grid architecture principles[20]

Principle	Description
Observability	Function related to operational visibility of the distribution network and the DERs that are connected to it. Sensing and data collection can help to assemble an adequate view of system and DER behaviour for control and grid management. The data can also be used to validate planning models.
Scalability	Ability of the system's processes and technology design to function effectively with very large quantities of DERs on the system. Coordination architecture can enhance or detract from this desired capability. To be maximized.
Cybersecurity vulnerability	Reduce cyber vulnerability through architectural structure, as the structure can expose bulk energy systems to more or less vulnerability depending on data flow structure, which depends on the coordination framework. To be minimized.
Layered decomposition	Layered decomposition solves large-scale optimization problems by breaking them down multiple times into sub-problems that work in combination to solve the original problem. Layered decomposition can be an effective structure for avoiding tier bypassing, hidden coupling and latency cascading.
Tier bypassing	Creation of information flow or instruction/dispatch/control paths that skip a tier of the physical power system hierarchy, with the potential for creating operational or reliability problems. To be avoided.
Hidden coupling	Two or more entities controlling the same resource while having partial views of the grid state and operating separately according to individual goals and constraints without effective coordination (e.g., DER receives simultaneous, but conflicting signals from both the DSO and TSO). To be avoided.
Latency cascading	Creation of potentially excessive latencies in information flows due to the cascading of systems and organizations through which the data must flow serially. To be minimized.

3.3 An analysis of Ontario's emerging industry structure

Determining how to guide the ongoing evolution of Ontario's electricity system requires an understanding of how the grid is currently structured and its anticipated near-term evolution. Given the range of factors that will influence Ontario's electricity system evolution over the next five to 10 years, grid structure models are a useful tool to identify the functional capabilities needed to coordinate operations for a reliable and safe grid,[21] along with the Ontario-specific objectives and grid architecture principles discussed in Sections 3.1 and 3.2. Table 2 describes the current state of core IESO and LDC (i.e., distribution owner-operator or DO)[22] functions in a low-DER environment. However, as described in

[20] *Ibid*.

[21] The structure diagrams in this paper represent functional capabilities needed in the operational time frame (i.e., up to months in advance for resource adequacy procurement through real-time operations). These diagrams do not seek to capture functional capabilities required in the planning time frame (i.e., multiple years in advance to inform decisions around investment, such as infrastructure upgrades or replacement). Section 4 discusses how assigning operational roles and responsibilities will have implications for planning activities.

[22] Distribution owner-operator is the generic term for the distribution system functional role of Ontario's LDCs.

Section 3.5, the ongoing evolution of the distribution system may require the DO to be responsible for some functions that to date have primarily resided with the IESO.

Table 2: Breakdown of current core IESO and LDC functional roles and responsibilities[23]

Function	IESO	LDC
Balance supply and demand	Balances for its area, including the net load of all local distribution areas (LDAs) and interchange with adjacent balancing authority areas	Delivers energy from the T-D interface to end-use customers and does not balance supply and demand
Maintain frequency	Supports frequency for its system and regional interconnections, along with other balancing authorities	Does not maintain frequency, but DERs may be eligible to provide frequency support to the system[24]
Schedule and coordinate resources	Schedules and coordinates transactions across its area and interties	Role to date has largely been limited to pilot projects, e.g., dispatchable DERs providing distribution deferral
Provide open-access transmission service[25]	Provides open access, i.e., non-discriminatory service	No current analog ensures open access on the distribution level
Operate spot market	Clears wholesale spot markets for balancing energy and operating reserves	No active spot market at the distribution level (i.e., beyond initial pilot projects); only delivers wholesale spot market energy to or from customers and DER providers
Plan for infrastructure requirements	Plans the bulk power system in coordination with transmitters, which own, maintain and physically operate transmission assets; coordinates with transmitters and LDCs as part of the regional planning process	Plans distribution asset replacements and system upgrades, and coordinates with the IESO and transmitters as part of the regional planning process
Oversee interconnections	Maintains interconnection process for DERs that are above 10 MW (LDC involved in the connection assessment), participate in the wholesale market, or otherwise provide other bulk power system reliability services (e.g., regulation, black start)	Has interconnection processes for loads and DERs[26]

[23] De Martini, P., & Kristov, L., *Distribution Systems in a High Distributed Energy Resource Future: Planning, Market Design, Operation and Oversight*, 2015. https://emp.lbl.gov/sites/default/files/lbnl-1003797.pdf.

[24] Distributed energy storage is eligible currently to provide frequency regulation as part of the IESO's Phase 1 Energy Storage Program. Separately, distributed generation larger than 10 MW must provide a specified response as a result of changes to frequency.

[25] In the U.S., all TSOs must provide open-access transmission service pursuant to federal law.

[26] In the U.S., distribution owners also have open-access federal-jurisdictional interconnection procedures for DERs that will inject energy for wholesale market participation.

The two most important functional entities for defining a T-D interoperability approach are the TSO,[27] which in Ontario is the IESO, and the DSO. Under Ontario's emerging industry structure, a DSO represents a range of possible distribution operator models that incorporate enhanced functional capabilities beyond those of today's LDCs, serving a future system with a much higher number of DERs. While incumbent LDCs are responsible for the safe and reliable operation of today's distribution system, a DSO will require additional functional capabilities in a high-DER distribution system (further discussed in Section 4).[28] The concept of a DSO is neutral about whether the LDC becomes the DSO or a separate DSO entity is created.

There are other key players in Ontario's emerging industry structure, aside from the TSO and DSO. As technology costs continue to decline and the IESO expands opportunities for wholesale market participation, a greater role could emerge for diverse DER providers, including: owner-operators of energy storage and distributed generation connected directly to the distribution system; customers with dispatchable DERs interconnected behind the customer's meter; and DER aggregators who bring small DERs together into virtual resources to meet the size threshold for participation in the IESO's wholesale market.

Table 3 provides an overview of all the functional entities that are likely to be part of Ontario's emerging industry structure and their corresponding roles and responsibilities.

Table 3: Ontario's emerging industry structure functional entities

Functional entity	Description of roles, responsibilities and interaction types
Bulk generation	Generation assets connected to the bulk electric system and participating directly in wholesale markets. Receives schedules and dispatch instructions from the wholesale market operator and bulk system balancing authority. May contract directly with the IESO for energy and capacity.
Bulk storage	Storage assets connected to the bulk electric system and participating directly in wholesale markets. Receives schedules and dispatch instructions from the wholesale market operator and bulk system balancing authority. May contract directly with the IESO for energy and capacity.
Customer DER	Located on the customer side of the meter to provide energy services directly to the customer, and may also provide services to the wholesale market operator and LDC operations, either directly or through a DER aggregator. Includes dispatchable demand response. May contract directly with the IESO for energy and capacity.
Customer load	Includes residential, commercial and industrial customers who receive power from either the distribution system or customer DERs.

[27] The IESO, similar to independent system operators (ISOs) in the U.S., bundles both the bulk system balancing authority and wholesale market operator functions described in Table 3. In other jurisdictions, particularly the United Kingdom and Europe, these functions are performed by separate entities.

[28] LDC is the Ontario-specific acronym for local distribution companies or what is more generically called the owner-operator of the distribution system.

Table 3 (continued)

Functional entity	Description of roles, responsibilities and interaction types
DER (utility-side)	Provides bulk services either directly to the wholesale market operator or through a DER aggregator. Provides distribution services either directly to LDC operations or through a DER aggregator. May contract directly with the IESO to provide energy and capacity.
DER aggregator	Develops and operates aggregations of DERs for wholesale market participation by aggregating multiple small DERs to meet the required size threshold or to provide distribution services. Disaggregates wholesale market schedules and dispatch instructions from the IESO and/or the LDC to individual DERs. May contract directly with the IESO to provide energy and capacity.
Distribution system owner	Owns and maintains physical distribution assets that move power between the transmitter, distribution-level DER and customer load. Coordinates outages/derates with and receives control signals from LDC operations.
Bulk system balancing authority	Maintains reliable real-time operation of the bulk electric system by balancing supply and demand and supporting system frequency by issuing dispatch signals to resources, including DERs participating directly in the wholesale market. North American ISOs/RTOs, including the IESO, combine and functionally integrate the balancing authority and wholesale market operator functions under a single entity.
Wholesale market operator	Operates the wholesale market in both day-ahead and real-time. Receives bids/offers and issues schedules for capacity, energy and operating reserves. North American ISOs/RTOs, including the IESO, combine and functionally integrate the balancing authority and wholesale market operator functions under a single entity.
LDC operations	Responsible for the safe and reliable operation of the distribution system, with some operational control (i.e., the ability to direct, regulate or stabilize DER behaviour)[29] over DERs, load, and distribution assets as needed for operation. Coordinates with bulk system balancing authority, wholesale market operator and transmitter to the extent needed.
Load-serving entity (LSE)	In other jurisdictions, procures supply (energy and capacity) and provides retail kWh to meet customer load, and performs other activities, such as planning, hedging and billing. In Ontario, the IESO performs the planning and procurement of supply functions in addition to being the wholesale market operator and balancing authority.
Transmitter	Owns, maintains and operates the assets that transmit power between bulk resources and the distribution system. Coordinates outages/de-rates with and receives control signals from the IESO balancing authority. Maintains some coordination with LDC operations.

[29] Taft, JD, *Electric Grid Market-Control Structure*, PNNL-26753, Pacific Northwest National Laboratory, June 2017. https://gridarchitecture.pnnl.gov/media/advanced/Market_Control_Structure_v0.2.pdf.

3.4 Functional layers of the electricity system

A useful grid architecture tool is the structure diagram, which helps to identify operational control and coordination requirements among the various functions and across T-D interfaces. Structure diagrams display the main system functions or functional players as boxes and the interactions among them as connecting lines or arrows (see Figure 2). Some functions, such as the wholesale market operator and balancing authority, are performed by an individual player. Others, such as bulk generation and customer load, are performed by a number of players. The diagrams locate these functional players within the three domains of the electricity grid: the bulk power system, which includes the wholesale market and transmission system; distribution, which includes the low-voltage distribution system below the T-D interface; and the customer, which encompasses all end-use customers and behind-the-meter DERs.

Because there are multiple types of interactions among the main players (indicated by connecting coloured lines), each type of interaction is displayed as a distinct functional layer of the electricity system with its own structure diagram. To explore the implications of alternative T-D interoperability architectures, this report considers four layers: (1) physical flows of electric power; (2) communications and control; (3) market transactions; and (4) data exchanges. Table 4 provides an overview and examples of each interaction type, including the line/arrow colour representing these layers, as in Figure 2.

Table 4: Four types of interactions for electricity grid operation

Interaction layer (Arrow color)	Description	Examples
Power flow (Grey)	The physical movement of electric power over wires (e.g., poles, wires, substations)	• Bulk generation injects power onto the transmission system (i.e., transmitter) • Customer DERs may provide power to customer load and inject into the distribution system
Operational control (Orange)	The ability to direct, regulate or stabilize the physical operation of energy resources (including loads) and electricity system facilities (e.g., distribution circuit switching)	• Bulk system balancing authority exerts control over wholesale market resources and those providing other bulk power system reliability services today by sending control signals (i.e., dispatch instructions and basepoints) to direct their operation in a way that allows them to provide the targeted service. It may also exert control over the transmission system in response to a constraint or contingency to preserve safety and reliability • LDC operations exerts control over the distribution system (e.g., reconfiguring a circuit due to abnormal system conditions), and will likely increase its level of control over DERs (e.g., sending control signals to DERs to enable them to provide distribution services)

Table 4 (continued)

Interaction layer (Arrow color)	Description	Examples
Market transaction (Green)	Any form of market arrangement (e.g., power purchase agreement, capacity or service contract, participation in a spot market) to purchase or sell energy, capacity and grid services (including NWA or infrastructure investment deferral). Includes market schedules and dispatch instructions	• Resources participating in the wholesale market send bids/offers to the wholesale market operator, who then sends the resource a schedule • The LSE function (currently within the IESO) procures supply from the bulk system and/or distributed resources to provide retail kWh and meet resource adequacy requirements
Information/ data exchange (Blue)	Receipt or provision of information or data necessary to maintain safe and reliable operation of the electricity system (e.g., resource telemetry) and support the above three coordination layers and any other core objectives for the system (e.g., tracking of system topology changes)	• Resources participating in the wholesale market submit telemetry to the market operator and bulk system balancing authority to indicate asset performance in real time • LDC operations provides information on distribution system conditions to the wholesale market operator, bulk system balancing authority and wholesale-participating DER providers to ensure their operation does not jeopardize distribution system safety and reliability

The direction of a given arrow in the structure diagram conveys important details about the relationships between functions. While operational control could be a one-way interaction, information/data exchange often goes both ways. For example, if a generator is providing operating reserve to the wholesale market, the bulk system balancing authority would use a one-way control signal to direct the generator's operation and the generator would send an acknowledgement of the instruction and telemetry information to the bulk system balancing authority for purposes of tracking the actual generator performance and operating level.

The industry structure diagrams in Figure 2 capture the full range of possible interaction types, but these diagrams do not suggest that each individual player in a given functional box engages in all possible interactions. For example, the operational control layer diagram shows DERs and customer DERs receiving control signals from the bulk system balancing authority, LDC operations and the DER aggregator. In practice, a DER receiving control signals from the DER aggregator wouldn't receive control signals from the bulk system balancing authority or LDC operations (and vice versa). However, these resources could receive control signals from both the bulk system balancing authority and LDC operations if providing both bulk system and distribution services.

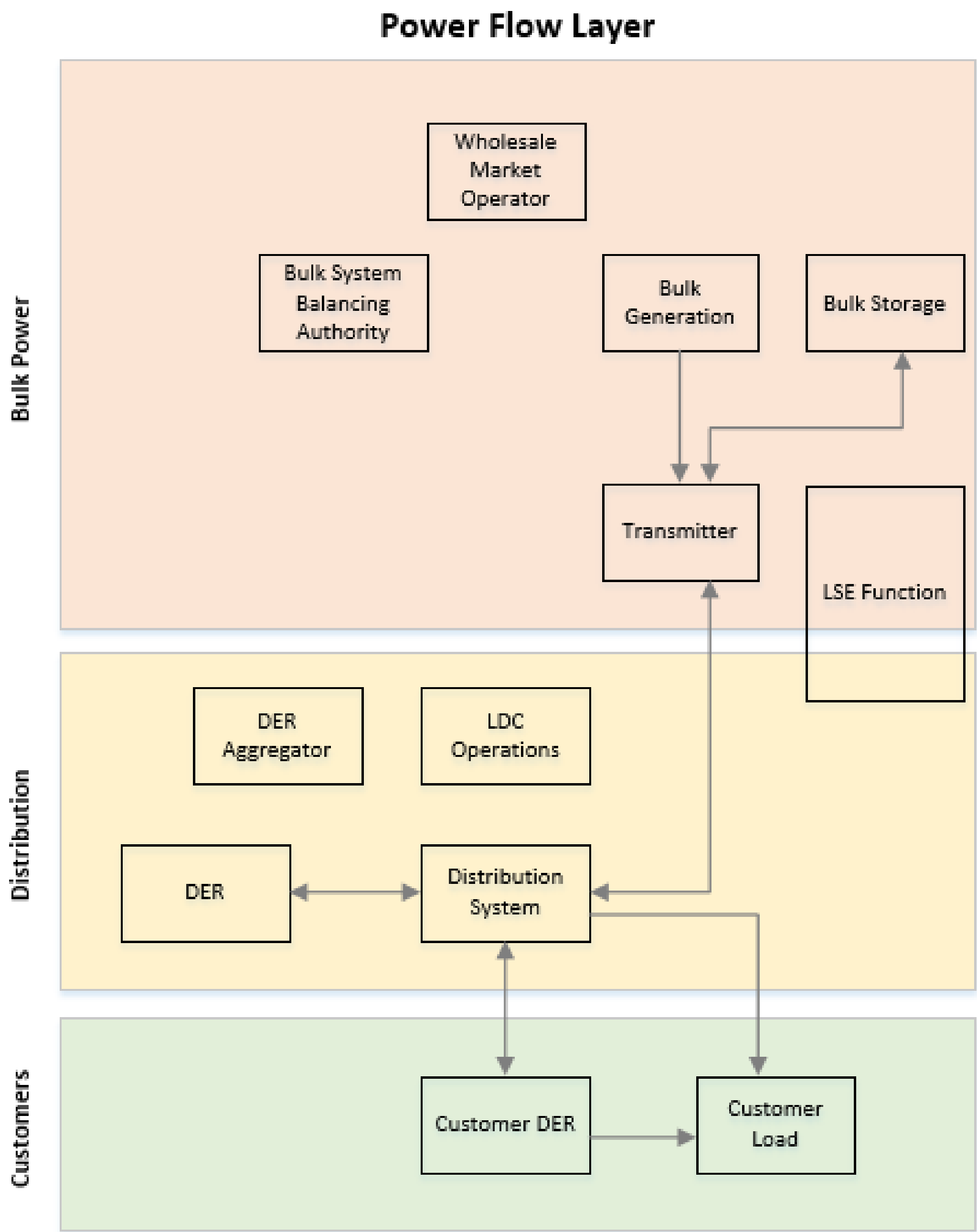
Analyzing the industry structure in this manner can reveal gaps between what currently exists (or will soon exist) in terms of players, interactions and functional capabilities, and the objectives that have been set for the province's electricity system. Achieving these objectives might require the introduction of new functional roles or interactions, or enhancements to existing capabilities and interactions already captured in these diagrams (see Sections 4.2.1 and 4.2.2 for further discussion).

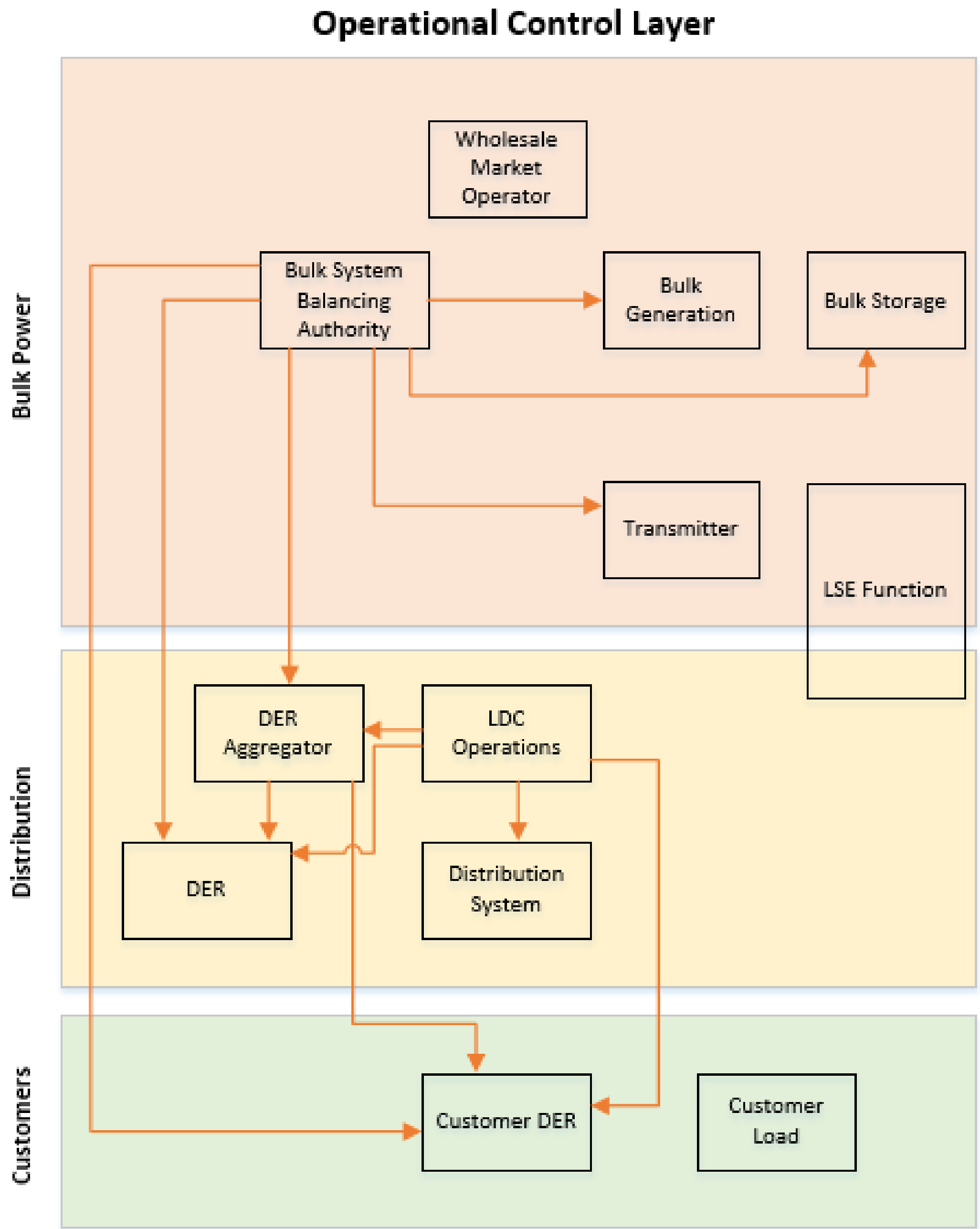
Ultimately, all the interaction layers must be displayed on a single diagram to capture the operation of the whole electricity system (last diagram in Figure 2). This comprehensive visual can be challenging to decipher, so showing each interaction type on a separate diagram makes it easier to grasp and can help identify gaps between the emerging industry structure and the province's desired future state.

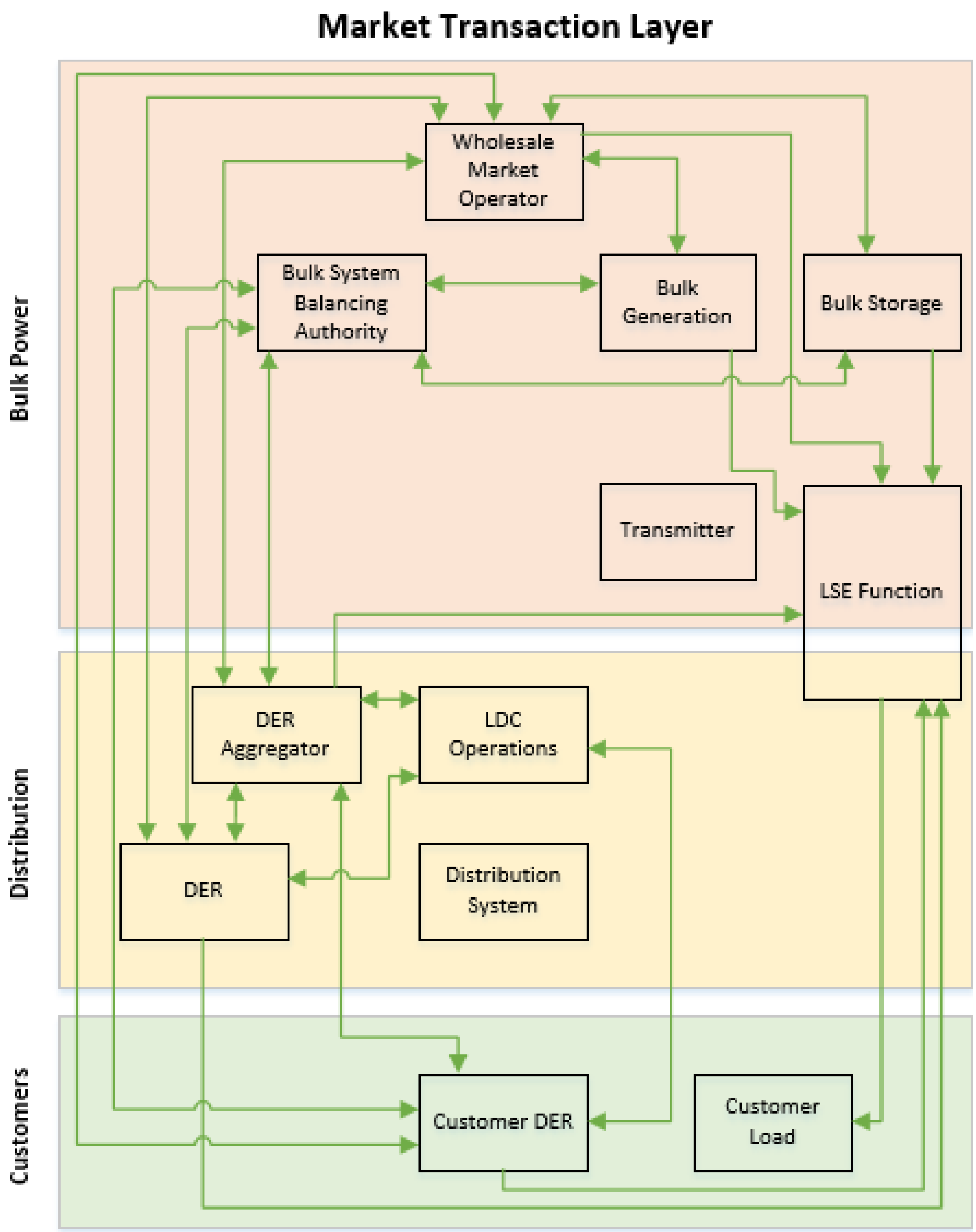
While the first four diagrams in Figure 2 capture each interaction type individually, a logical layering of each interaction type recognizes that power flow is the foundation of the electricity system – it exists to move electric power from where it is produced to where it is consumed. However, for the power flow layer to maintain balance of supply and demand in real time, respond to contingencies and preserve system reliability and safety, the players responsible require the means to exert operational control over some energy resources and electric system facilities (e.g., to dispatch regulation service via automatic generation control). In jurisdictions that adopt market mechanisms, these mechanisms typically align with and are designed to support reliable system power flows by complementing operational control mechanisms (e.g., using the five-minute bid-based market dispatch to follow load and restore regulation resources to their default set point).[30] All of these layers will require the exchange of data/information to ensure entities are able to meet or attain desired performance, which will ultimately enable safe and reliable operation of the system to continue.

[30] *Ibid*.

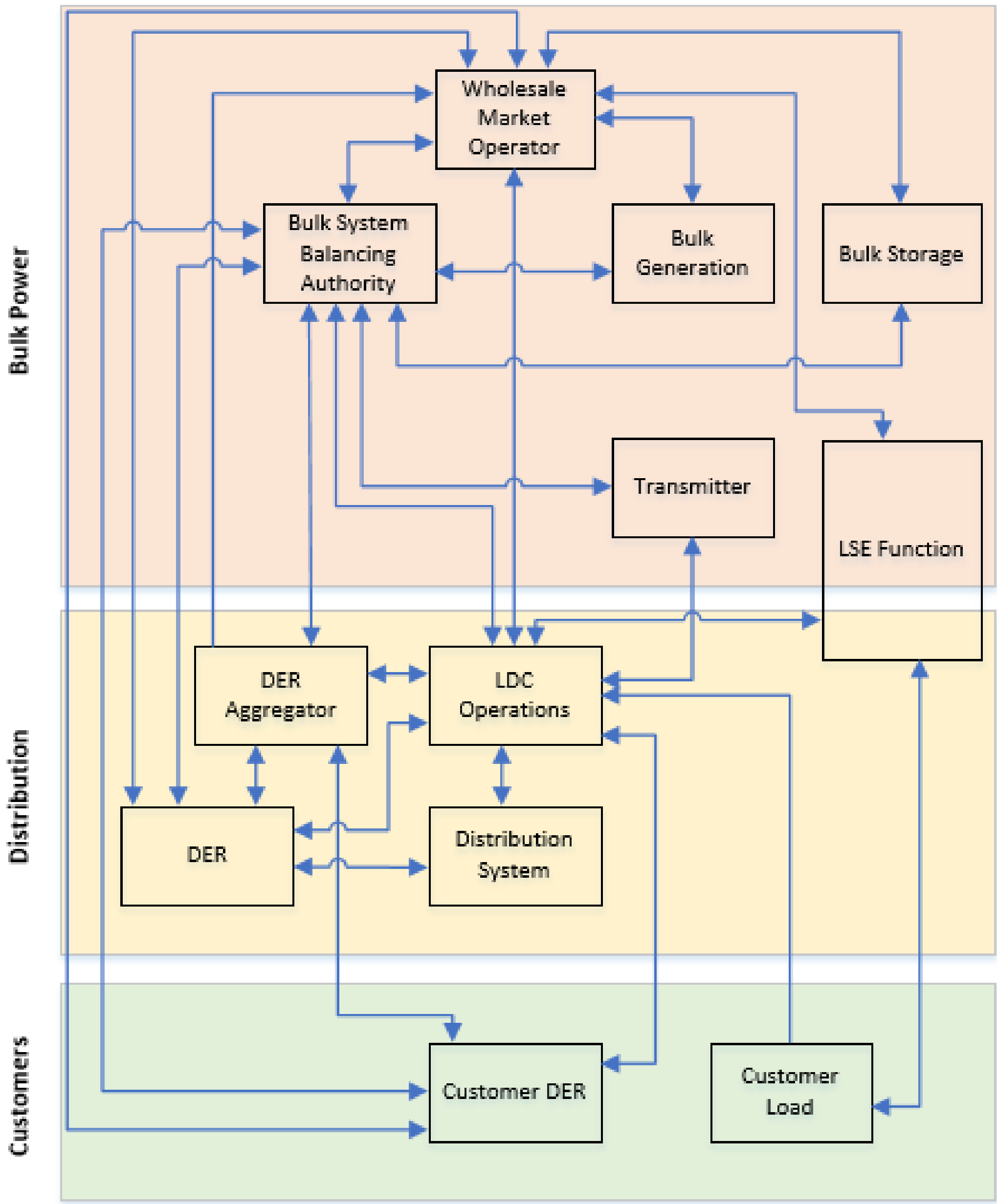
Figure 2: Ontario emerging industry structure diagrams



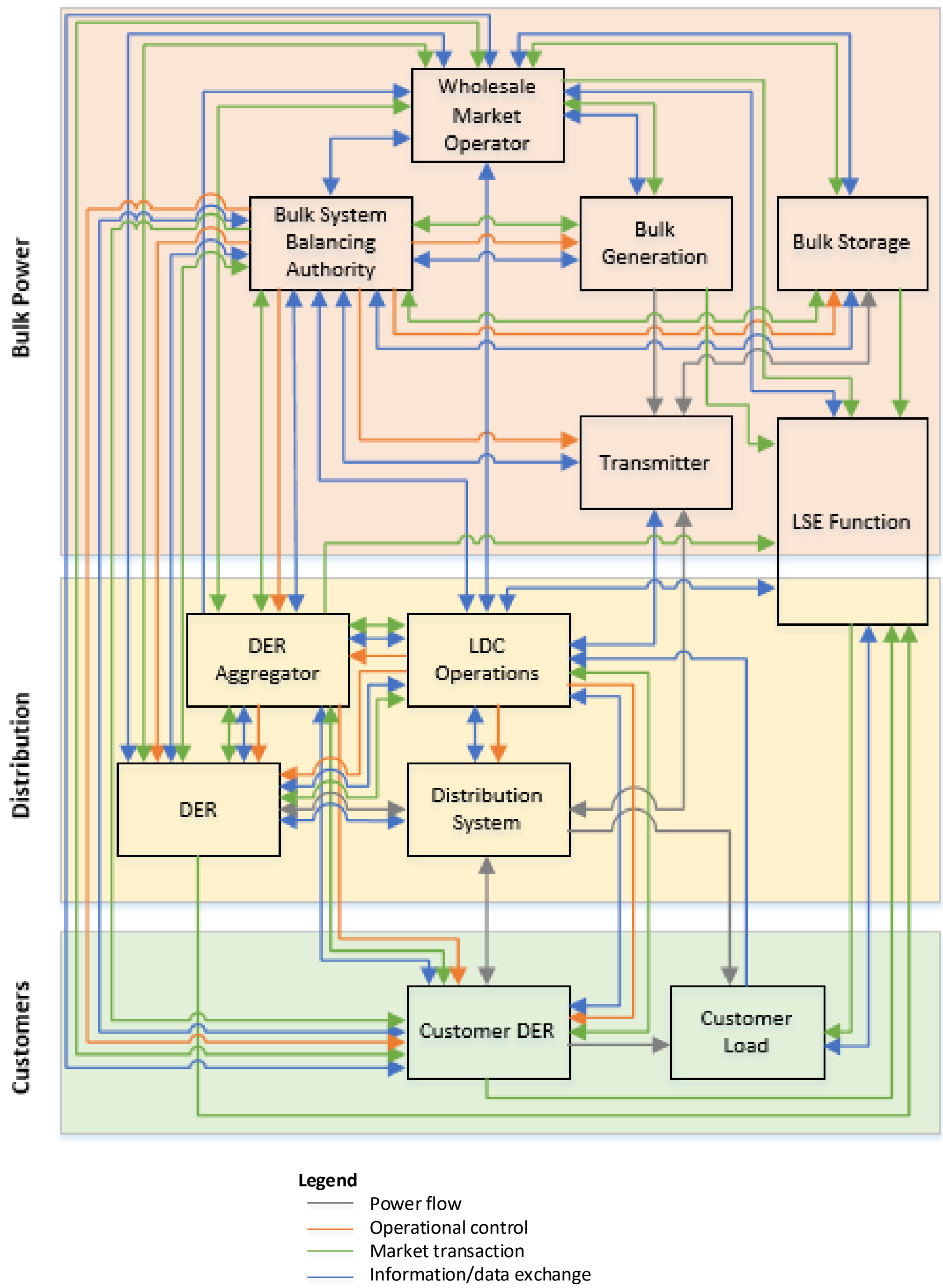

Operational Control Layer
Bulk Power
Distribution
Customers
Wholesale Market Operator
Bulk System Balancing Authority
Bulk Generation
Bulk Storage
Transmitter
LSE Function
DER Aggregator
LDC Operations
DER
Distribution System
Customer DER
Customer Load


Market Transaction Layer
Bulk Power
Distribution
Customers
Wholesale Market Operator
Bulk System Balancing Authority
Bulk Generation
Bulk Storage
Transmitter
LSE Function
DER Aggregator
LDC Operations
DER
Distribution System
Customer DER
Customer Load

Information/Data Exchange Layer



All Layers



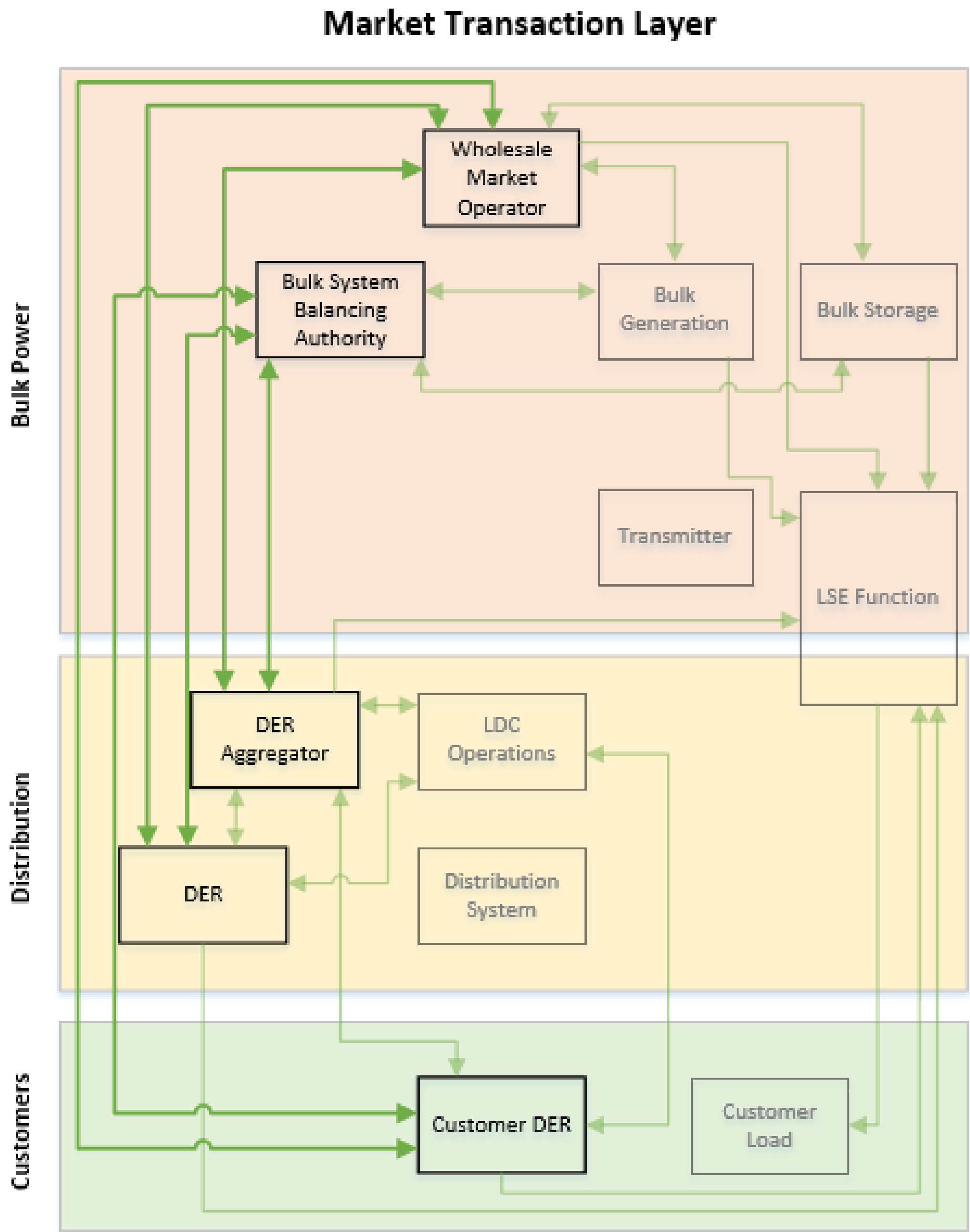
Bulk Power
Distribution
Customers
Wholesale Market Operator
Bulk System Balancing Authority
Bulk Generation
Bulk Storage
Transmitter
LSE Function
DER Aggregator
LDC Operations
DER
Distribution System
Customer DER
Customer Load
Legend
Power flow
Operational control
Market transaction
Information/data exchange

The structural diagrams in Figure 2 are intended to capture the likely evolution of functional capabilities in Ontario over the next five to 10 years. While DER participation in the IESO wholesale market is currently generally limited to aggregations of demand response (DR) resources and distribution-connected resources greater than 1 MW, efforts[31] to explore expanded pathways for participation in wholesale markets may help identify opportunities for DER aggregations, DERs and customer DERs (i.e., dispatchable DERs behind the customer's meter). Paving the way for DERs to access the wholesale market will require multiple enhancements to functional capabilities.

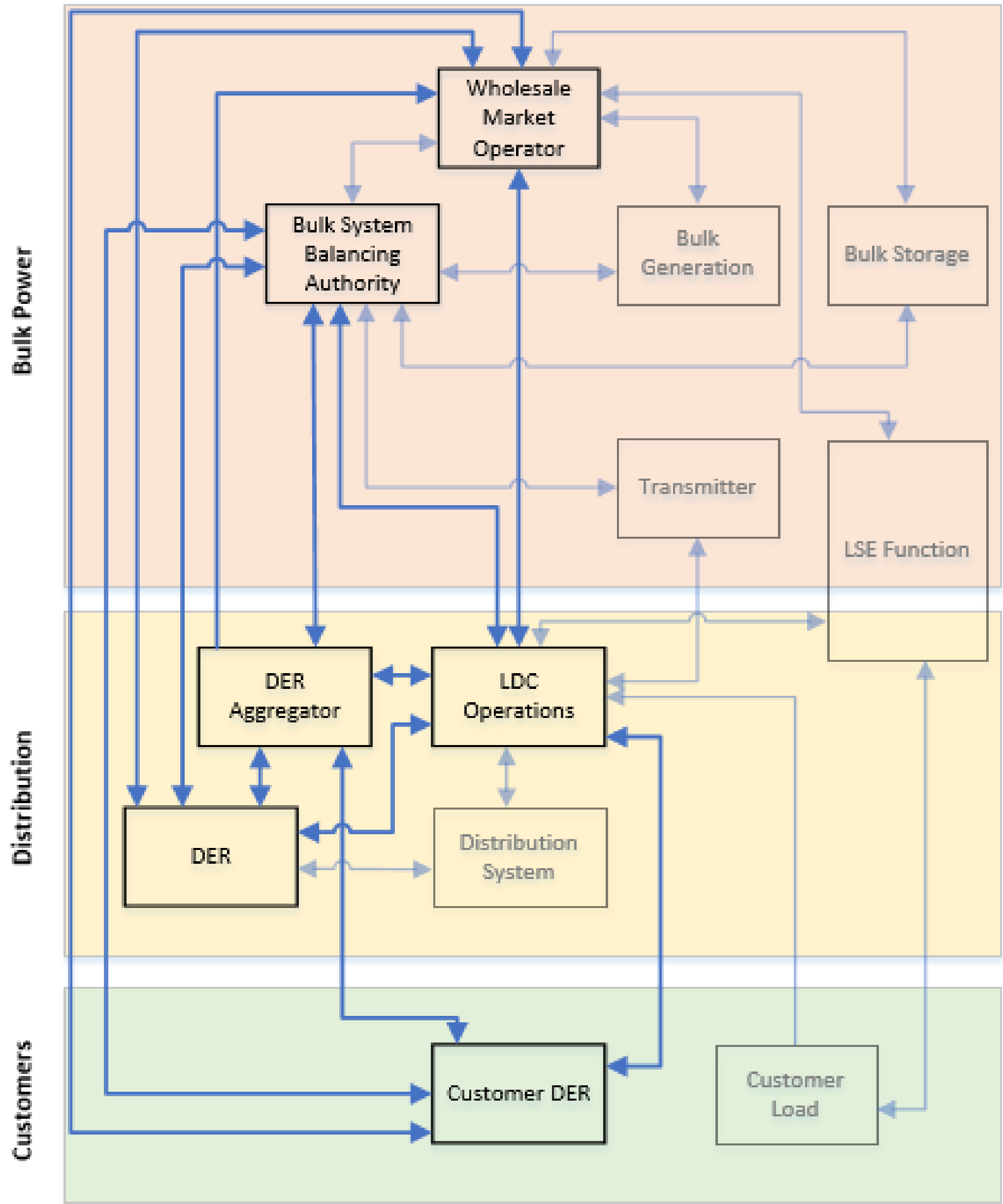
The first type of enhancement, due to the continued evolution and adoption of DER technologies, could spur the need for new capabilities to ensure distribution system safety and reliability while integrating higher levels of DERs. Market transactions (first diagram of Figure 3) between the IESO (i.e., wholesale market operator) and DERs (both distribution-connected and customer DERs) do not yet consider distribution system conditions given the IESO's limited visibility into the distribution system. As such, there must be mechanisms through the information/data exchange layer (second diagram of Figure 3) to coordinate distribution operations with the IESO, individual DERs and DER aggregators to ensure wholesale market participation does not compromise distribution system safety and reliability. For example, if LDC operations determines that a wholesale-participating DER must be taken offline due to distribution system conditions, a mechanism must be established to ensure the IESO's final dispatch does not include that DER. The LDC could serve this function, or a new DSO entity could assume this and other roles and responsibilities that emerge as DER penetration increases (further discussion of this topic in Section 4).

[31] IESO, *Project Brief: Exploring Expanded DER Participation in the IESO Administered Markets*. http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/isewp/isewp-der-participation-project-brief.pdf?la=en.

Figure 3: DER wholesale market participation requires enhanced coordination

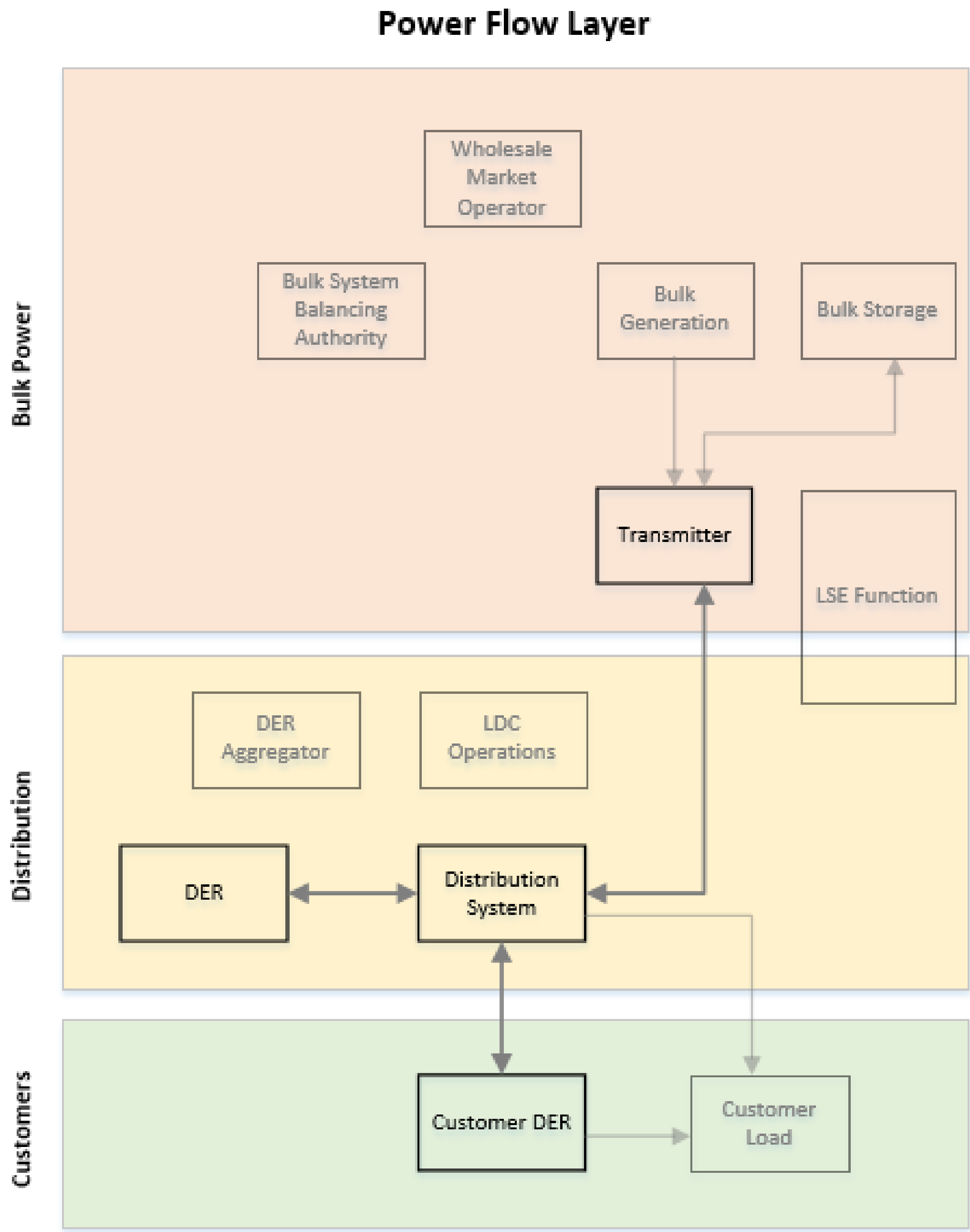


Information/Data Exchange Layer

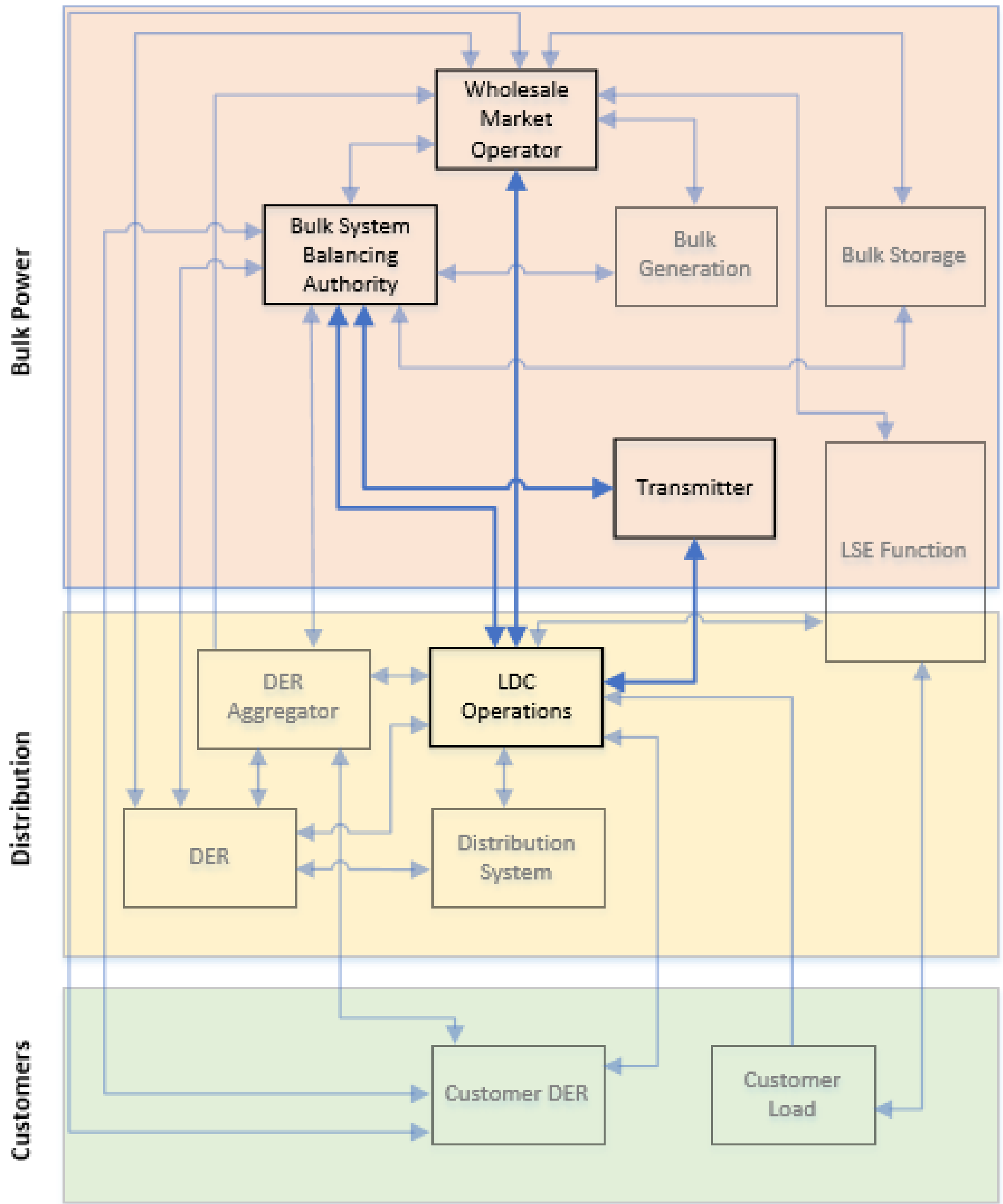


A second reason for additional functional capabilities is that the emerging industry structure could introduce two-way power flows where electricity generation on the distribution system can reverse the normal flows on distribution circuits (see Figure 2) and even flow up to the bulk power system (first diagram of Figure 4). Currently, the Ontario electricity system is largely characterized by one-way power flows from the bulk power system to the distribution system, but this model is changing with the growing number of DERs. This possibility will require new forms of operational coordination through the information/data exchange layer between the LDC, bulk system balancing authority, wholesale market operator and transmitter (second diagram of Figure 4) to preserve bulk power and distribution system safety and reliability. Historically, the operational coordination between these entities has been limited given the distribution system only receives power from the bulk system. However, the potential for two-way power flows to the bulk power system will make it increasingly important for LDC operations to notify these functional entities when it forecasts energy flowing back up across the T-D interface to preserve bulk power system safety and reliability.

Figure 4: Two-way power flows across the T-D interface require new forms of operational coordination



Information/Data Exchange Layer

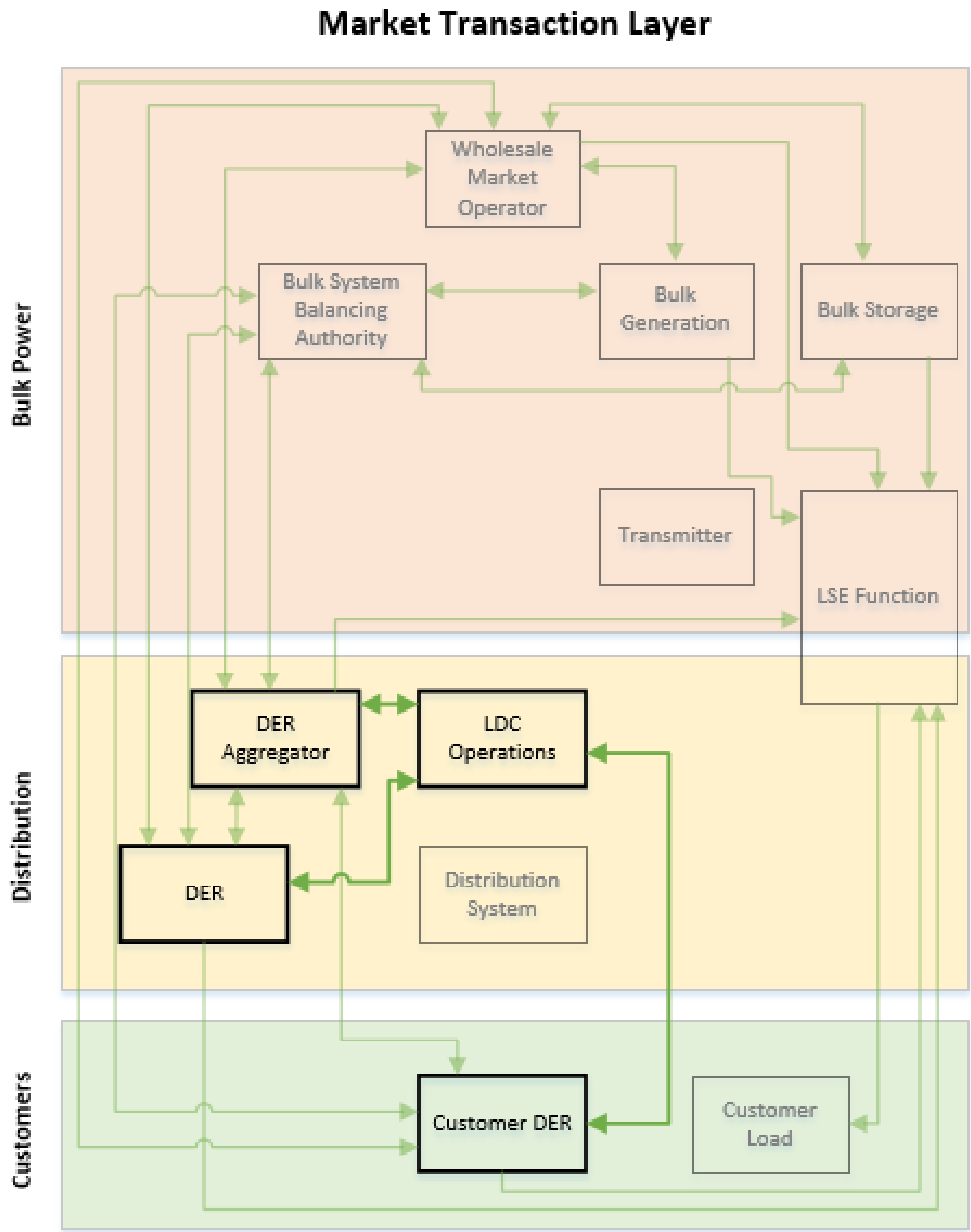


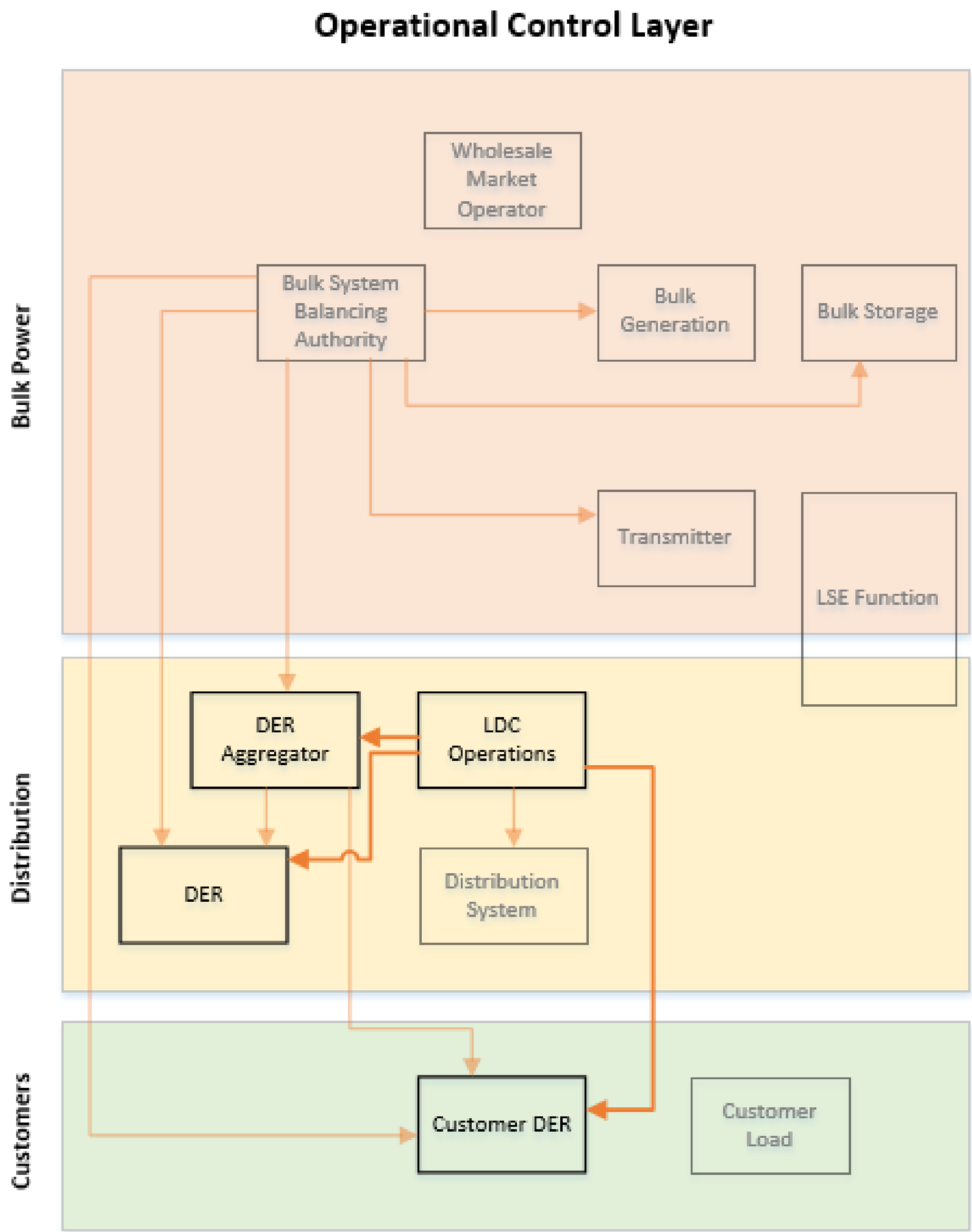
Another major development in this emerging industry structure is the introduction of distribution-level services and market transactions (first diagram in Figure 5). While initiatives like the IESO's York Region demonstration project are still in the early stages, LDCs could have more opportunities to leverage portfolios of DERs and/or energy efficiency to meet distribution deferral needs. The resources providing these NWA services can be dispatchable (e.g., DERs and customer DERs) or non-dispatchable (e.g., energy efficiency), and may or may not involve a DER aggregator as the coordinating party with the LDC.[32] The use of these types of services and market transactions[33] for NWAs will require greater levels of LDC operational control over the dispatchable DER (second diagram in Figure 5), an expanded LDC role in specifying the desired parameters of the non-dispatchable resources (e.g., load shape impacts of energy efficiency) and greater information/data sharing (e.g., provision of telemetry) between these entities to ensure optimal asset performance (third diagram in Figure 5).

[32] As discussed above, DERs and customer DERs receiving control signals from a DER aggregator would not receive control signals from either the bulk system balancing authority or LDC operations (and vice versa). However, resources providing bulk system and distribution services could receive control signals from both the bulk system balancing authority and LDC operations.

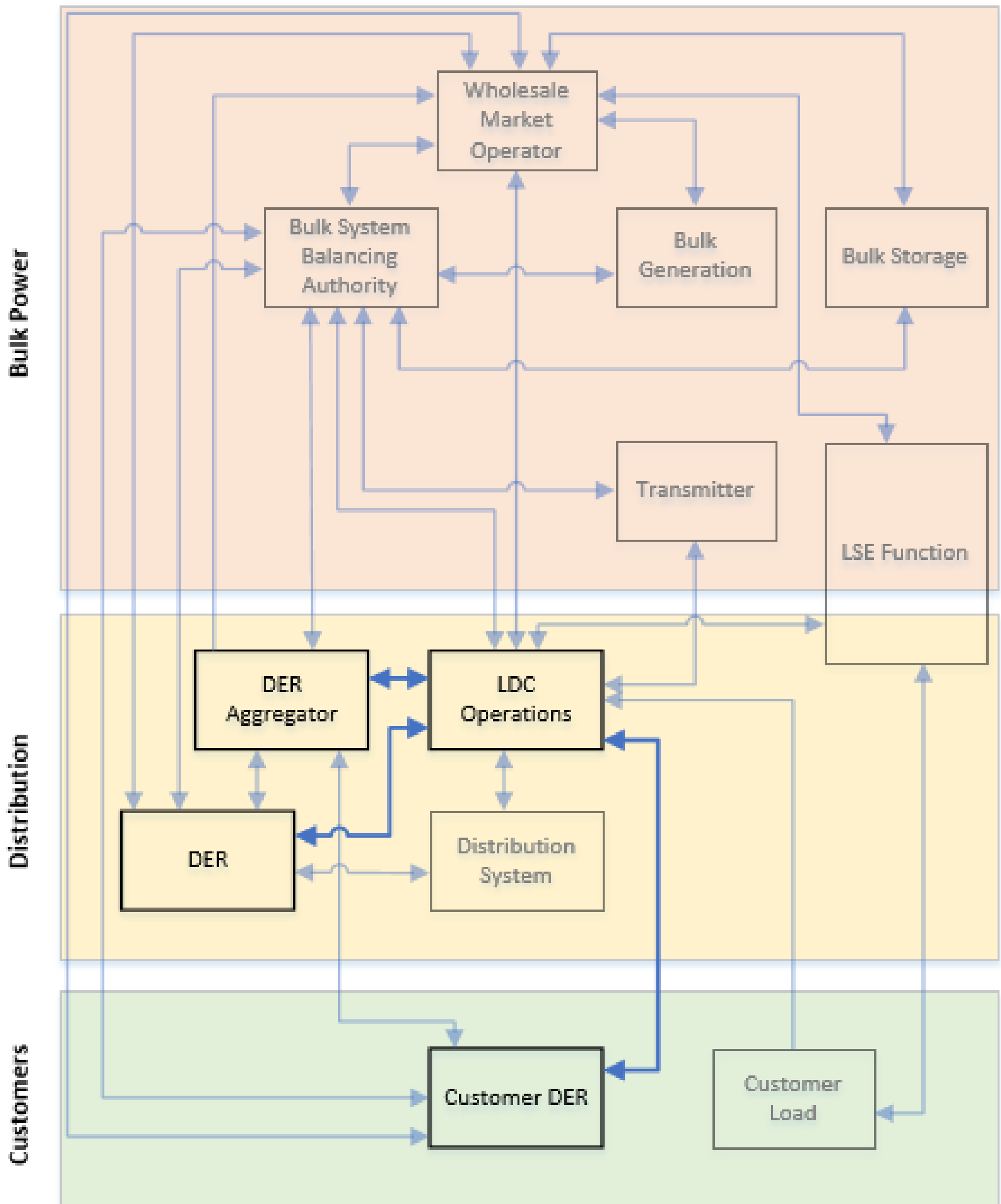
[33] The scope of distribution services expected to materialize over the next five to 10 years may not include real-time distribution operations services.

Figure 5: DER provision of distribution services requires greater operational control and coordination




Operational Control Layer
Bulk Power
Distribution
Customers
Wholesale Market Operator
Bulk System Balancing Authority
Bulk Generation
Bulk Storage
Transmitter
LSE Function
DER Aggregator
LDC Operations
DER
Distribution System
Customer DER
Customer Load

Information/Data Exchange Layer

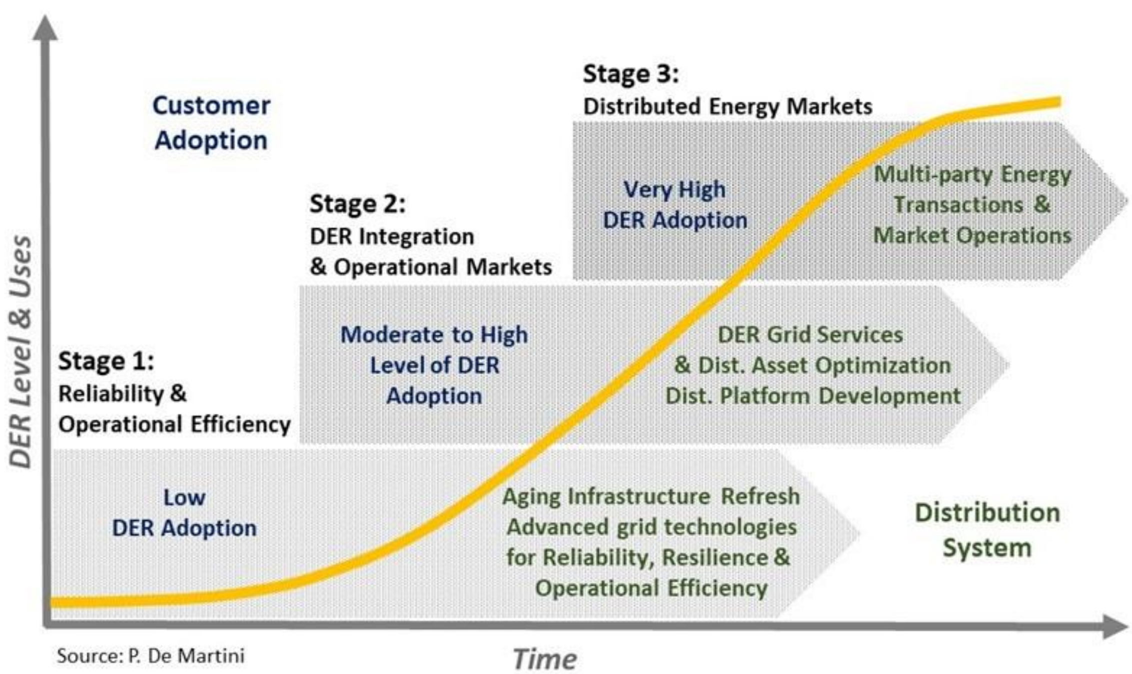


3.5 Continued evolution of Ontario's electricity system

At the heart of Ontario's electricity system evolution is the changing landscape of the distribution system. The emerging industry structure described in Sections 3.3 and 3.4 captures how the evolution of the province's grid builds on distribution system changes in response to a set of drivers, including increasing numbers of DERs and expanded opportunities for them to provide services to the grid (e.g., NWAs, wholesale market participation). As these drivers materialize, distribution systems throughout Ontario will require functionality that increases in complexity and scale over time. The distribution system will need to become more dynamic, flexible and resilient to effectively integrate new DER technologies and manage a grid increasingly characterized by two-way power flows.

Since these drivers of distribution system change are location-specific, the pace and scope of change will vary geographically across Ontario. Figure 6 illustrates a three-stage evolutionary framework for the distribution system assuming a combination of top-down drivers (e.g., public policy) and bottom-up drivers, such as customer preference.[34] Distribution system evolution across the stages will be driven by a need for additional functionalities to operate the grid more reliably and efficiently, support increased DER adoption by customers, and integrate DERs into operations and markets. The yellow line represents a typical technology adoption curve applied to DERs, showing how growing numbers of DERs will correspond to a staged evolution of the distribution system, resulting in an increasingly complex grid.

Figure 6: Distribution system evolution as influenced by increasing DER penetration and uses



[34] U.S. Department of Energy, *Modern Distribution Grid: Decision Guide, Volume III,* Office of Electricity Delivery & Energy Reliability, June 28, 2017. https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid-Volume-III.pdf.

The three evolutionary stages can be described as follows:

Stage 1 – Reliability and operational efficiency
This stage centres around enhancements to reliability, resilience and operational efficiency, while replacing aging infrastructure. DER penetration remains low and their participation in wholesale markets is either nonexistent or limited. The existing distribution system is capable of accommodating low levels of DER penetration and market participation with minimal infrastructure or operations changes. Distribution planners will begin to assess proactive grid enhancements needed to prepare for Stage 2 and beyond.[35]

Stage 2 – DER integration and operational markets
As more customers acquire DERs and public policies make it possible for more of these resources to provide wholesale and distribution services, integrating DERs into distribution system operations becomes more critical. The higher number of DERs may create operational impacts and result in two-way power flows. Depending on the extent DERs participate in the wholesale market, coordination with the distribution operator (e.g., with DER providers and the TSO) will be needed to preserve distribution safety and reliability (further discussion in Section 4). These changes will require enhanced functional capabilities to operate the grid reliably and optimize the use of DERs.

Stage 3 – Distributed energy markets
The third stage is characterized by a high number of DERs providing services to the wholesale market, retail customers and the distribution system, and could potentially introduce (and scale) bilateral energy transactions between sellers and buyers across the distribution system. This stage requires a significant number of dispatchable DERs that are fully capable of providing distribution services (i.e., not subject to net energy metering tariffs or interconnection rules or regulations that preclude the sale of energy or grid services on the distribution system).

With Ontario largely in Stage 1, it is important to consider how drivers, such as customer choice and public policy, will affect the pace and timing of Ontario's electricity system evolution to Stage 2 and beyond. Different areas of Ontario will likely progress to these advanced stages at different rates, based on existing LDC capabilities and the number of DERs in the region. For example, the United Kingdom described three key drivers that influence the speed at which a system evolves to a more advanced stage: (1) the existing gap in distribution functional maturity; (2) the level of business change required within system operators; and (3) the level of technological enhancement needed to enable desired change.[36] As discussed earlier, objectives serve to guide this evolution. Table 5 illustrates when distribution operators require various functions related to the three evolutionary stages.

[35] Even if the DER penetration rate across the entire system is low, portions of the system may have higher numbers of DERs and require the development of advanced capabilities associated with later evolutionary stages.
[36] Baringa, *Future World Impact Assessment*, Energy Networks Association, February 22, 2019. http://www.energynetworks.org/assets/files/Future%20World%20Impact%20Assessment%20report%20v1.0_pdf.pdf.

Table 5: Distribution functions by evolutionary stage[37]

Distribution functions	Stage 1	Stage 2	Stage 3
Planning			
Scenario-based, probabilistic distribution engineering	✓	✓	✓
DER interconnection studies and procedures	✓	✓	✓
DER hosting capacity analysis	✓	✓	✓
DER locational value analysis		✓	✓
Integrated transmission and distribution planning		✓	✓
Operations			
Design-build and ownership of distribution grid	✓	✓	✓
Switching, outage restoration and distribution maintenance	✓	✓	✓
Physical coordination of DER schedules		✓	✓
Real-time coordination with ISO at T-D interface		✓	✓
Market			
Sourcing of distribution grid services		✓	✓
Optimal dispatch of DER-provided distribution grid services		✓	✓
Aggregation of DERs for wholesale market participation		✓	✓
Creation and operation of distribution-level energy markets; transactions among DERs			✓
Clearing and settlements for inter-DER transactions			✓
Market facilitation services			✓

4 Alternative architectural models to facilitate T-D interoperability

Determining how to best coordinate operations between TSOs and distribution utilities with a high volume of DERs is a major ongoing discussion globally wherever there are bulk power systems and operators.[38] Although different jurisdictions are considering a variety of T-D interoperability models or frameworks, they all reflect the dichotomy of either a centralized structure for operational control of the combined T-D system, or a layered structure where operational control is performed within concentric layers and at the interfaces between them, such as transmission to distribution, distribution to microgrid, and microgrid to individual building. Discussing that choice at this point in time is crucial. Revolutionary changes in electricity technologies are challenging the traditional centralized one-way power flow paradigm, and with it all aspects of the industry, including real-time operation, infrastructure investment, utility business models and wholesale markets, raising new regulatory questions that require an expedited resolution.

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[37] De Martini, P., & Kristov, L., *Distribution Systems in a High Distributed Energy Resource Future: Planning, Market Design, Operation and Oversight*, 2015. https://emp.lbl.gov/sites/default/files/lbnl-1003797.pdf.

[38] Joint Working Group C2/C6.36, *System Operation Emphasizing DSO/TSO Interaction and Coordination*, CIGRE, June 2018. https://e-cigre.org/publication/733-system-operation-emphasizing-dsotso-interaction-and-coordination.

The question then becomes whether to maintain the centralized structure for coordinating high volumes of DERs or to transition to a more decentralized layered structure. The choice must be grounded in the operation of the physical system and the traditional objectives of reliability, efficiency and safety.

This type of analysis focuses on two very distinct bookend models: one where the distribution system is overseen by the TSO and the other where it is completely overseen by the DSO (see Section 4.1).

The fully centralized Total TSO entails the TSO systems modelling distribution circuits and mapping DERs at their actual locations on the distribution system. In this model, the TSO is responsible for reliable distribution system operation with DERs bidding into the TSO's markets for wholesale energy and grid services. The corresponding DSO – the Minimal DSO or M-DSO – is restricted to implementing the minimum functional enhancements to the existing distribution utility required for reliable operation.

In contrast, the Total DSO is the fully layered approach in which responsible operators at each layer coordinate with adjacent layers at physical electrical interface points and are not concerned with the internal devices and behaviours within the adjacent layers. For example, a single building may be entirely self-sufficient for electricity and able to "island" from the grid. That requires a control system for the building that can also interact with the control system of the next layer up, perhaps a campus microgrid. The microgrid may have dozens of such buildings, an on-site portfolio of DERs, and the ability to island from the utility grid, which is its next layer up. Above that is the T-D interface substation, which prompts the all-important TSO-DSO coordination question: what is the best way to specify the scope and responsibilities of the TSO and DSO in a high-DER future to realize the objectives and full potential of these technologies? At each layer of such an architecture, the operator, in addition to managing operations within its own layer, manages its side of the interfaces between its own and the adjacent layers without needing visibility into or control of devices internal to the adjacent layers.

The choice of a TSO-DSO coordination framework is not limited to one of the two bookend models, which mark the endpoints of a range of possibilities referred to as Hybrid DSO models. These are differentiated by the specific functions and roles entities may assume and include the degree of visibility and control the TSO will have over DERs and distribution system operations. Section 4.2 illustrates this idea by describing two hybrid alternatives.

The choice of a model will depend on policy discussions and analysis that consider many factors and will be influenced by the existing industry structure and policy objectives for system change. Policy discussions should explicitly consider the centralized-versus-layered question because a preference for one or the other will shape other design and implementation decisions. For a large TSO service area with multiple LDCs, different DSO models may be appropriate for different LDCs due to differences in factors like population density, DER adoption rates and current LDC visibility and control capabilities.

The spectrum of possible Hybrid DSOs provides policy-makers and system players with:

- A range of options to specify a single desired future end-state or target
- An evolutionary path for moving from the current structure toward a preferred structure, e.g., starting from a centralized model and moving to a more layered model as the volume of DERs increases
- A tool to specify two or three models that would be best suited to different LDCs co-existing within a TSO service area

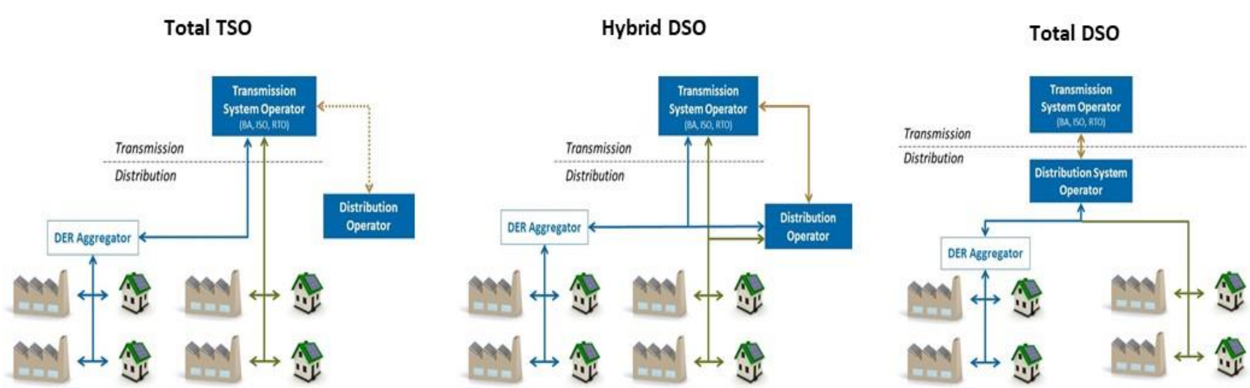
As the current industry structure evolved in conjunction with a system of large power plants and centralized operational control, the centralized end of the spectrum, which accommodates a low level of DERs with minimal changes to the system, is the most likely default. At the same time, transmission and distribution operators may develop strategic plans that model their preferred future state.[39] The endpoint options of Total DSO and Total TSO, and the spectrum of hybrids in between, enable policy-makers to visualize the implications of their choices.

This white paper examines two Hybrid DSO coordination models, moving away from the choices on either end of the spectrum to illustrate how a hybrid approach could reflect an underlying preference for a more centralized or layered structure (see Section 4.2). As is the case with any coordination model, the roles and responsibilities of the TSO, DSO and other key players must be clearly specified. While these hybrid DSO approaches only represent two of the possibilities, they serve as a useful mechanism to apply the Ontario-specific decision framework and determine how well each alternative meets the province's objectives for the system.

4.1 Conceptual T-D interoperability model framework and bookends

Based on different allocations of roles and responsibilities between the DSO and TSO with regard to DERs, important contrasts emerge, resulting in different functional requirements and capabilities for each entity. As shown in Figure 7 below, the Total TSO and Total DSO provide bookends for a range of models. The Hybrid DSO represents a spectrum of intermediate models rather than a single model (see Section 4.2).

Figure 7: Conceptual reference for T-D interoperability models[40]



[39] An example from the United Kingdom is Western Power Distribution's December 2017 update to its *DNO-to-DSO Transition* report, available at https://www.westernpower.co.uk/downloads/260.

[40] De Martini, P., Kristov, L., & Taft, J., *Transmission - Distribution - Customer Operational Coordination.* U.S. Department of Energy Final Draft, 2018.

4.1.1 Total TSO

The Total TSO operates a fully integrated electricity system and market. In this fully centralized approach, the TSO performs all DER operational coordination based on direct access to the wholesale markets for all DERs and DERAs above a minimum size threshold for market participation. It performs an economic dispatch, including dispatch coordination of all DER services and schedules. The TSO's economic dispatch algorithm includes distribution circuits and represents DERs at their actual locations on the distribution system, enabling the TSO to account for distribution system conditions and impacts. In this way, the TSO assumes considerable responsibility for reliable real-time operation of the distribution system.

The DSO associated with the Total TSO Model is referred to as the Minimal DSO (M-DSO), reflecting the fact that the DSO retains but does not expand upon the traditional LDC role of maintaining reliable and safe distribution operations (e.g., maintaining and operating physical distribution assets; managing distribution interconnections and performing engineering analyses). New operational capabilities are implemented only as needed to perform that role with a higher number of DERs on the system, and frequent reversal of power flows. Although these new activities may be significant from an operational perspective, an M-DSO would not take on new roles, such as aggregating DERs for wholesale market participation or operating a distribution-level market for DER services. Instead, DERs and DERAs would participate directly in the TSO markets.

While useful for conceptual purposes, the Total TSO Model could be challenging to implement, first because it involves tier bypassing, which poses grid architecture concerns. Market transactions between the TSO and the DER operator ignore the physical power flow over the distribution system for which the M-DSO retains some responsibility, but is not a party to the market transaction. This situation could lead to conflicting operating instructions to a DER from both the TSO and M-DSO. For example, after the TSO issues a dispatch instruction to a DER, a sudden transformer failure eliminates the distribution capacity needed by the DER to respond to the dispatch, so the M-DSO instructs the DER to come offline. This results in conflicting signals for the DER, requiring coordination to ensure its operation preserves distribution system safety and reliability. Second, this model creates scalability concerns for replicating the coordination framework between the TSO and DSO at the T-D interface to other levels of the system (e.g., structuring the coordination between the DSO and a microgrid within a local distribution area).

4.1.2 Total DSO

The Total DSO Model minimizes the role of the TSO with regard to DER coordination and maximizes that of the DSO by eliminating direct participation in the TSO market by DERs/DERAs. Instead, the DSO coordinates all wholesale market services provided by DERs/DERAs. In that role, the DSO would submit a single bid/offer (i.e., the price and quantity combinations of how much energy the resources below a T-D interface can provide or seek to purchase) to the TSO market for each individual T-D interface, and receive TSO market schedules and dispatches as if it were a single aggregated resource or virtual power plant located at the T-D interface. This role requires substantially enhanced capabilities, including establishing transparent market mechanisms for procuring DER/DERA services and optimizing the system of wires and resources below each T-D interface to submit a bid/offer, and then coordinating an optimal response to TSO dispatches from participating DERs/DERAs within the LDA.[41] As discussed in Sections 4.2 and 4.3, this type of approach would also require important regulatory changes to govern how the DSO operates the distribution system and the relationship between the DSO and TSO.

In many respects, the Total DSO Model assumes the characteristics of a local ISO at the distribution level. Upon receiving a dispatch instruction from the TSO, the DSO, by virtue of its role as aggregator for wholesale participation, must determine the most economical combination of DERs downstream of the given T-D interface to respond to the TSO's dispatch, while preserving distribution system safety and reliability. Additionally, the Total DSO is responsible for balancing supply and demand in its service territory, relying as needed on imports or exports with the TSO across the T-D interface.

There are six key features of a fully layered architecture:

1. The operator at each level is responsible for the reliable performance of its own layer and its interfaces with adjacent layers.
2. Each operator only needs to deal with (and have visibility into and control of) its interfaces with the adjacent layer, not with the system and resources inside other layers.
3. Although not an essential requirement of the Total DSO Model, substantial security, resilience and resource adequacy benefits would be realized if each layer can smoothly island from and reconnect with the layer above.
4. Layers can trade services with adjacent layers via economic transactions at the interfaces.
5. Each layer may have specific objectives and constraints not common to other layers, although all layers share responsibility for the functioning of the larger electricity system.
6. Different layers can have different transactional regimes (e.g., centralized transactions between the TSO and DSO, or peer-to-peer markets operated within an LDA by the DSO).

Although the Total DSO Model would be a major change to the fully centralized control structure that has characterized the power industry for decades, it offers greater operational simplicity, resilience and other architectural advantages for an electricity grid with high levels of DERs. However, in the Ontario context, consideration would first need to be given to existing LDC roles and responsibilities to avoid any potential conflicts of interest with their new role as DSO (e.g., poles and wires ownership, DER ownership). The division of roles and responsibilities at the transmission level in Ontario may provide insight into how roles and responsibilities might be allocated at the distribution level to avoid conflicts.

4.1.3 Hybrid DSO

A Hybrid DSO could be implemented in many ways, and potentially help avoid the near-term implementation challenges associated with the structural changes required for the Total TSO and Total DSO models. However, a Hybrid DSO approach usually comes with added complexity in structure, roles, responsibilities and coordination processes, making it more manageable with lower levels of DER participation. Growing numbers of DERs participating directly in the wholesale market could raise the grid architecture concerns of tier bypassing and hidden coupling, operational risks impacting reliability and resilience, and constraints on scalability. Although automated processes enabled by technological

[41] While the DSO serves as the sole aggregator for interacting with the TSO at each T-D interface, third-party DER aggregators are still capable of aggregating DERs within a T-D interface and offering the virtual resource into the DSO market to be included in the DSO's single aggregated bid/offer to the TSO.

advancements can help facilitate coordination, the number of distinct entities that need to coordinate would pose challenges to most Hybrid DSO models.

Most jurisdictions with a low number of DERs on their systems initially start toward the Total TSO side of the spectrum, and evolve their framework based on the subsequent growth of DERs and longer-term objectives, such as market efficiency, affordability, and transparency. For example, distribution utilities in New York have taken steps to document how their roles and responsibilities as a Distributed System Platform (DSP) may evolve over time, but acknowledge that longer-term evolution in a high-DER environment requires further analysis.[42]

In the face of challenges presented by Hybrid DSO models, a jurisdiction can use grid architecture principles, such as tier bypassing, hidden coupling and scalability, to guide decisions to achieve objectives (see Section 3.2). Decision frameworks for system evolution should go beyond grid architecture principles to account for the existing system functionality, the roles and responsibilities of existing and future entities – for example, the intended future role of third-party DER operators and aggregators – and the prospective resource mix, including the number of DERs on the system.

4.2 Alternative Hybrid DSO models

The two Hybrid DSO models in this section illustrate how the Ontario T-D interoperability decision framework outlined in Section 3 applies to potential system architectures. Since both Total DSO and Total TSO models bring some complexities or less desirable features, Hybrid DSO models are worth exploring as alternative solutions. For example, the Total TSO Model requires the TSO to create a complete transmission plus distribution system network model for its system optimization and to model all DERs (above a minimum-size threshold[43]) at their point of interconnection to the network. The TSO would take on considerable new responsibilities for distribution system operation and reliability. However, it would not have complete responsibility because the LDC would still own, maintain and operate the physical assets of the distribution system, and either it or the Minimal DSO (if created as a separate entity) would still coordinate with the TSO. As a result, one of the Hybrid DSO alternatives considered here moves away from the Total TSO Model slightly by giving the DSO responsibility for operating the distribution system and dropping the need to model distribution circuits in the TSO optimization. Instead, the TSO models DERs as if located at their associated T-D interface, which forms the basis for alternative 1 (see Section 4.2.1).

At the Total DSO end of the spectrum, many DER owner-operators and aggregators are opposed to having their wholesale market participation mediated by the DSO. Their concern stems from the fact that DSO models and distribution-level markets are still mainly conceptual and require the resolution of important policy and regulatory matters before they are functional. Some DER owner-operators are concerned that a DSO that is not independent of the LDC would favour its own participating DERs to the disadvantage of third-party DER owner-operators. For example, the Australian Energy Market

[42] Con Edison. *Distributed System Implementation Plan*. July 31, 2018. https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/distributed-system-implementation-plan.pdf?la=en.

[43] TSOs generally have a minimum-size threshold for participation in their markets, below which the activity of the resources is either subsumed in net load calculations for purposes of the optimization, or too small to have any measurable impact on the grid.

Commission concluded that LDC ring-fencing mechanisms to separate the DSO function from distribution operations may not fully prevent the DSO from making decisions that benefit the LDC at the expense of third-party providers (e.g., by cross-subsidizing a competitive service from the LDC's regulated activities, acquiring commercially sensitive information that gives the LDC a competitive advantage, or restricting access to infrastructure to limit competition).[44] This type of concern has sparked interest in defining an open-access framework for DSOs, comparable to that created in the 1990s to enable competitive wholesale power markets in the U.S.[45] For this reason, it may make sense to move away from the Total DSO Model to allow larger DERs/DERAs to participate directly in the wholesale market, while separately developing open-access rules for the DSO's treatment of smaller DERs/DERAs. This structure forms the basis for alternative 2 (see Section 4.2.2).

Alternatives 1 and 2 described below and other hybrids could be implemented with the existing LDC becoming the DSO or by creating an independent DSO (IDSO). The latter would separate distribution infrastructure planning from the entity that owns the distribution infrastructure and has economic incentives to build and rate-base assets and create a competitive arena for third-party providers of DERs and customer services. Such competition would be distorted if a DSO provided advantages to its own or affiliate DERs. This type of concern could exist with any Hybrid DSO model, where the DSO is responsible for distribution planning, interconnection procedures, and real-time operating decisions, such as curtailing DERs to maintain reliable operation. However, creating an IDSO requires complex coordination (e.g., replication of network models; coordination for outages/derates) with the LDC, which would continue to own, operate and maintain the physical assets of the distribution system. It may be preferable for the LDC to become the DSO if it is possible to establish a regulatory framework that addresses the issues mentioned above. Establishing this type of regulatory framework in Ontario would require further investigation.

Separating distribution infrastructure planning from ownership requires financial incentives for the DSO based on distribution service performance metrics as a complement to or instead of a return on assets. This framework would be helpful to advance NWAs for transmission and distribution infrastructure needs and does not depend on a particular level of DER adoption in an area. For example, the Office of Gas and Electricity Markets (Ofgem) in the United Kingdom has established a price controls model where the revenue of electricity and gas network providers is equal to payments tied to incentives, innovation and outputs.[46] In the U.S., most efforts to establish performance-based ratemaking remain at an early stage, with Hawaii having made the most progress in developing an incentive-driven framework.[47]

Creating a competitive arena for third-party DER owner-operators requires an open-access regulatory framework for the DSO. Open-access principles apply to infrastructure planning, interconnection

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[44] Australian Energy Market Commission, *Distribution Market Model: Final Report,* August 22, 2017, p.32. https://www.aemc.gov.au/sites/default/files/content/fcde7ff0-bf70-4d3f-bb09-610ecb59556b/Final-distribution-market-model-report-v2.PDF.

[45] U.S. Federal Energy Regulatory Commission, *Order 888,* 1996. https://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp.

[46] Ofgem, *Network regulation – the 'RIIO' model*. https://www.ofgem.gov.uk/network-regulation-riio-model.

[47] Public Utilities Commission of the State of Hawaii. *Convening Phase 2 and Establishing a Procedural Schedule,* Instituting a Proceeding to Investigate Performance-Based Regulation, Docket No. 2018-0088, June 26, 2019. https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A19F26B11108I00310.

procedures, real-time operating actions and any procurement or market operation activities of the DSO.[48] These principles will become more important as the volume of DERs on the system and the numbers of third-party providers increase.

4.2.1 Alternative 1: closer to Total TSO

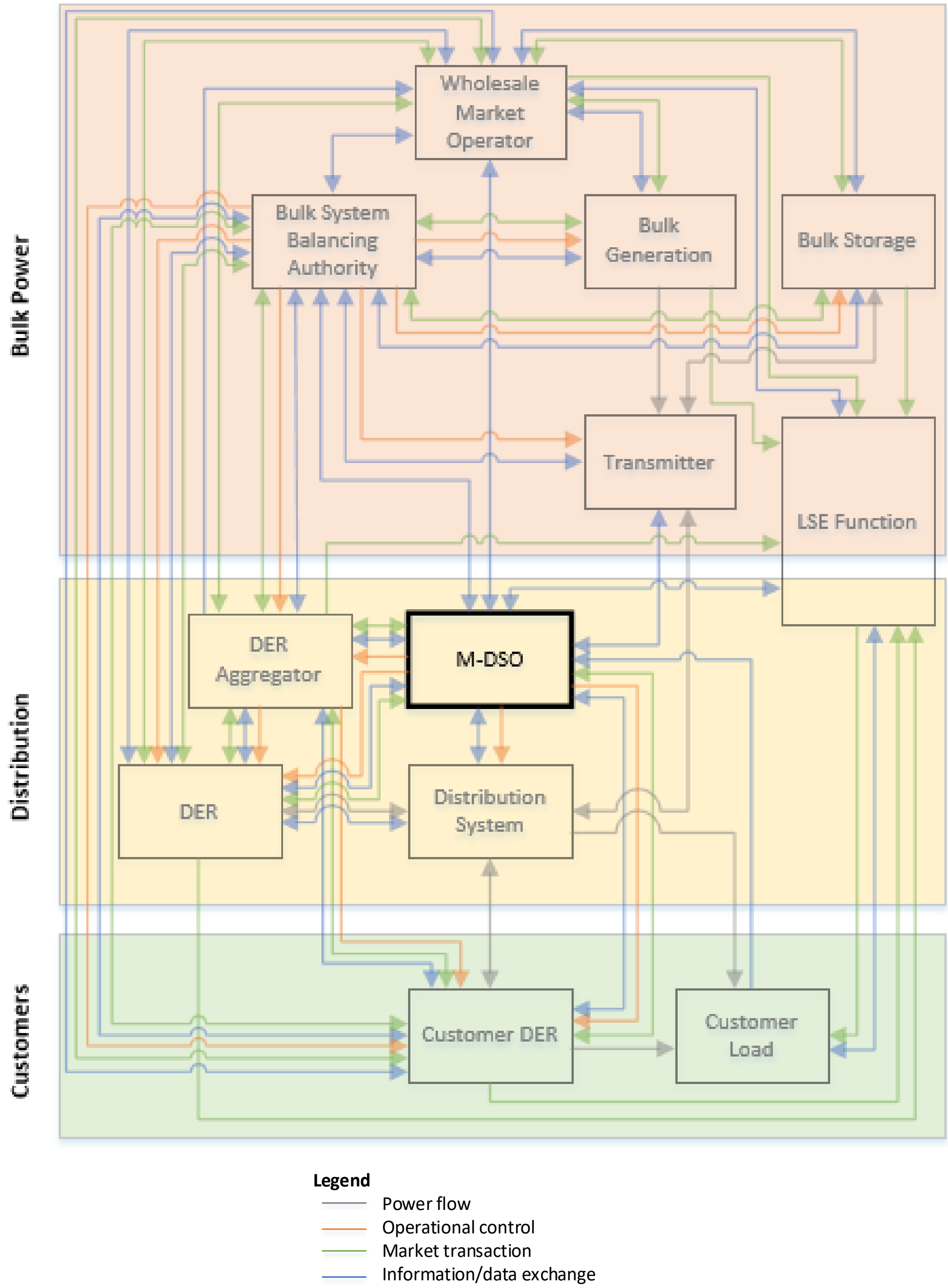
The alternative 1 TSO optimizes and dispatches all DERs and DERAs that are eligible to participate in the wholesale market but, unlike the Total TSO, does not model the distribution system in its optimization network model. Instead, each DER/DERA is modelled as though it were connected at the T-D sub-station.[49] Alternative 1 keeps responsibility for distribution system operation with the DSO, while limiting new DSO activities and capabilities to the minimum required for reliable distribution operation and TSO-DSO coordination. While this option is comparable to the M-DSO associated with the Total TSO, it retains more operational functions. The M-DSO could be an enhancement to the existing LDC or a new separate entity.

The alternative 1 M-DSO is responsible for traditional LDC activities, including distribution system planning, interconnections and real-time operation. It is also responsible for coordinating with the TSO for DERs that participate in the TSO market, particularly in instances where current distribution system conditions will constrain or impact DER operations and vice versa.

Figure 8 shows that the only difference between the alternative 1 industry structure and the emerging industry structure (Figure 2) is that the M-DSO has replaced the LDC operations function and assumed its responsibilities. While the M-DSO may require significant functional enhancements, these constitute minimal additions to LDC operations in the emerging industry structure.

[48] Some of the TSO-DSO efforts in the UK and Europe characterize the DSO as a neutral market facilitator.
[49] If the TSO's rules allow multi-node DERAs, these would be modelled at multiple T-D interfaces in a manner that reflects the share of DERA capacity at each T-D interface.

Figure 8: Alternative 1 industry structure skeletal diagram



4.2.2 Alternative 2: closer to Total DSO

The alternative 2 DSO departs from the Total DSO Model by allowing direct wholesale market participation by DERs and DERAs, but only above a somewhat higher size threshold than the minimum the TSO normally requires for resources to participate. A higher threshold could significantly decrease the number of individual resources the TSO sees at any given T-D interface, in turn reducing the number of resources that contribute to tier bypassing and potentially conflicting instructions from the TSO and DSO. In practical terms, the DSO in alternative 2 assumes all the responsibilities and roles of alternative 1, as well as some new ones. These are primarily related to aggregating DERs/DERAs that do not meet the TSO's minimum-size threshold into a single virtual resource at the T-D interface, procuring distribution grid services from DERs/DERAs and dispatching them to provide those services (including NWAs and real-time services).

Like alternative 1, alternative 2 can function with either a DSO that includes the owner-operator of the distribution assets or an IDSO. In the first case, and with a high number of DERs and third-party providers, an effective open-access regulatory framework will be critical to ensuring the DSO does not provide unfair advantages to its own or an affiliate's DERs. As this issue emerges with both alternatives, policy-makers must consider whether creating a competitive marketplace of third-party DERs/DERAs and customer services is a core objective for power system change. Alternatively, if the DSO is the owner-operator of DERs that provide grid services (including NWAs), then third-party providers will have a more limited role (i.e., wholesale market participation and potentially some distribution services) and concerns about open access for such providers become less important. These types of fundamental regulatory decisions governing DSO roles and responsibilities require further investigation in relation to objectives for Ontario's electricity system.

Unlike alternative 1, Figure 9 illustrates the substantial changes in alternative 2 related to Ontario's emerging industry structure. One significant change is that DERs can participate in the wholesale market via the DSO, requiring the DSO to develop new capabilities to aggregate and optimize DERs/DERAs for the wholesale market. Central to this new responsibility is the DSO's ability to coordinate with DERs/DERAs. For example, the DSO must provide information to DERs/DERAs on distribution system conditions (e.g., a reconfigured circuit preventing DER operation) to inform their bids/offers to the DSO for wholesale market services and convey dispatch instructions to individual DERs/DERAs to comply with TSO dispatch. Conversely, DERs/DERAs must send the DSO greater amounts of data (e.g., telemetry) to ensure their operation is consistent with dispatch instructions and respects distribution system conditions. These new forms of coordination will help the DSO fulfill its responsibility to dispatch individual DERs/DERAs in a manner that complies with the IESO's overall dispatch.

Wholesale market participation through the DSO also introduces new forms of coordination between the DSO and multiple IESO functions. First, there will now be market transactions between the DSO, wholesale market operator and bulk system balancing authority. The DSO submits a single bid/offer (i.e., the price and quantity combinations of how much energy the resources below a T-D interface can provide or seek to purchase) at each T-D interface for the DERs/DERAs it aggregates, the wholesale market operator sends a day-ahead or hour-ahead schedule to the DSO for the response required at that T-D interface, and the bulk system balancing authority may send the DSO a single dispatch signal in real time for that T-D interface.

Second, since the DSO will be a wholesale market participant, the bulk system balancing authority function may require the ability to direct the DSO via real-time (non-market) operating instructions to preserve bulk power system safety and reliability. For example, if a bulk power system contingency requires load shedding to maintain safety and reliability, the DSO may receive operating instructions to curtail a portion of its load beneath a T-D interface. Since these forms of coordination are new relative to the current and emerging industry structure, they may ultimately require new regulatory provisions and communications systems to comply with IESO requirements.

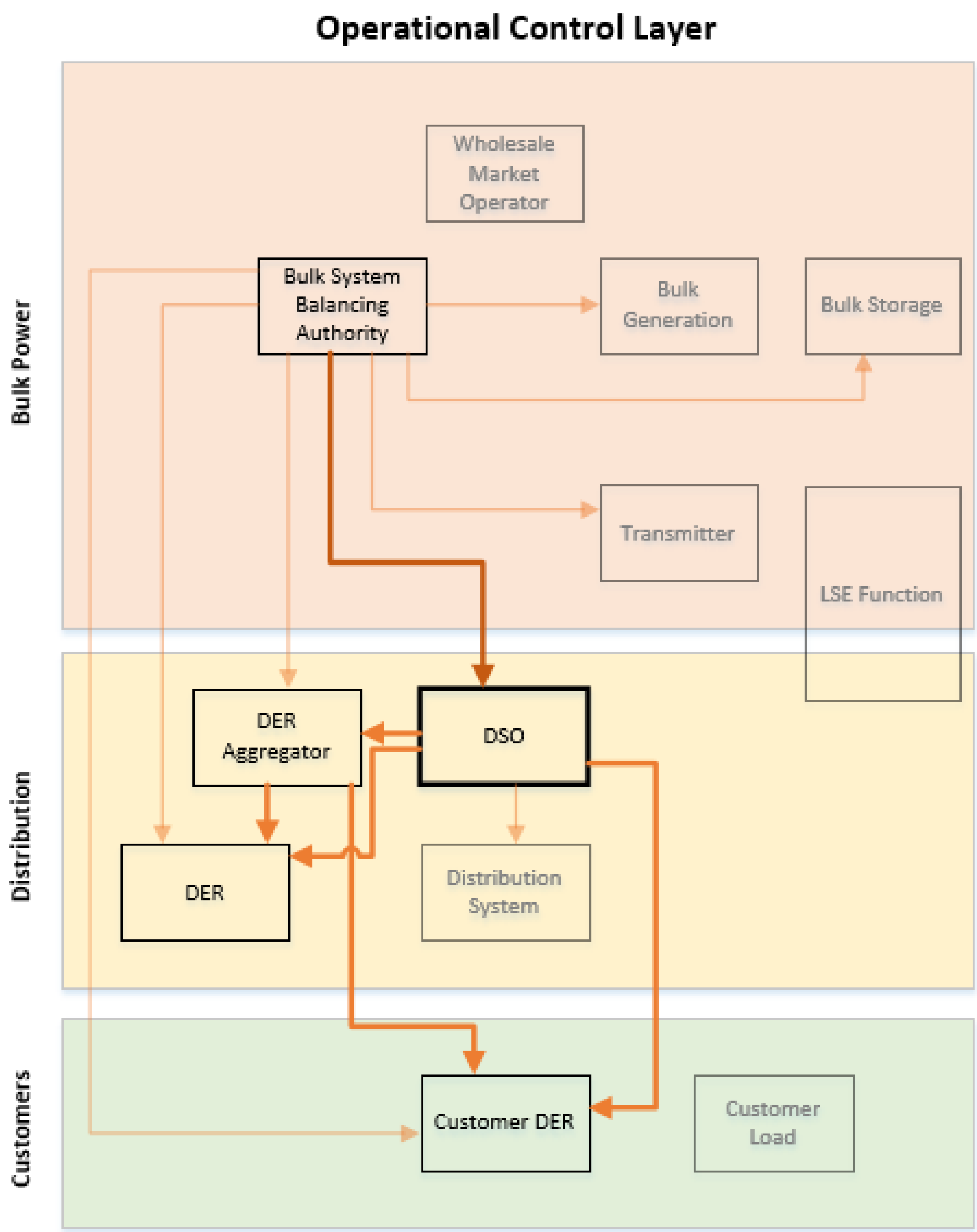
Another source of significant change in alternative 2 is the expanded ability for DERs to provide distribution deferral and operations services. Although these changes do not introduce new lines or arrows to the industry structure diagrams, they require enhancements to existing forms of coordination.

The first significant change involves the level of operational control the DSO exerts over DERs, DERAs and customer DERs. In the emerging industry structure and under alternative 1, LDC operations has minimal operational control over these resources to help preserve system safety and reliability. The ability to provide dispatchable real-time services to the distribution system will require greater DSO operational control of these resources to ensure compliance with dispatch instructions.

While alternative 1 may rely on notifying DERs/DERAs of day-ahead system needs without the means to actually control the DER/DERA operation in real time, alternative 2 will require the DSO to enhance its capabilities to receive physical measurements from the DER/DERA (e.g., telemetry) and issue control signals in real time. The second significant change involves the potential scale of distribution market transactions. While these transactions in alternative 1 are limited to a lower number of passive distribution NWA opportunities, alternative 2 allows DERs to provide and be compensated for a much broader set of services.

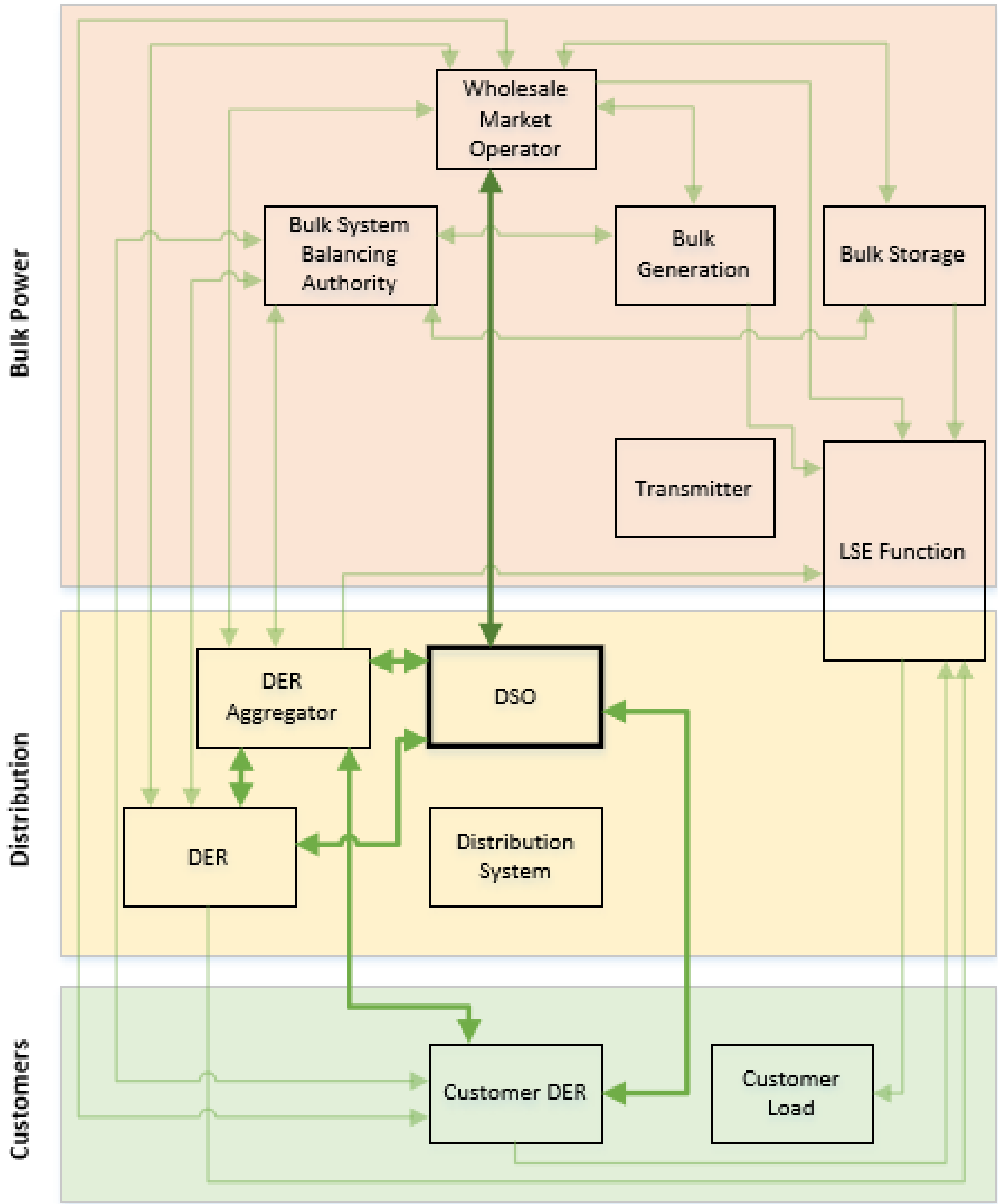
The changes contemplated under alternative 2 do not introduce new information/data exchange lines/arrows in the industry structure diagram (Figure 9); however, they require enhanced levels of interaction to ensure the DSO effectively manages its new responsibilities and the wholesale market operator and bulk system balancing authority effectively preserve bulk system safety and reliability. The enhanced ability for DERs to provide a range of distribution services will likely increase the scale of communications needed among the DSO, wholesale market operator, bulk system balancing authority and DERs/DERAs to ensure their operation is compatible with system safety and reliability.

Figure 9: Alternative 2 industry structure skeletal diagrams – changes to operational control, market transactions and information/data exchange



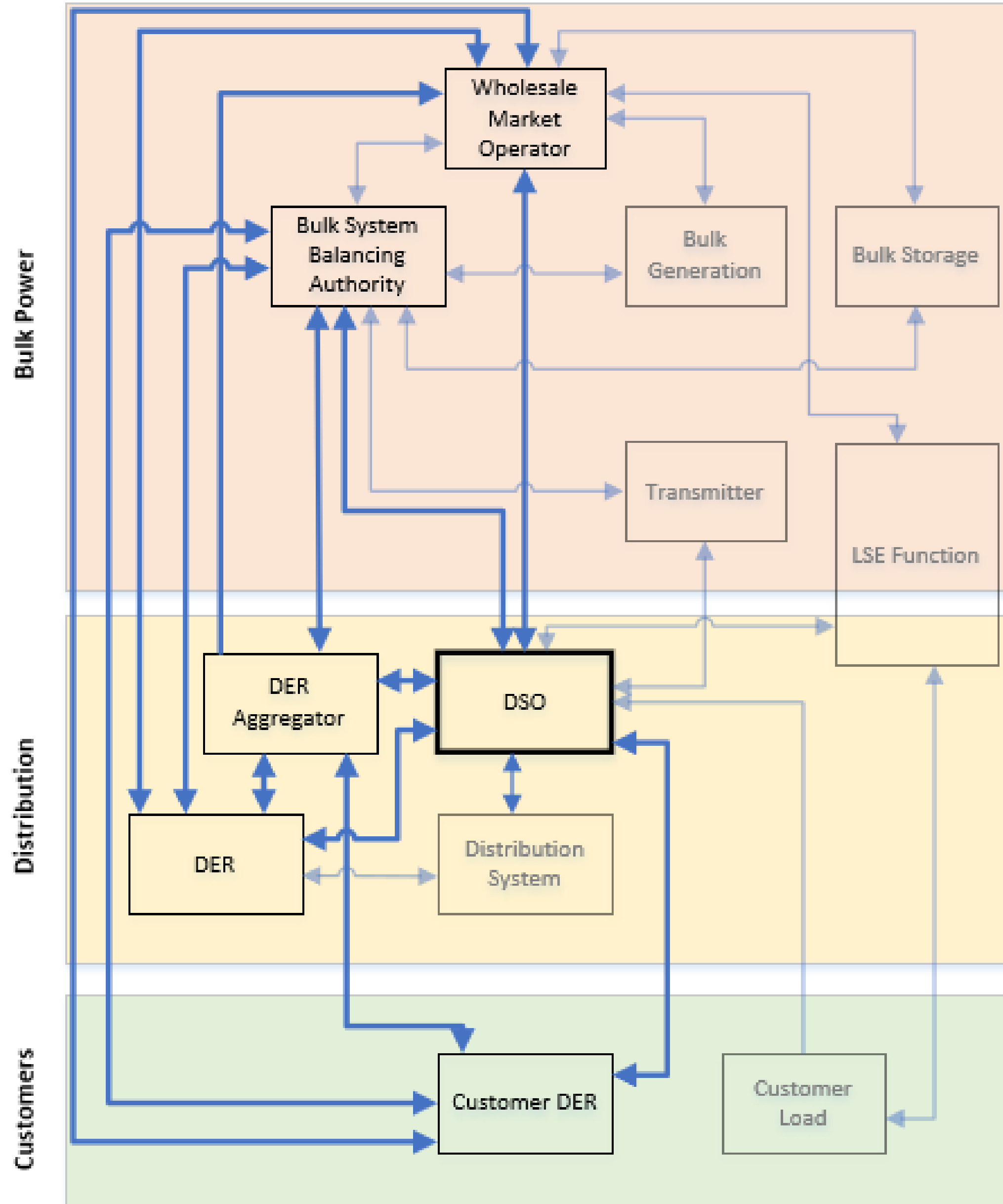
Note: The bold dark orange (in the operational control layer) and dark green (in the market transaction layer) lines represent new interactions in alternative 2 relative to the emerging industry structure. The bold orange, green and blue lines represent enhanced/expanded forms of interaction relative to the emerging industry structure.

Market Transaction Layer



Note: The bold dark orange (in the operational control layer) and dark green (in the market transaction layer) lines represent new interactions in alternative 2 relative to the emerging industry structure. The bold orange, green and blue lines represent enhanced/expanded forms of interaction relative to the emerging industry structure.

Information/Data Exchange Layer



Note: The bold dark orange (in the operational control layer) and dark green (in the market transaction layer) lines represent new interactions in alternative 2 relative to the emerging industry structure. The bold orange, green and blue lines represent enhanced/expanded forms of interaction relative to the emerging industry structure.

4.3 Comparative analysis of alternatives 1 and 2

The more centralized architecture in alternative 1 and the more layered architecture of alternative 2 allow for a comparison of the relative merits of each model in the context of an Ontario-specific decision framework.

Table 6 displays the key differences between the alternative 1 and 2 models, and the Total TSO and DSO models.

Table 6: Key differentiators between the two alternative T-D interoperability models

Alternative 1: Closer to the Total TSO Model with the TSO having relatively greater roles and responsibilities and the M-DSO role limited to existing LDC capabilities. Greater opportunities for direct DER/DERA wholesale market participation, but more limited opportunities to provide distribution services (i.e., only non-dispatchable services).

Alternative 2: Closer to the Total DSO Model, where the DSO has additional roles and responsibilities that require enhanced capabilities relative to today's LDCs, and the TSO has more limited roles and responsibilities. The DSO facilitates wholesale market participation for smaller DERs/DERAs by serving as an aggregator, and allows for greater DER/DERA provision of distribution services, including dispatchable services.

Considerations	Total TSO[50]	Alternative 1	Alternative 2	Total DSO[50]	Description
1. DER/DERA direct participation in the wholesale market	Yes	Yes	Yes	No	Although allowed for both alternatives, alternative 1 involves a lower minimum-size threshold for wholesale market participation (i.e., greater numbers of smaller resources) and alternative 2 involves a higher minimum-size threshold relative to alternative 1 (i.e., lower numbers of larger resources).

[50] De Martini, P., & Kristov, L., *Distribution Systems in a High Distributed Energy Resource Future: Planning, Market Design, Operation and Oversight*, 2015. https://emp.lbl.gov/sites/default/files/lbnl-1003797.pdf.

Table 6 (continued)

Considerations	Total TSO[51]	Alternative 1	Alternative 2	Total DSO[50]	Description
2. TSO[52] sees individual DERs	Yes	Yes	Market-participating DERs/DERAs only[53]	No	In alternative 1, all DERs participate directly (i.e., individually or through an aggregator) in the wholesale market, providing visibility to the TSO. In alternative 2, the TSO would only have visibility into individual DERs directly participating in the wholesale market. In both, if DERs participate as part of an aggregation, the TSO may not have visibility into individual DERs.
3. Able to aggregate DERs for wholesale market participation	DER aggregator	DER aggregator	DER aggregator or DSO	DER aggregator or DSO	While limited to DER aggregators for alternative 1, in alternative 2 the DSO develops additional capabilities, enabling it to serve this function.
4. Responsible for distribution system operations	TSO	M-DSO	DSO	DSO	The M-DSO in alternative 1 maintains responsibility for these core distribution functions, but develops minimal additional capabilities beyond those currently possessed by LDCs. The DSO in alternative 2 has greater capabilities for these functions.
5. Responsible for operational coordination with TSO	DSO[54]	M-DSO	DSO	DSO	
6. Responsible for distribution system planning	TSO	M-DSO	DSO	DSO	
7. Responsible for procuring distribution deferral services (NWAs)	TSO	M-DSO[55]	DSO	DSO	

[51] De Martini, P., & Kristov, L., *Distribution Systems in a High Distributed Energy Resource Future: Planning, Market Design, Operation and Oversight*, 2015. https://emp.lbl.gov/sites/default/files/lbnl-1003797.pdf.

[52] TSO as used in this table is synonymous with the IESO and includes both the wholesale market operator and balancing authority functions.

[53] This design feature captures only those DERs/DERAs directly participating in the wholesale market. The TSO/IESO would not have visibility into individual DERs included in the DSO's aggregated/virtual resource at the T-D interface for wholesale market participation.

[54] Even under a total TSO structure, there is still some need for the DSO to coordinate with the TSO, particularly as DER penetration grows.

[55] Limited to passive resources (e.g., energy efficiency and non-dispatchable demand response).

Table 6 (continued)

Considerations	Total TSO[56]	Alternative 1	Alternative 2	Total DSO[50]	Description
8. Responsible for dispatching/ scheduling participating DERs/DERAs for wholesale market participation and transmission services	TSO	TSO	TSO/DSO	DSO	The introduction in alternative 2 of the DSO role for aggregating DERs for wholesale participation results in a more complicated sharing of dispatching and scheduling between the IESO and DSO. In all models, if the dispatch is to a DERA of a third-party aggregator, the TSO or DSO may interact only with the aggregator and not with any of the DERs within the DERA.
9. Dispatches/ schedules DERs/DERAs for distribution NWA services	TSO	None	DSO	DSO	Unlike the M-DSO, the DSO in alternative 2 has enhanced capabilities, enabling it to schedule/dispatch DERs for NWAs and operations services.
10. Dispatches DERs/DERAs for distribution operations services[57]	TSO	None	DSO	DSO	
11. Scale of DER adoption required	N/A	N/A	Medium-high[58]	High	While alternative 1 does not depend on a specific number of DERs on the system, the enhanced capabilities of the DSO in alternative 2 would likely only be justified at individual T-D interfaces with greater DER penetration.

[56] De Martini, P., & Kristov, L., *Distribution Systems in a High Distributed Energy Resource Future: Planning, Market Design, Operation and Oversight*, 2015. https://emp.lbl.gov/sites/default/files/lbnl-1003797.pdf.

[57] Real-time dispatch of DERs/DERAs to support distribution operations includes, but may not be limited to, distribution voltage support, congestion management and resilience. These services are separate and distinct from dispatch and scheduling of NWAs for distribution capacity deferral, as captured in row 9.

[58] In relation to Figure 6, medium DER adoption aligns with stage 2 of distribution system evolution and high-DER adoption aligns with stage 3. As noted earlier, it is quite likely that some LDAs will have higher or lower DER adoption levels than the average for Ontario as a whole.

Table 6 (continued)

Considerations	Total TSO[59]	Alternative 1	Alternative 2	Total DSO[50]	Description
12. Allocation of LSE function (i.e., provider of retail electricity to end-use customers)	Policy choice	Policy choice	Policy choice	Policy choice	Allocation of the LSE function is related to two other policy choices: whether the LSE will be a monopoly or perform a competitive function, and the intended role of competitive third-party DER providers. For competition in these areas to thrive and be efficient, the market operator and system operator functions should be separate from the competitive participants who need to use the market and the grid on a non-discriminatory basis.
13. Responsible for clearing and settlements for distribution market transactions	TSO	None	DSO	DSO	Related to 10 and 11, there is no role for the M-DSO given the lack of dispatchable DER services.

One of the most important differences between the two alternative models is the size threshold above which DERs/DERAs can directly participate in the wholesale market. The lower-size threshold for DER/DERA participation in alternative 1 allows for greater direct wholesale market competition by opening up participation to larger numbers of DERs/DERAs.[60] However, this design feature also introduces some key issues, as larger numbers of DERs/DERAs participating directly in the wholesale market increase the complexity of T-D interoperability, resulting in a higher volume of tier bypassing. Since DERs/DERAs participating directly in the wholesale market bypass consideration of distribution system conditions, the DSO will need to develop mechanisms to ensure the IESO's dispatch of DERs/DERAs does not violate distribution constraints or limits, and that real-time changes in distribution system conditions that may constrain DERs/DERAs from responding to a dispatch are communicated to the IESO. Alternatively, greater levels of direct market participation may require the TSO to make up shortfalls when dispatched DERs/DERAs are unable to perform due to changing distribution system conditions, such as line outages or circuit switches. This is a significant consideration since the distribution system tends to be more dynamic than the bulk power system.

Alternative 2 mitigates some tier bypassing issues by introducing a higher minimum-size threshold for direct wholesale market participation. In addition to decreasing the amount of tier bypassing, this change reduces both the number of resources the IESO would model and dispatch, and the operational

[59] De Martini, P., & Kristov, L., *Distribution Systems in a High Distributed Energy Resource Future: Planning, Market Design, Operation and Oversight*, 2015. https://emp.lbl.gov/sites/default/files/lbnl-1003797.pdf.

[60] In all cases, there would be some minimum-size threshold for wholesale market participation, below which a resource would not have a noticeable impact on the optimization or would be incorporated into net load.

coordination requirements between the IESO and DSO. However, the more limited ability for DERs/DERAs to directly access the wholesale market raises concerns about competition and transparency until the establishment of open-access rules governing DSO performance ensures the DSO cannot give a competitive advantage to its own or an affiliate's DERs. While the layered approach can help simplify system operations by reducing the number of interfaces, Ontario will need to further evaluate a new open-access DSO regulatory framework if the objective is to create a robust market for third-party DER providers.

The other issue raised by the increasing amount of DERs participating directly in the wholesale market, as is the case in alternative 1, is scalability challenges for the IESO to replicate the type of coordination at the T-D interface with every DER/DERA that participates in its markets. While technological advances (e.g., enhanced computing power) may help mitigate this concern over the long term, they may not be feasible over the near term, and may involve greater costs and complexity.

A second key difference between the two models involves the ability of DERs to provide various distribution services. The more limited capabilities of the M-DSO in alternative 1 imply that distribution NWAs are limited to passive, non-dispatchable resources, such as energy efficiency. However, in alternative 2, the DSO has responsibility for distribution operations because it is uniquely positioned to dispatch DERs/DERAs to support this function, and is able to procure, dispatch and schedule DERs/DERAs for a range of distribution grid services (including deferring traditional distribution system investments as an NWA and real-time provision of distribution services). If distribution grid services and competitive provision of those services are desired features of the evolving power system, the DSO in alternative 2 must take on a much more advanced set of capabilities to optimize DERs over timescales that relate to the applicable distribution services.

A third significant difference between alternatives 1 and 2 relates to dispatching and scheduling DERs to provide distribution, transmission and bulk system services (Table 7). Alternative 1 results in a more simplified allocation of these roles and responsibilities. On the distribution side, the relatively limited capabilities of the M-DSO limit DERs from providing distribution services to passive NWAs; consequently, the M-DSO cannot actively dispatch DERs. As for the bulk system, since DER wholesale market participation can only occur when DERs/DERAs directly submit bids/offers to the IESO, sole responsibility for dispatching and scheduling DERs/DERAs for these transmission and bulk system services is assumed by the IESO.

Table 7: Allocation of roles and responsibilities for DER scheduling and dispatching

	Roles and responsibilities for DER scheduling/dispatching	
Service	**Alternative 1**	**Alternative 2**
Distribution deferral services (NWAs)	N/A	DSO
Distribution operations services	N/A	DSO
Transmission deferral services (NWAs)	TSO	TSO and DSO*
Bulk system energy	TSO	TSO and DSO*
Bulk system operating reserves	TSO	TSO and DSO*

*TSO retains market dispatch function; DSO dispatches constituent DERA resources

In contrast, alternative 2 allows for dispatchable distribution NWAs and operations services, which will require the DSO to take on the additional role of scheduling and dispatching DERs to provide these services. As mentioned in Section 4.3, this larger role for the DSO will require a much more advanced set of capabilities and related additional costs to optimize DERs over the relevant timescales (i.e., from seconds to multiple hours or days) for the various distribution services.

Allowing for these expanded distribution services and for DERs/DERAs to still directly participate in the IESO's wholesale market will introduce additional complexity to other roles and responsibilities related to IESO and DSO coordination. Alternative 1 requires some level of coordination between the DSO (i.e., M-DSO), IESO and DERs/DERAs to ensure IESO dispatch instructions are compatible with distribution system safety and reliability (given the IESO's limited visibility into real-time distribution system conditions).

Separately, alternative 2's expanded scope of distribution services will require increased coordination given the higher potential for conflict between the DSO's dispatch for distribution services and the IESO's wholesale market dispatch for DERs/DERAs directly participating in the wholesale market. For example, the IESO may dispatch a battery energy storage device to supply bulk system energy from 12 p.m.to 4 p.m. and the DSO may dispatch the same resource for a distribution deferral need from 4 p.m.to 8 p.m. Under this scenario, and assuming the energy storage device can only discharge energy at maximum capacity for four hours, the resource would only be able to meet one of these two obligations in full because it would not have sufficient time to recharge. This type of scenario will require pre-determined priorities among the various services or another mechanism to ensure that the IESO or DSO amends its DER schedule or dispatch to ensure DER operation is compatible with system safety and reliability, and will likely lead to more frequent communications between the DSO, IESO and DERs/DERAs.

The complexity introduced by the potential for conflicting DER schedules/dispatch instructions also affects the DSO's role of aggregating DERs/DERAs (i.e., those that otherwise cannot meet the IESO's minimum-size threshold) for wholesale market participation. Unlike alternative 1, the DSO is now responsible for aggregating DER/DERA bids and offers into a single virtual bid/offer to the IESO at each T-D interface, and then disaggregating the IESO's single dispatch instruction at each T-D interface to provide dispatch instructions to each individual DER/DERA.

In addition, unlike the Total DSO Model, the alternative 2 DSO must optimize the DERs/DERAs it aggregates, while at the same time coordinating the dispatch of those DERs directly participating in the IESO's wholesale market. Similar to the open-access rules discussed earlier, this dynamic will require processes governing how the DSO treats DER dispatch for those resources it aggregates versus those directly participating in the wholesale market to the extent both types of DERs can address distribution system needs. For example, if a distribution system constraint requires a 100 kW reduction of DER power output, the DSO should follow transparent operating procedures to determine how much of this amount will be met by curtailing DSO-aggregated DERs versus DERs directly participating in the wholesale market. If Ontario anticipates third-party DER competition will continue, uncertainty and lack of transparency around real-time operating decisions will increase the risk associated with the DER provider's revenue stream.

While there are significant differences between the two alternative models, Table 8 highlights some of the consistencies. First, the IESO models DERs at the T-D interface in each alternative, which unlike the Total TSO Model, means it does not have to enhance its capabilities to model portions (or the entirety) of the distribution system. Second, DERAs can include DERs at either a single transmission node or multiple transmission nodes, with the latter making it easier for DER aggregations to enlist a sufficient number of DERs to meet IESO minimum-size thresholds. Third, neither model allows for distribution-level balancing (i.e., the responsibility for balancing supply and demand on an ongoing basis in the LDA), as this service is only possible under a Total DSO approach. Importantly, both alternative models require some form of operational coordination with the IESO to ensure its dispatch of DERs/DERAs does not violate distribution constraints or limits, and that real-time changes in distribution system conditions that may constrain the ability of the DERs/DERAs to respond to the dispatch are communicated to the IESO and the DERs/DERAs.

Table 8: Consistencies between the two alternative T-D interoperability models

Considerations	Alternatives 1 and 2	Description
1. Where does TSO model DER locations?	T-D interface	Unlike a Total TSO Model, in both alternatives the TSO (i.e., the IESO) will not model DER locations below the T-D interface.
2. Can a DERA include DERs at multiple T-D nodes or only within a single node?	Single node or multiple nodes	Generally, allowing DERAs across multiple nodes makes it easier to enroll enough DERs to meet the minimum-size threshold for wholesale market participation, but requires distribution factors that reflect the impact of a DERA's response across the nodes.[61] This setup allows the TSO to model the response in its power flow, and settle based on the energy-weighted average of the relevant locational marginal prices. Depending on the prevalence of congestion on the transmission system, the TSO may want to require that a multi-node DERA be entirely within a pre-specified zone.
3. Which entity is responsible for distribution-level balancing within the local distribution area (individual T-D interface)?	None[62]	This function is only possible under a Total DSO Model, where the DSO aggregates all DERs within the LDA and is therefore able to act similar to an adjacent balancing authority, importing or exporting energy and services with the TSO at each T-D interface.

[61] CAISO, *Post-Technical Conference Comments of the California Independent System Operator Corporation*, FERC RM18-9-000, June 26, 2018. https://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=14956721.

[62] The Total DSO is similar to an adjacent balancing authority. By assuming responsibility for aggregating all participating resources in a local area to present a virtual power plant to the TSO at each T-D interface, the Total DSO will in essence use energy sales to/purchases from the TSO to balance supply and demand in the local area, both in the day-ahead market and in real time. One possible approach is to implement a distribution-level optimization market for participating DERs/DERAs in the local area to establish an aggregated energy bid/offer the Total DSO submits to the TSO market. If the TSO clears that bid/offer, the Total DSO distributes the appropriate schedules/dispatches to the DERs/DERAs. This type of distribution-level balancing is only possible for the Total DSO because that model is the one case where the DSO aggregates everything for purposes of the T-D interface and there is no tier bypassing. It remains a market and system design question whether distribution-level balancing includes frequency regulation, and depends on the DSO's ability to island at a given T-D interface.

Table 8 (continued)

Considerations	Alternatives 1 and 2	Description
4. Is the DSO function bundled with the LDC?	Both options available	While the answer will impact certain forms of interaction between functional entities and achievement of objectives (e.g., a competitive environment for third-party DER providers), both options are feasible under each alternative. This decision relates back to considerations around pursuing an IDSO (see Section 4.2) and the principles of open access.

4.4 Considering alternatives in the Ontario context

As described in Section 3.3, Ontario's emerging industry structure effectively serves as a starting point for future evolution of the electricity grid. The two alternative T-D interoperability models analyzed in this white paper illustrate the range of possibilities, instead of serving as two definitive alternatives for consideration.

One of the most critical considerations involves the diversity of LDCs within the province. As of 2018 only four of the 63 Ontario LDCs served more than 250,000 customers (this may change if there are further LDC consolidations).[63] In practice, the more significant set of roles and capabilities for the DSO in alternative 2 would only be relevant for the largest LDCs where the growth of DERs is likely to be most significant. Without sufficient potential cost savings, DER adoption, and opportunities for DERs to provide various distribution-level services, the added costs for the alternative 2 DSO would make it more challenging for smaller LDCs to pursue this type of structure. These LDCs may prefer to pursue simpler T-D interoperability approaches, which would likely require the IESO to operate with more than one DSO model in its service area at the same time.

In addition to diversity among LDCs, there may be diversity of the distribution system within an LDC that serves multiple T-D interfaces. While some of the largest LDCs will be better suited for a more layered approach, this layered structure and the requisite DSO functional capabilities do not need to be implemented throughout the LDC's distribution system. For example, a larger LDC may be responsible for some T-D interfaces that have a higher DER penetration and may be more susceptible to system constraints, and other interfaces where the type of functionality provided by alternative 2 is not warranted. As such, the multi-node DSO could selectively choose to model in greater detail only the highest-need areas.

There is a parallel to this example in the context of a more centralized approach like alternative 1. Even in a structure where the IESO is not responsible for distribution system planning and operations, it could assume this responsibility on a selective basis for smaller or less capable LDCs managing T-D interfaces characterized by high DER penetration. Since it may be cost-prohibitive for these LDCs to develop the

[63] OEB, *2018 Yearbook of Electricity Distributors*, August 19, 2019. https://www.oeb.ca/oeb/_Documents/RRR/2018_Yearbook_of_Electricity_Distributors.pdf.

modelling capabilities required to preserve the safety and reliability of an LDA in the face of high DER penetration, the IESO may be able to more cost-effectively incorporate these LDAs into its existing bulk power system models.

These examples highlight the fact that a single T-D interoperability approach may not be appropriate for the entire province. Since each T-D interface serves as a separate unit of analysis when considering T-D interoperability, Ontario may instead allow for a future industry structure characterized by a set of alternative approaches both across and within LDCs. This setup would require active coordination between the IESO, LDCs and other parties to determine where alternative approaches are appropriate.

Another major factor affecting Ontario's future path is the minimum-size threshold for DER participation in the IESO's wholesale market. As part of its ongoing work to create wholesale market participation models for DERs,[64] the IESO may define a minimum-size threshold and alternative participation options for aggregations (e.g., whether DERs can be aggregated at multiple T-D nodes or only at a single node) that move Ontario relatively closer to the more centralized approach of alternative 1 or the more layered approach of alternative 2. These types of market design decisions will impact the roles, responsibilities and functional capabilities required of both the IESO and DSO to meet system objectives.

In addition to wholesale market reform, the scale and scope of distribution services that DERs are able to provide will also inform the types of roles, responsibilities and functional capabilities required. As described in Section 4.3, a move toward alternative 2 would require relatively greater ability of the DSO to make use of DER-provided real-time distribution services and to manage DERs that provide NWAs. Ontario has made recent progress in identifying barriers to NWA implementation and assessing opportunities for DERs to serve as NWAs,[65] but these initiatives are still under development and their outcomes will critically affect how these opportunities continue to evolve. If enabling a more competitive environment for DERs to provide distribution grid services is a priority, then consideration should be given to how a more centralized versus layered structure impacts the allocation of roles, responsibilities and capabilities between the IESO and DSO.

As increased market opportunities spur the growth of DERs, greater levels of complexity will emerge in forecasting for real-time operation, economic scheduling and dispatch, and planning. Under the Total TSO Model, the TSO assumes responsibility for forecasting the entire system, including the distribution system. Shifting from this model to alternative 1, the IESO still has a large role in developing forecasts of net load at the T-D interfaces.[66] With higher DER levels, the accuracy of these forecasts will depend on high-quality inputs from the DSO (i.e., more granular forecasts, both on a locational and temporal basis, of DER operations and net load on the distribution system). Under alternative 2 and generally for the Total DSO end of the spectrum, where the DSO has substantial responsibility for DER coordination and aggregation, these activities will naturally add to the DSO's ability to provide reliable forecasts of net load at the T-D interfaces.

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[64] IESO, *Project Brief: Exploring Expanded DER Participation in the IESO Administered Markets*. http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/isewp/isewp-der-participation-project-brief.pdf?la=en.

[65] IESO, *Barriers to Implementing Non-Wires Alternatives in Regional Planning*. http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/rpr/rprag-20181101-barriers.pdf?la=en.

[66] This approach is consistent with the current state as the IESO develops forecasts of net load at every T-D interface in Ontario.

These types of considerations may also impact another topic under discussion in Ontario: the potential to reallocate the LSE function. Fundamentally, the role of an LSE is to procure energy supply and capacity to serve its portion of system load. While the IESO currently fills this role in Ontario, the allocation of this function will relate to two policy choices: whether the LSE will be a monopoly or perform a competitive function, and the intended role of competitive third-party DER providers. A guiding principle to ensure competition and efficiency in these areas is to separate the market operator and system operator from the competitive market participants who must use the grid on a non-discriminatory basis. Further work is needed to define system objectives, which will ultimately determine whether Ontario contemplates these changes to the LSE function.

5 T-D interoperability system considerations

After specifying the functional capabilities for system architecture and the roles and responsibilities of key players, the types of operational coordination systems, technologies, and processes required to make it all work must be assessed. Both the IESO and LDCs will need a baseline level of operational technology to ensure adequate operational coordination, but there are multiple ways to establish these capabilities.

One conceptual approach, which builds upon the status quo, involves each LDC and the IESO individually identifying and implementing the technologies they require to support high volumes of DERs (i.e., both distribution-connected and behind-the-meter DERs), and interconnection and utilization for bulk power and distribution services (i.e., both deferral and operations services). A second conceptual approach is based on leveraging a common platform for Ontario to unify market and operational coordination to support a variety of T-D interoperability structures,[67] as well as vastly simplify the protocols for establishing various interfaces.

These approaches raise three important considerations. First, while they may vary depending on the applicable system architecture, inevitably both the IESO and LDCs will require some minimum level of technological capability to coordinate with each other and manage their own systems in a high-DER future. Second, although this section describes two high-level approaches, each has the flexibility to meet the specific needs of the IESO and LDCs. For example, different LDCs will have different systems requirements for operational coordination given existing systems and expectations for DER growth, so each LDC need not have the same technological systems. Finally, the costs and complexity differ, with the second approach better suited to minimize both.

5.1 Approach 1: separate IESO and LDC technology investments

This first approach largely represents an extension of the status quo where the IESO and each LDC independently identify and implement a suite of technologies to manage their respective systems. As discussed below, this approach represents a combination of the IESO and LDC conceptual systems and interface architectures in Figure 10 and Figure 11, respectively.

[67] In earlier parts of the paper, structure largely represents the architecture of the system (i.e., the key players, their interactions with one another, and corresponding roles and responsibilities). Within this section, structure is used to describe the arrangement of technological systems and processes necessary to support operational coordination between the IESO, LDCs and DERs/DERAs.

This approach leads to a greater likelihood that the IESO and LDC investments will result in duplication of operational capabilities, given the inability to leverage shared systems and the requirement for each to actively manage (albeit to potentially varying degrees) aspects of DER integration. Additionally, this type of approach will likely result in greater operational complexity given the volume of interfaces and diversity of protocols to support them.

5.1.1 IESO operational systems

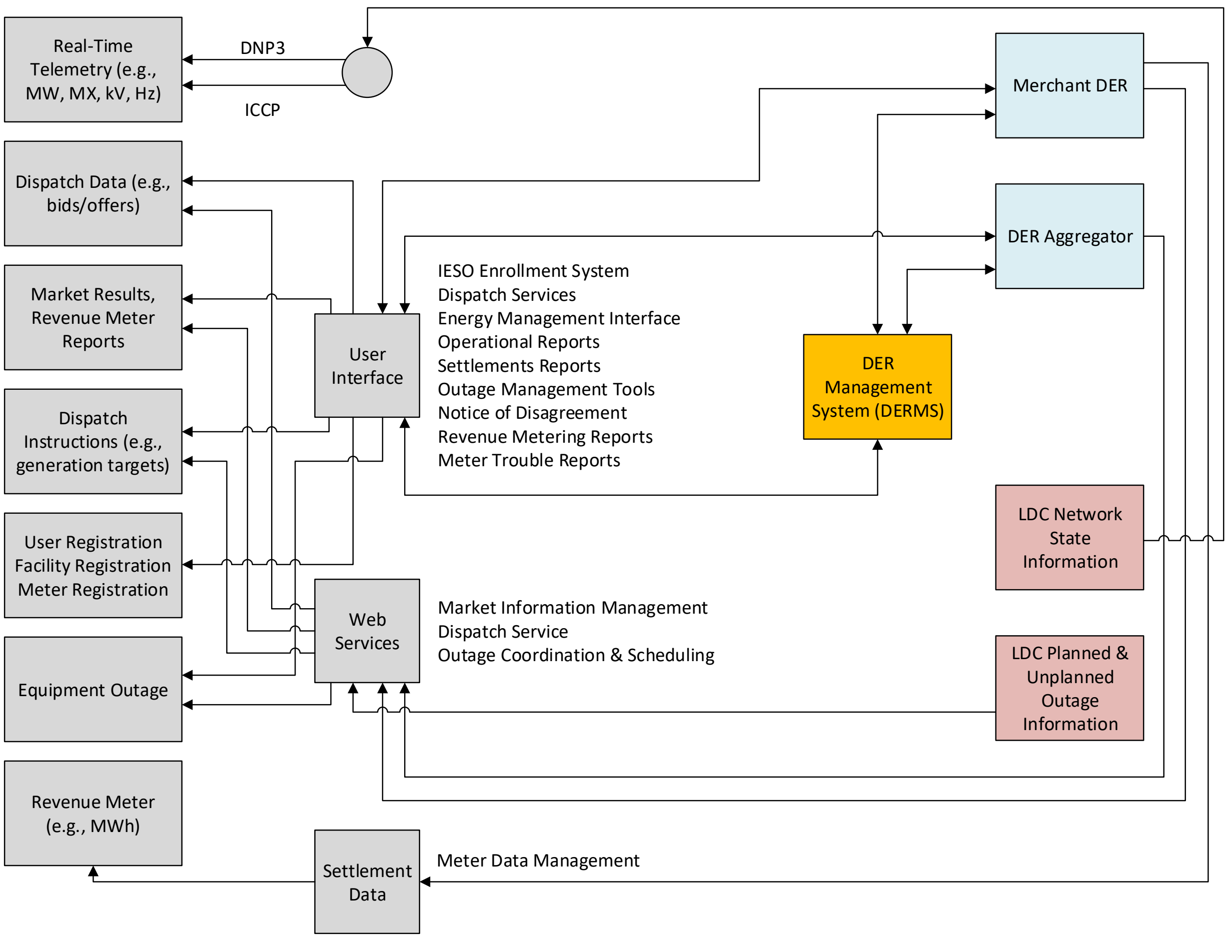
The IESO currently uses a suite of systems to provide the functional capabilities necessary to operate Ontario's bulk power system and coordinate with other entities. With growing levels of DER participation in the wholesale market, additional systems and capabilities may be required to effectively integrate these resources and oversee the services they provide. As opportunities emerge for DERs to provide a greater range of services at the bulk power level, the IESO may need to consider implementing a DER management system (DERMS), as described in Table 10.

While the IESO's existing interfaces and systems facilitate coordination with DERs providing bulk power system services, a DERMS can enable the IESO to more effectively manage DERAs and smaller DERs, if a lower minimum-size threshold enables a greater number of DERs and DERAs to directly participate in the wholesale market (i.e., a more centralized system architecture). As described in Section 6, mapping the IESO's required functionalities to systems in a high-DER environment will require a more detailed architectural assessment of the desired T-D interoperability model.

Figure 10 shows that DERs participating in the wholesale market (either directly or through an aggregator for demand response) can use existing interfaces and systems. A critical component of the IESO's existing systems architecture is the user interface provided by Online IESO, a web-based registration system allowing organizations to complete a variety of interactive business tasks and post information to the IESO in a safe, secure and efficient manner. As examples, Online IESO enables the IESO to manage market participant enrolment, disagreement with settlement statements and metering issues.

This type of conceptual architecture is best suited for a more centralized approach, where greater roles and responsibilities for DER coordination and system operation are allocated to the TSO. This configuration would also involve leveraging and creating new operational information interfaces between the LDCs and the IESO to facilitate coordination, such as LDC network state information, including T-D substation status, and LDC planned and unplanned outage information. However, the LDC network state information depends on having distribution operational systems that provide this kind of information.

Figure 10: Approach 1 conceptual architecture for IESO operational functionalities and interfaces



Note: Grey boxes represent existing IESO functionalities. Blue boxes represent the DER entities that interface with the IESO. Red boxes represent information provided by the LDC to the IESO to facilitate T-D interoperability. The yellow box for DERMS represents a potentially new IESO system if DER wholesale market penetration reaches high levels. DNP3 and ICCP refer to standards for communicating information (see Section 5.1.3 for further discussion).

5.1.2 LDC operational systems

Managing large-scale integration and the use of DERs for distribution services and coordination with the IESO (i.e., both the market operator and balancing authority functions) may require significant increases in LDC operational capability and related technology. Fundamentally, LDCs may need to increase visibility of DER assets, distribution grid state information, distribution grid analytics and controls, and DER management and settlement systems. As such, Canadian and U.S. utilities have identified the following key systems (Table 9) to address DER integration and utilization.

Table 9: Foundational LDC system capabilities for DER integration and use

System	Description
Distribution SCADA (D-SCADA)	The application of SCADA software to the distribution grid enables the LDC to receive operating data (i.e., real-time telemetry) and control the distribution system.[68] For example, the application of D-SCADA could allow the LDC to identify instances when it must reconfigure a distribution feeder to maintain safety and reliability.
Network model	A distribution system model is a representation of the physical distribution system infrastructure (including the characteristics of system components and system topology) and adapts to the system state/configuration; it is usually contained in a software system and may also be referred to as a distribution connectivity model.[69] This network model provides LDCs with visibility into distribution system conditions, allowing them to take any necessary actions to preserve safety and reliability.
Outage management system (OMS)	A computer-aided system used to better track and respond to facility outages or other planned or unplanned power quality events.[70] It can serve as the system of record for the as-operated network model, as can the DMS.[71] Given the dynamic nature of the distribution system, and the growing penetration of DERs, an OMS will become an increasingly important tool for LDCs to effectively communicate to DERs when they must limit their operation due to outages and other system constraints.
Geographic information system (GIS)	A software system used to maintain a database of grid assets, including distribution equipment and their geographic locations.[72] GIS enables presentation of the distribution system (or portions thereof) on a map, helping LDCs understand with greater accuracy where there are specific locational needs on the system.

[68] U.S. Department of Energy, *Distribution System Platform (DSPx) Project, Modern Distribution Grid – Volume III: Decision Guide,* 2017, p.7. https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid-Volume-III.pdf.

[69] U.S. Department of Energy, *Distribution System Platform (DSPx) Project – Volume I: Customer and State Policy Driven Functionality, v1.1,* 2017, p.56. https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf.

[70] U.S. Department of Energy, *Quadrennial Technology Review 2015, Chapter 3: Enabling Modernization of the Electric Power System – Technology Assessments, Measurements, Communications and Controls,* 201, p.24. http://energy.gov/sites/prod/files/2015/09/f26/QTR2015-3E-Measurements-Communications-and-Controls.pdf.

[71] U.S. Department of Energy, *Distribution System Platform (DSPx) Project, Modern Distribution Grid – Volume III: Decision Guide,* 2017, p.8. https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid-Volume-III.pdf.

[72] *Ibid.*

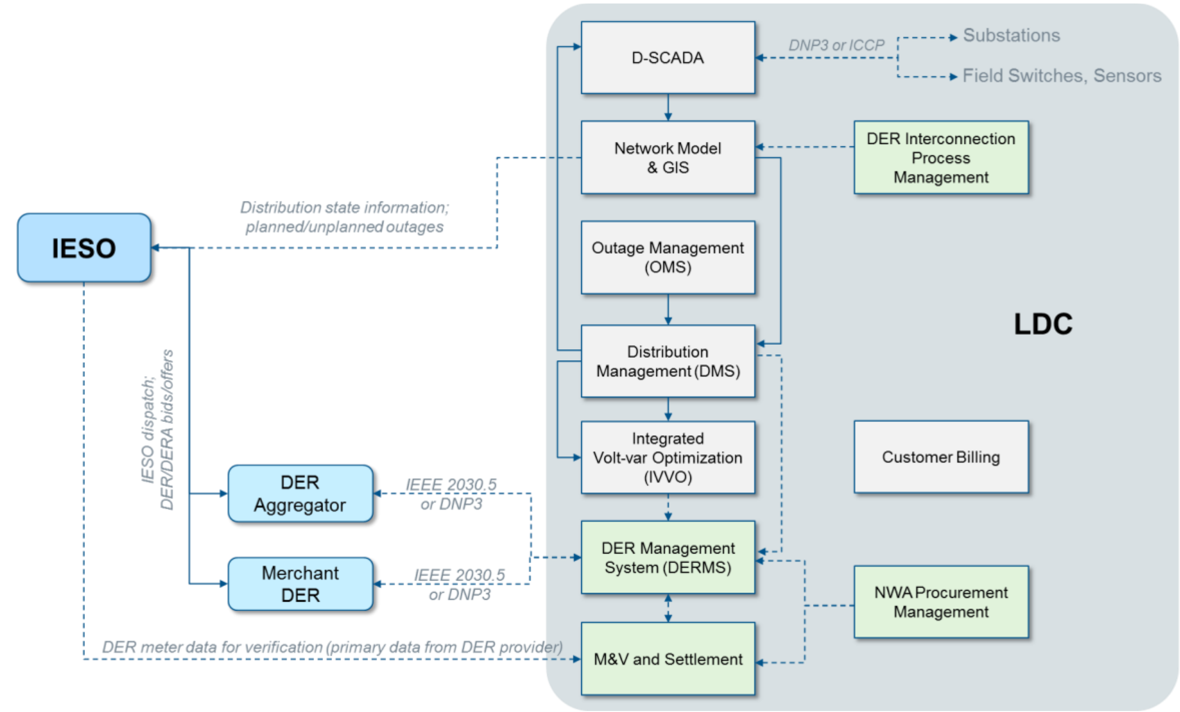
Table 9 (continued)

System	Description
Distribution management system (DMS)	An operational system capable of collecting, organizing, displaying and analyzing real-time or near-real-time distribution system information. A DMS can enable operators to manage complex distribution system operations to increase system efficiency, optimize power flows and prevent overloads. It can also create an integrated view of distribution operations by interfacing with other operations applications, such as GIS, OMS and customer information systems (CIS).[73,74]
Integrated volt-VAR optimization (IVVO)	Application that LDCs can use to address increasingly sophisticated management of voltage variability on the distribution system, largely driven by increasing amounts of DERs. Includes analytics models to determine which grid devices to adjust for optimal performance, and sends corresponding control-setting adjustments to devices.[75]

Many of the largest LDCs in Ontario – including Hydro One, Alectra, Toronto Hydro, Ottawa Hydro, London Hydro and Oakville Hydro – have implemented or are in the process of implementing distribution operational systems, including SCADA, GIS, DMS, OMS and ADMS. Smaller LDCs may also be investing in some of these capabilities, typically on a software-as-a-service (SaaS) subscription basis. SCADA and ADMS systems (light grey boxes in Figure 11) are primarily implemented to address reliability, resilience and operational efficiency (e.g., using IVVO to lower overall energy consumption and peak demand, while simultaneously reducing line losses or leveraging OMS to enable faster restoration times). However, these systems also provide crucial information, analytics and automation to more broadly support DER integration, the use of DERs to provide distribution services and T-D interoperability.

[73] *Ibid*.
[74] OpenEI. *Definition: Distribution Management System*. http://en.openei.org/wiki/Definition:Distribution_Management_System.
[75] U.S. Department of Energy, *Distribution System Platform (DSPx) Project, Modern Distribution Grid – Volume II: Advanced Technology Maturity Assessment*, 2017, p.38. https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-II_v1_1.pdf.

Figure 11: Approach 1 conceptual architecture for LDC operational systems and interfaces



Note: Grey boxes represent existing LDC systems. Blue boxes represent the IESO and DER entities interfacing with the LDC. Green boxes represent potentially new LDC systems, with dotted lines showing potential (or enhanced) interfaces in the future. DNP3, ICCP and IEEE 2030.5 refer to standards for communicating information (see Section 5.1.3 for further discussion).

To enable large-scale DER interconnection and LDCs to use DERs to provide a broader set of distribution services (i.e., beyond non-dispatchable deferral services), a second set of capabilities specific to managing the entire DER lifecycle – from interconnection request through distribution service settlement (i.e., the green boxes in Figure 11) – also requires consideration. While the systems outlined in Table 9 are necessary for DER integration in all T-D interoperability models, those captured in Table 10 represent the systems LDCs may require under a more layered, DSO-centric system architecture.

Table 10: LDC operational systems required under a more layered system architecture

System	Description
Interconnection process management and portal	Software system that automates management of LDC DER interconnection requests, related data and queues to improve LDC request processing time, DER asset information management and process transparency for customers and developers.
NWA procurement management system	Software-based system and portal to manage solicitations for non-wires services from third parties. This system provides public and secure portal access to procurement documentation and related data, as well as a repository for procurement proposal submissions. The system also facilitates management of the procurement process.

Table 10 (continued)

System	Description
Distributed energy resource management system (DERMS)	A software-based solution that increases an operator's real-time visibility into the status of DERs, and allows for the heightened level of control and flexibility (i.e., the ability to direct, regulate or stabilize DER behaviour) necessary to optimize DERs and distribution grid operation, particularly when integrated with an ADMS.[76] A DERMS can also be used to monitor and control DERAs, forecast their capability, and communicate with other enterprise systems and DER aggregators.[77,78]
Measurement and verification (M&V) settlement	Includes the process and systems to assess the operational performance of DERs as required in the provision of distribution grid services. M&V serves as the basis of financial settlements for services supplied that often involve much smaller individual DER transactions that are unsupported by traditional retail customer billing systems.[79]

The drivers for the systems in Table 9 and Table 10 are the large-scale adoption of DERs and a higher number of opportunities for DERs to provide distribution services. LDCs, particularly those with a smaller number of customers, lower DER adoption and/or fewer opportunities for DERs to provide distribution services, may find manual processes and existing systems sufficient and have no need for these systems. The description of these systems is for reference only; not all LDCs will require them to enable T-D interoperability in the next 10 years. The second conceptual approach discussed in Section 5.2 focuses on the essential functions and flexibility for each LDC to evolve as needed.

5.1.3 Operational interfaces

It is also important to define the interfaces between the various players and systems. Table 11 summarizes the types of information exchange that will become increasingly important in a high-DER environment across four operational interfaces: (1) IESO-LDC; (2) IESO-DER/DER aggregators; (3) LDC-DER/DER aggregators; and (4) DER-DER aggregators.

[76] U.S. Department of Energy, *Quadrennial Technology Review 2015, Chapter 3: Enabling Modernization of the Electric Power System – Technology Assessments, Flexible and Distributed Energy Resources*, 2015, p.15. http://energy.gov/sites/prod/files/2015/09/f26/QTR2015-3D-Flexible-and-Distributed-Energy_0.pdf.
[77] U.S. Department of Energy, *Distribution System Platform (DSPx) Project, Modern Distribution Grid – Volume III: Decision Guide*, 2017, p.7. https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid-Volume-III.pdf.
[78] Electric Power Research Institute, *Common Functions for DER Group Management, Third Edition*, Product ID 3002008215. https://www.epri.com/#/pages/product/3002008215/.
[79] U.S. Department of Energy, *Distribution System Platform (DSPx) Project – Volume I: Customer and State Policy Driven Functionality, v1.1*, 2017, p.78. https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf.

Table 11: Ontario operational interfaces

Interface	Description of information exchange
IESO-LDC	Higher numbers of DERs/DERAs participating directly in the IESO's wholesale market will require coordination to ensure IESO dispatch instructions are compatible with distribution system conditions. However, how much of this coordination takes place between the IESO and LDC or between the LDC and DER/DER aggregator is largely an implementation decision. For example, in New York and California, the ISO primarily coordinates with DERs/DER aggregators rather than with the distribution utility.
IESO-DER/DER aggregator	With DERs/DERAs participating directly in the IESO's wholesale market by submitting bids/offers, the IESO will need to communicate market schedules and dispatch instructions[80] to DERs and DER aggregators; in return, DERs and DER aggregators must provide telemetry to the IESO to confirm their operational status in real time. For dispatchable DERs/DERAs, the IESO would be able to actively control their operation according to its dispatch instructions.
LDC-DER/DER aggregator	As outlined in the IESO-LDC interface description, whether the LDC will need to communicate distribution system conditions to the DER/DER aggregator or to the IESO when it impacts the DER/DERA's ability to meet its obligation to the IESO remains in question. The LDC may still require operational coordination with DERs/DERAs that do not participate in the wholesale market. For example, LDCs may require DERs to provide real-time telemetry if they are above a certain size threshold (e.g., 1 MW) or if they are providing distribution services (and for the latter, the LDC would likely provide an upfront notification and/or dispatch instructions to the DER or DER aggregator of when resources are needed). Additionally, regardless of whether DERs provide grid services, the LDC may still require operational control to direct or change their operations in a way that preserves system reliability and safety.
DER-DER aggregator	Similar to the processes described in Section 4 where the DSO may need to disaggregate TSO dispatch instructions to create individual instructions for a DER, DER aggregators receiving operating/dispatch instructions from the IESO and/or LDC may need to provide a virtual response on behalf of its DERA. To effectively manage and optimize its portfolio of DERs within an aggregation, the DER aggregator will likely need to receive telemetry and other information (e.g., notification of outages) from the individual DER to know its real-time status and ability to operate.

Some aspects of these operational interfaces may involve manual processes today (e.g., LDC communication of distribution system constraints to a DER or DER aggregator), but most, if not all, of these interfaces are likely to leverage operational systems to help automate coordination processes and facilitate interoperability.[81] Enabling these interfaces to exchange meaningful and actionable

[80] Only dispatchable DERs/DERAs would receive IESO dispatch instructions.

[81] NIST, *NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 3.0*, September 2014. https://www.nist.gov/sites/default/files/documents/smartgrid/NIST-SP-1108r3.pdf.

information, such as telemetry and market schedules, will support the continued safe, reliable and secure operation of the electricity system.

Standards can serve as a mechanism to achieve interoperability. The National Institute of Standards and Technology (NIST) explains that standards "define specifications for languages, communication protocols, data formats, linkages within and across systems, interfaces between software applications and between hardware devices, and much more."[82] Many legacy standards currently in operation – such as DNP3, MODBUS, OpenADR, ICCP and MESA – support electricity system interoperability. As of 2014, NIST had identified over 70 standards that were actively being used across various jurisdictions.

Although NIST-approved standards undergo rigorous testing and validation to ensure their effectiveness, risks increase with the use of multiple interoperability standards. Supporting all of these standards simultaneously can create implementation challenges and added costs for the operational systems (described in Sections 5.1.1 and 5.1.2). Some will become obsolete more quickly than others, leading to scenarios where assets become stranded or require retrofits to meet active standards. The diversity of standards and associated requirements for each may increase cybersecurity vulnerability, given the challenge of developing a single set of cybersecurity requirements that all standards could adopt.[83]

The IESO currently employs only DNP3 and ICCP for receiving resource telemetry from market participants, but the interfaces between the LDC, DERs and DER aggregators (i.e., all permutations of interfaces between those three entities, as captured in the last two rows of Table 11 typically entail a much larger variety of these standards. Initiatives such as California's Rule 21 interconnection requirements aim to harmonize these interoperability standards for utility (i.e., LDC) and DER aggregator coordination by implementing the IEEE 2030.5 standard, which defines an application profile that provides an interface between the smart grid and users that enable utility management of the end-user energy environment.

However, these efforts do not address the interfaces between both the ISO and utility with an individual DER, and between the DER aggregator and individual DERs. In addition, although harmonizing standards helps mitigate some risks, it does not reduce the total number of interfaces required between various entities, which will continue to increase with the growth of DERs. Finally, though steps like the implementation of IEEE 2030.5 to streamline standards can create meaningful value, converting all resources and systems to a single standard will take significant time. The growing numbers of DERs will continue to drive the importance of these considerations and potential issues.

While California's Rule 21 requirements around standards harmonization represent one way other jurisdictions are attempting to address interface complexity, Section 5.2 describes an alternative approach that leverages third-party software platforms to address this challenge.

5.2 Approach 2: shared DER lifecycle management platform

While the approach described above represents an extension of the status quo, another more proactive approach mitigates the complexity and added costs of the first, which involves separate IESO and LDC

[82] *Ibid.*

[83] The implementation of cybersecurity measures at the DER device level has largely been at the manufacturer's/installer's discretion, typically outside of regulatory oversight.

operational systems, and multiple operational interfaces and standards. This second approach is emerging in North American markets (e.g., California) that use DERs to provide grid services, and is being actively explored in other jurisdictions, including Australia.

Any T-D interoperability structure will require both the IESO and LDCs to simplify the operational interfaces for information and controls (dispatch). For example, a system architecture that allows for direct DER participation in the wholesale market could include a large number of entities and related DER assets, posing challenges for the IESO's existing systems. In addition to simplifying the information interfaces from each LDC, DERA and individual DER throughout the DER lifecycle – from initial LDC interconnection through provision of grid services – the IESO will require a system to manage DER optimization, dispatch and settlement in concert with the related LDC operator.

Likewise, the LDCs that experience substantial levels of DER adoption, including the provision of distribution services, will need new capabilities to manage the DERs and coordinate with the IESO. However, Ontario's industry structure and composition includes a large number of small LDCs (i.e., under 100,000 customers) that have varying existing capabilities, rates of DER adoption and opportunities to use DERs for distribution services. While some LDCs have been able to pursue DERMS and other DER lifecycle management systems described earlier, others may not be able to justify the cost of the systems or have the resources to support them.

That said, LDCs may need to have access to the capabilities these systems offer. Typically, the operational systems discussed in Section 5.1.2 for LDCs with fewer than 500,000 customers are sourced through an SaaS model to reduce both the cost and impact on internal resources. This type of approach to the distribution and DER lifecycle management systems, described in Table 9 and Table 10, respectively, Table 10 is new for Ontario, and would allow LDCs to pursue significantly more permutations of operational systems and configurations.

An emerging trend is the exploration of third-party software platforms to simplify interfaces and coordination (i.e., streamline and automate processes) and establish a secure interface to DERAs and individual DER devices (i.e., mitigate cybersecurity risk).

Current use of these shared platforms is generally limited to combining the market and operational coordination systems in Table 9 and managing information interfaces. California has leveraged this type of system on a limited basis to date, mainly as a way for third parties to manage the participation of demand response aggregations in the California ISO (CAISO)'s markets (including financial settlement) and coordination between the CAISO, the demand response aggregator and the distribution utility.

However, Australia is looking at developing a more holistic market and operational coordination platform for all forms of DERs (not just load modification) that includes the types of operational functionalities captured by the systems in Table 10. As described in a recent report[84] by the Australian Energy Market Operator (AEMO) and Energy Networks Australia (ENA), the decision to explore this type of platform as part of a Hybrid DSO approach (see Section 4.1.3) was based on stakeholder agreement

[84] AEMO and Energy Networks Australia 2019, *Interim Report: Required Capabilities and Recommended Actions*, July 22, 2019. https://www.energynetworks.com.au/sites/default/files/open_energy_networks_-_required_capabilities_and_recommended_actions_report_22_july_2019.pdf.

that the Total TSO approach (see Section 4.1.1) would entail too much effort for a single entity to manage the entire electricity system.

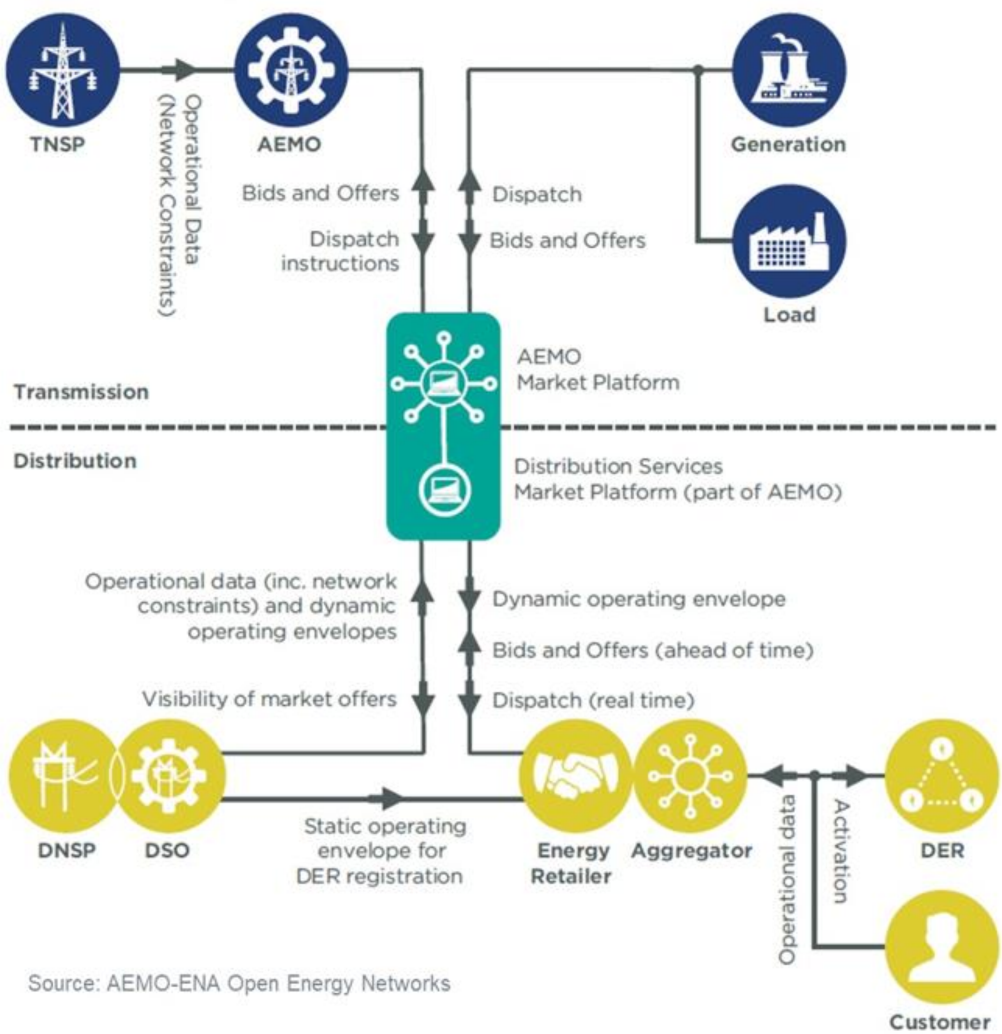
As shown in Figure 12, the AEMO would own and manage the single central market platform that spans both the transmission and distribution systems and involves active participation from the distribution utility (i.e., distribution network service provider (DNSP)) and DER aggregator and/or energy retailer.[85] To enable DER participation at both the bulk power and distribution level and facilitate coordination, AEMO-ENA defined 13 high-level use cases that capture the various roles and responsibilities of the players and types of functionality the platform would provide (Table 12).[86] With the distribution services market platform embedded in the overarching AEMO market platform, participating DERs/DERAs would receive dispatch instructions from the platform after the AEMO finalized its co-optimization based on transmission and distribution conditions.

[85] Although AEMO and ENA's hybrid platform shows that all DER participation is coordinated through an aggregator or energy retailer, a shared market platform could also allow for direct participation of and coordination with individual DERs.
[86] Energy Networks Australia, *Hybrid Model*. https://www.energynetworks.com.au/sgam/hybrid/index.htm.

Table 12: Australia hybrid platform high-level use cases

High-level use case	Description
1. Distribution system monitoring and planning	Primarily focuses on gathering data to support development of a long-term distribution network infrastructure plan, but also involves coordinating a long-term transmission network infrastructure plan.
2. Distribution constraints development	Develops a regulatory framework for constraint determination (similar to the open-access rules discussed in Section 4.2) and determines long-term distribution network requirements.
3. Forecasting systems	Develops both distribution and transmission short-term forecasts and defines requirements.
4. Aggregator DER bid and dispatch	Spans initial formation of a DERA to active engagement in the market, including registration, submission of bids and receipt of dispatch instructions.
5. Retailer DER bid and dispatch	Same as use case 4, but for a retailer.
6. DER optimization at the distribution network level	Includes development by the DNSP of long-term (i.e., planning time frame of months or years) static operating envelopes and short-term (i.e., intraday to multiple days or weeks) dynamic operating envelopes. Operating envelopes include notifications of any DER export and/or import limits based on distribution system conditions. This information enables aggregators/retailers to submit wholesale market bids that comply with dynamic operating envelopes.
7. Wholesale-distributed optimization	AEMO determines a co-optimized dispatch schedule by accounting for existing bilateral contracts for grid services and any distribution and transmission network requirements and market offers (i.e., bids/offers from resources to provide both distribution and bulk power system services).
8. Distribution network services	Spans the definition and activation of distribution network services to the procurement of these services from DERs either through bilateral contracts or active bids and dispatch. Similar to use case 2, requires development of a regulatory construct governing the provision of the services by the DNSP.
9. Data and settlement (distribution)	Both of these use cases encompass the processes to collect revenue-grade metering data and conduct financial settlement, including dispute resolution.
10. Data and settlement (transmission)	
11. DER register	Involves the collection and sharing of DER data (i.e., data from the interconnection process) to provide updated information on the current levels and capabilities of DERs in Australia.
12. Connecting DERs	Manages the DER interconnection process, including the identification of regulatory frameworks, connecting DERs through system engineering analyses and disseminating their data to a DER register.
13. Network and system security with DERs	Coordinates system operations under various abnormal system conditions, including granularly at the distribution level and more broadly for whole system security.

Figure 12: AEMO and Energy Networks Australia conceptual hybrid platform



Shared DER lifecycle management platforms, like the one being analyzed in Australia, could provide Ontario with flexibility in how the IESO and LDCs obtain the functionalities they need to support T-D interoperability in a high-DER environment. This type of platform could be extended as needed to include SaaS-based operational systems functionality to augment the IESO's or an LDC's existing systems. For example, an LDC can elect to use functionalities such as interconnection process management, DERMS and network model on a SaaS subscription basis, or directly invest in building and owning those capabilities in house. The same flexibility applies to the IESO and does not depend on what the LDC decides – if an LDC chooses to obtain DERMS functionality via a SaaS subscription, the IESO could independently choose to invest in and own its own DERMS. This type of flexible SaaS platform approach is ideally suited for Ontario, given the significant number of LDCs with varying operational system capabilities and resources to obtain additional capabilities.

Second, a shared DER lifecycle management platform does not mean all supporting IESO and LDC processes live within the platform. Rather than conducting their system planning through the platform, the IESO and LDCs could maintain their own planning processes, and enter resulting inputs to achieve the types of use cases described in Table 12. Many aspects of the transmission and distribution systems that the IESO and LDCs are respectively responsible for operating would not necessarily be captured in this type of shared platform. For example, an LDC would have to maintain its OMS because coordinating system operations in response to an outage (e.g., reconfiguring a distribution circuit) could require the LDC to control assets other than the DERs/DERAs providing grid services through the shared platform.[87]

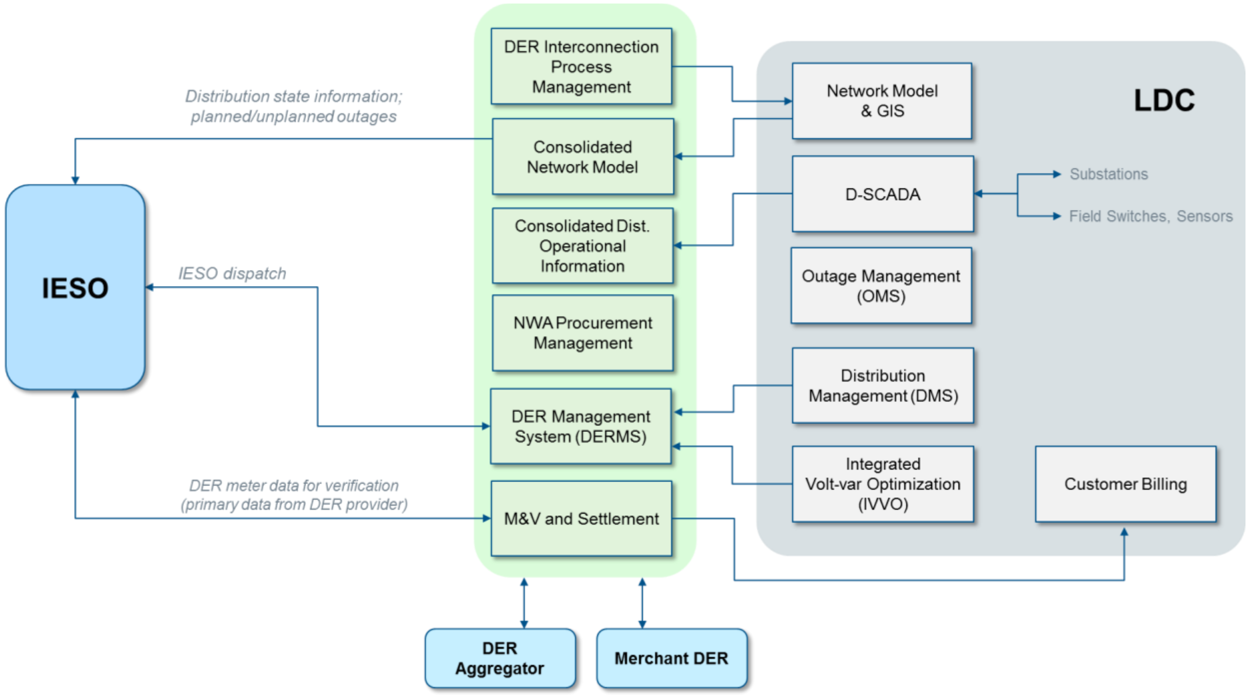
Third, leveraging this type of platform would vastly simplify the operational interfaces described in Section 5.1.3 for all entities involved – the IESO, LDC, DER aggregators and individual DERs – and drastically reduce the scale of existing interface points. Rather than maintaining separate coordination links with each other (e.g., a DER aggregator having to communicate separately to the IESO and LDC to facilitate wholesale market participation), each entity would be able to have one direct link to the shared platform where all parties could input and extract required information.[88] This benefit grows significantly as the number of DERs increases. While standards harmonization targeted by California's Rule 21 may still be desirable for Ontario, this type of shared platform could support a wide range of standards, making it less critical for the industry to align on a single standard in the near term. In the longer term, standards could be introduced that the platform did not originally support, but the likelihood of stranded assets would be reduced because it is easier and more cost effective for a single platform to adopt capabilities to support new standards rather than requiring multiple DERs and aggregators to adopt them.

Figure 13 provides an illustration of how this type of market and operational coordination platform could apply to Ontario, with the green-shaded boxes representing platform capabilities. While DER interconnection process management, NWA procurement management, DERMS and M&V and settlement refer to the capabilities enabled by the operational systems in Table 10, consolidated network model and consolidated distribution operational information refer to information necessary to enable market and operational coordination provided to the platform by the LDC. The consolidated network model would include information about the distribution system structure required for dispatch and optimization functionality, but would likely stop short of replicating the complete network model housed within the LDC. Additionally, the consolidated distribution operational information would include key information on real-time distribution system conditions, similar to the dynamic operating envelopes provided by the DSNP in the Australian example.

[87] Although a shared platform can introduce significant efficiencies, important processes and efforts still occur outside of the platform, which explains why Australia found it impractical to pursue a Total TSO approach, with one entity responsible for planning and operating the entire system.

[88] Platforms can provide permission rights to govern which entities can access certain types of data/information. For example, if confidential information is shared between the IESO and DER aggregator for the settlement of wholesale market services, the shared platform could prevent the LDC(s) from accessing that data.

Figure 13: Conceptual market and operational coordination architecture for Ontario



Note: Grey boxes represent existing LDC systems. Blue boxes represent the IESO and DER entities interfacing with the platform. The green boxes represent new functionality obtained through the shared platform.

5.3 Conceptual cost estimate

The following assessment (Table 1313) estimates costs associated with the shared DER lifecycle platform described in Section 5.2. The estimate includes incremental functionality for DER interconnection process management, NWA procurement, operational coordination and dispatch, and settlement (i.e., the green boxes in Figure 13). Given the diversity of LDCs in Ontario, the province is uniquely positioned to leverage this type of shared platform to significantly reduce costs and complexity for the IESO, smaller or less capable LDCs and DER providers.

In the absence of publicly available cost information for these types of platforms, this conceptual cost estimate augments vendor quotes with historical reference data from other ISO/LDC public data, using a parametric cost-estimating method. Parametric estimating uses historical data on key cost drivers to estimate costs for different parameters such as scale. For example, the SaaS cost of operational software is often based on the size of an LDC in terms of the number of customers served or number of users. This parameter can be used to adjust the cost of a particular software for the number and size of LDCs that will be active in the operational coordination.

The costs provided are based on commercially available SaaS solutions and cover initial software configuration, integration and testing, and the annual SaaS operating expense. This estimate is based on a five-year service term for approximately 50 coincident users among 20 LDCs and the IESO, all of which share this system.

This cost estimate also includes platform integration to address additional integration required between commercial solutions that comprise the entire platform. However, the SaaS platform functionalities identified are heavily data-dependent, and industry experience suggests considerable time and effort may be required to digitize data currently in analog form, which would entail significant effort to format and clean the data for use. This cost assessment does not include potential supporting data management costs, including databases, security systems, computing hardware or other back-end systems that may be required.

These costs will need to be allocated among the users, but there is no single answer as to how much the IESO would pay versus the LDCs, DER aggregators or operators.

Table 13: Conceptual cost estimate

	Conceptual estimate (CDN$2019)	
Item	**Initial cost**	**Annual expense**
DER interconnection and NWA procurement SaaS platform	$3,000,000	$1,500,000
Operational coordination and dispatch SaaS platform	$6,500,000	$2,000,000
Platform integration	$500,000	-
Total	**$10,000,000**	**$3,500,000**

This estimate does not include the costs for DER providers to integrate their systems. A complete survey of existing operational systems for Ontario LDCs or detailed DER adoption and NWA use forecasts would be needed to estimate the costs associated with integrating the additional LDC distribution operational systems (Table 9) required to support large-scale DER adoption and use for grid services across Ontario.

This conceptual estimate is intended only to highlight the potential magnitude of operational coordination systems costs that may be required to enable the T-D interoperability models discussed. More work is needed to determine functional requirements and other related information before a formal pricing estimate for this type of platform in Ontario can be developed. These approximations are not a substitute for the detailed engineering estimates required for funding authorization. By refining a T-D interoperability model to develop functional requirements and detailed systems architecture, Ontario can derive a more complete cost assessment.

6 Conclusion

This paper provides a foundation to guide the evolution of Ontario's electricity grid by illustrating how the province could consider potential system architectures and assess the relative merits of each. Further work is needed to identify, design and implement a final system architecture for the province. The following key takeaways and next steps build on the findings of this paper and provide a path forward for Ontario.

6.1 Key takeaways

Key takeaway #1: Defining objectives for Ontario's electricity grid will help determine the most suitable T-D interoperability model to achieve those goals

The fundamental decision Ontario faces is whether to pursue a more centralized or layered T-D interoperability architecture. Setting objectives for electricity grid evolution can help guide this decision by identifying and designing the most suitable T-D interoperability models to further those goals. The objectives will also determine the pace at which the province can implement the selected models (e.g., if Ontario allows for a range of models to serve the unique needs of individual T-D interfaces). Refer to Section 6.2.1 for further discussion.

Initial objectives defined by various Ontario entities – such as reliability, certainty, affordability, competition and regulatory simplicity – were discussed in Section 4.1. Aligning the structure of the system with these objectives is critical to the design of a T-D interoperability model. This, in turn, will help determine the functional capabilities required, entity(ies) responsible for each function and the interactions between them.

As an example, an objective to enable a competitive marketplace for third-party DER providers could help direct decisions about whether to bundle the LDC and DSO functions. As described in Section 4.2, creating an independent DSO (IDSO) could prevent the DSO from giving its affiliates a competitive advantage by virtue of owning and operating the distribution system, but it would also create more complex coordination requirements between the LDC and the IDSO. Alternatively, Ontario could establish a regulatory framework for a bundled DSO-LDC that addresses the financial incentives and open-access rules necessary to enable a competitive arena for third parties. However, these changes could undermine the ability to achieve regulatory simplicity, highlighting that DSO model choices inevitably involve trade-offs, rather than solutions that maximize all objectives simultaneously.

Also related to the focus on facilitating competition is the need to clarify Ontario's objectives when evaluating the benefits and challenges of an LSE model. For example, if the LSE is seen as a means to enable third-party competition in Ontario, then having an LSE affiliated with a DSO would likely create an uneven playing field for third-party/competitive LSEs. Similarly, if Ontario wants these third parties to provide various grid services, including NWAs, then having to compete against the DSO or DSO-affiliate while the DSO is also the market operator would likely create market distortions, leading to the need for open-access rules on the distribution system to ensure open and fair competition.

These two key questions that arise when considering the objective of competition highlight how objectives effectively guide decisions about system architecture. By determining answers that promote competition, it becomes evident that the ideal system architecture would allow the DSO a greater role to operate an open and transparent distribution system marketplace. This suggests a more layered approach would be better suited to meet this objective, versus the more centralized approach characterized by an M-DSO with greater limitations on its functional capabilities.

This example also highlights how decisions about grid architecture will affect and be affected by the pace of change. For example, if the number of DERs increases gradually, Ontario would be able to implement a more centralized, closer-to-the-status quo architecture like alternative 1 more quickly than one similar to alternative 2, which could require establishing open-access rules and creating an LSE function independent from the DSO. However, if the number of DERs grows rapidly, a centralized architecture would offer fewer implementation advantages compared to an alternative 2 model that enhances DSO functionality in regions with the highest DER proliferation.

Key takeaway #2: System reliability is the first consideration when determining the types of interactions between key players and their roles and responsibilities

At the core of bulk power and distribution system operations lies the need to preserve reliability and safety. To achieve this, system operators must identify the types of responses they require from system assets and resources, spanning anywhere from less than a second to multiple months and years. For example, while bulk system ancillary services (e.g., frequency regulation) are typically provided on the order of seconds, resource adequacy is generally procured months or years in advance. Ultimately, the success of all planning and procurement activities is measured by real-time system performance. Consequently, operators should use the operational responses they need to determine the operational control, market signals, resource procurement and system planning necessary for system reliability and safety.

These types of decisions will impact required interactions, such as operational control, market transactions and information/data exchange described throughout this paper and displayed via industry structure diagrams. These interactions will determine how Ontario structures its future electricity system and the corresponding roles and responsibilities of the various players. Similar to the first key takeaway, the need to preserve reliability as the number of DERs grows will also affect the pace of electricity system evolution. The increasing ability for DERs to provide distribution services will require the distribution system to evolve in a fashion that corresponds with the three stages outlined in Section 3.5, with stage 1 focusing on reliability and operational efficiency, stage 2 focusing on DER integration and operational markets, and stage 3 focusing on developing distributed energy markets with a very high level of DER adoption.

Key takeaway #3: A flexible approach to coordinating operations is necessary to address the diversity among and also within local distribution companies in Ontario

Ontario is characterized by a diverse range of LDCs that vary in size, functional capabilities and the amount of DERs on their systems. These variations in DER penetration can also exist within an LDC's service territory, making it essential to analyze grid architecture changes from the perspective of each T-D interface. The IESO or each LDC may not be able to effectively employ a single T-D interoperability approach for its entire service territory. Instead, LDCs may need to coordinate with the IESO and other key players to determine alternative models to best serve the unique characteristics of each T-D interface. However, Ontario will also need to ensure the IESO, LDCs and DER providers can support system operations in a scenario where individual entities have separate sets of roles and responsibilities for operational coordination across different T-D interfaces.

The growth of DERs and opportunities for them to provide grid services are key drivers for enhancing DSO functionality. As such, T-D interfaces characterized by lower levels and growth rates of DERs or minimal opportunities for them to provide services will have less need to incur the costs and complexity that come with a more DSO-centric approach. However, T-D interfaces with a higher amount of DERs warrant enhanced DSO capabilities, especially where DER operation has a greater potential to adversely impact distribution system reliability and safety without effective coordination. For the remaining interfaces, the system could default to a more centralized approach.

This variation between current LDC capabilities could justify a shared platform for the IESO, LDCs and DER providers to manage the entire DER lifecycle (See Section 5.2). This platform would give LDCs the flexibility to integrate existing systems, or alternatively subscribe on a software-as-a-service (SaaS) basis with a third-party platform provider, to acquire the incremental functionality required to facilitate market and operational coordination under the applicable T-D interoperability approach. A flexible approach could enable LDCs and the IESO to save money and mitigate the complexities resulting from continued investment in separate systems and the likelihood of duplicating functions (see Section 5.1).

6.2 Next steps

Building on these key takeaways, Ontario can take steps to further the evolution of the electricity system. These fall into two broad categories: (1) identifying, designing and selecting a primary T-D interoperability model, and (2) implementing the selected model. The next two sections list the steps in chronological order.

6.2.1 T-D interoperability model identification, design and selection

Building on the foundation established in this paper, these steps continue to analyze which T-D interoperability models are most suitable for the province.

1. **Define Ontario's system objectives and enable regulatory changes**
   As described in the first key takeaway in Section 6.1, objectives form the basis for evaluating T-D interoperability models. Initial objectives defined by various Ontario entities were outlined in Section 4.1, but a final set of objectives must be collaboratively defined and accepted by key Ontario stakeholders. Ontario will need to consider the relative priority of each and the criteria for trade-offs when it is not possible to simultaneously achieve all of the objectives.

   Equally important to defining system objectives is determining the regulatory changes required to achieve them. While this white paper focused heavily on the development of open-access rules for the distribution system, Ontario will need to fully analyze the complete set of required changes to achieve its objectives (e.g., interconnection processes; sale of energy or grid services on the distribution system).

2. **Identify and describe T-D interoperability models of interest to Ontario and apply the Ontario-specific decision framework to choose the interoperability architecture**
   This paper used two conceptual grid architecture approaches to illustrate how Ontario could apply its decision framework to evaluate the relative merits of alternative models. Similar to the United Kingdom and Australia, Ontario may want to pursue more options by identifying and describing additional T-D interoperability models. After fully describing these options, Ontario can use the decision framework described in Section 3 to determine the most suitable T-D interoperability model for further analysis. If, as described earlier, Ontario pursues an approach, that allows for alternative T-D interoperability architectures based on the unique characteristics of each T-D interface rather than a single architecture for the entire province, then this step would need to be repeated for each individual T-D interface.

3. **Conduct a detailed grid architecture assessment of the selected model**
   This paper provides conceptual grid architecture approaches to describe how Ontario could structure its future electricity system, but stops short of validating either model as operationally feasible. Ontario will need to conduct a detailed architectural assessment of the selected T-D interoperability model(s), applying engineering analysis and operational risk assessments to determine effective structural options (i.e., the specific attributes or performance characteristics the system must exhibit to achieve the objectives, which will then drive decisions around required functions and system structure). Through this detailed analysis, the IESO will be able to map the functionalities it requires in a high-DER environment to the operational systems (e.g., DERMS) that will enable them.

   This detailed assessment will also allow Ontario to refine the preferred model(s) and update the cost estimate, including the costs incurred by the IESO and LDCs to acquire the functionality to integrate DERs, either through investments in separate systems or by developing a shared DER lifecycle management platform. This detailed analysis is required to support policy decisions and the type of detailed discussions on electricity grid evolution currently underway in the United Kingdom and Australia.

6.2.2 T-D interoperability model implementation

These next steps will directly facilitate Ontario's efforts to implement its chosen T-D interoperability model, and can continue at the same time as those described in Section 6.2.1.

1. **Continue efforts to integrate DERs and reflect their value in market opportunities**
   In Ontario, work is continuing to integrate DERs into the electricity system and create opportunities for them to be compensated for the services they provide. Examples are the IESO's York Region demonstration project, which aims to better understand the value of DERs as NWAs, enhancements to its regional planning process to enable DERs as cost-effective local solutions, efforts to identify participation models for DERs, and implementation of a capacity auction, which will evolve over time to open participation to more resource types. Identifying T-D interoperability models does not depend on the scope of DER grid services, but will inevitably affect how Ontario seeks to allocate various roles and responsibilities to key players and the functionalities necessary to enable provision of these services.

2. **Facilitate collaboration between the IESO, LDCs and DER providers on operational coordination requirements and systems**
   Emerging opportunities for DERs to provide bulk power and distribution services will require new forms of coordination between the various players. Discussions should continue about how best to structure this coordination in the near term. In particular, Ontario should consider the potential for developing a shared DER lifecycle management platform, as described in Section 5.2. This approach could save the province money, while helping to mitigate the challenges resulting from differing standards and protocols governing communications between key players and being applied directly to DER assets.

3. **Design and implement pilots and demonstration projects to test key aspects of T-D interoperability**
   While the York Region demonstration project will allow Ontario to test key aspects of T-D interoperability, such as the operational and market coordination that enables DERs to defer a system investment, Ontario should explore additional opportunities to assess other aspects. These efforts could focus on:

   - Validating T-D interoperability models in terms of operational coordination processes between key players
   - Testing use cases for DERs to provide various grid services
   - Enhancing LDC/DSO capabilities to model the distribution system and its constituent DERs in greater detail, both in terms of location and timing of operation
   - Operationalizing key technologies or systems, such as a shared market and operational coordination platform

7 Glossary[89]

Balancing authority: The entity responsible for integrating resource plans, maintaining load-interchange-generation balance within an electrically defined balancing authority area, and supporting interconnection frequency in real time. This role is normally served by a TSO or ISO for a given area, but could be a DSO for the distribution system under a Total DSO approach (see Section 4.1.2).

Distributed energy resource (DER): Includes all electricity resources connected on the distribution side of the system, except for energy efficiency. DERs may be connected on a customer's premises behind the utility revenue meter, or directly to the distribution utility (i.e., LDC) facilities. The term DER is used broadly to include distributed generation, energy storage, demand response, electric vehicle charging infrastructure, all of which contribute to the need for robust T-D interoperability and coordination.

Distributed energy resource aggregator: Entity responsible for grouping individual DERs together to provide wholesale market or distribution system services. Depending on the T-D interoperability architecture, a specific DERA (aggregated virtual resource) operated by a given aggregator may either participate directly in the wholesale market or submit its offer/bid to the DSO for consideration as part of a single aggregated wholesale bid/offer at the T-D interface (i.e., if the DSO is capable of serving this role – see Section 4.1.2).

Distributed energy resource aggregation (DERA): A virtual resource created by an aggregator to bring multiple DERs together to provide wholesale market or distribution grid services.

Distribution system operator (DSO): The entity responsible for planning and operational functions typically associated with a high-DER distribution system. This entity may be either the incumbent distribution utility or a separate, independent entity. The term DSO can refer to a range of business models, organizational structures and functional capabilities, which go beyond those of an existing distribution utility. This role could be limited to planning and operating the distribution system reliably with high amounts of DERs and multi-directional power flows, or expanded to use market mechanisms to deploy DERs to meet an area's needs. Only one DSO would exist for each LDA associated with an individual T-D interface substation, but a single DSO may operate more than one LDA within a larger service area.

Independent distribution system operator (IDSO): An independent entity established to plan an integrated distribution system, procure DER services to operate the distribution system, and facilitate distributed energy markets in a non-discriminatory, open-access manner that ensures the distribution system's safety and reliability. Independence means the operator is unaffiliated with buyers and sellers of wholesale or retail energy or capacity, or with the owners of physical distribution assets.

Independent system operator (ISO): An independent entity that is a transmission system operator, wholesale market operator and balancing authority, essentially the same as a regional transmission organization (RTO) in the U.S.

[89] Derived from: De Martini, P., & Kristov, L., *Distribution Systems in a High Distributed Energy Resource Future: Planning, Market Design, Operation and Oversight*, 2015. https://emp.lbl.gov/sites/default/files/lbnl-1003797.pdf.

Load serving entity (LSE): Entity responsible for procuring supply (energy and resource adequacy) and providing retail kWh to meet its customers' load.

Local distribution area (LDA): Consists of all the distribution facilities, DERs connected to them and customers below a single T-D interface on the transmission system, with each LDA not being connected electrically to facilities below another T-D interface, except through the transmission system.

Minimal distribution system operator (M-DSO): Entity that provides non-discriminatory distribution service in terms of interconnection to the distribution system and coordination of DER wholesale market participation. Unlike a more enhanced DSO, this entity typically only has minimal additional functional capabilities (as needed) above existing distribution utilities to reliably manage a high-DER system.

Software as a Service (SaaS): Generally refers to a software delivery and licensing method where users access the software online via a subscription rather than purchasing and installing the software directly.

Transmission-distribution (T-D) interface: The physical point at which the transmission and distribution systems interconnect, serving as a reference point for electricity system planning, scheduling of power, and in ISO markets, determining locational marginal prices of wholesale energy.

Transmission system operator (TSO): Entity responsible for the safe and reliable operation of the transmission system that could be a functional division within a vertically integrated utility, a separate agency or a function of an ISO.

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