Distribution System Structures For A High Distributed Energy Resource (DER) Future - A Blueprint to Guide the Local Energy Transition in Ontario

December 2021

ENERGY TRANSFORMATION
NETWORK OF ONTARIO

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1. Executive Summary

The Energy Transformation Network of Ontario (ETNO) set out to address the question, *"Which distribution-level structure is best suited to accommodate the integration of increased numbers of DERs, in accordance with the principles the ETNO has recommended to guide the energy transformation in Ontario?".*

ETNO identified four structures, as possible options, to enable the integration of higher-volumes of DERs in a way that can maximize the value of DERs from an economic and technical perspective. The four structures are Community Choice Aggregator (CCA), Distribution System Operator (DSO), Fully Integrated Network Operator (FINO) and Load Serving Entity (LSE).

These structures were evaluated against the principles identified in ETNO's July 2021 report "Principles Guiding the Transformation of Energy System In Ontario". The fit of these structures was assessed in fulfilling the key roles and responsibilities associated with integrating DERs at the distribution-level and behind-the-meter.

Following the initial analysis, ETNO shortlisted DSO and LSE structures for further analysis. CCA structure was not selected for further analysis as the primary objective of this structure is to achieve environmental and social objectives for the customers, and it does not directly enable the integration of high volumes of DERs. The FINO structure was not selected for further analysis as it is inconsistent with the principles of competition that underpin the design of Ontario's bulk/wholesale electricity structure.

Following further analysis of DSO and LSE structures, the DSO structure was identified as the one that directly addresses the near-term challenge of effectively integrating high volumes of DERs at the distribution level, through creation of a local market (energy, capacity, ancillary services). The establishment of DSOs does not preclude the future establishment of LSEs and it is worth exploring how the two constructs could work in tandem to maximize the potential of growing numbers of DERs to deliver improved outcomes for all Ontario electricity customers and ratepayers.

ETNO recommends:
1. Implementation of the DSO structure to enable integration of an increased number of DERs in a way that maximizes their value to the ratepayer. ETNO also recommends incorporating the considerations outlined in this report for development of a new regulatory framework.
2. Local Distribution Utilities (LDCs) take on the role of DSOs, as they are well positioned to manage the DERs connected at the distribution system and behind-the-meter.

3. Further investigation of the LSE structure, noting that the DSO and LSEs are not mutually exclusive options. Roles and responsibilities of a LSE may be incrementally added either to the current structure, or to a DSO-based structure.

2. Introduction

The Energy Transformation Network of Ontario

The Energy Transformation Network of Ontario (ETNO) is a group of senior leaders from across Ontario's utilities, non-utility solution providers, business and non-profit organizations, government agencies and universities, working together to drive a more efficient, affordable energy system in Ontario.

ETNO is supported by a Working Group. Additionally, in 2021, ETNO was supported by MaRS Discovery District which provided support in coordination, facilitation, and execution of ETNO and Working Group meetings.

The list of ETNO and Working Group members is in Appendix A for reference.

This report is the final report of the ETNO. Over two years ago ETNO set out the following goals for itself:

1. To ensure the challenges and opportunities posed by the onset of Distributed Energy Resources (DERs) are addressed in Ontario
2. To encourage coordination between the Independent Electricity System Operator (IESO) and Ontario Energy Board (OEB) on the issue of DER integration and grid modernization
3. To encourage a more diverse array of organizations to participate in industry dialogue on DER integration and grid modernization

With this final report, which provides a suggested blueprint for the future, ETNO has delivered on these objectives. ETNO's success is evident in the multiple new initiatives underway across Ontario's energy industry focused on DERs and grid modernization, the unprecedented levels of collaboration between the OEB and the IESO (highlighted by the Minister of Energy, Northern Mines and Development (ENDM) in his recent mandate letter to the OEB), and the inclusion of a broad array of new stakeholders and solution providers in sector initiatives focused on DER integration and grid modernization. Given the success ETNO has achieved with regards to its objectives, it is the right time for ETNO to sunset and allow the OEB, IESO and ENDM Ministry to implement the recommendations identified in this report.

Report Methodology

In undertaking this report, ETNO set out to address the following question:

"Which distribution-level structure is best suited to accommodate the integration of increased numbers of DERs, in accordance with the principles the ETNO has recommended to guide the energy transformation in Ontario?"

The distribution structure options identified for evaluation in this report:
- Were evaluated against the principles identified in ETNO's July 2021 report "Principles Guiding the Transformation of Energy System In Ontario"
- Are not mutually exclusive options
- Were evaluated with the primary focus of recommending the structure best suited for maximizing the value of DERs to the ratepayers; therefore, structure options that maybe beneficial for overall energy system but do not directly address the question that ETNO set out to investigate, were not prioritized for evaluation and recommendation in this report
- Are focused on the distribution system

This analysis assumes that:
- DERs will continue to be adopted at scale
- DERs represent a significant resource that can be harnessed to lower the overall costs of the system to ratepayers
- There is potential to allow ratepayers to participate more directly in the energy market
- The recommendation from this report will enable *evolution* of Ontario's current structure as opposed to *overhauling* the current structure
- Parts of the energy system that are not addressed in this report (such as the transmission system) will continue to operate as per the current structure
- The distribution structure recommendation will be effective for at least the next 10 - 15 years in maximizing the value of DERs, acknowledging that the structure will continually evolve as the stakeholder needs evolve
- Local DERs refer to DERs connected directly to the distribution system as well as DERs connected behind-the-meter
- Local Distribution Utility (LDC) refers to the parent utility which may have a regulated and an unregulated arm

Report Overview

This report represents the advice of the ETNO as a whole. It is not meant to represent the position or opinions of individual members or their organizations. Accordingly, the positions and opinions of individual members and their organizations may not be reflected in the report, which is without prejudice.

The report is structured as follows:

Section 3: Overview of Distribution System Structures

- Provides an overview of energy system stakeholders, describes Ontario's current distribution structure as well as outlines four structural options identified for evaluation. Visual representation of the different structural options is also included in this section

Section 4: Distribution Structure Evaluation

- Provides an overview of the evaluation methodology and results of the evaluation criteria used to shortlist the distribution structures that ETNO recommends for enhanced DER integration in Ontario

Section 5: Recommendation

- Provides ETNO's recommendation for the evolution of Ontario's distribution structure

Section 6: Next Steps

- Outlines focus areas for consideration of decision-makers to build upon this work

Research components that informed the discussion on principles are outlined in Appendix J.

3. Overview of Distribution System Structures

Why The Distribution Structure In Ontario Needs to Evolve?

DER (definition in Appendix L) deployment is growing in Ontario. More than 4,000 megawatts (MW) of DERs have been contracted or installed over the past 10 years, with 1000 MW of DER contracts expected to expire over the next decade[1]. The number of DERs, including storage, EVs, is expected to continue growing in the coming decades[2] [3].

Ontario has the opportunity to harness the full potential of local DERs, from both a technical as well as economic perspective, with the support of an enabling regulatory framework. Harnessing the full potential of DERs means that regardless of the size or location, DERs:

- Can provide services to the grid such as power quality support, voltage support, resilience, local resource capacity etc.
- Are leveraged to enhance reliability (e.g. by providing backup during an outage) and optimize investment (e.g. via deferral of capital investment)
- Can be incentivized to be placed at optimal locations from a grid perspective

Harnessing the full potential of local DERs also includes the value of the DER to the customer as well as the overall system (including the transmission system), however, the focus of this report is on the potential as it relates to the distribution system.

Energy System Stakeholders

ETNO started the work by identifying the stakeholders_that are responsible for the management and operation of the energy system. These stakeholders include:

- Transmission System Owner and Operator
- Distribution System Owner (DO) also known as the Distribution Network Operator (DNO)
- DER Owner and Operator
- End Customer
- Aggregator (of loads or DERs)
- Retailer
- Independent System Operator (ISO)

[1] Source: IESO, Section 2.3 Exploring Expanded DER Participation in the IESO-Administered Markets -Part 2

[2] "ICF - Ontario Distributed Energy Resources Impact Study - Jan 18, 2021"

[3] Electric Charging and Alternative Fuelling Stations Locator, 4 September 2018, https://www.nrcan.gc.ca/energy-efficiency/transportation-alternative-fuels/electric-charging-alternative-fuelling-stationslocator-map/20487#/find/nearest?fuel=ELEC&ev_levels=all&location=ontario. Accessed 6 December 2021.

Definitions of these stakeholders are in Appendix B for reference.

What Is A Distribution System Structure?

The question that ETNO set out to address refers to a distribution-level structure, "*Which distribution-level structure …"*. For this report, ETNO focused on defining the 'structure' as the roles and responsibilities carried out by the energy system stakeholders for grid and market operation at the distribution level. The visuals to represent the different structural options (shown later in the report), highlight these roles and responsibilities by showing the interaction between the energy system stakeholders as it relates to system operation (energy flows and services procurement) and market operation (settlement). The roles and responsibilities defined in this report are not exhaustive, and instead aim to provide a high-level outline, with the understanding the detailed and comprehensive list will be developed as part of the regulatory framework development process.

Ontario's Current Structure

Figure 1 below shows Ontario's current structure. It depicts the energy flow, services procurement, and settlement (including contracts, PPAs etc.) relationship between the different energy sector stakeholders in the province. The electricity sector in Ontario and the corresponding roles and responsibilities have changed substantially over time. For additional context, Appendix C outlines the historical context of Ontario's current structure, and Appendix D outlines the challenges that inhibit integration of DERs at scale in Ontario.

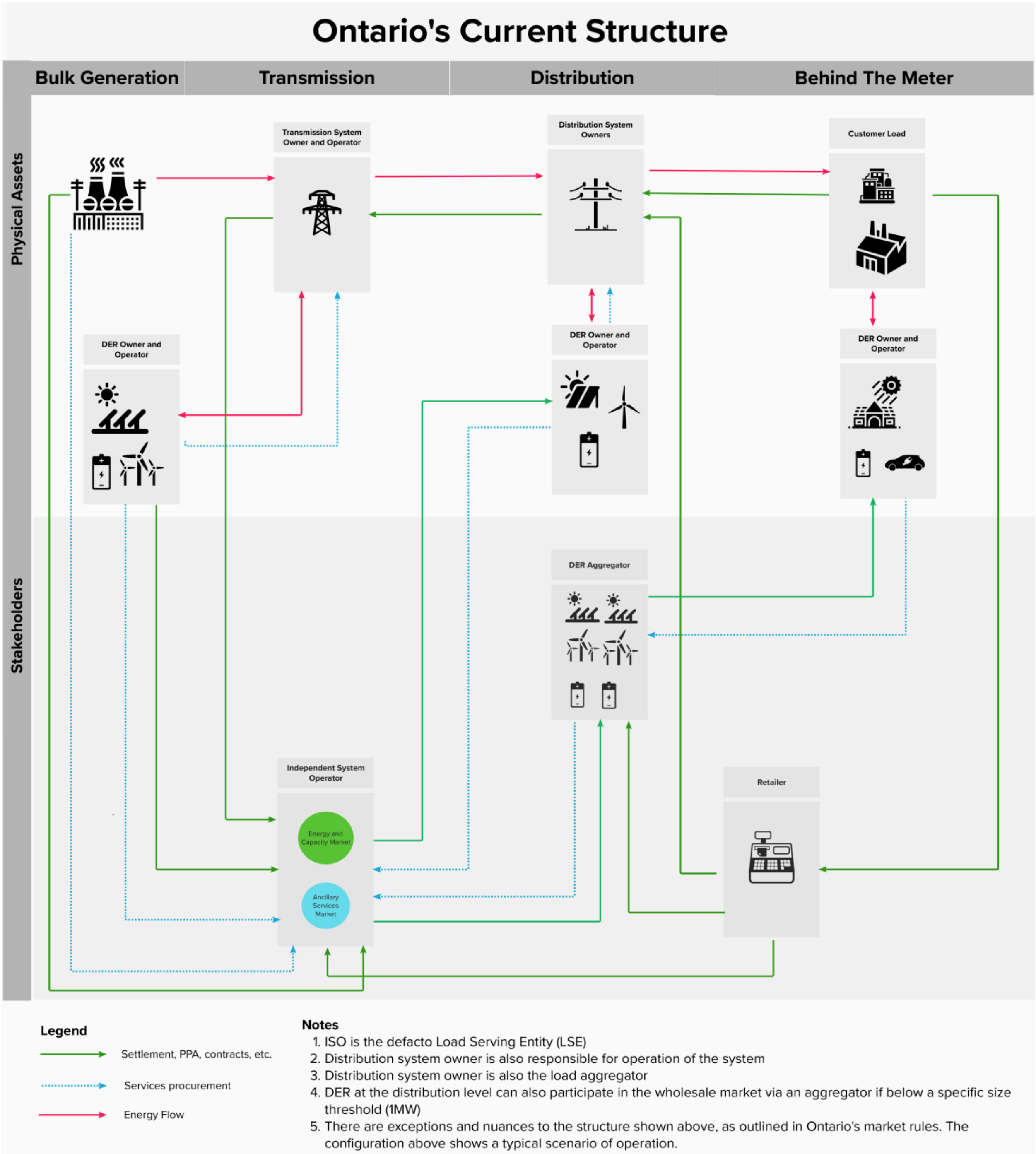


Figure 1. Ontario's current structure

Overview Of Options For Ontario’s Distribution System Structure

Given the number and range of functions required for the integration of high volumes of DERs into the electricity system, and the range of potential organizations that could carry out these functions, several approaches have been tested and evolved in other jurisdictions. Some of these approaches are summarized in Appendix I. In its 2019 report, "Structural Options for Ontario's Electricity System in a High-DER Future" the ETNO defined four such structures, the implications of which are assessed in this report:

1. Community Choice Aggregators (CCAs)
2. Distribution System Operators (DSOs)
3. Fully Integrated Network Operator (FINO)
4. Load Serving Entities (LSEs)

The four structures are outlined below. The following considerations should be noted for each:

- There are variations of these four structures. The descriptions outlined in this report represent a typical implementation.
- The exact nature of any structure that is implemented in Ontario would need to be defined in a new regulatory framework, and thus the details included in this report may not be exactly what is developed in Ontario.
- The four structures are not mutually exclusive; they may co-exist and offer synergistic benefits
- There are various definitions and interpretations of the four structures depending on the jurisdiction in which they are implemented. In some instances, these options maybe referred to as 'programs' or 'business structures', as opposed to 'structures' by the industry stakeholders. For the purpose of this report, we are referring to these four options as 'structures'. The key features of each structure option, as interpreted by ETNO, are outlined next. A table summarizing key features is in Appendix F for reference.

Community Choice Aggregators (CCAs)

Figure 2 shows a typical implementation of the CCA structure. Key features of CCAs include[4] [5]:

- CCAs are often set up with environmental (e.g. supporting the adoption of renewable energy, net zero targets etc.) and social objectives.
- CCAs are responsible for procuring wholesale electricity on behalf of retail electricity customers, within a defined geographic area. CCAs procure electricity services in the wholesale market or through bi-lateral contracts with resources and resell these services.
- CCAs may be run directly by a city or county government (local government or coalitions of government) or by a third party through a contractual arrangement such as a joint powers agreement.
- A key feature of CCAs is that customers must actively opt out of the program.
- The transmission system owner and operator, and distribution system owner (i.e. utilities) remain responsible for local transmission and distribution networks, and are responsible for serving the loads that opt out of CCAs.
- In the current structure, the distribution system owner or a retailer provides energy programs to the customers. In the CCA structure, the CCAs take on the role of providing energy programs to the customers with the objective of providing customers with more environmentally friendly choices and services.

[4] https://www.nrel.gov/docs/fy19osti/72195.pdf
[5]https://www.pge.com/en_US/residential/customer-service/other-services/alternative-energy-providers/community-choice-aggregation/community-choice-aggregation.page

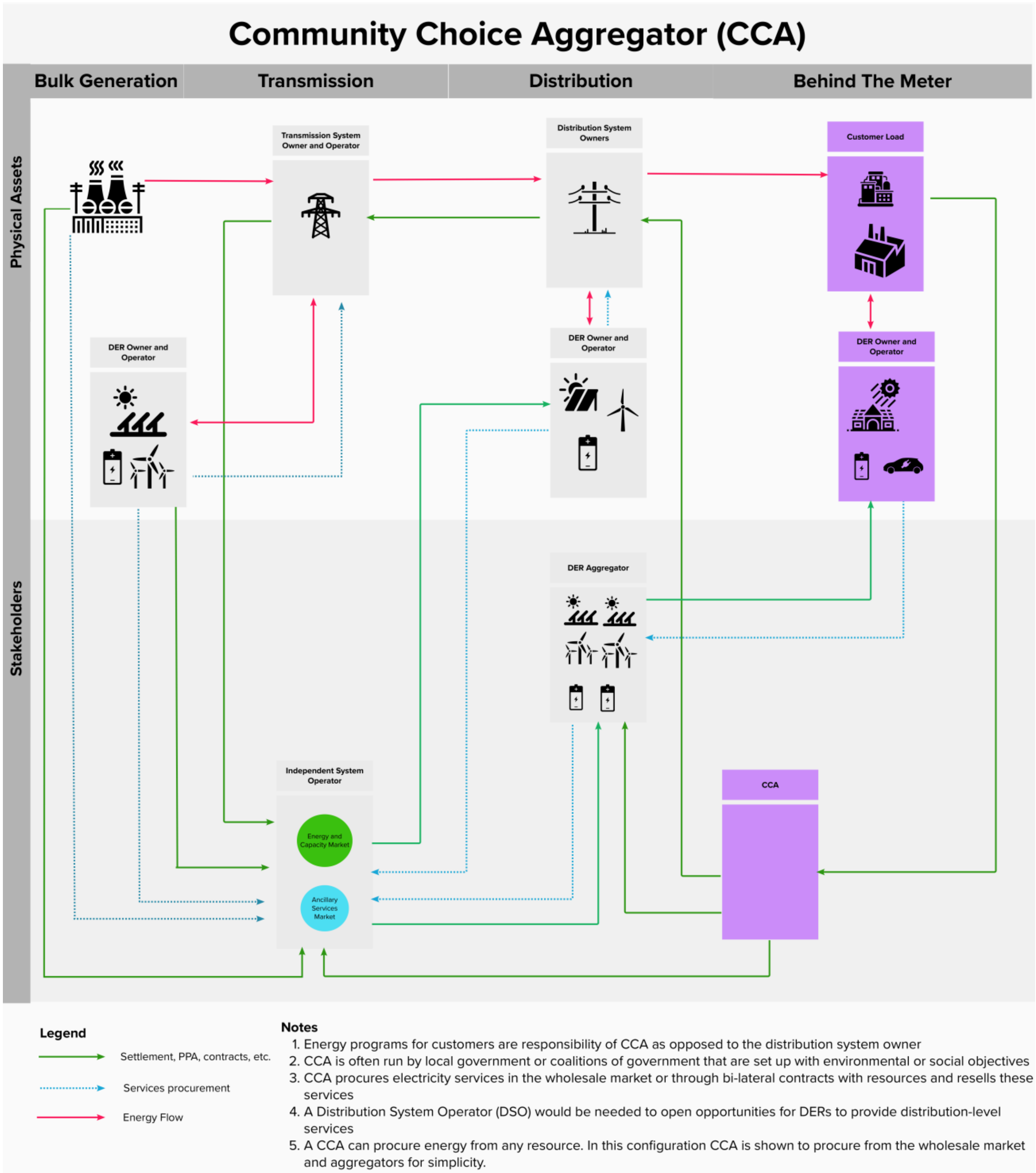


Figure 2. Overview of Community Choice Aggregator structure

Distribution System Operators (DSO)

Figure 3 shows a typical implementation of a DSO structure. Key features of DSOs include:

- Creation of a local market - energy, capacity, and ancillary services - for DERs connected at the distribution level or behind-the-meter (of a customer that is connected at the distribution level).
- DSOs facilitate the transaction of energy services across their networks (including between customers) and enable local DERs to provide grid services.
- DSOs can use the local markets to address network constraints, deferring grid investment.
- A DO may take on the role of a DSO, however, it may also exist as a separate entity.
- Compared to the role of a DO, the DSO is an active manager of the distribution network that is able to harness the full potential of local DERs

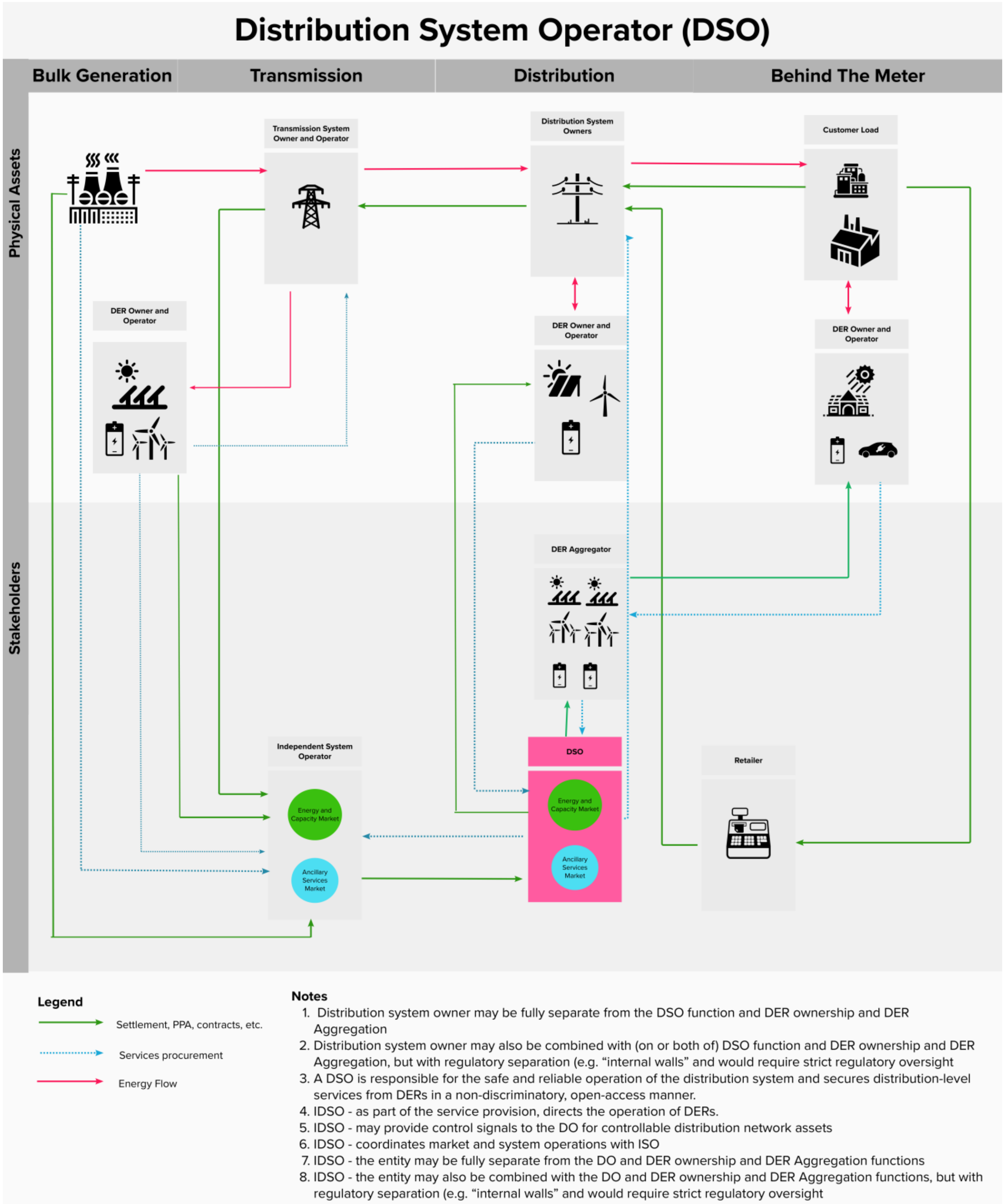


Figure 3. Overview of Distribution System Operator (DSO) structure

Fully Integrated Network Operator (FINO)

Figure 4 shows the implementation of a FINO structure. Key features of FINO includes[6]:

- FINO is a single entity that performs the roles of a distribution system owner and those that relate to effectively integrating DERs within a service territory.
- FINO is actively involved in the development and ownership of DERs, and controls and operates DER resources.
- In this structure, the customers do not have the option to deal with a retailer, instead they deal directly with the FINO.
- Compared to the current structure, the FINO enables the DOs to have:
    - A higher degree of control on operation and management of DERs as FINO's may own DERs. However, noting that similar outcomes can be achieved without ownership of DERs in alternative structures.
    - An increased capability to own DERs, while noting that ownership is not necessary for effective DER integration.

[6] "Power To Connect: Advancing Customer-Driven Electricity Solutions for Ontario." *Electricity Distributors Association*, https://www.eda-on.ca/Advocacy/Research-and-Reports/Power-To-Connect-Advancing-Customer-Driven-Electricity-Solutions-for-Ontario. Accessed 7 December 2021.

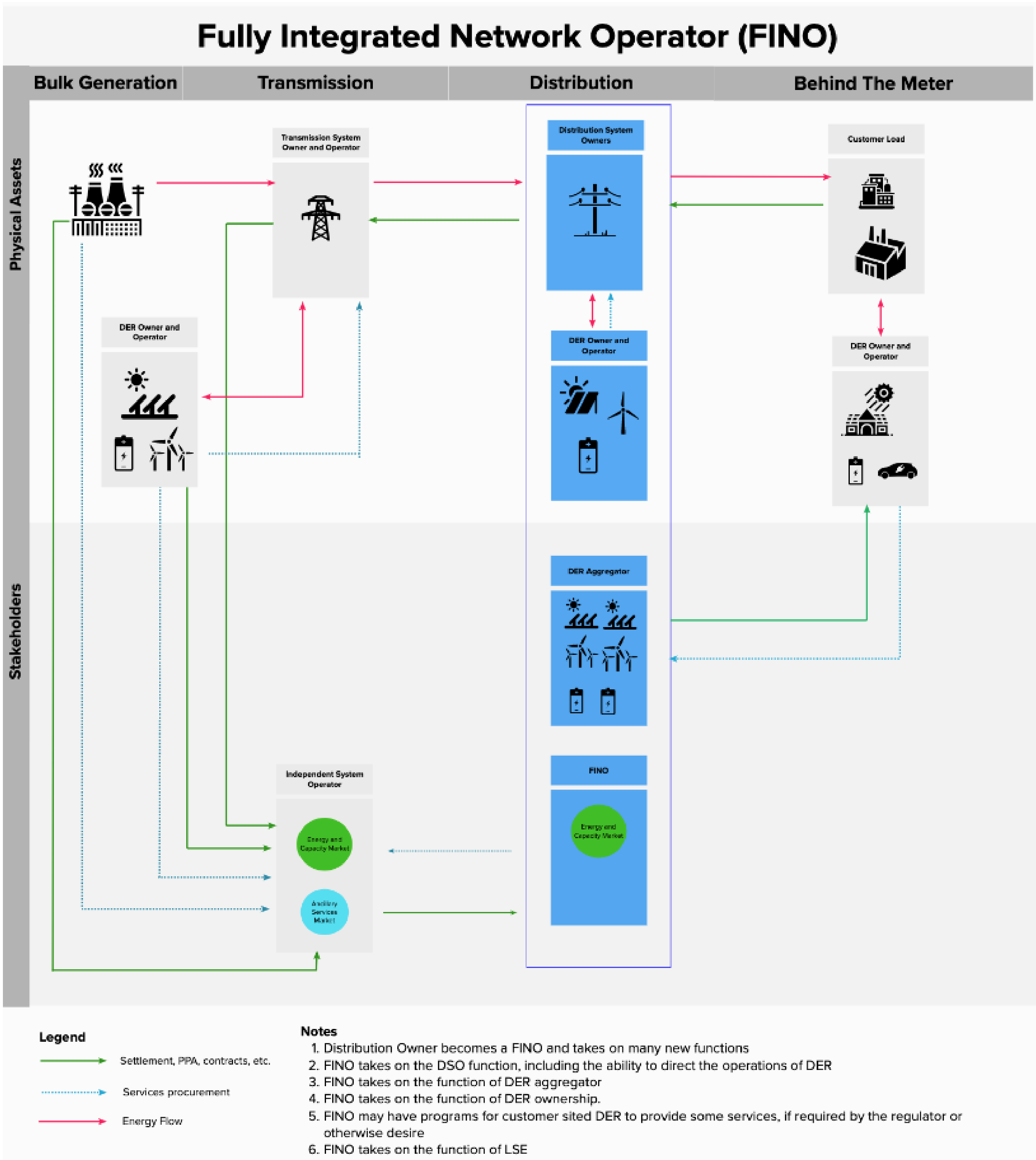


Figure 4. Overview of Fully Integrated Network Operator (FINO) structure

Load Serving Entities (LSEs)

Figure 5 shows a typical implementation of a LSE. Key features of LSEs include:

- LSEs procure energy and capacity on behalf of the customers (loads) they serve. The core activity of an LSE is to aggregate load on behalf of customers and make appropriate arrangements in wholesale markets to meet the load.
- LSEs are generally responsible for planning the resource adequacy needs of its customers and for directly (or indirectly through a centralized process) procuring electricity for their retail customers.
- A LSE may procure energy and capacity via bilateral contracts, or through the wholesale market[7]. In some jurisdictions, LSEs can also directly own generation, though that is not a prerequisite.
- LSEs could be positioned to use DERs to satisfy local or overall resource adequacy requirements
- LSEs take on commercial risk associated with forecasting and procuring electricity on behalf of their loads. Taking on this risk means that the LSEs will pay more if they underestimate the load and overpay if they overestimate the load. Taking on this risk provides an incentive for LSEs to:
    - Ensure the forecasting is as accurate as possible
    - Enable/incent the demand to be more flexible. E.g., ConEdison is advocating for a special tariff to enable solar generation on the roofs of their customers.
- A DO, CCA, retailer or large customer may take on the role of the LSE. Depending on the entity that is taking on the role of the LSE, the responsibilities of a LSE may also include hedging, providing distribution services, being a provider of last resort, retail functions including billing, establishing rate schedules for customers, and customer engagement.
- The new markets that the IESO is putting in place via Market Renewal include the concept of a Price Responsive Load (PRL), like an PRLs will have the ability to submit their own bids into the day-ahead electricity market based on their own forecast of their real-time electricity needs. Since day-ahead prices are more certain than real-time, this gives the PRL more certainty as to their electricity costs. If the PRL's real-time demand is higher than its day-ahead forecast, it would be required to either a) make-up the difference by purchasing more in real-time at less certain (likely higher) prices OR reduce demand through load shifting/self-generation. If the real-time demand is lower, it would need to sell-out its position (or store the electricity).

[7] Berkeley Labs: https://ei-spark.lbl.gov/power-markets/load-serving-entities/info/

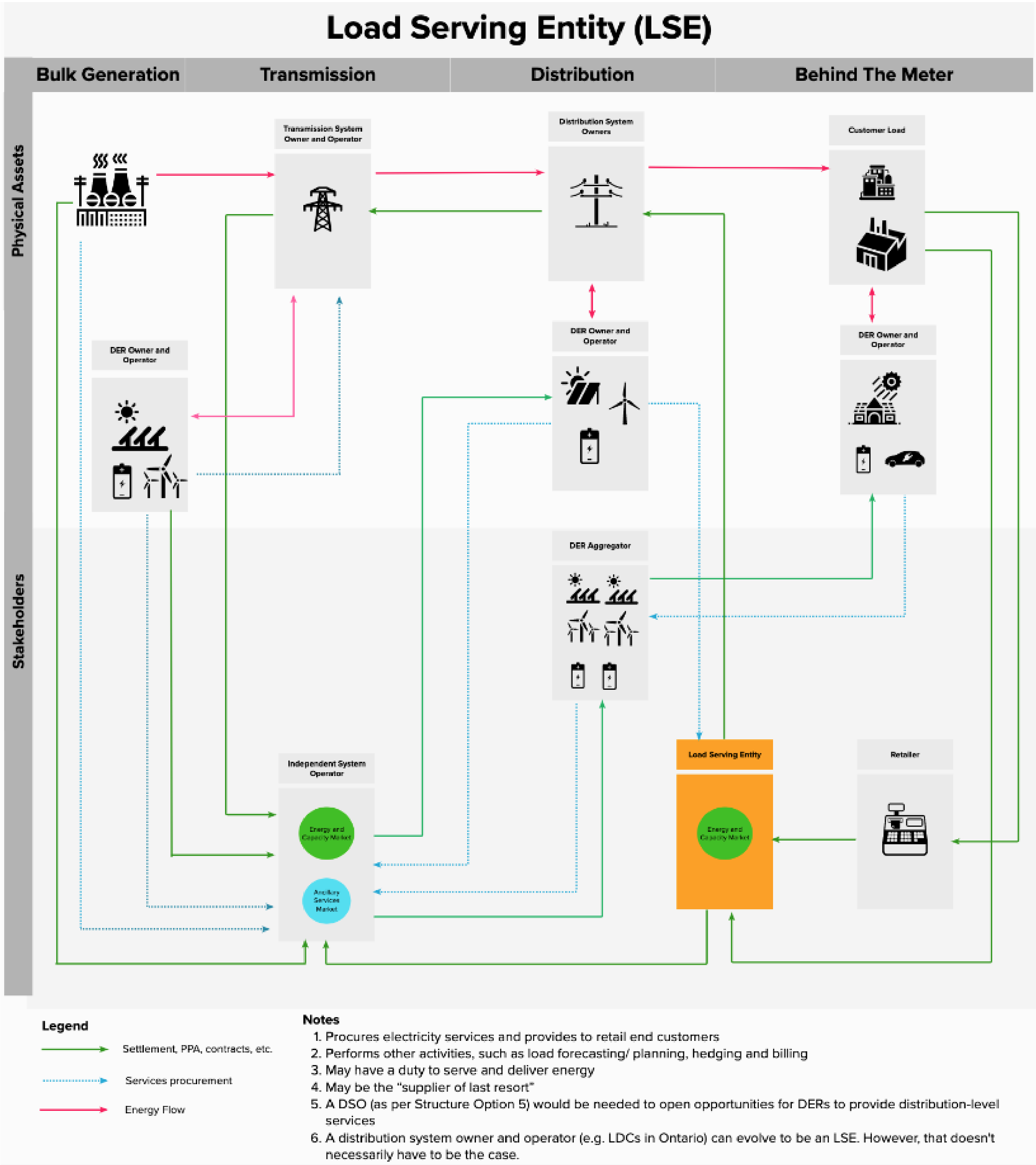


Figure 5. Load Serving Entity (LSE) structure

4. Distribution Structure Evaluation

Evaluation Methodology

ETNO took a systematic approach to evaluate the four structures. The structures were evaluated against the principles identified by ETNO in the "Principles Guiding the Transformation Of The Energy System In Ontario" report. The guiding questions used for evaluation are listed in Appendix E for reference.

Guiding questions related to two principles, "Affordable" and "Optimized and Efficient" were addressed in a high-level analysis. These principles required assessment of the impact of these structures on the cost for customers (affordability) as well as the feasibility of financing these structures. Presentations from Dominion Bond Rating Service (DBRS) and Toronto-Dominion Bank (TD) informed this directional analysis. Learnings from the jurisdiction scan (Appendix I) were also important inputs. Further work is expected to comprehensively assess cost-benefits of these structures and consumer electricity rate-impact before any implementation decisions are made. This is indicated in proposed next steps.

Each structure was evaluated using the above methodology to assess its fit for implementing key roles and responsibilities associated with integration of local DERs, such that their value is maximized from a technical and economic perspective. These roles and responsibilities include:

1. Developing, owning and maintaining local DERs (i.e. physical asset development, ownership and maintenance)
2. Operating DERs (i.e. providing control signals to the DERs to turn them on/off etc.) for:
    a. Participation in the local energy and capacity market
    b. Participation in the local ancillary services market
    c. Providing grid services such as power quality support, voltage support, reactive power support, local backup in case of a power outage, peak load management etc.
3. Incorporating local DERs into distribution grid planning for:
    a. Resource adequacy (i.e. ensuring long-term supply is available for the customers)
    b. Optimizing grid investment for example via deferral of building new infrastructure or via incentivizing optimal placement of DERs from a grid perspective

Evaluation Overview

Pros and cons for each of the structural options were identified leveraging the questions associated with the 10 principles that ETNO developed for guiding the energy system transformation in Ontario. This analysis is outlined in Appendix G. The feasibility of the different structures to enable the roles and responsibilities associated with integration of DERs (outlined above) is summarized next.

Roles and Responsibilities Associated With Integration of DERs Under a CCA Structure
1. Developing, owning and maintaining local DERs (i.e. physical asset development, ownership and maintenance) ● A CCA entity may own DERs (depending on the regulatory framework) but does not have to do so to serve its load. It may procure directly from the market. ● Customers (behind-the-meter) can continue to own DERs.
2. Operating DERs (i.e. providing control signals to the DERs to turn them on/off etc.) for: **a. Participation in the local energy and capacity market** **b. Participation in the local ancillary services market** **c. Providing grid services such as power quality support, voltage support, reactive power support, local backup in case of a power outage, peak load management etc.** ● A CCA structure does not inhibit or enable DER operation.
3. Incorporating local DERs into distribution grid planning for: **a. Resource adequacy (i.e. ensuring long-term supply is available for the customers)** **b. Optimizing grid investment for example via deferral of building new infrastructure or via incentivizing optimal placement of DERs from a grid perspective** ● A CCA structure does not inhibit or enable integration of DERs into distribution grid planning, as a CCA entity does not typically have planning responsibilities.

Roles and Responsibilities Associated With Integration of DERs Under a DSO Structure
1. Developing, owning and maintaining local DERs (i.e. physical asset development, ownership and maintenance) ● Ownership of DERs by a DSO entity depends on the regulatory framework. In the scenario where the LDC is the DSO, typically the DSO does not own DERs for commercial objectives. ● Customers (behind-the-meter) can continue to own DERs.
2. Operating DERs (i.e. providing control signals to the DERs to turn them on/off etc.) for: **a. Participation in the local energy and capacity market** **b. Participation in the local ancillary services market** **c. Providing grid services such as power quality support, voltage support, reactive power support, local backup in case of a power outage, peak load management etc.** ● In a DSO based structure, there is a creation of a local energy and capacity market. A local ancillary services market can also be created, depending on the regulatory framework. ● The DERs connected at the local level participate in the distribution-level market without the need of an aggregator (as is required in the current structure to reach a specific capacity threshold). ● The DERs connected at the local level can also provide services to the grid and be compensated for it through the distribution-level market.
3. Incorporating local DERs into distribution grid planning for: **a. Resource adequacy (i.e. ensuring long-term supply is available for the customers)** **b. Optimizing grid investment for example via deferral of building new infrastructure or via incentivizing optimal placement of DERs from a grid perspective** ● In the current structure the IESO is the defacto LSE. Unless specified in the new regulatory framework, that responsibility would remain with the IESO. Therefore, the IESO would continue to be responsible for resource adequacy. Incorporation of local DERs into the resource adequacy planning would depend on the coordination and data exchange between the DSO (that has visibility into the local DERs) and the IESO. ● In the scenario where the LDC is the DSO, the LDC would be further enabled to integrate the local DERs into distribution grid planning for optimizing investment.

Roles and Responsibilities Associated With Integration of DERs Under a FINO Structure
1. Developing, owning and maintaining local DERs (i.e. physical asset development, ownership and maintenance) ● A FINO (i.e. the LDC) will own DERs connected at the distribution-level. The delineation between DER ownership and other utility operations will depend on the requirements outlined in the regulatory framework. ● Customers (behind-the-meter) can continue to own DERs.
2. Operating DERs (i.e. providing control signals to the DERs to turn them on/off etc.) for: **a. Participation in the local energy and capacity market** **b. Participation in the local ancillary services market** **c. Providing grid services such as power quality support, voltage support, reactive power support, local backup in case of a power outage, peak load management etc.** ● In a FINO structure, a local energy and capacity market may exist at the distribution level. However, a local ancillary services market does not exist under this structure. ● DERs connected at the distribution-level are leveraged for grid services and participate in the local energy market. ● DERs connected behind-the-meter, may participate in the local market and provide services to the grid, depending on what is requested by the FINO.
3. Incorporating local DERs into distribution grid planning for: **a. Resource adequacy (i.e. ensuring long-term supply is available for the customers)** **b. Optimizing grid investment for example via deferral of building new infrastructure or via incentivizing optimal placement of DERs from a grid perspective** ● In the current structure the IESO is the de facto LSE. Unless specified in the new regulatory framework, that responsibility would remain with the IESO. Therefore, the IESO would continue to be responsible for resource adequacy. Incorporation of local DERs into the resource adequacy planning would depend on the coordination and data exchange between the FINO (that has visibility into the local DERs) and the IESO. ● As the DERs connected at the distribution-level are owned by the FINO, they can be easily incorporated into grid planning for optimizing the investment.

Roles and Responsibilities Associated With Integration of DERs Under a LSE Structure
1. Developing, owning and maintaining local DERs (i.e. physical asset development, ownership and maintenance) ● Ownership of DERs by a LSE entity depends on the regulatory framework. In the scenario where the LDC is the LSE, typically the LSE does not own DERs for commercial objectives and participation in the distribution-level market. ● Customers (behind-the-meter) can continue to own DERs.
2. Operating DERs (i.e. providing control signals to the DERs to turn them on/off etc.) for: **a. Participation in the local energy and capacity market** **b. Participation in the local ancillary services market** **c. Providing grid services such as power quality support, voltage support, reactive power support, local backup in case of a power outage, peak load management etc.** ● If a local market (energy and capacity services) exists, the LSE can leverage local DERs to meet its requirements for serving the load. If the LSE is also a DSO, then the ability to enable DERs may be further enhanced. ● In the scenario where the LDC is the LSE, the LDC can also leverage local DERs to provide services to the grid, and the DERs would be compensated through the local market.
3. Incorporating local DERs into distribution grid planning for: **a. Resource adequacy (i.e. ensuring long-term supply is available for the customers)** **b. Optimizing grid investment for example via deferral of building new infrastructure or via incentivizing optimal placement of DERs from a grid perspective** ● The LSE has the responsibility for resource adequacy planning and would be responsible for that. ● In the scenario, where the LDC is the LSE, the LDC can leverage local DERs into grid planning for optimizing investments.

ETNO also met with both DBRS and TD to better understand the financial implications of these structures. Highlights of DBRS and TD presentations are in Appendix H for reference. Key takeaways from these discussions include:

- Financial institutions often look at LDCs – both the regulated and unregulated arms – as a single entity when evaluating credit rating or determining interest rate.

    - The regulated arm will typically have a higher rating/lower interest rate due to having a predictable return
    - The unregulated arm will typically have a lower rating/higher interest rate as they carry more risk due to the nature of their operation
    - The percentage of activities (regulated vs. unregulated) matters as well. If the activities in the unregulated arm are small relative to the regulated arm, there may not be an impact on the overall interest rate of the combined entities.
    - If the credit rating of the holding company, with both a regulated and unregulated arm, is downgraded due to the activities under the unregulated arm, the customers of the regulated arm may pay more for the cost of capital, and the customers of the unregulated arm will pay less.
        - If the LDCs were to take on the role of a DSO, LSE, CCA or FINO, or if they were to own DERs as part of the unregulated business, they could be at an advantage compared to private sector players.
        - The regulator (OEB) will have to consider this in a future structure.
- Other factors (in addition to regulated vs. unregulated) that are utilized to determine credit rating of the organization include: overall sector rating, rating of the province/jurisdiction in which a utility has operations, and Environmental, Social, Governance (ESG) commitments.

ETNO also noted that in the scenario where a utility takes on the role of a CCA, DSO, FINO or LSE, the extent to which the activities are regulated or unregulated will be relevant to the overall cost of capital, along with the structural and contractual arrangements that underlie the functions. In the scenario where a utility takes on the role of a CCA, DSO, FINO or LSE and owns merchant DER assets, it will be important to consider appropriate separation between the functions so that competitive advantages/disadvantages are not being inadvertently created between utility and the non-utility participants. The relevance and results of these factors would depend critically on the particular structure and set-up of the CCA, DSO, FINO or LSE structure.

<u>Shortlisting The Structural Options To DSOs and LSEs</u>

Following the initial evaluation, LSEs and DSOs were shortlisted for further investigation. ETNO decided not to further investigate CCA and FINO structures for the following reasons:

1. The primary objective of the CCA structure is to achieve environmental and social objectives for the customers. A CCA structure increases choice for customers. It does not directly enable integration of high-volumes of DERs nor stimulates the growth of DERs. It was noted that the CCA structure may have applicability in certain parts of Ontario (e.g., Indigenous communities or rural communities) to increase customer choice and control and should not be disregarded entirely. However, there was broad agreement that implementation of this structure would

not meaningfully improve the opportunity to integrate high volumes of DER's into Ontario's current structure.

2. The FINO structure is not feasible as it is inconsistent with the principles of competition that underpin the design of Ontario's bulk/wholesale electricity structure. There was also consensus that at a high-level, the costs incurred to implement this structure would not be justified based on the anticipated benefits of a FINO structure. FINO would also be a Ontario specific structure, with no precedence in other jurisdictions, making it more complex for stakeholder to navigate Ontario's market.

The group focused the discussion on structures that are best suited to facilitate the integration of high volumes of DERs over the next 10-15 years, while noting that overtime, various aspects of structures such as CCAs, LSEs and DSOs may all co-exist in Ontario.

DSO and LSE Structure Evaluation

The DSO and LSE structures were analyzed in further detail and Appendix H provides the full analysis by each principle. The diagram (Figure 6) below shows the key roles and responsibilities associated with integration of local DERs as well as those associated with a DSO and LSE.

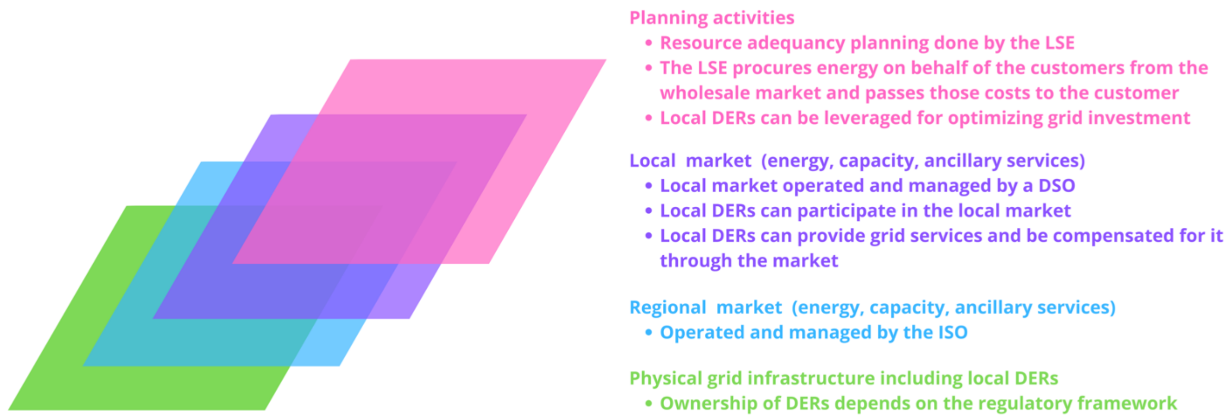


Figure 6. The roles and responsibilities of DSOs and LSEs

As per the above analysis, the DSO structure was identified as the one that directly addresses the challenge of effectively integrating high volumes of DERs at the distribution level through creation of a local market (energy, capacity, ancillary services).

The LSE structure was also identified as a possibility for Ontario, primarily because it is an effective option to procure long-term supply and ensure resource adequacy. It was also noted that to assess the feasibility of the LSE structure for Ontario, following items will need to be considered:

- The IESO is the de facto LSE in Ontario. To shift the responsibility to alternate entities the risk vs. reward will need to be balanced. For example, if the LSEs over/underestimate the resource adequacy requirements they must bear the corresponding financial consequences.
- While LDCs are an obvious candidate to take on the role of the LSE, they are not the only candidate. Other entities such as CCAs, retailers or large customers may also take on the role of LSEs.

Furthermore, ETNO also noted that:

- DSOs and LSEs are not mutually exclusive options. Roles and responsibilities of a LSE may be incrementally added either to the current structure, or to a DSO-based structure.
- If there was a scenario where the LDC took on the role for both a DSO and a LSE, the roles could be complementary. However, it was noted that the LDC is not the only candidate to take on the role of a LSE - and indeed some large/multi-site customers would likely want to take on this role for themselves. Further analysis needs to be conducted to determine entities best-suited to take on the role of LSEs.
    - For example: as LDCs increasingly plan for and partner with DER owners to deliver local attributes (e.g., local capacity), those arrangements could be more effective and more valuable to DER owners if those arrangements could also incorporate services of the DSO (e.g., reliability, power quality, etc.), the LSE (e.g., resource adequacy), or both. There are opportunities for economies of scope in relation to DERs when the LDC is both the LSE and DSO.
- DSOs enable higher-levels of DER integration through creation of a market. Whereas the LSE enables DER integration to meet the resource adequacy requirements at optimal costs.

5. Recommendation

ETNO recommends the implementation of the DSO structure to enable integration of an increased number of DERs in a way that maximizes their value to the ratepayer. ETNO has made this recommendation because:

- A DSO structure will create a local market (energy, capacity, ancillary services) for DERs connected at the distribution level as well as behind the meter. This will enable DER owners and operators to maximize the economic value of DERs.
- A DSO will enable DERs, connected at the distribution level as well as behind the meter, to provide services to the grid and incorporate them into distribution grid planning, to maximize the technical value of DERs.
- A DSO structure will also provide a platform for energy system stakeholders to explore new business models such as aggregating DERs for market participation or grid service, peer-to-peer electricity trading, energy-as-a-service etc.

ETNO recommends that LDCs take on the role of DSOs (as is the case in many jurisdictions), as they are well positioned to manage the DERs connected at the distribution system and behind-the-meter. LDCs are well positioned to take on this role as they already have visibility of local DERs, conduct assessments to determine feasibility of DER connection on specific locations on the grid and implement DER safety standards. Large LDCs that are interested, have the capabilities, and the financial standing can take on this role for their service area. Smaller LDCs may choose to work together in coalitions to jointly take on this responsibility, or they may choose to delegate this responsibility to another LDC that does not serve their service area, or they may choose to delegate this responsibility to the IESO. Analysis during the regulatory framework development process will help determine the best options for LDCs that are either not interested, or do not have the resources to take on the role of the DSO.

ETNO recommends further investigation of the LSE structure. Currently, IESO is the de facto LSE in Ontario. The high-level analysis outlined in this report demonstrated the potential for the LSE structure to leverage local DERs for resource adequacy planning. It was also noted that the LDC could potentially take on the role of both DSO and LSE, while noting that other entities such as retailers, CCAs or customers, could also take on the role of LSE. Follow-up analysis on LSEs will enable decision makers to identify next steps with respect to the LSE structure.

<u>Considerations for Implementation</u>

To design and implement the DSO structure, additional items listed below will need to be considered:

- *Regulatory framework:* appropriate legislative and regulatory frameworks will need to be developed for LDCs to adopt and implement the DSO structure. There are different ways in which a DSO structure can be implemented. Examples include total DSO, independent DSO and hybrid DSO. Exact specifications will need to be determined for the Ontario context.

- *Cost/benefit analysis:* impact (cost, complexity etc.) of shifting existing, and assigning new responsibilities amongst energy sector stakeholders will need to be evaluated and balanced against the benefits over the long-term horizon.
    - *Rate-impact analysis:* the rate-impact of DSO structure will need to be assessed.
- *Enabling DER technology implementation*: to enable safe and effective integration of DER technologies at scale, there will be a need to ensure the electrical, communication, and cybersecurity standards are developed/updated accordingly.
- *Number of entities:* it is expected that 5-10 DSOs will be formed in Ontario. The exact number of DSOs will be determined when the regulatory framework is developed. Parameters for consideration include defining regions of operation, evaluating revenue stability such that the DSOs are not at risk of becoming illiquid (should have broad based minimum capitalization requirements to deal with fluctuation in market price).
- *Market design and rules:* market rules for the bulk (IESO) level as well as the distribution-level will play a significant part in achieving the desired end functionality i.e. creation of a robust DER market. Design decisions will need to be made around procuring and controlling local DERs, coordination between the DSO, ISO and other stakeholders, DERs compensation, net-billing schemes etc.
- *Ownership of DERs:* The question of whether LDCs taking on the role of DSOs should own DERs or not, will need to be addressed as part of the regulatory framework development process. Considerations include:
    - Purpose of DERs - whether they are being used for commercial or grid objectives
    - The location of the DERs - at the distribution level or behind-the-meter
    - Ownership of DERs - the regulated or unregulated arm of the LDC
    - Market participation - local or wholesale market
    - Ensuring a fair and competitive market for both the LDC and non-LDC owned DERs
- *Data sharing and management:* these requirements would need to be developed in the new regulatory framework to ensure the appropriate stakeholders have access to data, while balancing the data privacy requirements.

Additional considerations are outlined in Appendix J.

6. Next Steps

This report will be presented to the CEO of the OEB, the CEO of the IESO, and the Deputy Minister of ENDM for their review and consideration.

ETNO recommends that the industry forums listed below take the blueprint identified in this report and build off of it to continue the evaluation and design of the distribution system structure for Ontario to inform the changes required to the regulatory framework. These forums include:

- IESO’s DER Roadmap and related engagement
- OEB Framework for Energy Innovation (FEI) Working Group
- Bi-annual OEB/IESO engagements to support alignment/coordination on DER integration
- OEB Energy X Change
- IESO Stakeholder Advisory Committee

Proposed next steps include:

1. Evaluate the impact of implementing the DSO structure as it relates to “Affordable” and “Optimized and Efficient” principles. Guiding questions for both principles are listed in Appendix G.
2. Review the variations of DSO and identify design features best suited for implementation in Ontario. This will also include an analysis of roles and responsibilities of various stakeholders under the DSO structure.
3. Further analyze the LSE structure and determine its feasibility for implementation in Ontario as it pertains to resource adequacy. LSE and DSO structures are not mutually exclusive.
4. Further review the CCA structure and determine its feasibility for implementation in Ontario as it relates to rural customers and Indigenous communities. CCA and DSO structures are not mutually exclusive.

Appendix A - ETNO And Working Group Membership

The energy sector in Ontario is undergoing significant change. ETNO's work is driven by a recognition that Distributed Energy Resources (DERs) and new structural structures for organizing the sector are all challenging foundational notions of market boundaries, industry roles and responsibilities. Enhanced data and analytical capabilities, advanced transportation technology, environmental policy and other technological changes outside of the energy sector are also having an increasing impact on the energy system. To ensure that these innovations are integrated into existing energy systems in a way that enhances consumer choice, reliability and cost-effectiveness, new approaches to policy-making, regulation and energy markets will be needed.

ETNO's Membership includes:

- David McFadden, President & CEO, Generation 4 Capital Corporation (ETNO Chair)
- Ron Dizy, Co-Founder & Managing Director, Red Jar Capital (ETNO Vice Chair)
- Alexandre Prieur, Director, Renewable Energy Integration, CanmetENERGY
- Amanda Klein, Executive Vice President, Public and Regulatory Affairs, Toronto Hydro
- Anthony Haines, President & CEO, Toronto Hydro
- Brad Carr, President, Canada, Mattamy Homes
- Brian Hewson, Vice-President, Consumer Protection and Industry Performance, Ontario Energy Board
- Carlyle Coutinho, President & COO, Enwave
- Chris Carradine, Executive Vice President, Business Development, Ecobee
- Chris Ireland, Managing Director, Infrastructure and Natural Resources, Greenfield Investments and Renewables, Ontario Teachers' Pension Plan
- Claudio Canizares, Fellow at the Institute of Electrical and Electronics Engineers, The University of Waterloo
- Cynthia Hansen, Executive Vice President & President, Gas Distribution & Storage, Enbridge Gas Distribution
- David Collie, President & CEO, Electrical Safety Authority
- David Lebeter, Chief Operating Officer, Hydro One Inc.
- Jeff Lehman, Mayor, City of Barrie
- John Avdoulos, President and CEO, Essex Power Corporation
- Katherine Sparkes, Director, Innovation, Research & Development, IESO
- Linda Wainewright, Vice-Chair, Corporate Partners Committee, ETNO
- Mark Fernandes, Chief Information & Technology Officer, Hydro Ottawa Limited
- Matthew Sachs, Chief Operating Officer, Peak Power
- Mike Smith, Director, Distribution and Agency Policy Branch, Strategic Network and Agency Policy Division, Ministry of Energy,Northern Development and Mines
- Neetika Sathe, Vice-President, GRE&T Centre, Alectra Inc
- Nicholas Pender, Vice President of Energy Markets, Ontario Power Generation
- Paul Grod, President & CEO, Rodan Energy Solutions
- Steven Muzzo, Chairman, President & CEO, Ozz Clean Energy, Ozz Electric
- Tyler Hamilton, Director, Cleantech Ecosystem and Capital, MaRS Discovery District
- William Milroy, Vice-President, Engineering & Operations, London Hydro

ETNO's Working Group for Sprint 2 includes:

- April Barrie, Director, Regulatory Affairs, Hydro Ottawa
- Ammar Nawaz, VP, Distributed Energy Solutions (DES), Alectra
- Anjali Wadhera, Research Officer, NRCan
- Christina Dimitrov, Senior Manager, Strategic Initiatives, OPG
- Colton Pankhurst, Student, University of Waterloo
- Dervla Murphy, Senior Policy Advisor, MENDM
- Geri Yin, Head, Grid Innovation, GRE&T Centre, Alectra
- Ian McCarter, Senior Manager, Business Development, MaRS Discovery District
- Imran Noorani, Chief Strategy Operator & Late Founder, Peak Power
- Justin Ngomsi, Senior Manager, Operating Engineering & Performance Reporting, Hydro One
- Kaleb Ruch, Manager of Government Relations, Toronto Hydro
- Mario Chiarelli, Chief Technology Officer, Cricket Energy
- Melanie Torrie, Hydro One
- Mima Mimic, Senior Advisor, Regulatory Affairs
- Moeen Salibe, Senior Director, Smart Operations & Optimization, Enwave
- Mohammed Etleb, Investment Associate, Ontario Teachers' Pension Plan
- Nazanin Hashemi Attar, Research Scientist, NRCan
- Rachele Levin, Innovation Sandbox Lead, OEB
- Ryan Zade, Team Lead, Ministry of Energy, Northern Development and Mines
- Shawn Peterson, Account Manager, Ecobee

Appendix B – Energy System Stakeholder Definitions

Stakeholder	Definition
Transmission System Owner and Operator	Operator: An entity responsible for the safe and reliable operation of the transmission system (the assets that transmit power between bulk resources and the distribution system). Coordinates outages/de-rates with and receives control signals from the ISO balancing authority. Maintains some coordination with LDC operations. Owner: An entity that owns and maintains the transmission system in a defined franchise service area.
Distribution System Owner (DO) or Distribution Networks Operator (DNO)	An entity that owns an electric distribution grid (physical distribution assets that move power between the transmitter, distribution-level DER and customer load) in a defined franchise service area. Coordinates outages/de-rates with and receives control signals from LDC operations.
DER Owner and Operator	An entity that owns and is responsible for the operation of electricity-producing resources or controllable loads that are connected to a local distribution system or connected to a host facility within the local distribution system.
End Customer	An entity who receives power from either the distribution system or customer DERs. There are different approaches to defining customer types (e.g. by size, geographical region, DER type). Proposed definitions for customer types: • Residential customers: demand under 50kW • Small Business customers: demand under 50kW (also known as General Service under 50kW) • Commercial & Industrial customers: demand over 50kW (also known as General Service over 50kW)
Aggregator (of loads or DERs)	An entity responsible for grouping individual loads or DERs together to provide wholesale market or distribution system services. DER Aggregator: develops and operates aggregations of DERs for wholesale market participation by aggregating multiple small DER to meet the required size threshold or to provide distribution services. Disaggregates wholesale market schedules and dispatch instructions from the ISO and/or the LDC to individual DERs. May contract directly with the ISO to provide energy and capacity. Load Aggregator (Community Choice Aggregator): Formally defined in the state of California and a small number of other U.S. states that allow community-level buying consortiums to purchase energy on their behalf. Unlike LSEs, however, CCAs typically don't have an obligation to secure an adequate amount of capacity or maintain the distribution network.
Retailer	Private entity that procures electricity services in the wholesale market or through bi-lateral contracts with resources and resells these services to end-use retail consumers.

Stakeholder	Definition
Independent System Operator (ISO)	An entity established to coordinate regional transmission in a non-discriminatory manner and ensure the safety and reliability of the electric system. Operates the wholesale electricity market and bulk electricity system independently of any market participant or interest in the wholesale market.

Appendix C - Ontario's Historical Context

Historical Context

For most of the 20th century, the publicly owned (Crown corporation) Ontario Hydro was the major force in Ontario's electricity sector. Ontario Hydro dominated all aspects of the province's electricity sector, serving as the primary generator and transmitter of power. It also had authority to regulate and set the rates at both the wholesale and retail levels. The OEB was created in 1960 with a limited mandate to set rates for the sale, distribution and storage of natural gas.
In the late 1990s, the government decided to restructure the electricity sector. These regulatory reforms included the breakup of Ontario Hydro, the creation of a wholesale electricity market and giving the OEB responsibility for regulating part of the sector.

Timeline
1950s: Ontario has a single public electricity utility, the Electric Power Commission of Ontario, made up of small local systems. Coal-fired power stations are built as population and industry grow, and electricity needs outpace existing hydro-electricity capacity.

1960: The Ontario Energy Board is founded as an impartial public agency responsible for regulating local distribution companies and for ensuring that the distribution companies fulfill their obligations to connect and serve customers. The OEB currently approves the rates that utilities can charge their customers, creates policy, and approves construction.

1970: All of Ontario's power systems are combined into one synchronized grid, with the exception of remote communities. Natural gas prices rise due to the crisis in the Middle East and nuclear generation comes to the forefront.

1973: The Ministry of Energy is created with the mandate to manage the province's electricity system.

1971: Expansion of electricity generation: The Pickering Nuclear Generating Station comes into service.

1974: The existing Hydro Electric Power Commission of Ontario is recreated as Ontario Hydro, a crown corporation governed by a board of directors. The corporation is not intended to generate profits or pay taxes, but to provide energy at cost.

1989: Ontario Hydro initiates a 25-year demand-supply planning exercise.

1977 - 1990: The Bruce Nuclear Generating Station and later, the Darlington Nuclear Generating Station come into service. The building of these nuclear plants is costly and results in a debt of over $38.1 billion, causing electricity rates to increase.

1992: Ontario Hydro faces a downturn in the economy and falling demand, but the demand-supply plan is not implemented. Consumer rates rise by 40%.

1993: The Ontario government freezes energy prices, and they remain so for nearly a decade.

1995 - 1996: The Macdonald Committee is created to advise on electricity competition and provide recommendations on the restructuring of Ontario's electricity industry.

October 1998: The Energy Competition Act authorizes the restructuring of Ontario Hydro and the eventual opening of wholesale and retail electricity markets in the province.

April 1, 1999: Due to the Energy Competition Act, Ontario Hydro is restructured into 5 separate companies:

Ontario Power Generation (OPG) – A commercial company that generates electricity and competes with other smaller generating companies in the Ontario marketplace. Examples of other generating companies in the province include: Bruce Power, Algonquin Power, Hamilton Renewable Power Inc., Portage Power (formerly Energy Ottawa), Sky Generation, and Brookfield Renewable Power.

Ontario Hydro Services Company (later to become Hydro One) - A commercial company that owns and maintains transmission and distribution lines to move electricity across the province. Examples of other smaller distribution companies include Toronto Hydro Electric System, Elexicon (previously Veridian), and Northern Ontario Wires Inc.

Independent Market Operator (later to become the Independent Electricity System Operator) - A crown corporation responsible for directing the flow of electricity across the network owned by Ontario Hydro Services Company (Hydro One) and other transmission companies. It also manages the competitive wholesale electricity market and administers an integrated North American electricity network.

Electrical Safety Authority - A private non-profit corporation having administrative authority mandated by the Government of Ontario to enhance and promote public electrical safety, ensure compliance with regulations, promote awareness, and educate.

Ontario Electricity Financial Corporation – A crown agency charged with managing the $38.1 billion in total debt and other liabilities inherited from the former Ontario Hydro. A portion of the $38.1 billion is supported by the value of the assets of Ontario Hydro successor companies, leaving $19.4 billion in stranded debt. This $19.4 billion is to be paid down by Ontario consumers through a Debt Retirement Charge on their monthly bills.

May 1, 2000: Ontario Hydro Services Company is re-launched as Hydro One, a corporate holding company with five subsidiaries: Hydro One Networks Inc., Hydro One Remote Communities Inc., Hydro One Markets Inc., Hydro One Telecom Inc., and Ontario Hydro Energy Inc.

May 1, 2002: Ontario opens its electricity market so that private companies can compete, allowing customers to choose between continuing to buy electricity from their electricity distributor or from an independent electricity retailer licensed by the Ontario Energy Board.

2002: unstable and high wholesale prices caused political pressure to freeze default supply rates. This action took place at a time where the newly created market was already experiencing difficulty with attracting necessary project development and new supply investment. The compressed supply led to reduced retail competition and ultimately the market was "closed." Private investment declined and generation development was delayed.

2003: The transmission grid is old, fragile, and composed of aging generation plants and coal stations causing air pollution. This poor infrastructure results in a blackout, which rolls through eastern Ontario in the summer. The government promises to strengthen the system.

2004: Electricity Restructuring Act is passed, aiming to reinvigorate the province's electricity sector in order to encourage new electricity supply, promote energy conservation, and provide stable prices at a level reflecting the true cost of electricity.

2004: In order to revive investment, the Ontario Power Authority ("OPA") was established through the Electricity Restructuring Act (Bill 100). It acted as a "single buyer" (i.e. LSE) to procure generation resources. OPA was an independent non-profit corporation, is established and charged with assessing the long-term adequacy of electricity resources, forecasting and managing demand, achieving targets set by the government for conservation and renewable energy, and preparing an integrated electricity system plan. Included in its mandate is facilitating the removal of coal in the province's energy supply mix.

2005: The Independent Marketing Operator (IMO) is renamed the Independent Electricity System Operator (IESO), and is an independent, not-for-profit entity, directed by a board of directors appointed by the government of Ontario. Its fees and licenses are set by the Ontario Energy Board.

2005: Ontario stimulates private investment in new electricity generation by offering new generators long-term fixed-price contracts at above-market rates.

2005: government mandated the OEB to set residential and small business electricity rates under the Regulated Price Plan.

2006: Government of Ontario imposes a charge (or rebate) on all electricity consumers called the Global Adjustment Charge (also known as the Provincial Benefit) to cover the difference between the market rate for electricity and what is paid to private electricity generators based on the fixed contracts. Customers buying electricity under the Regulated Price Plan, pay an estimate of the Global Adjustment, which is already built into the rate for electricity set by the Ontario Energy Board. Customers buying from an electricity retailer see the Global Adjustment displayed as a separate line item on their bill, based on their consumption.

Global adjustment charge subsidies between 2006 and 2011 inclusive:
45% nuclear generation
34% natural gas generation
8% energy efficiency programs & hydro generation 6.7% coal power plants
6% renewable energy generation (primarily wind and solar)

Global adjustment charge subsidies in July 2014*:
63% nuclear & natural gas generation
29% renewable energy generation (hydro, solar, biomass & landfill, wind)
6.7% conservation efforts
0.06% Industrial Electricity Incentive Program

2006: Renewable Energy Standard Offer Program is established, offering a number of fixed 20-year feed-in tariffs for hydro, wind, solar (PV) and biomass projects. This program would later be expanded under the Green Energy Act of 2009 to include higher rates and various changes to the connection process to simplify the development process.

2007: Ontario introduces its Climate Change Action Plan, which includes greenhouse gas emissions reduction targets. It is reported in 2014 that Ontario's greenhouse gas emissions have been reduced by 5.9% since 1990

2009: The Green Energy Act is passed, aiming to attract new investment, create green jobs, and provide clean renewable power to Ontario. The renewable energy Feed-in Tariff (FIT) Program is part of this legislation.

2010: The five-year Ontario Clean Energy Benefit is created, providing customers a 10% discount off the total cost of electricity charges on their bill. It is intended to help with the increased costs of updating infrastructure and implementing clean power sources.

2011: The Government updates its Supply Mix Directive to the Ontario Power Authority to include conservation targets, refurbishment of nuclear plants, continued phase-out of coal-powered generation, increased capacity of renewables, etc.

2012: Electricity rates for consumers continue to rise due to system upgrades, generation plant refurbishments, investments in transmission and distribution costs, conservation and renewable energy efforts, and the replacement of coal-fired power.

2012: Industrial Electricity Incentive Program is created to use up surplus energy produced in Ontario by encouraging businesses to ramp up their industrial production in exchange for discounted electricity rates.

2013: Ontario's Long-Term Energy Plan is released, detailing five principles: cost effectiveness, reliability, clean energy, community engagement, and emphasis on conservation and demand management.

2013: Import and export of surplus Ontario electricity is a hot issue, with the province exporting a large amount of its energy to neighboring provinces and states at rates that do not include the Global Adjustment charged to Ontarians.

2014: Over 1,900 MW of new wind, solar, biofuel and hydro power is being fed into the province's transmission and distribution systems.

January 1, 2015: The Ontario Power Authority (OPA) merges with the Independent Electricity System Operator (IESO) to create a new organization combining both mandates, under the IESO name. IESO becomes Ontario's de facto LSE. At the time of its inception, the OPA was never intended to become the province's permanent LSE. It was a "transitional" organization with the objective to migrate the hybrid system toward a competitive structure that ensured adequate new investment in infrastructure while transferring investment risk away from customers in a controlled way. While the original intent behind the OPA was to shepherd the hybrid market to a competitive system, this has not come to fruition with Ontario embracing a more centralized generation planning and procurement system. With projections suggesting significant growth in DERs connected to Ontario's distribution systems and utilities already evolving to strengthen planning and procurement capabilities in the face of that, it is an optimal time to re-examine the role LSEs in Ontario.

Spring 2015: The Debt Retirement Charge (DRC) is still being paid by customers at a rate of 0.7 cents per kilowatt-hour of electricity consumed (about $70 per year for most consumers). The government announces plans to remove the DRC cost from residential electricity bills after December 31, 2015. The stranded debt is still over $2.5 billion.

Fall 2015: Electricity prices are raised by the Ontario Energy Board. Reasons cited for the rate hike: increased costs from Ontario Power Generation (OPG) nuclear and hydro- electric power plants, expenses related to renewable energy generation systems, and cost-recoveries sought by the OPG.

2021: many of the actions and initiatives underway at the IESO currently, including Market Renewal, Capacity Auctions and T-D DER Coordination, are likely to be vital to integrating DERs.

Appendix D - Distribution Grid Challenges Impacting DER Integration

#	Distribution Grid Challenge	How does this challenge impact integration of DERs	Is this a current challenge or a challenge we anticipate Ontario will encounter in the future?
1	**Operational challenges and risks** utilities are facing with increasing penetration of DERs on the distribution grid – i.e. capacity constraints, power quality, voltages fluctuation, reliability, resilience, lack of visibility, controlling bidirectional power flow, etc.	Inability to 1) accommodate DERs coming onto the grid beyond technical thresholds; 2) carry out DERs interconnection efficiently, safely and reliably; 3) maintain same safety and reliability standards; 4) harness the values of DERs at grid edge as non-wire alternatives, etc., discouraging DERs development and integration to the Grid	Not a current challenge but an anticipated challenge as Ontario enters high DERs adoption stage in the near future.
2	**Grid Investment challenges –** grid modernization/make-ready investments are fundamental and imperative for distribution grid to enable DER integration and enhance grid interoperability, while maintaining reliability and resilience standards; current regulatory regimes may not recognize "enabling" grid investments for the future.	This financial challenge of not being able to secure funding impedes utilities' ability to invest into the grid, to make the grid ready to take on and accommodate growing numbers of DERs, and to effectively address the operational challenges and risks imposed by DERs.	A current challenge.
3	**Lack of consensus amongst industry stakeholders on DER technical standards** for DER integration to utilities operating systems – OMS, GIS, SCADA, ADMS; Utilities DERMS technology is not mature enough – it is largely still at piloting stage	Hinder utilities' ability to scale in terms of managing, controlling, optimizing and dispatching DERs to meet grid services requirements at local, regional and system level.	A current challenge and will continue if not being effectively addressed.
4	**Utilities ownership of DER.** Utilities may own or contract for DER usage to provide system benefits (i.e., congestion, peak system	Not able to realize the use of DERs as a utility asset, where the value is based on location within the distribution franchise and the potential replacement or deferral	A current challenge and will continue if not being effectively addressed.

#	Distribution Grid Challenge	How does this challenge impact integration of DERs	Is this a current challenge or a challenge we anticipate Ontario will encounter in the future?
	demand relief, power quality, local reliability, etc.) irrespective of whether the DER asset is FTM or BTM. An examination of utility ownership of DER assets and utility remuneration for enabling DER infrastructure is crucial. Necessity to share information between LDC and a contracted third party (such as an affiliate) may contradict Affiliate Relationships Code (ARC).	of a conventional utility asset. Review of the Affiliate Relationships Code (ARC) may be necessary to allow for information sharing between LDC and affiliates.	
5	**Remuneration and Cost Recovery Challenges** remain to fully account for the vital role of utilities in facilitating the deployment of DERs to meet customer needs and expectations. A well-developed regulatory framework should establish, or permit LDCs to establish, evaluation criteria for DERs which weigh risks and opportunities in relation to customers, the local distribution grid, and the sector at large. The regulatory framework must recognize LDCs' integral role in helping customers realize opportunities and manage risks; and the economic consequences of these changes, including utility remuneration, rate design, and cost allocation.	Discourage and disincentivize utilities to integrate DERs into the distribution system planning process, as non-wires alternatives to traditional investments. Prevent utilities from investing in DERs as the new cost-effective, clean, and decarbonized grid. Prevent utilities from harnessing the values of DERs at the grid edge that are capable of providing grid services and capital costs deferral.	A current challenge and will continue if not being effectively addressed.

#	Distribution Grid Challenge	How does this challenge impact integration of DERs	Is this a current challenge or a challenge we anticipate Ontario will encounter in the future?
	A regulatory framework would enable costs (including stranded assets) associated with a DER that provides a system benefit to be captured in rate base (if owned) or capitalized (if contracted); while costs associated with a DER that benefit a specific customer or customer class would be apportioned accordingly.		
6	**Electricity Market structures** that respond to the need for and enable the transition to procurement of capacity, energy and ancillary products through market actions. This will enable DERs to provide multiple benefits with revenue stacking opportunities and decrease the use of system wide "single purpose assets" which are inefficient and costly. The DER integration and innovation adoption need to be implemented at both transmission level and distribution level. The market needs to be accessible and offer participation opportunities for traditional and non-traditional players.	DERs under a certain threshold or certain type of DERs are currently not able to participate in the wholesale market. The IESO York Region NWA pilot – North America's first local electricity market unlocks DERs values to local, regional and bulk systems; regulatory hurdles need to be removed to scale the pilot. Ultimately, a DER should be able to revenue stack and not be dependent on a single major revenue stream. The growth of flexibility markets and Ofgem's enabling regulatory framework provides valuable learnings for the Ontario market.	A current challenge and will continue if not being effectively addressed.
7	**Roles and responsibilities of different stakeholders** in the energy ecosystem including regulators (rates, financial, standards), policy makers, market operators,	Unclarity of roles and responsibilities prevents effective policy/regulation making and appropriate incentives for DERs investment and integration; it potentially leads to market	A current challenge and will continue if not being effectively addressed.

#	Distribution Grid Challenge	How does this challenge impact integration of DERs	Is this a current challenge or a challenge we anticipate Ontario will encounter in the future?
	utilities, customers and non-traditional players need to be clarified. E.g. What is the role of different stakeholders in developing and adopting innovation? Who needs to drive/lead adoption of solutions such as electrification of transportation, heating etc.? What is the role of the customer as the grid evolves and how is the customer input incorporated into the decision-making processes?	confusion or inadequate, inefficient market mechanism/constructs hindering the full realization of DERs values to the grid, customers, society and economy.	
8	**New business models** need to be tested and adopted such that benefits, and costs are shared in an equitable way for DER integration, innovation adoption. E.g. integration of DERs at a local distribution level may pose technical challenges. Who bears the cost to integrate these DERs and how the rewards are allocated isn't clear, leading to barriers in adoption and scaling of such solutions?	Utilities play a central role in transforming and modernizing the grid, towards a clean and decarbonized economy. The remuneration and cost recovery for utilities to integrate DERs, if not being addressed appropriately, timely and effectively, will become one of the major barriers preventing DERs proliferation and integration.	A current challenge and will continue if not being effectively addressed.

Appendix E - Guiding Questions to Evaluate Distribution System Structures

ETNO evaluated each structure against the principles outlined in ETNO's July 2021 report "Principles Guiding the Transformation of Energy System in Ontario". The guiding questions indicated in this report were adopted for the evaluation of the structures outlined in this Appendix for reference.

Principle: Affordable (Customer)
A. How does this structure impact customer rates, bills and ability to pay for all customers? B. How does this structure provide customers with the best value for their money? C. What are the costs (e.g. financing, payments, support) and benefits associated with this structure? How are they impacting different stakeholders (customers, utilities, etc.)? Who is responsible for the costs?
Customer Focused (Customer)
A. What outcomes does this structure deliver to customers? B. How does this structure balance and respond to different customer needs, now and in the future? C. How are the trade-offs between customer value and utility returns balanced?
Accessible and Transparent (Energy Network)
A. How does this structure provide equitable access to the energy network, markets, and/or funding (innovation or other) opportunities? B. How does this structure enable transparency and interoperability as it relates to data collection, access and use? C. How does this structure enable and enhance equitable access to energy for all customer types?
Optimized and Efficient (Energy Network)
A. How does this structure impact system costs and revenues in the short- and long-term? How does the structure impact future decisions (e.g. is the current structure locking us into future long-term decisions that will impact cost and benefits)? B. How does this structure balance trade-offs between short- and long-term costs/benefits as they relate to enhancing grid efficiency optimization, and adequacy? C. How does this structure optimize the use of existing and new assets (traditional and non-traditional) immediately and over the asset life cycle?
Reliable and Resilient (Energy Network)
A. How does this structure affect reliability, resiliency and safety across the entire system? B. How does this structure help improve cybersecurity across the entire system? C. How does this structure consider contingencies for disruptive events to the energy network (like extreme weather, pandemics, or black swan events)?
Competitive (Governance)

Principle: Affordable (Customer)
A. How does this structure promote or inhibit open, transparent, fair, and predictable competitive opportunities? B. How does this structure create and promote an enabling environment for investment? C. How does this structure promote Ontario's competitive advantage in a global context? D. How does this structure enable implementation of "technology agnostic" solutions? E. Which structure will best promote consumer welfare (lower prices, better service, and reduced carbon emissions) given changes in technology?
Collaborative and Innovative (Governance)
A. How does this structure incentivize collaboration between different stakeholders? What structures will enable this collaboration? Is there alignment between innovation efforts, to ensure a common, coordinated, and efficient allocation of research & development and commercialization efforts without duplicating those efforts? B. How does this structure encourage open innovation (in hardware, software, systems, processes, services, standards, pricing, etc.)? C. What is the value proposition of the proposed innovation for stakeholders across the value chain? Is the value proposition well understood? D. Does this structure enable/consider a pathway to scale beyond proof-of-concept (e.g. piloting)? What structures will enable implementation of the pathway to scale solutions? E. Does this structure account for all aspects, and not just the bulk component of the system?
Regulatory Evolution (Governance)
A. How does this structure respond to changing needs and demands from stakeholders (customers, energy network service providers including traditional and non-traditional players) and the market? Is this regulatory process transparent and participatory? B. How is this structure able to withstand changing political landscapes? C. How does this structure align with public policy commitments in order to close the gap between policy and regulations? Have the appropriate regulatory frameworks been considered for implementing this choice? D. How does this structure promote policy and regulatory predictability to enable longer-term decision making?
Just, Equitable, Diverse and Inclusive (Society)
A. How does this structure promote equitable access, and opportunity (e.g. for those participating in the market)? B. How does this structure address challenges and systemic barriers, and enable participation from underprivileged communities? C. How does this structure enable representation from diverse stakeholders? D. How does this structure uphold the justice and equity goals set out in public policy (including with regards to the Indigenous community)?
Decarbonize (Society)
A. How does this structure incentivize or help achieve reduction of carbon emissions? B. How does this structure align with broader climate targets (community, provincial, federal, global) around net zero emissions? C. How does this structure balance short-term and long-term (including intergenerational) costs

Principle: Affordable (Customer)
associated with climate change? Does this structure consider the cost and opportunities of the energy network as a whole (i.e. the net benefit for the net cost in the network)?

Appendix F – Initial Assessment of The Distribution System Structure Options

General assumptions used for the purpose of the analysis

- There will be multiple entities that will emerge in Ontario regardless of the structure that is chosen e.g. multiple DSOs, FINOs, CCAs, and LSEs
- LDCs are likely to take on the roles associated with new structures

Ontario's Current Structure

Pros	Considerations
• Affordable: A single large market supports completion and economic efficiency when compared to fragmented market structures. • Affordable: Continuing with the same structure will ensure no additional costs are incurred for the customers (there are differing opinions around this aspect). • Reliable: A reliable and resilient system. • DER enablement: Allows DERs (larger sized) to access and participate in the market. • Optimized: Familiar to all industry stakeholders who understand and participate in the current structure. • Customer Focused: Could enhance utilities ability to work with municipalities / customers to achieve their decarburization goals.	• DER enablement: Does not evolve and account for increased penetration of DERs and the services they can provide. • DER enablement: Does not consider whether other entities should have responsibility for certain DSO functions – particularly if regulated DER markets are expected to form over the longer term. • Market participation: Leaves lots of DER capabilities out of the market, which means growing demand will need to be fulfilled with new supply and the attenuate additional costs (different opinion on this aspect). • Market participation: Current system is competitive, but in a limited way (e.g. there is only one purchaser on behalf of the province and there is no direct financial incentive for the buyer to drive forecast accuracy, although other factors - such as public good, regulatory and government oversight are at play). Current wholesale market rules prevent smaller sized DERs (<1MW) from participating in the market (although work is underway to expand DER participation models). Current structure (long-term contracts) and presence of a large government-owned generator impact attractiveness of Ontario from an investor perspective

Community Choice Aggregator (CCA)

Pros	Considerations
• Encourages customer investment in the types of electricity resources they want and reduces their dependence on utility-owned generation. • JEDI: CCAs can be beneficial for remote and Indigenous communities which have been underserved due to physical and cost constraints plus a focus on urban growth. CCAs can give these communities a stronger say.	• Competition: Does not stimulate DER growth as that will depend on market rules. Customers can demand DERs, but no guarantee that the demand will be matched (the same is true of LSEs). ○ Does not enable distribution services, which would be needed to create new value streams for DERs. • Affordable: Does not account for the potential of stranded assets and burdening customers with associated costs of those assets. • Regulatory Evolution: Need to consider if the distribution system owner and operator becomes the backstop if CCAs are unable to manage the load. • Optimized and Effective: Added constraint to grid operation makes it more difficult to optimize the system. • Regulatory Evolution: CCA's buying power within a certain part of the distribution system may also have to be regulated to ensure fair market access for all DER owners in that local area

Distributed System Operator (DSO)

Pros	Considerations
• Competitive: Maximizes competition and open access to markets. • Seemingly the most practical option as it is an expansion of our current structure and allows for capital optimization at a distribution level. • Enables DERs at a distribution level and behind the meter. • Transparency: More transparent and accessible than the current structure (i.e. government would be able to issue directives to utilities as DSOs). • Markets available for additional grid support resources. • There is belief among some stakeholders that this structure will maximize new investment and enable more innovation while allowing LDCs to compete through their unregulated	• Regulatory Evolution: Requires a lot of oversight and regulation. • Risk of different pricing dependent on the region. • Some stakeholders have expressed concern that this structure could negate the ability of Ontario LDCs to realize new sources of revenue and could discourage distribution-level innovation. • Affordable: The cost of operating small markets may outweigh the economic benefits of this approach.

Pros	Considerations
affiliates.	

Fully-Integrated Network Operator (FINO)

Pros	Considerations
• Optimized and Effective: Efficiencies in scope with the FINO taking on multiple functions compared to the status quo with the single provincial market. • Ability to leverage DERs into local power systems makes for a more flexible and sustainable grid • Regulatory Evolution: Centralized structure is able to optimize with all responsibilities under one entity. • Affordable: Costs of equipment needs to be considered as well, but in the long term, this might be better. It also depends on what geographical area FINO supports. There could be limitations for large geographical areas.	• Affordable: Centralized structure could help support affordability, but consolidation would likely counteract those savings. • Customer Focused: Depending on how market rules are set up, it could result in driving the focus away from the customer. • Decarbonization: Similarly, depending on the design of FINO decarbonization may or may not be a focus. • Accessible and Transparent: Energy and Capacity market operations may not be very transparent if they happen inside FINO. • Competition: May hinder competition and reduce fair and open access to local markets for non-regulated third parties. • Competition: Should there be a lack of interoperability standards, deliberate or accidental creation of artificial monopolies could surface.

Load Serving Entity (LSE)

Pros	Considerations
• Could stimulate the growth of DER markets given their interest in meeting their capacity obligations through the most efficient means possible. • Energy and capacity market will also enable optimal and efficient use of DER assets • Energy and capacity market can attract capital investments • Creates more access and transparency compared to the current structure • Will enable improved planning at a distribution level for integrating DERs	• Additional costs to create a new entity, with some overlap with the role & responsibilities of ISO that can lead to inefficiencies. The extent of these costs will depend on the entity taking on the role of the LSE (i.e. LDC, CCA, retailer or a large customer) • If the responsibility of the LSE were shifted from IESO to alternate entities, then the timing of this would need to be considered to ensure minimal costs for the contracts currently under IESO. • The ability of the LSE to provide services to the grid would depend on the entity taking on the role of the LSE and the corresponding regulatory framework as well as market design. • The LSE structure is a significant departure from the current utility business model, imposing potential risks from operation, financing and grid/load balancing perspectives. Increase in accountability and risk is looked at negatively by credit rating agencies (in the scenario that

Pros	Considerations
	a utility assumes the role of a LSE). However, it should also be noted that Ontario is the only jurisdiction identified to have the ISO as the defacto LSE based on the jurisdiction scan conducted by ETNO (outlined in Appendix J)

Appendix G - Financing Considerations

DBRS

- Context - the different structure options will have to be financed and therefore, we want to understand what considerations credit rating agencies take into account.
- Utilities finance their operations - regulated and non-regulated - through different mechanisms including debt. The debt is raised through banks, pension funds etc. The interest rate at which the utilities are able to borrow depends on the credit rating.
- DBRS is a credit rating agency and rates 50 or so regulated utilities in addition to organizations from other sectors.
- The time period which the utilities take into account for analysis is 4-5 years. One good or bad year doesn't warrant a change in ratings unless there is an overlying trend.
- There are different methodologies that are applied to organizations to evaluate their credit rating. A key factor is whether the functions of the utility are regulated or unregulated. Other factors include the overall sector rating as well as rating of the province/jurisdiction in which a utility has operations. ESG is also a factor. In the past, extreme weather events have been dealt with individually, however, in the future, as they become more regular, they may need to be considered as part of the core evaluation and may have an impact on the rating.
- Utilities borrow money at a holding co level. A holding co that has both a regulated and an unregulated arm is evaluated independently. Typically, a regulated arm will have a higher rating due to having a predictable rate. Un-regulated arms will typically have a lower rating as they carry more risk due to the nature of their operation. In such a case, for example Hydro Ottawa, the overall holding co rating may be lowered, if the utility engages in unregulated activities. The % of these activities (reg. vs. unreg) matters as well. Key implication is that the regulated customers are then paying a bit more for the cost of capital then they would have otherwise, and the unregulated are paying a bit less. This is something that the OEB (regulator) will have to consider going forward.

TD

- Regulated utilities remain an attractive vertical for Canadian banks and the expansion of these utilities into non-regulated businesses will offer compelling lending opportunities
- TD is a leading provider of capital to Ontario's LDC sector through its Corporate and Commercial Bank segments, providing syndicated or bilateral loans to 13 Ontario LDCs
- While increased exposure to non-regulated businesses may impact the internal ratings of utility borrowers with their lenders, TD expects these entities to remain highly bankable.
    - Bank's investment strategy is very much dependent on the magnitude of change when looking at non-regulated energy businesses.
- As shareholders of regulated utilities consider diversifying their asset mix into nonregulated businesses, different capital structure options are available:
    - Debt Ring-Fencing for Regulated Assets (Opco approach)
        - Particularly effective strategy for shareholders of regulated utility assets domiciled in multiple jurisdictions and with multiple regulators
        - Ring-fenced approach ensures a clearly defined capital structure and debt recovery model for these individual utility investments
    - Holdco Financing Structures
        - Holdco financing structures are a bankable and cost-effective alternative for shareholders of regulated utilities to lever the residual equity interests in their underlying investments
            - Banks are typically unnatural providers of Holdco debt financing but have broadly accepted this structure for regulated utilities given the punitive consequences to equity returns if Opco debt incurrence for a regulated utility materially exceeds its deemed capital structure
        - Holdco debt can typically be made available for general corporate purposes including funding of non-regulated business investments and / or acquisitions
        - Excessive Holdco debt incurrence can adversely impact the credit ratings of regulated utility subsidiaries
    - Non-Recourse Financing
        - Depending on the nature of any non-regulated business investments, shareholders of regulated utilities can source debt capitalization for these investments on a non-recourse basis
        - Non-regulated businesses with a contractual offtake arrangement underpinning the revenue models for these investments are ideally-suited for non-recourse financing (distributed generation with PPA's in place would fall into this category)
        - Non-recourse financing requires substantially more due diligence from lenders than direct or Holdco lending to regulated utilities and

a cost-benefit analysis should be undertaken before embarking on this type of structure

- Fortis is a good example of an Opco debt capitalization strategy at the regulated subsidiary companies with a complementary Holdco financing structure at the parent
- Emera employs an Opco debt capitalization strategy at its regulated subsidiary companies, non-recourse financing for select assets and a Holdco financing at Emera
- AltaGas employs an Opco debt capitalization strategy at its regulated subsidiaries and a complementary Holdco financing to debt capitalize its substantial non-regulated holdings

Appendix H – DSO and LSE Evaluation

Principle: Customer Focused

Distribution Structure	Pros	Cons
LSEs	• Sensitive to customer needs within a local region, optimizing for best value (price and choices) for customers within the local region.	• Potential for duplication and additional costs attributable to the ratepayer as ISO would have long-term and capacity planning obligations, but the LSE might also have this function embedded at the local level.
DSOs	• Optimizes the use of DERs, creating new value streams, thus making them more affordable.	• N/A
Shared	• N/A	• Creation of a new structure will have costs that will need to be balanced against the overall benefits. Who bears the cost of implementation will need to be determined? • Coordination and management of an increased number of entities (DSOs/LSEs) will be more costly compared to the current structure. • In the scenario where distribution system owner and operators (i.e. LDCs) are taking on increased accountability, it may negatively impact the credit rating of the utility. How these costs are covered will need to be considered.

Principle: Customer Focused

Distribution Structure	Pros	Cons
LSEs	• N/A	• N/A
DSOs	• Increased integration of DERs	• N/A
Shared	• Customer-centric programs and services can be provided under both options.	• N/A

Principle: Accessible and Transparent (Energy Network)

Distribution Structure	Pros	Cons
LSEs	• N/A	• N/A
DSOs	• DSO structure could create a defined responsibility for entities to develop consistent distribution markets. This could ensure the ability for DERs to provide value to the system in a consistent and reliable manner, rather than relying upon individual distribution system owner and opera	• N/A
Shared	• Customer-centric programs and services can be provided under both options.	• N/A

Principle: Optimized and Efficient (Energy Network)

Distribution Structure	Pros	Cons
LSEs	• Could stimulate the growth of DER markets given their interest in meeting their capacity obligations through the most efficient means possible.	• Overlap with the role & responsibilities (energy/capacity auction etc.) of ISO can lead to inefficiency
DSOs	• Leverage DERs and facilitate their usage for both distribution system management, and bulk power market participation. • Beneficial in a high-DER, capital constrained future, where DSOs would be able to incent efficient deployment of DERs to optimize multiple value streams and overall capital investments in the energy sector. This would also allow distribution system owners and operators to optimize their capital deployment by leveraging third party owned DERs.	• N/A
Shared	• Energy and capacity market will enable optimal and efficient use of DER assets. • Definition and allocation of appropriate roles and responsibilities, will enable improved planning at a distribution level for integrating DERs. • DSOs/LSEs could be an efficient and effective vehicle to address system constraints in specific regions and/or administer localized energy markets.	• With multiple entities (DSOs/LSEs), restoration may become less efficient, safe, and difficult to coordinate. It may also create potential risks from operation, financing and grid/load balancing perspectives. •

Principle: Reliable and Resilient (Energy Network)

Distribution Structure	Pros	Cons
LSEs	• N/A	• LSE can't buy from anywhere in the province. It must buy from DERs located in areas that can serve (e.g. is deliverable) to the loads that the LSE is buying for.
DSOs	• Ability to harness the value of DERs, will increase redundancy. It is also a way to provide resource adequacy at a local level.	• N/A
Shared	• There is an opportunity for DERs to support reliability of the system and tapping into their potential could combat issues that arise in the future	• There is a complementary role for DERs to play because they are unable to substitute grid efficiency on a high level • Issues surrounding cybersecurity may pose a potential threat to the system’s resiliency

Principle: Competitive (Governance)

Distribution Structure	Pros	Cons
LSEs	• N/A	• Does not provide a mechanism for DERs at a distribution level to participate in the ancillary services market. • Does not enable distribution services (e.g. providing volt/var support at the local level), which would be needed to create new value streams for DERs. This would apply in the scenario of the LDC is not the LSE.
DSOs	• DSOs open distribution services to third party competition.	• N/A
Shared	• Energy and capacity market can attract capital investments. • •	• A fragmented capacity and energy market is likely to have less liquidity and competition vs. a single provincial market, as multiple markets with different rules present a barrier to participation. • It is important to recognize the law of diminishing returns in this scenario, as more players and competition could lead to a trade-off with regards to efficiency

Principle: Collaborative and Innovation (Governance)

Distribution Structure	Pros	Cons
LSEs	• N/A	• N/A
DSOs	• DSOs open distribution services to third party competition.	• N/A
Shared	• The market will leverage new technologies to deliver new services.	• There will need to be some regulatory evolution with regards to this space, as creating an independent entity means the need for a new licensing system

Principle: Regulatory Evolution (Governance)

Distribution Structure	Pros	Cons
LSEs	• N/A	• Is likely to depend heavily on government direction if there is only one LSE
DSOs	• N/A	• N/A
Shared	• Regulatory evolution will be required with a structure change/evolution.	• Challenges and complexity in designing and enforcing regulations for local power markets.

Principle: Just, Equitable, Diverse and Inclusive (Society)

Distribution Structure	Pros	Cons
LSEs	• N/A	• N/A
DSOs	• N/A	• N/A
Shared	• Structures do not inhibit or enable the attributes associated with this principle	• N/A

Principle: Decarbonization (Society)

Distribution Structure	Pros	Cons
LSEs	• N/A	• LSE structure doesn't specifically incentivize decarbonization. A clear link of long-term planning between the LSEs and the ISO would need to be established in order to make this structure successful in its objectives. This structure would allow for the inclusion of incremental DER resources across the LSE regions in isolation, not in a coordinated fashion and not taking into consideration the energy network as a whole.
DSOs	• Opening distribution services to third party competition allows for incorporation of cleaner energy sources, helping to decarbonize the sector.	• N/A
Shared	• Overall, the integration of more DERs	• N/A

Appendix I - Jurisdiction Scan

A. UK

The UK is developing DSO centered legislation, and concurrently testing DSO pilot projects.

The Regional Transmission Operator (RTO) is not the LSE.

The government has laid out a series of measures that would see distribution network operators (DNOs) increasingly become more like distribution system operators.

Distribution network operators in the U.K. are some of the most advanced in the world in their efforts to become distribution system operators. All six U.K. DNOs operate in some form of local flexibility market. In 2020, U.K. Promoted through U.K. regulator Ofgem, local flexibility markets are the primary tool used by DNOs in the U.K. to manage power flows and the infrastructure connected to their networks. This new platform allows the DNOs to pay distributed energy resources (DER), such as batteries, to relieve stress on specific pieces of network equipment, with the goal of reducing the cost of network operation.

U.K. local flexibility markets all follow standards set out by the industry body, the Energy Networks Association. The markets are all tender platforms and are either operated by a sole DSO in collaboration with a software provider, for example UK Power Networks and Greensync, or a third party such as Piela Flex. In the third-party example, a non-network company builds the platform and brings network operators (flex buyers) and flexible resources (flex sellers) together.

This market-based approach can support goals such as increased renewables integration and higher penetration of electric vehicles. DNOs more than tripled their local flexibility capacity, contracting 3.3GW of flexible capacity, up from 1 GW in 2019. Both network operators and distributed-energy asset developers, owners and operators (i.e., flexibility providers) are becoming more comfortable with these mechanisms, signaling further growth in years ahead. DNOs are expected to regularly use local flexibility markets to manage their networks, and for the local flex concept to spread to other countries too.

Local flexibility markets currently operate independently of other system-level services, such as wholesale energy markets or National Grid's ancillary services. However, as the traded capacities increase, they will start to affect other parts of the power system. For example, activating local flex could change an energy retailer's contracted supply or demand in the wholesale market, which may lead to undue costs for that retailer due to additional balancing payments. Network and power system operators are aware of this risk and are discussing ways to avoid such conflicts or about who should pay for any additional costs.

Figure 4: Local flex capacity contracted by U.K. DNOs

	Customers (millions)	Contracted local flex (MW)
Western Power Distribution	7.9	3,230
UK Power Networks	8.3	788
SSE Networks	4.1	337
SP Energy Networks	3.5	48
Electricity North West	2.4	12
Northern Powergrid	3.9	0

Source: Ofgem, Energy Networks Association. Data as of end of 2020.

Policy makers have an important role to play in supporting DSOs in this transition - not least by enabling and incentivizing flexibility providers to enter and participate in the local markets. The grid-connection process for flexible assets could be streamlined in some countries. Government could also finance pilot local markets similar to the U.K. government's $5-million competition to fund trials of local flexibility exchanges. Other support could take the form of training DSO personnel or incentives to implement digital technologies (such as a dedicated budget in their investment plans). Whether we see more local flexibility markets in operation around the world depends on regulation and policy. The success of those markets or their effectiveness will depend on the number of trades on the platform, so on the market's liquidity. The market design will influence the liquidity.
Transmission system operators (TSOs): TSOs buy flexibility from smaller resources to solve system or transmission-level issues. Services include congestion management and reinforcement deferral, which are localized issues.

Distribution system operators (DSOs): DSOs buy flexibility to manage the power flows on the grid, similarly to how transmission system operators have historically managed the power system. The services include voltage management, congestion management, reinforcement deferral, relief for planned maintenance and solving unplanned faults.

DSOs use the markets to mitigate network constraints or faults, deferring grid investment. The U.K. markets accept all resources, including the aggregation of DER, and have high participation in electric-vehicle charging.

The European Commission's Clean Energy Package

There are concerns whether the network company, which buys the flexibility, should also be the market operator. It raises questions about market independence and fairness. If the network company is both the flexibility buyer and the market operator, then who sets the market rules and how can flex sellers be confident that they will receive a fair value for their services.

There may also be a conflict between the same organization being both the system and network operator. This is an important issue in the U.K., where the energy regulator suggests separating the role of TSO entirely from National Grid, which is also the transmission network operator. The argument is that National Grid may have split incentives. The network operator would favor building more wires, which it will be paid to build and maintain, as opposed to more innovative and asset-light solutions such as local flexibility markets.

B. Australia

Australia is exploring DSO structures through pilot projects.

Australia is the first non-European country we see exploring local flexibility markets. In late 2020, the Australian Energy Market Operator (AEMO) announced Project EDGE (Energy Demand and Generation Exchange). The A$28 million ($22.32 million) trial will run for three years in the state of Victoria. AEMO will partner with AusNet Services, a transmission network operator, and Mondo, which will provide the energy monitoring and management capabilities. The project aims to allow customer-sited DER to bid into the wholesale energy market. Similar to Gopacs, network operators can then access those DERs to relieve local grid congestion.

DR and DERs have limited access / to compete with large scale generation. Wholesale access is restricted, and grid services markets don’t really exist.

Several incentives are being tried:
- Market rules changes to allow DR aggregators to participate in frequency control ancillary service markets.
- VPPs are emerging as a popular way to aggregate storage and open up more revenue streams
- Market operator is conducting a trial of an emergency DR program

- The regulator has introduced legislation to incentivize electricity distribution businesses to use DER as an alternative to traditional network infra investments.

DERS are not visible or controllable by the network or market operators. There is a centralized small scale PV database that allows for better forecasting and planning of load, but there is no database for BTM storage or other DERs. A rule change request is under consideration which would require the market operator to keep a register of DERs.

The Australian Renewable Energy Agency is funding a project by Australian software company GreenSync to develop a platform for a distribution-level marketplace for the provision of various services by distributed energy resources. It is intended to improve market access, visibility and control of distributed energy resources. The rule-maker has set out preliminary steps to facilitate the development of such a marketplace.

Visibility, and regulatory constraints on participation in the energy market restricts consumers from contributing behind-the-meter assets to the larger energy market. The rule-maker has therefore initiated a 'Distribution Market Model' project that aims to enable consumers to maximize the value of their distributed energy assets; and have the choice to participate in the most valuable services in the market. A range of market reviews such as the Reliability Frameworks Review and Frequency Control Frameworks Review shall look at ways to enable distributed resources to participate in the wholesale and FCAS markets.

Licensed distribution companies will be able to buy or rent distribution lines owned by grid utilities and operate them as microgrids. These microgrids can operate in island mode during disasters, keeping electricity flowing even when the rest of the grid is down. Depending on how the new system is designed, which is to be determined starting later this year, new business models on the distribution network could emerge, such as microgrids, efficient operation and maintenance through AI and IoT, and peer-to-peer power trading.

Regulators have approached incentives in varying ways:

- U.K. network regulator Ofgem has implemented several incentive mechanisms that encourage U.K. network utilities to use distributed energy resource services. Ofgem's opex-capex equalization allows distribution network operators (DNOs) to rate base operational expenditures for all types of distributed services. Ofgem also uses RIIO (Revenue= Incentives + Innovation + Outputs), a performance-based framework, to set price controls. The innovation allowance and incentive metrics reward network operators that use distributed energy resources.
- U.S. utilities submit request for proposals (RFPs) for localized-network services, called non-wires alternative projects. Each project will need regulatory approval for different parts of the planning and contracting process.

- U.K. distribution network operators rely on market mechanisms like third party or utility-owned flexibility platforms to procure localized network services. The U.K. approach appears to be more flexible than its U.S. equivalent (Table 4).

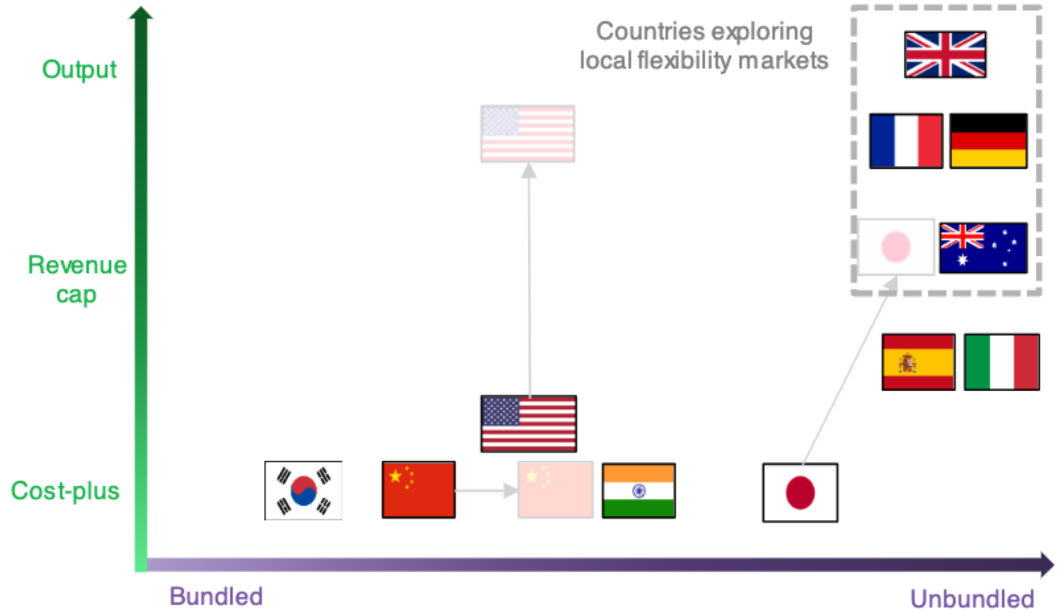
Distributed energy resources already provide system-level services in several markets. In the U.K., demand response and batteries will provide 3GW of capacity for the 2023 to 2024 period, up from 0.2GW for the 2017 to 2018 period (Figure 12). The growth in demand response and battery storage in U.K. capacity markets showcase that DERs are competitive with existing technologies and with each other.

It is harder to compare the costs of distributed energy resources to traditional network infrastructure options for local network services. Regulators, developers and utilities are still negotiating and developing methods to properly evaluate these resources when providing such services. It is both location and business model dependent (Section 2, Table 3). There are some examples where aggregating distributed energy resources appears competitive for network deferral, but they appear so far to be a small minority of cases. It is also less clear how the aggregation of distributed energy resources for network services aligns with decarbonization goals. Displacing a thermal power plant that provides capacity or ancillary services with distributed energy resources results in lower emissions. Using distributed energy resources instead of traditional poles and wires does not have the same impact.

In the U.K., distribution network utilities do not need to assess the cost competitiveness of distributed energy resources against network projects to traditional network options. U.K. distribution network utilities contract DERs through their own flexibility market or third-party markets.

In New York and California, the utilities have to show that the distributed energy option is cheaper than the initial network upgrade. This is part of the reason why there are fewer examples of distributed energy resources providing network services in the U.S. compared to the U.K. Network services are proposed on a project-by-project basis, known as non-wires alternatives. Utilities file requests for proposals for a specific network project. There are often insufficient existing distributed energy resources in the specific location. Distribution upgrades are then needed to connect new distributed resources for non-wires projects. The additional complexity also has an associated cost. This often results in non-wires projects being considerably more expensive than alternative network upgrades. Few examples of successful, cost competitive non-wires projects in the U.S. exist.

Figure 12: Landscape of countries' network revenue mechanisms and power system unbundling



Source: BloombergNEF Smart Grid: From Buzz to Business (web | terminal)

Output- or performance-based regulation typically comes with a more 'unbundled' power system.

'Unbundled' means the different elements of the power system - generation, networks and supply are operated by different entities. As opposed to a 'bundled' system where one organization manages a vertically integrated power system. Revenue-cap regulation incentivizes cost efficiency and can promote local flexibility markets, if they reduce operating costs. The U.K.'s RIIO framework is a prominent example of output- or performance-based regulation and, at least in part, can be credited for the prominence of local flexibility markets in the country.

C. California ISO ("CAISO")

The competitive electricity market in California is run by the California ISO (CAISO). The CAISO operates a day-ahead and real-time market, in a footprint that encompasses 80% of California. It has a peak load of approximately 47,000 MW and serves 30 million ultimate customers.[1] Market participants include investor owned utilities and merchant generators. California permits retail choice providers for a capped percentage of commercial and industrial consumers of its the three major IOUs.[2]

CAISO does not operate a centralized capacity market. Rather, its rules support resource adequacy requirements established by the California Public Utilities Commission ("CPUC") and resource planning activities that are undertaken by a number of entities including the CPUC, the CAISO, the California Energy Commission ("CEC"), and the IOUS and other LSEs.[3]

Long-Term Planning for Resource Adequacy
The primary long-term planning for resource adequacy is performed by the CPUC, in collaboration with the IOUs.[4] The CPUC and the IOUs fulfill this responsibility by developing long-term procurement plans ("LTPP") on a biennial basis. These plans look forward 10 years and consider forecasted supply, demand, new builds, retirements, demand response, and other system conditions. Similar to the IESO's proposed Resource Adequacy Framework timeline, the LTPP informs short-and medium-term procurement (largely contracts) to meet needs of bundled customers. Second, the LTPP is used to determine long-term system-wide needs, including those of competitive service providers and community choice aggregators, and whether the IOUs will contract to build new conventional generators.[5] If the plan ultimately determines that new conventional generation is necessary, the generation is procured using a request for offers by which assets are developed through long-term contracts or IOU ownership.
Resource Adequacy Requirements of the CPUC
The CPUC's Resource Adequacy Requirements ("RAR") has three parts:[6]

- **System-wide resource adequacy**: obligation calls on LSE under CPUC jurisdiction to procure capacity sufficient to meet its customers' peak load plus 15% reserve requirement.
- **Local resource adequacy**: obligation ensures LSEs are able to serve load reliably within import-constrained load areas.
- **Flexible resource adequacy**: largely in response to increased ramping needs resulting from renewable penetrations, requirements are set monthly based on the maximum forecasted contiguous three-hour net load plus a contingency factor.

Each LSE must demonstrate that it has fulfilled its RAR obligation and reference the specific resources from which it has procured capacity. Annually, LSEs must submit supply plans for each month of the coming calendar year showing 90% of system and flexible requirements and 100% of both requirements. This creates a short-term bilateral market for capacity where LSEs procure their incremental capacity needs to fulfil their full RAR obligation. California has significant penetrations of energy efficiency and distributed generation assets. These assets are need from system load forecasts by the CEC in the process that leads to the CPUCs determination of LSEs' RAR obligations.[7]
LSEs that fail to fulfill their obligation are subject to a penalty and the cost that CAISO will incur in replacing the capacity on their behalf (note, this has never happened).
CAISO Backstop

If an LSE fails to fulfill their RAR requirements or if other circumstances introduce resource adequacy concerns, the CAISO has a backstop reliability mechanism to allow to address any deficiencies by procuring an amount of capacity necessary to remedy the deficiency at the cost of the LSE plus a penalty. The CAISO may also determine the need to procure backstop capacity under the capacity procurement mechanism (CPM) for reliability reasons other than those associated with RAR obligations. For example, if a resource is slated to retire but will be needed to meet future RAR obligations, the CAISO can intervene to prevent the retirement.[8]

Resource Adequacy Obligation
LSEs generally bead the obligation to procure sufficient capacity to satisfy resource adequacy requirements based on CPUC standards and in coordination with the CPUC and the CAISO.

Integrated Planning Process
The LTPP is a suite of planning processes performed by the CPUC, the CAISO, and the CEC. The CEC's roll is focused on forecasting energy demand and develops and integrated energy policy report on a biennial basis. These demand processes are used as inputs in other planning processes. The third interlinked planning process is the CAISO's transmission planning process (TPP) which is two years long and staggered with the LTPP. It is informed by the resource plan established in the LTPP, and its outputs also serve to inform LTPP processes by providing information on transmission development, transmission constraints, and establishment of flexible capacity needs.[9]

Cost Recovery Mechanism
The CPUC reports the most forward capacity procurement is accomplished through bilateral contracting, however, some resources may have their costs allocated through the CAISO tariff, including the cost allocation mechanism (CAM) and RMR units. Resources procured through with the CAM mechanism are procured on behalf of the IOUs' bundled customers or on behalf of all benefiting customers. When procurement is on behalf of bundled customers, those customers pay. When procurement is on behalf of all customers, the project costs may be allocated to all customers through non-bypassable charges in retail rates.

California is in the exploration phase of DSO systems. They ran a successful pilot flexibility "DRAM"[8] market but have not implemented system wide legislative change to the TSO centered system.

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[8] https://fuelsave-global.com/californias-dram-auction-contracts-for-82mw-of-distributed-energy-as-grid-resource/

An absence of visibility and coordination remains a key shortcoming in the current model. CAISO, which has historically dispatched transmission-connected generators, is increasingly dipping its toes into the distribution market - yet without the necessary information to do so. Its dispatch processes do not account for constraints on the distribution system; meanwhile, neither CAISO nor DER operators communicate with distribution operators on a real-time basis. These gaps will need to be dealt with as adoption rises.

An ongoing CAISO initiative on Energy Storage and Distributed Energy Resources aims to identify such obstacles to the full participation of storage and DER in the CAISO markets. We expect CAISO will seek to address these concerns by iterating and improving upon its current mechanisms, learning as they go along.

D. New York

New York has explored DSO pilot projects and implemented REV; however, the grid is still TSO focused. REV has had mixed success in the integration and deployment of DERs[9].

In New York, regulators have begun reforms to the utility business model under the Reforming the Energy Vision (REV) proceedings. The REV proceedings allow utilities to earn a rate of return for non-infrastructure expenditures on non-wires solutions. They can also sell services to distribution system providers and earn additional revenues by meeting REV objectives through the earnings adjustment mechanism (EAM). Utilities are not allowed to earn revenues from operational expenditures for distributed energy resource services other than non-wires alternatives. Network utilities cannot own front-of-meter batteries outside of pilot projects.

In a pilot program to create a transactive energy marketplace for owners of energy resources, National Grid has launched a distributed system platform (DSP) on the Buffalo Niagara Medical Campus. Through the platform, National Grid can integrate campus member institutions' energy resources to the local electricity distribution grid while offering participants an opportunity to earn market rate compensation for that energy.[10]

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[9] https://www3.dps.ny.gov/W/PSCWeb.nsf/All/B2D9D834B0D307C685257F3F006FF1D9?OpenDocument

[10] https://www.nationalgridus.com/news/2018/06/national-grid-launches-distributed-system-platform-with-buffalo-niagara-medical-campus-members/

E. PJM Interconnections

PJM Interconnections ("PJM") is an RTO that spans 14 states[11]in the mid-Atlantic US. PJM's territory includes more than 61 million customers and total installed capacity of more than 182,000 MW. Supply in PJM is provided primarily by similar quantities of coal, gas, and nuclear generation, complemented by smaller amounts of oil, hydro, pumped hydro, biomass, wind, and solar resources.[12]

PJM operates a day-ahead market, a real-time market, and a capacity market, with competition by a large number of suppliers in each. Market participants include investor owned utilities and merchant generators. [13] Retail competition in PJM's footprint is dictated by state policy, and provision of service by competitive suppliers is allowed in some member states and banned in others. Likewise, member states have implemented diverse renewable and environmental policies, as well as other economic policies that affect relative economic outcomes in the PJM markets.

Capacity Market – Reliability Pricing Model
PJM's capacity market is called the Reliability Pricing Model ("RPM"). It is mandatory for LSEs in the PJM footprint, though it provides the option for an LSE to fulfill its own requirement needs through a carve out. RPM provides locational price signals for annual commitments to provide capacity to serve load in PJM. In addition to generation resources, capacity may be supplied RPM by demand response, energy efficiency, imports, and transmission upgrades.

Resource Adequacy Obligation
PJM is responsible for determining the quantity of capacity to be procured within RPM, as necessary to serve the forecast peak load and to satisfy the reliability criterion. PJM also holds the obligation to procure this quantity of capacity. [14] Participation in, and payment to, the RPM by LSEs in the PJM region is mandatory unless an LSE elects the fixed resource requirement (FRR) alternative. The FRR alternative allows for an LSE to submit and execute a plan to meet its capacity requirements outside of the RPM market. It will neither pay RPM locational reliability charges or will capacity resources included in the LSE's FRR capacity plan receive RPM clearing prices. Election of the FRR alternative for an LSE's services area has a minimum term of five consecutive delivery

[11] PJM Interconnection footprint includes: Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia .
[12] Charles Rivers Associates, *A Case Study in Capacity Market Design and Considerations for Alberta*, 2017, at page 63.
[13] Charles Rivers Associates, *A Case Study in Capacity Market Design and Considerations for Alberta*, 2017, at page 63.
[14] Charles Rivers Associates, *A Case Study in Capacity Market Design and Considerations for Alberta*, 2017, at page 66.

years. Load associated with service areas that have elected the FRR alternative is deducted from the overall RPM auction procurement target. [15]

Integrated Planning Process

PJM performs transmission planning on an annual basis that considers reliability, economic, and public policy needs as required by FERC. This is known as the "Regional Transmission Expansion Plan". PJM does not perform integrated planning in the sense that it does not plan the timing, characteristics, and location of generation investments in the RTO footprint. Rather, those decisions are made primarily by private entities that participate in the RPM.[16]

Clearing Mechanism

PJM conducts two types of auctions, the base residual auction ("BRA") and the incremental auction ("IA"). The BRA is the primary forward auction wherein PJM procures capacity to meet its expected needs less an amount reserved for short term resources and minus any requirements fulfilled outside the market by LSEs with an FRR obligation. The IAs take place between the BRA and the delivery year and allow for the RTO and LSEs to procure replacement resources as necessary.

Cost Recovery Mechanism

The cost of capacity resources procured through the RPM auctions is primarily allocated through locational reliability charges, which are paid by LSEs. They are calculated as the product of the LSE's daily unforced capacity obligation and the final zonal capacity price for the delivery year. The daily unforced capacity obligation is the produce of an LSE's peak load obligation, which is based on the LSE's contribution to the zonal peak demand, and the zonal peal capacity obligation divided by the zonal weather normalized peak. Capacity charges are calculated daily and settled weekly. LSEs pass the costs associated with their capacity needs to consumers through state jurisdictional retail electricity tariffs. [17]

F. ISO-New England ("ISO-NE")

ISO-NE is an RTO in the US that spans the six New England states. ISO-NE's territory has a population of 14.7 million and a peak demand of just more than 28,000 MW. Approximately half of all electricity generated in ISO-NE is provided by gas-fired generators, and more than half of the balance comes from nuclear power. Renewables and hydro make up much of the rest of the generation mix while coal and oil play a

[15] Charles Rivers Associates, *A Case Study in Capacity Market Design and Considerations for Alberta*, 2017, at page 66.
[16] Charles Rivers Associates, *A Case Study in Capacity Market Design and Considerations for Alberta*, 2017, at page 66.
[17] Charles Rivers Associates, *A Case Study in Capacity Market Design and Considerations for Alberta*, 2017, at page 73.

small and shrinking role. ISO-NE has more than 400 participants in its day-ahead, real-time, and capacity markets. Generation ownership is entirely unbundled in the ISO-NE footprint and Vermont is the only state in which retail competition is not allowed. [18]

Capacity Market – Forward Capacity Market (FCM)

ISO-NE's capacity construct is called the forward capacity market (FCM). Participation in FCM is mandatory for LSEs in the ISO-NE footprint and provides locational price signals for annual commitments to provide capacity to ensure reliability. The primary competitive structure is the forward capacity auction (FCA), a descending clock auction that allows for active participation. Cleared resources take on a one-year commitment to provide capacity three years in the future. Between each FCA and the ultimate commitment period, there are several opportunities for resources to buy and sell capacity positions.

Rule changes are frequent in ISO-NE and FCM is currently transitioning to a revised downward-sloping demand curve and a pay-for-performance (PFP) regime that seeks to align compensation incentives with the goal of encouraging market participants to be available during peak periods. [19]

Resource Adequacy Obligation

ISO-NE is responsible for determining the quantity of capacity to be procured within FCM, as necessary to serve the forecast peak load and to satisfy the reliability criterion. ISO-NE also holds the obligation to facilitate procurement of this quantity of capacity. The procurement is based on the forecast peak load plus a component to account for additional physical capacity needs to ensure that a loss-of-load event is only likely to occur one day every ten years (commonly known as the "one-in-ten" criterion). The resulting quantity is called the installed capacity requirement (ICR). [20]

Participation in FCM by LSEs in the ISO-NE region is mandatory. There is no alternative structure because all load-serving utilities in the New England region have fully divested their generation. [21] FCM qualified resources may be variable, non-variable, or associated with an internal elective transmission upgrade (ETU). Also, the capacity associated with modifications to existing resources may count as a new resource under

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[18] Charles Rivers Associates, *A Case Study in Capacity Market Design and Considerations for Alberta*, 2017, at page 77.
[19] Charles Rivers Associates, *A Case Study in Capacity Market Design and Considerations for Alberta*, 2017, at page 77.
[20] Charles Rivers Associates, A Case Study in Capacity Market Design and Considerations for Alberta, 2017, at page 79.
[21] Charles Rivers Associates, A Case Study in Capacity Market Design and Considerations for Alberta, 2017, at page 79.

certain circumstances. Resources may also take the form of demand resources, imports, and external ETUs. [22]

Integrated Planning Process

ISO-NE performs transmission planning on a biennial basis that considers reliability, economic, and public policy needs. The results of this planning process, described in the Regional System Plan, inform and are informed by the results of the FCM. However, <u>ISO-NE does not perform integrated planning in the sense that it does not plan the timing, characteristics, and location of generation investment in the New England region. Rather, those decisions are made primarily by private entities that participate in the FCM.</u> [23]

Clearing Mechanism

ISO-NE's FCA uses a descending clock auction format, which allows participants to adjust their offers through successive auction rounds based on real-time information. Descending clock auctions are thought to be transparent and efficient and are generally used to obtain the lowest price when bidders in an auction are selling the same product at different costs. At its most basic level, a descending clock auction starts at a high price, at which it is likely that more than enough product is available to meet general and locational needs. During the auction, prices drop and information is provided to participants as to how close the buyer, ISO-NE, is to achieving its procurement goal. In successive rounds, some participants will determine that the auction price has fallen below the revenue needed to make a resource profitable and those participants will withdraw their offers from the auction. This process is repeated and prices drop until the point at which the demand curve intersects what is left of the supply curve. [24]

Cost Recovery Mechanism

FCM payments to resources are based on any credits earned through FCA, bilateral transactions, or reconfiguration auctions, minus any peak energy rent ("PER") adjustments, performance penalties, and credits/incentives. FCM charges are applied to each capacity zone, customer, and load asset. FCM settlement must balance at the zonal level, and settlement is performed on a monthly basis during the CCP, with final billing completed approximately four months following the delivery month.

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[22] Charles Rivers Associates, A Case Study in Capacity Market Design and Considerations for Alberta, 2017, at page 80.
[23] Charles Rivers Associates, A Case Study in Capacity Market Design and Considerations for Alberta, 2017, at page 80.
[24] Charles Rivers Associates, A Case Study in Capacity Market Design and Considerations for Alberta, 2017, at page 80.

FCM charges are billed to all LSEs with a capacity load obligation ("CLO") at a level equivalent to the product of the CLO and the applicable net regional clearing price ("NRCP"). The CLO is based on a capacity requirement–calculated based on peak load contributions--adjusted for self-supply, bilateral transactions, and any Hydro-Quebec interconnection credits. NRCPs are separate from auction clearing prices and equal to the sum of total payments paid to CSO resources in the capacity zone–net of PER adjustments, excluding bilateral transactions, and adjusted for performance penalties–divided by the sum of capacity supply obligations not served through bilateral transactions or self-supply.[25]

[25] Charles Rivers Associates, A Case Study in Capacity Market Design and Considerations for Alberta, 2017, at page 80.

Appendix J - Implementation Considerations

In addition to the considerations/questions outlined below, please also refer to the guiding questions outlined in Appendix E.

a. What is the implementation cost for the structure and how does that impact customer rates and affordability? Who will bear the cost of implementation?
b. The coordination and management of an increased number of entities may be more costly compared to the current structure in the short term, resulting in potential customer dissatisfaction and political risk.
c. Are distribution services being procured such that they are relevant to the local needs? E.g. urban and rural settings require different ancillary services.
d. What are the net metering rules?
e. Net projected reliability following the adoption of the new structure should exceed the current system.
f. Inclusion of DERs presents many technical challenges. For example, there is perceived difficulty in the ability to install and maintain proper protection circuitry in some scenarios. Additionally, the distribution system does not yet possess the ability to enable the reverse power flow from the prosumer.
g. It will be important to minimize entry for DER participants. For example, making it easy to navigate etc.
h. Investigate the possibility of a hybrid structure that includes LSEs and CCAs.
i. What are the market rules and strategies? E.g., what are the more innovative programs available to customers so that they would be able to recover their costs and participate in the DER market?
j. There will be challenges in designing, implementing and enforcing regulations for local power markets. In short, the introduction of new technologies into the market means ever-increasing market complexity, with regards to oversight, regulation and pricing.
k. It will be important to ensure that LDCs have the tools, resources and coordination protocols in place with the operator. With the adoption of these new structures, the role of LDCs is going to expand, meaning it will be important to explore what this means in terms of the ownership and procurement of assets.
l. Who is building Distributed Energy Resource Management Systems (DERMS) and to whom will DERMS be available? Who will control DERMS? What role do aggregators play in the control of DERMS? How is an aggregator role different from the customer?

Appendix K - Glossary

Term	Definition
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.
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 supply and demand 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.
Load-serving entity (LSE)	NERC defines an LSE as the entity that "secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers".
Load-serving entity (LSE) function	In other jurisdictions, it 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.
Local distribution company (LDC)	In Ontario, a local distribution company owns and operates a distribution system but is not commercially responsible for the difference between the wholesale price it pays for electricity and retail price at which it is sold to retail customers. LDCs earn most of their revenues from the delivery of the underlying commodity as opposed to the wholesale/retail price spread.

Term	Definition
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) 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.
Utility-side DER	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.
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.
Fully Integrated Network Operator (FINO)	Fully integrated network operator (FINO): Proposed by the Ontario Electricity Distributors Association, a FINO has the combined responsibilities of an LDC and a DSO and may also be involved in commercial activities with respect to developing DER-related services and ownership.
Fully Independent ISO	Fully independent DSO: Like an ISO at the bulk electricity system level, a fully independent DSO conducts physical dispatch of the distribution system to facilitate market access for DERs.
Distributed Energy Resources (DERs)	Distributed Energy Resources (DERs) are smaller-scale units of power generation, storage, or controllable loads that are connected to a local distribution system or a host facility within the local distribution system. An important distinction of a DER is that the energy it produces is often consumed close to the source. DERs can include solar panels, combined heat and power plants, electricity storage, small natural gas-fueled generators, electric vehicles (EVs), and controllable loads, such as heating, ventilation, and air-conditioning (HVAC and electric water heaters.[26] When using renewable energy resources, the imminent nature of some resources requires the need for storage, which can include batteries and fly wheels among other means. DERs are typically smaller in scale than the traditional generation facilities that serve most of Ontario demand.

[26] "Distributed Energy Resources." *Independent Electricity System Operator*, https://www.ieso.ca/en/Learn/Ontario-Power-System/A-Smarter-Grid/Distributed-Energy-Resources. Accessed 6 December 2021.