

POWER TO CONNECT

A ROADMAP TO A BRIGHTER ONTARIO

POWER OF
LOCAL HYDRG



FEBRUARY 2018

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LIST OF ACRONYMS

CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DERMS	DER Management System
DR	Demand Response
DSC	Distribution System Code
DSP	Distribution System Plan
EDA	Electricity Distributors Association
EV	Electric Vehicle
FINO	Fully Integrated Network Orchestrators
FIT	Feed-in Tariff
GA	Global Adjustment
GHG	Greenhouse Gas
HOEP	Hourly Ontario Electricity Price
ICA	Incremental Capacity Auction
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
LDC	Local Distribution Company
LMP	Locational Marginal Price
LMP+D	Distribution Locational Marginal Pricing
LRP	IESO's Large Renewable Procurement
LSE	Load-Serving Entity
LTEP	Long-Term Energy Plan
MW	Megawatt
MWh	Megawatt Hour
MCP	Market Clearing Price
OEB	Ontario Energy Board
OPG	Ontario Power Generation
RFP	Request for Proposal
RPP	Regulated Price Plan
RRFE	Renewed Regulatory Framework for Electricity
RSC	Retail Settlement Code
TS	Transformer Station
TSC	Transmission System Code

1. EXECUTIVE SUMMARY

The Electricity Distributors Association (EDA) recognizes that its industry is in transformation and that the roles and responsibilities of Local Distribution Companies (LDCs) are evolving rapidly from the simple 'poles and wires' businesses of the past. For this reason, the EDA's vision paper entitled *The Power to Connect, Advancing Customer-Driven Electricity Solutions for Ontario* ("Vision Paper"), released in February 2017, outlined a robust vision for the role of LDCs that supports the industry landscape of the future.

Given that LDCs are confronted with greater demand for the integration of distributed energy resources (DERs), such as distributed generation resources, load control and other technologies, such as solar, wind, energy storage, electric vehicle (EV) charging infrastructure, fuel cells, demand response (DR), and conservation and demand management (CDM), the Vision Paper proposed a framework for LDC transformation through three dimensions:

1. **DER-enabling Platform** – development of an intelligent platform for DER integration in distribution systems;
2. **DER Integration** – LDC ownership of DERs; and
3. **DER Control and Operation** – optimize and coordinate usage of DERs.

LDCs that embrace an evolution in respect of these three dimensions will ultimately become Fully Integrated Network Orchestrators (FINOs) which actively manage DERs within their network and provide greater value and services to their customers. This report builds on the foundation set by the Vision Paper by identifying the challenges and barriers for the evolution of Ontario's LDCs towards becoming FINOs through an assessment of current policy, legislation, and regulations including the Ontario Government's 2017 Long-Term Energy Plan (LTEP) and provides input for implementation considerations.

The 2017 LTEP and the Vision Paper are strongly aligned. Both documents place a focus on electricity customers and the need to provide cost-effective electricity while meeting greenhouse gas (GHG) emissions reduction targets set by the province in an evolving energy landscape. And, both documents envision changing roles and responsibilities of LDCs in conjunction with the deployment of DERs.

Like many North American jurisdictions, Ontario is reaching an important inflection point. Advancements and cost reduction of distributed generation, EVs, and other smart grid technology, coupled with aggressive GHG emissions reduction targets mean that LDCs will experience increased penetration of DERs within their networks. If unplanned and uncoordinated, customers may be exposed to increased costs and lower reliability. Alternatively, strategic planning and an alignment of the policy and regulatory environment could lead to benefits for customers, such as decreased costs, increased control, and improved reliability.

Five underlying themes have been identified that hinder LDCs from fully transforming to FINOs. Within the context of Ontario's statutory framework, these are:

- **Updated Rules and Provisions:** Rules and provisions governing LDCs have not been updated to reflect an increase of DERs within distribution networks (e.g., priority access); there is a need for clearer definition with respect to the services provided by certain DERs (e.g., energy storage); and LDCs' licences are restricted to distribution services limiting their ability to operate DERs;
- **Augmented Distribution Planning:** DERs increase complexity of distribution planning; there is a need for additional guidance with respect to rate-basing DERs and deployment of smart grid; and the current Ontario Energy Board (OEB) Renewed Regulatory Framework for Electricity (RRFE) scorecard evaluates LDCs based on a traditional utility model;
- **Uncoordinated Centralized Procurement:** Centralized procurements of electricity resources (e.g., distributed generation, etc.) do not necessarily align with LDC planning and LDCs do not have a requirement to serve load;
- **Perception of LDC Capabilities:** LDCs will transition to FINOs with different trajectories, and therefore a range of LDCs must be accommodated within Ontario's statutory framework; and
- **Pricing and Rate Design:** Current wholesale electricity prices do not accurately reflect the locational cost and value of electricity demand and supply, which in turn does not allow full benefits of DERs to be realized.

CHALLENGES	SOLUTIONS
<p>1. UPDATES TO RULES AND PROVISIONS</p> <ul style="list-style-type: none"> ■ Rules for access to distribution systems ■ Define additional DER services ■ Limits with respect to distribution services 	<p>1. Levelling the playing field for DERs</p> <p>2. Improved definition of DERs and potential services</p>
<p>2. AUGMENTED DISTRIBUTION PLANNING</p> <ul style="list-style-type: none"> ■ DERs increasing complexity of DSPs ■ Uncertainty with respect to rate-basing DERs ■ Updates to RRFE Scorecard ■ Uncertainty with respect to smart grid development 	<p>3. Improving DSPs through investments in grid visibility</p> <p>4. Remove restrictions on LDC ownership of resources</p> <p>5. Guidelines for rate-basing of DERs and DER-enabling assets consistent with DSPs</p>
<p>3. UNCOORDINATED CENTRALIZED PROCUREMENTS</p> <ul style="list-style-type: none"> ■ Consideration of local impacts ■ No specific obligation to serve load 	<p>6. Coordinating and decentralizing procurement of resources and DERs</p> <p>7. Allowing LDCs to control and operate DER assets</p>
<p>4. PERCEPTION OF LDC CAPABILITIES</p> <ul style="list-style-type: none"> ■ Varying structures of LDCs ■ Coordination with and amongst LDCs 	<p>8. Shared services of LDCs with respect to control and operations</p>
<p>5. PRICING AND RATE DESIGN</p> <ul style="list-style-type: none"> ■ Inefficient and non-transparent prices ■ Ineffective rate design 	<p>9. Eventual development of LMP+D</p>

To address these issues, the following nine high-level solutions have been identified:

- Levelling the playing field for DERs;
- Improved definition of DERs and potential services;
- Improving distribution system plans (DSPs) through investments in grid visibility;
- Remove restrictions on LDC ownership of resources;
- Guidelines for rate-basing of DERs and DER-enabling assets that are consistent with DSPs;
- Coordinating and decentralizing procurement of resources and DERs;
- Allowing LDCs to control and operate DER assets;
- Shared services of LDCs with respect to control and operations; and
- Eventual development of distribution locational marginal prices (LMP+D).

A PROPOSED IMPLEMENTATION TIMEFRAME IS PROVIDED BELOW:

ACTION	YEAR														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Amendments to <i>Electricity Act</i> and OEBA	■	■	■												
Amendments to the DSC		■	■												
IESO Stakeholder Engagement - LDC support in procurements		■	■	■											
<ul style="list-style-type: none"> ■ OEB criteria for grid-visibility investment 				■	■										
<ul style="list-style-type: none"> ■ Review of potential government funding mechanisms for grid-visibility investments 				■	■										
<ul style="list-style-type: none"> ■ OEB criteria for rate-basing DERs and DER-enabling assets 					■	■	■								
<ul style="list-style-type: none"> ■ OEB criteria for shared services (e.g., control and operation) 								■	■						
<ul style="list-style-type: none"> ■ Development of LDC-led procurement mechanisms 									■	■					
Changes to RRFE Scorecard (grid visibility)					■										
New Market Renewal Stream (LMP+D)						■	■	■							
Amendments to Net Metering Regulation (pricing)											■	■			

Advisory Committee Tasks

In summary, proposed solutions identified within this paper are in line with Ontario's goals and objectives of achieving greater value for electricity customers and GHG emissions reductions, including:

- Provides options for customers and helps achieve GHG emissions reductions through the adoption of new technologies (e.g., EVs);
- Provides guidance to LDCs who in turn will provide customers with choices to manage electricity costs, and will improve the deployment of energy storage and EVs;
- Augmented planning will help ensure investments are right-sized to meet customers' needs (e.g., active visibility and control of resources would also inform distribution planning with respect to when resources should be maintained, retired, or replaced);
- Improves economic sustainability of LDCs;
- Better alignment of procurement activities will help reduce costs to customers overall;
- Allows a mechanism for LDCs to invest in non-wires alternatives that are the best and most cost-effective option to meet local needs;
- More efficient use of resources could help reduce costs to customers;
- Reduces costs to customers through shared services that will also be designed to optimize distribution assets; and
- More efficient prices and rates will appropriately incent investments and provide input into distribution system planning.

Like many other segments of the economy, the electricity sector is undergoing a transformation given the potential for new technologies and services. The most transformative companies in today's economy not only leverage new technologies but have re-defined how services are provided to customers and maximize the latent value of existing infrastructure. Uber is the most obvious example of this new type of entrepreneurship – they are the largest new provider of taxi services without owning any taxis. Likewise, LDCs should maximize the latent value of resources within their networks (e.g., energy storage system that helps customers mitigate electricity costs may also be able to provide grid services cost-effectively, benefitting electricity consumers more broadly).

The EDA's Vision Paper provides a goal for LDCs that want to become active facilitators in a transformed electricity market, one that puts customers first and maximizes the utilization and value of electricity assets. This companion report has identified the challenges and barriers and can be used as a roadmap for consultation activities going forward through its proposed recommendations and solutions to facilitate LDCs transforming to FINOs.

2. INTRODUCTION AND BACKGROUND

2.1 BACKGROUND ON THE EDA'S VISION PAPER: *THE POWER TO CONNECT*

The EDA recognizes that its industry is in transformation and that the roles and responsibilities of LDCs are evolving rapidly from the traditional 'poles and wires' businesses of the past. For this reason, the EDA's *The Power to Connect*¹ ("Vision Paper"), released in February 2017, outlined a robust vision for the role of LDCs that supports the evolving industry landscape of the future.

Business as usual is no longer an option for LDCs. New advances in technology are becoming more affordable and accessible for electricity customers, and greater demands are being placed on LDCs with respect to climate change policies. The traditional 'poles and wires' model will become increasingly inadequate as LDCs are confronted with greater demand for the integration of DERs. This will, in turn, drive further competition and complexity in the electricity sector.

As defined within the Vision Paper, DERs could include distributed generation resources, load control and other technologies, such as solar, wind, energy storage, EV charging infrastructure, fuel cells, DR, and CDM. This includes LDC control room operations that would enable DER operation capability.

DERs enable customer choice in a cost-effective and safe manner. LDCs can use DERs to offer customers the appropriate level of service quality for their specific needs at a relatively lower cost. More broadly, customers will be able to use new technologies and innovations to access different electricity services (e.g., electric transportation). By decreasing system losses and increasing the adoption of renewable resources, DERs can further reduce the environmental impact of the electricity sector in Ontario. In addition, DERs provide greater optionality for customers to respond to price signals and manage their consumption more efficiently.

The changing landscape means that all sector participants will need to adopt new strategies to resolve challenges and position themselves for future growth. The Vision Paper proposes a framework for LDC transformation through three dimensions: 1) DER-enabling Platform; 2) DER Integration; and, 3) DER Control and Operation. LDCs that embrace an evolution in respect of these three dimensions will ultimately become FINOs, as summarized in this section of the report. The Vision Paper emphasizes flexibility by recognizing that LDCs may evolve along their own unique paths.

¹ *The Power to Connect, Advancing Customer-Driven Electricity Solutions for Ontario*, February 2017.

2.1.1 DER-enabling Platform

The first dimension represents the development of an intelligent platform for integration of DERs within distribution systems, while maintaining the stability and reliability of the grid. The platform would include network control and automation, Advanced Metering Infrastructure, smart inverters, two-way communication, and advanced distribution management systems, and would help improve the visibility of assets that are operating within their networks. As the existing owners and operators of the distribution network, LDCs have the knowledge and experience and are in the best position to develop and build distribution networks that are capable of being DER-enabling platforms. Investment in enabling platforms are essential and serve as a foundation for LDC transformation.

2.1.2 DER Integration

The second dimension pertains to ownership of DERs by LDCs, specifically by the regulated distribution business. The integration of DER ownership into LDC business models will further stimulate DER market development and create certainty with respect to achieving public policy goals, such as the reduction of GHG emissions, through coordinated DER planning. The intent is not to limit participation by other market players from owning and operating DERs, but recognizes that LDCs are well positioned to take leadership roles.

2.1.3 DER Control and Operation

The extent to which LDCs control and operate DERs represents the third dimension. By taking control and operating DER assets, LDCs will have greater ability to maximize the value and benefits that DERs provide to customers, distribution systems, and the broader electrical grid.

To control and operate DERs, a DER Management System (DERMS) will help to better optimize the coordinated usage of centralized and distributed resources. DERMS provides a variety of intelligent services that allow LDCs to optimize all resources on their system, including real-time network visibility, asset monitoring and control, scheduling and dispatch, active and reactive power import and export control, voltage control, forecasting, resource valuation, and optimal DR and CDM. Investments in DERMS is considered a critical investment with respect to the transition from an LDC to a FINO.

2.2 OVERVIEW OF FULLY INTEGRATED NETWORK ORCHESTRATOR

As described in the Vision Paper, a FINO is an LDC that has advanced in all three dimensions. FINOs would have built out distribution systems that integrate DER connections, be actively involved in development and ownership of DER assets, and actively control and operate DER resources. LDCs that evolve towards FINOs will be well positioned to deliver the benefits of DERs to their customers.

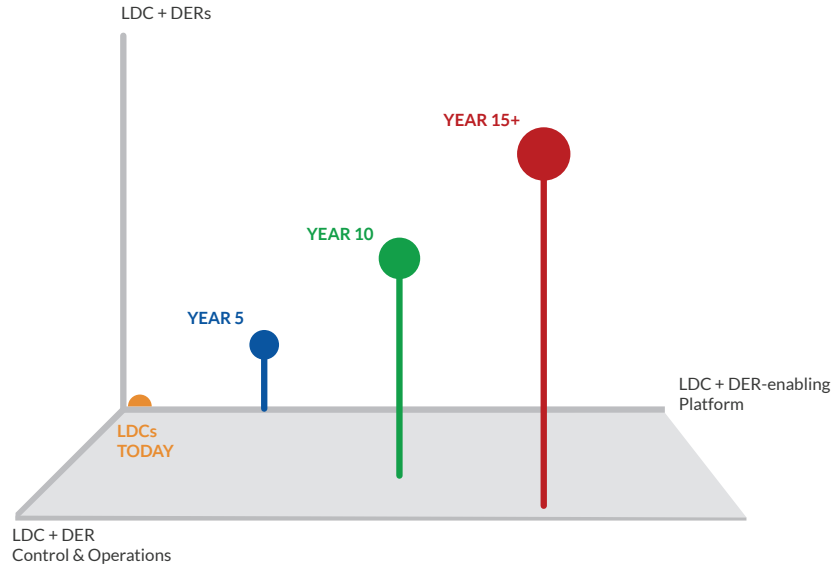


Figure 1. Evolution from LDC to FINO

YEAR 5 ●

- Alternative regulatory framework established
- Initial integration of DER into DSPs
- DER-enabling platform at limited scale

YEAR 10 ●

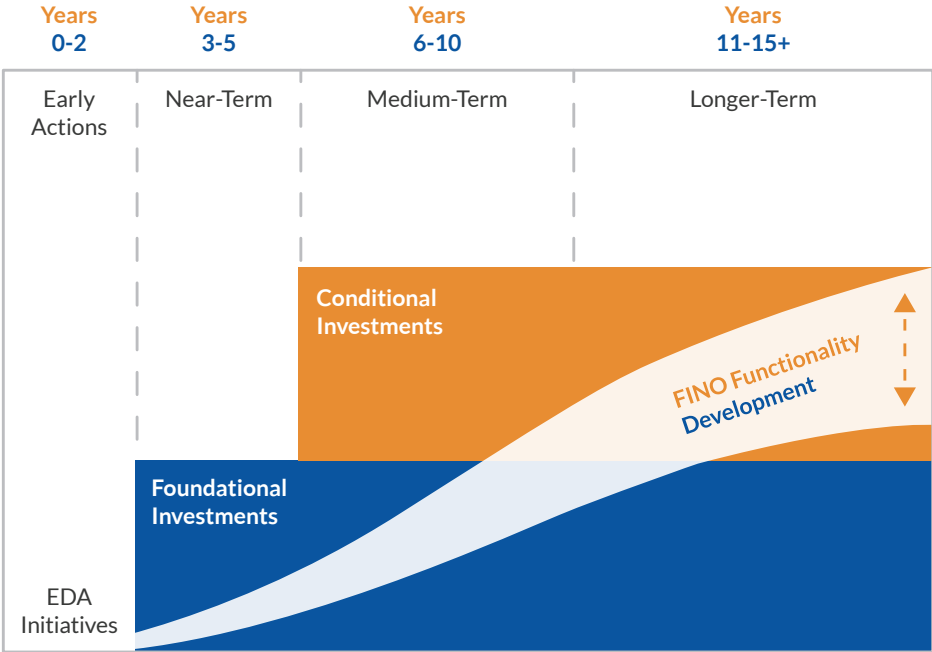
- DER-enabling platform at increased scale
- Initial integration of DER into markets and operations
- Evaluation of new business models

YEAR 15 ●

- DER-enabling platform at full scale
- Limited value-added DER products and services
- Some real-time visibility at distribution level
- Limited integration of DER into markets and operations

Source: *The Power to Connect, Advancing Customer-Driven Electricity Solutions for Ontario*, February 2017

The Vision Paper presents milestones over a 15+year time frame regarding potential transformation of LDCs, as illustrated in Figure 1, beginning with limited DERs integrated into their service territories today. The evolution of LDCs begins with foundational investments to build a DER-enabling platform within the first five years. Subsequently, evolution of LDCs focuses on increasing DER ownership opportunities and developing mechanisms for LDC control and operation of DERs within their networks.



Foundational investments, classified as technologies necessary to enable DERs (e.g., advanced metering infrastructure, smart inverters, distribution and substation automation, advanced communications, etc.) will need to be prioritized and should start in the near-term. Conditional investments are optional items that would depend upon market conditions and each LDC's unique situation.

Figure 2. FINO Development Time Frame

There will be different degrees to which LDCs transform into FINOs, as portrayed by the range of functionality within the curve, as illustrated in Figure 2 above. The functionality of individual LDCs as FINOs can be anywhere on the curve and will depend on market conditions and each LDC's unique circumstances.

Source: *The Power to Connect, Advancing Customer-Driven Electricity Solutions for Ontario*, February 2017

2.3 ONTARIO'S CURRENT POLICY CONTEXT

On October 26, 2017, the Ministry of Energy released Ontario's revised LTEP, Delivering Fairness and Choice, which outlines policy for Ontario's electricity and energy sectors. Some of the highlights of the 2017 LTEP include:

- Cost mitigation through measures such as the Fair Hydro Plan and the Independent System Operator's (IESO's) Market Renewal Program;
- Meeting future electricity supply needs through measures to be developed within the Market Renewal Program;
- Creating opportunities for energy innovation, including:
 - moving forward with pricing pilots;
 - examining barriers for energy storage;
 - implementing demonstration projects for strategically located distributed generation paired with smart grid technologies, as well as virtual net metering;
 - investigating how to facilitate LDC investments in new technologies, such as residential smart chargers;
 - exploring new business models that can be supported through grid modernization; an example includes peer-to-peer frameworks for transactive energy, which could be implemented through Blockchain technology; and
- Consulting on regulatory changes that would treat LDC expenditures in innovative and non-wires solutions that could lead to cost-effective outcomes for customers.

The 2017 LTEP and the Vision Paper are strongly aligned. Both documents place a focus on electricity customers and the need to provide cost-effective electricity while meeting GHG emissions-reduction targets set by the province in an evolving energy landscape. And, both documents envision changing roles and responsibilities of LDCs in conjunction with the deployment of DERs.

The 2017 LTEP places strong emphasis on the IESO's Market Renewal Program, which entails enhancing the existing wholesale electricity market through initiatives to implement Locational Marginal Pricing (LMP), improve scheduling and dispatch of supply-side and demand-side resources, and new mechanisms to help ensure future resource adequacy. The transformation of LDCs towards FINOs will enable greater participation within the future Ontario wholesale electricity market resulting from implementation of the Market Renewal Program, for example, DERs supplying energy and/or ancillary services to the bulk grid or DERs providing capacity and resource adequacy. This report leverages the direction of the 2017 LTEP and provides input for implementation considerations.

On December 14, 2017, Minister of Energy Glenn Thibeault, announced a review of the OEB to ensure that it can adapt to innovative services and new technologies in keeping with the 2017 LTEP. An expert panel led by Richard Dicerni will seek input starting in spring 2018 and report back to the Ontario Government by the end of 2018. The panel, amongst other things, will look at how the OEB can best protect consumers in a rapidly changing electricity marketplace.

Following the Minister's announcement, on December 18, 2017, the OEB released its Strategic Blueprint, a guide for the OEB's work over the next five years. The Blueprint outlines four challenges that the OEB expects to encounter as the electricity sector transforms through 2022, and goals to address those challenges. The challenges presented by the OEB are: transformation and consumer value; innovation and consumer choice; consumer confidence; and regulation "fit for purpose". This report is also consistent with the OEB's Strategic Blueprint in terms of modernization of the regulatory framework.

2.4 OBJECTIVE OF THIS REPORT

The objective of this report is to identify challenges and barriers for the evolution of Ontario's LDCs, as described in the Vision Paper, through a technical and detailed assessment of existing policy, regulation, and legislation. This report builds from the Key Challenges listed in Section 5.1 of the Vision Paper and proposes solutions to enable FINOs in Ontario.

To achieve this objective, the EDA engaged Power Advisory LLC (Power Advisory) to assess Ontario's current regulatory framework and policy environment. Together, the EDA and Power Advisory also reviewed Ontario's electricity market structure and design, along with the needs and expectations of electricity customers. The impacts of the IESO's Market Renewal Program and the 2017 LTEP were also considered.

Like many North American jurisdictions, Ontario is reaching an important inflection point. Advancements and cost reduction of distributed generation, EVs, and other smart grid technology, coupled with aggressive GHG emissions reduction targets mean that LDCs will experience increased penetration of DERs within their networks. If unplanned and uncoordinated, customers may be exposed to increased costs and lower reliability. For example, distribution networks may be overbuilt instead of optimized through the use of new technologies. Alternatively, strategic planning and an alignment of the policy and regulatory environment could lead to benefits for customers, such as decreased costs, increased control, and improved reliability. It is timely for Ontario to consider these frameworks as adoption of DERs remains comparatively low. While the Feed-in Tariff (FIT) and microFIT programs have spurred significant investment in distributed renewable energy, given the declining costs of solar, energy storage, and EVs it is anticipated that the adoption of DERs will increase in the near-term.

Ontario's LDCs are well positioned to lead in this transformation as an integral, customer-facing component within the electricity sector. With the appropriate tools, LDCs will be able to plan, operate, and coordinate DERs within their networks for the betterment of the customers they serve.

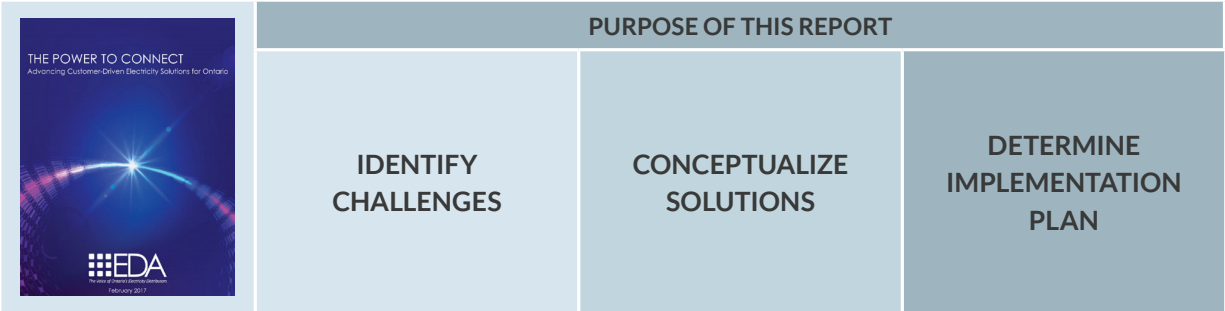


Figure 3. Overview of This Report

The balance of this report is organized as follows:

- Section 3 provides a review of the challenges and barriers identified within Ontario's legal and regulatory framework that are hindering the evolution of LDCs towards becoming FINOs;
- Section 4 proposes a series of recommended solutions that addresses the challenges and barriers identified in Section 3;
- Section 5 outlines an implementation plan for the near-, medium-, and long-term, for the solutions outlined in Section 4, and provides a scenario analysis if proposed solutions are not adopted; and
- Section 6 provides conclusion and summary remarks, and outlines benefits of the proposed actions to electricity customers.

3. CHALLENGES AND BARRIERS

This section of the report identifies the challenges and barriers Ontario’s LDCs face moving along the evolutionary path to becoming FINOs of the future. As outlined in the Vision Paper and summarized in Section 2 of this report, transformation of LDCs to FINOs is described in terms of progress along three dimensions – DER-enabling Platform, DER Integration, and DER Control and Operation.

VISION	REVIEW AND ANALYSIS	CHALLENGES
FINO: <ul style="list-style-type: none"> ■ DER-enabling Platform ■ DER Integration ■ DER Control & Operation 	Legislation & Regulation Long-Term Energy Plan Climate Change Action Plan Integrated Regional Resource Plans Market Renewal Program Conservation First Framework	<ol style="list-style-type: none"> 1. Updates to Rules and Provisions 2. Augmented Distribution Planning 3. Uncoordinated Centralized Procurements 4. Perception of LDC Capabilities 5. Pricing and Rate Design

Figure 4. Summary of Challenges

A review and analysis of the various laws, regulations, codes, and rules that govern LDCs in Ontario (i.e., “statutory framework”) was completed to determine the challenges that are preventing industry transformation. This included a review of the following:

- *Electricity Act, 1998;*
- *Ontario Energy Board Act, 1998;*
- *Green Energy and Green Economy Act, 2009;*
- *Strengthening Consumer Protection and Electricity System Oversight Act, 2015;*
- *Energy Statute Law Amendment Act, 2016;*
- *Climate Change Mitigation and Low-carbon Economy Act, 2016;*
- Distribution System Code (DSC);
- Transmission System Code (TSC);
- Affiliate Relationship Code (ARC);
- Renewed Regulatory Framework for Electricity;
- Delivering Fairness and Choice (2017 LTEP);
- Integrated Regional Resource Planning (IRRP);
- Market Renewal Program;
- Net Metering Regulation (O. Reg. 541/05); and
- Conservation First Framework.

In consultation with EDA members, five underlying themes have been identified and will need to be addressed in order to enable a full transformation of LDCs to FINOs. Within the context of Ontario's statutory framework, these are:

- Updates to rules and provisions;
- Augmented distribution planning;
- Uncoordinated centralized procurements;
- Perception of LDC capabilities; and
- Pricing and rate design.

Each of these themes are discussed in sections 3.1 through 3.5 below, with a description of how these challenges and barriers are impeding the evolution of LDCs.

3.1 UPDATES TO RULES AND PROVISIONS

As more DERs are anticipated in distribution networks, Ontario's statutory framework needs to resolve any inconsistencies with respect to DERs. The rules and provisions that govern LDCs, which are embodied within legislation, regulation, codes, and rules, need to be clear and consistent with respect to DERs to enable cost-effective deployment and to maximize their benefits to customers.

Listed below are specific challenges and barriers that LDCs have identified within the current statutory framework:

- **Rules for access to distribution systems:** *The Green Energy and Green Economy Act* granted renewable generation priority access to distribution systems² to facilitate greater deployment of renewable energy in the context of the FIT program, which has recently been phased out. Similar clarification for DERs has not been granted equivalent priority access to distribution systems, which calls into question the relative priority of all DERs and the planning requirements of the LDC.
- **Need to define additional DER services:** The OEB's DSC defines generators and loads but does not explicitly provide guidance in respect of resources that have characteristics of both load and supply, such as energy storage or vehicle-to-grid systems. While these resources can provide benefits to individual customers, distribution systems, and the broader Ontario grid, there is uncertainty with respect to how the services and benefits can be 'stacked', as described in more detail below.
- **Limits with respect to distribution services:** LDCs are licenced to provide distribution service (e.g., sale and distribution of electricity) which does not explicitly address the control and/or operation of resources connected to distribution systems whether owned by LDCs or other entities.

² Refer to Section 26 (1.1) of the *Electricity Act*.

When the *Green Energy and Green Economy Act* was implemented, Ontario’s regulatory framework was updated to help ensure consistency across the province and to provide guidance to LDCs, particularly with respect to the implementation of the FIT program. With continued evolution of the electricity sector, and emergence of new and cost-effective DER options for LDCs and customers, there is a need to reflect on whether the statutory framework continues to meet policy objectives. For example, is priority access to distribution systems for renewable generation still required, or should LDCs be required to plan and accommodate customer connection requests for all non-emitting DERs on an equal footing? This question is material as LDCs plan upgrades to distribution systems in anticipation of requests from customers for new net-metered solar systems, EV connections, or energy storage systems.

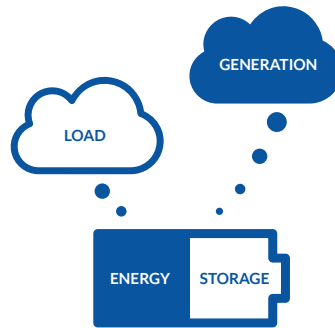


Figure 5. Energy Storage

In 2015 the OEB created a new class of licence for energy storage.³ With both attributes of load and generation, energy storage can provide a variety of electricity services ranging from essential reliability services (e.g., frequency response) to customer-driven utilization to help manage electricity costs (e.g., Industrial Conservation Initiative). As a result, energy storage resources can provide services to individual customers and the electricity grid more broadly; however, there is uncertainty with respect to how LDCs or its customers might access various revenue streams, or whether LDCs can control customers’ resources to provide electricity system benefits.

All LDCs must be licensed by the OEB and must comply with conditions of their licences. This includes compliance with the *Electricity Act*, the *Ontario Energy Board Act*, as well as various OEB Codes including the DSC and the Retail Settlement Code (RSC). The licence definition of distribution services includes services related to the distribution of electricity and the sale of electricity to consumers. However, it does not explicitly give LDCs the capability to control and/or operate resources on their distribution systems that are not owned by respective LDCs (as noted in the OEB’s July 2010 compliance bulletin).

In addition, the DSC defines both an “operational demarcation point” and an “ownership demarcation point”. The operational demarcation point is the location at which an LDC’s responsibility for the operational control of distribution equipment ends at the customer. The ownership demarcation point is the location at which an LDC’s ownership of distribution equipment ends at the customer. Both demarcation points were defined well before DERs became prevalent on the system. Depending on interpretation, it is unclear whether a DER would be considered “distribution equipment” which could limit the ability of LDCs to own or potentially control DERs on the customer’s side of the meter.

³ Electricity storage licence. <https://www.oeb.ca/industry/licensed-companies-and-licensing-information/apply-licence/electricity-storage-licence>

While the *Strengthening Consumer Protection and Electricity System Oversight Act* (i.e., Bill 112) allows the OEB to authorize LDCs to carry out business activities other than the distribution of electricity, it is not clear how the OEB will evaluate such proposals other than those classified as “special circumstances”. The RRFE states that LDCs must demonstrate value to customers for new investments, but there is currently no guidance provided. By way of discussion with many LDCs, they have stated that without clear guidance on the decision-making framework the OEB would use to review proposals under Bill 112, it is challenging to invest in the development of new business strategies, which could include deployment strategies for DERs and the control and/or operations of customer-owned DERs within their network.

Energy Storage: It should be noted that Ontario has recently taken some significant steps with respect to the deployment of energy storage:

1. As of July 2017, Ontario’s Net Metering Regulation (O. Reg. 541/05) permits energy storage to be used in conjunction with a renewable energy generation and the capacity restriction on the generation system has been eliminated;
2. The OEB recently developed a new class of licence for energy storage facilities;
3. In accordance with the 2017 LTEP, O. Reg. 429/04 is being amended to provide greater definition of energy storage and provides that Class B energy storage facilities with an average monthly peak demand under 1 MW remit Global Adjustment only on net consumption.

Summary of Impact:

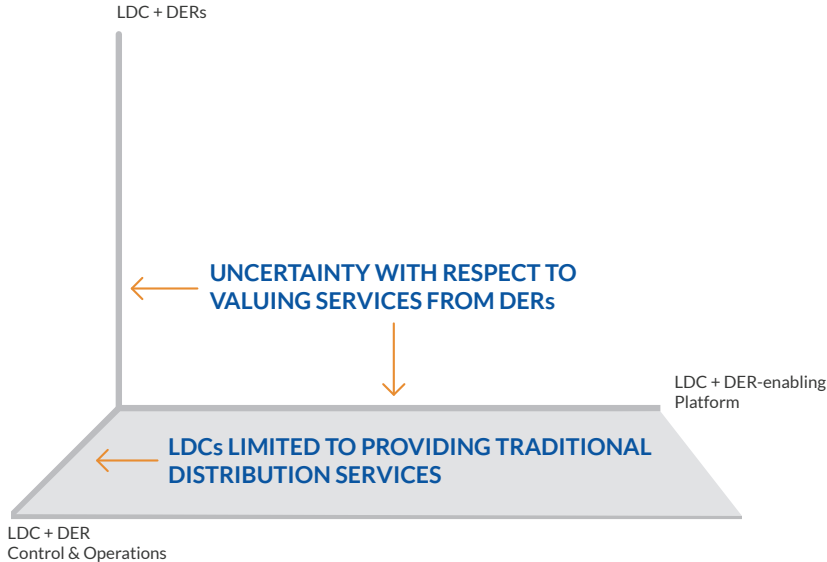


Figure 6. Impacts of Rules and Provisions

3.2 AUGMENTED DISTRIBUTION PLANNING

All LDCs are required to file DSPs as part of their rate applications to the OEB. The onus is on LDCs to demonstrate that investments are appropriate (i.e., they will support the ongoing provision of service) and eligible for inclusion in the rate base. This applies to all investments, including potential DERs. Currently, DSPs are expected to include smart grid investments, but not DERs specifically.

The purpose of a DSP is to present a long-term plan for revenue that LDCs need to fund capital improvements and evolution of their systems. Today's DSPs define system needs and describe distribution assets that are required to meet these needs and other policy objectives, such as CDM. While DERs can be useful to meet local system needs, LDCs have indicated that it is risky to leverage DERs in their DSPs because there is uncertainty with respect to the criteria for the evaluation of non-wires solutions versus traditional distribution assets.

Listed below are specific challenges and barriers relating to distribution planning and rate-basing as it pertains to the evolution of LDCs to FINOs:

- **Increasing complexity of DSP:** Investments in distribution assets identified within DSPs must necessarily be justified in respect of meeting system needs and policy objectives, to receive approvals from the OEB in the context of rate filing. As more DERs are adopted by customers, or considered by LDCs as non-wires alternatives, DSPs will need to evaluate multiple options (i.e., integrated resource plans may be required to evaluate multiple resource options). This adds complexity to regulatory review and creates risks for LDCs if the OEB does not agree with the options an LDC selects for rate recovery.
- **Uncertainty with respect to rate-basing DERs:** LDCs have indicated that there is a need for additional certainty and clarity with respect to what can be reasonably justified to be rate-based versus what should be accounted for through LDCs' unregulated affiliates or non-LDC third parties, including guidance with respect to rate-basing services from DERs (e.g., rate-basing partial value of a DER asset). Since a DER may have access to external revenue sources (e.g., IESO market revenues and on customers' benefits), the rate-basing decisions will need to consider quantification of external revenues, appropriate dispersal of benefits, and risk analysis.
- **Updates to the RRFE Scorecard:** The scorecard is focused on the traditional 'poles and wires' business model and does not consider transformative elements for LDCs, such as the integration or optimization of DERs. The OEB uses the RRFE Scorecard as a signal to LDCs to determine whether corrective actions are needed within a rate-setting approach, which may potentially include rate reduction. Therefore, LDCs experience incremental risk for pursuing activities that are not directly related to the scorecard since the non-scorecard activities are not a measure of performance under the RRFE.
- **Uncertainty with respect to smart grid deployment:** LDCs have stated that there is a need for clearer guidelines with respect to deployment of smart grid due to uncertainties regarding cost recovery, either through regulated rates or through qualification of programs.

DSPs are used to demonstrate that LDCs are taking steps to meet policy objectives and long-term planning - 'planting seeds' for future investments. This long-term view also allows LDCs to plan and take a measured approach on investments for rate smoothing and minimizing rate shocks.

Smart grid infrastructure is foundational for enabling DERs. While the *Ontario Energy Board Act* states that the OEB has a requirement "to facilitate the implementation of smart grid in Ontario", the OEB concluded, as part of the RRFE, that it would implement an integrated approach for infrastructure planning in all categories of network investment, including renewal, expansion, connection of renewables, and smart grid, without regulatory certainty on how to evaluate investments. As such, there is limited guidance with respect to expectations for smart grid investments.

Looking back to another time of transition within Ontario's electricity sector, when the *Green Energy and Green Economy Act* was implemented, the DSC was amended to make LDCs responsible for the costs of "renewable enabling improvements" – investments made by LDCs to accommodate increased levels of renewable generation. Those investments included upgrades to protection and control devices and communication protocols. Today, other DERs offer many benefits to distribution systems and Ontario's broader electricity system, including the ability to further increase the level of renewable generation. If part of the funding for DERs is from market revenue (e.g., energy sold into the IESO-Administered Market) while the other part of funding is recovered through rates for services provided directly to the LDC (e.g., peak shaving), there is a need to consider how much market revenue risk is appropriate for the rate-base. In other words, DERs may yield other revenues that LDCs believe would be eligible for inclusion in revenue offsets.

Effective DSPs should consider a wide range of inputs including the integration of resources. Asset management plans have been essential; however, going forward LDCs will need to consider information from a variety of sources, including feedback with respect to customer preferences and non-wire resource options. LDCs will need to incorporate this information into their DSPs, and leverage digitization and other software that provides greater visibility of resources within their networks. While distribution system planning will become more complex with more options to evaluate, LDCs are well positioned to adapt to this added complexity as they have increased experience with DERs over the years.

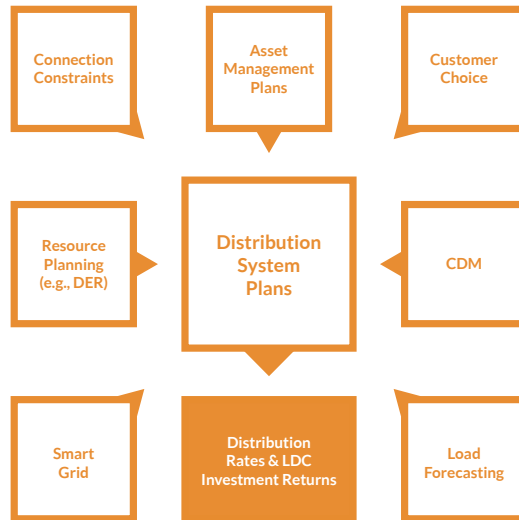


Figure 7. Augmenting Distribution System Plans

Summary of Impact:

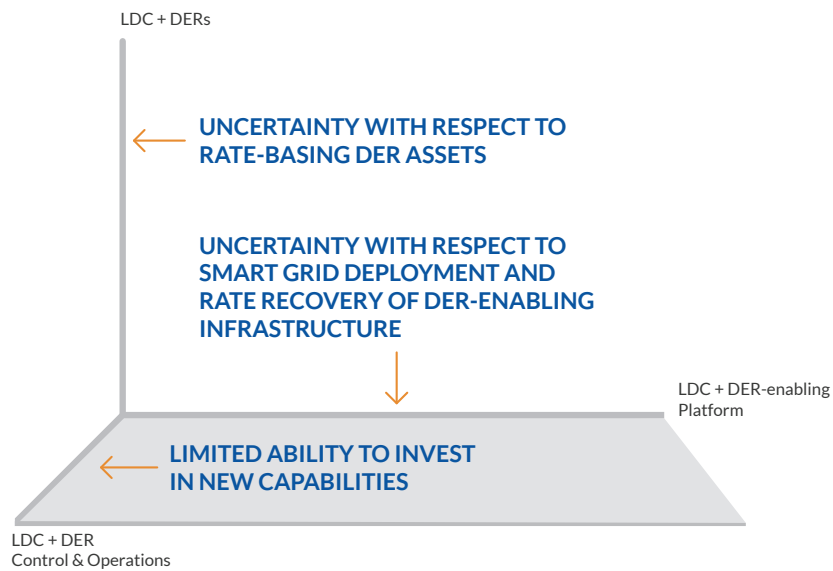


Figure 8. Impacts of Distribution Planning

3.3 UNCOORDINATED CENTRALIZED PROCUREMENTS

Within Ontario's statutory framework, the planning and procurement of electricity resources is mainly centralized and coordinated by the Ministry of Energy, IESO, and OEB. As described below, while Ontario has a defined approach for regional planning (i.e., IRRPs) the current resource procurement framework does not effectively coordinate or adequately consider local system impacts.

Listed below are some specific challenges and barriers relating to the current centralized procurement frameworks which are hindering the evolution of LDCs:

- **Limited consideration of local impacts:** The IESO leads the centralized procurement of electricity resources, including many distribution-connected resources, to meet system reliability needs, or in response to policy direction from the Ontario Government. As a result, there is the potential for the IESO's procurement initiatives to impede or conflict with LDCs' priorities as defined within applicable DSPs. This may result in the IESO procuring resources that could be inconsistent with a respective DSP. In turn, an LDC would need to accommodate the new resource which may have longer-term implications and costs (e.g., new resource lowers transmission connection rate revenue leading to unanticipated true-up payments by the LDC to the transmitter).
- **No specific obligation to serve load:** LDCs do not have an explicit mandate to 'serve their load'⁴ in the sense of ensuring that adequate resources are maintained and developed to meet specific resource adequacy requirements, including supply to meet their customers' load requirements. While LDCs have an obligation to connect customers, the obligation to serve load mainly resides with the IESO unlike many other jurisdictions (e.g., utilities across many U.S. states).

At the end of 2016, the Ontario Government passed the *Energy Statute Law Amendment Act* (i.e., Bill 135) that amended the planning process of Ontario's electricity sector. Bill 135 emphasized the importance of the LTEP and established a technical assessment stage for the IESO to complete⁵ that would inform the development of the LTEP. The LTEP is the central electricity plan, overseen by the Minister of Energy, and sets out the policy and priorities of the Ontario Government for the electricity sector and, in turn, influences investment decisions across the province. That said, while the LTEP will guide decisions with respect to procurement of resources, it has not yet to date prescribed a framework for IESO-LDC coordination.⁶

The FIT program is an example of a centralized procurement that has had significant impacts on Ontario's LDCs. LDCs were instrumental in the FIT program, and there has been significant coordination between LDCs, the IESO, the OEB and the Ministry of Energy with respect to the implementation of the FIT program. That said, for the most part, LDC engagement has been limited in scope focusing primarily on interconnection. LDCs provide information about "connection capability", but do not provide input with respect to "optimal" resource location. While customers were encouraged to engage with their LDC prior to proceeding with a FIT application, for the most part, LDCs had little visibility into the potential projects that might be approved within their networks, adding uncertainty to the distribution system planning process.

⁴ Load-serving entities secure energy and delivery service (and related interconnect operations services) to serve the electrical demand and energy requirements of their end-use customers.

⁵ In 2016, the IESO completed the Ontario Planning Outlook (OPO) as the technical assessment stage informing the development of the 2017 LTEP. The 2016 OPO did not include any commentary, analysis, conclusions, or recommendations regarding distribution systems relating to system needs, etc.

⁶ Neither 2010 LTEP, 2013 LTEP, or 2017 LTEP prescribed any framework for IESO-LDC coordination.

From a broader perspective, LDCs work with the IESO to prepare IRRPs, and provide relevant electricity system data to the IESO for bulk system planning and resource adequacy assessments. The regional planning process coordinates the needs of the electricity system across different service territories and establishes the cost responsibility for electricity system investments.

The first stage of regional planning is led by the transmitter in a ‘top-down’ approach. The planning process does not have the mandate to initiate procurements for resource options within a region or local area. Further, the potential for the use of local resources to meet identified needs have been assessed with the assumption of participation in central procurement initiatives, rather than the potential for procurement through targeted local initiatives.

Today’s electricity procurement process could improve with respect to optimizing the use of DERs on the electricity systems. As illustrated in Figure 9 below, how a DER is used, or the services that the asset owners or customers are seeking, will influence how a DER is connected onto the system. Should a DER be connected at the transmission-distribution interconnection? Should it be connected directly to the distribution system? Or behind-the-meter of a customer?

LDCs have also stated that there is a risk of stranded transmission connection facilities if procurements remain uncoordinated. Analysis and input from LDCs is required to ensure that the procurement of resources and DERs do not result in additional cost to that LDC’s rate-payers. The OEB’s TSC provides information regarding true-up calculations that may be required in the case of transmission expansion, and states that payment is required if the actual load is lower than the load in the initial load forecast. The cost and risk associated with a transmission connection will be an important component of integrated resource planning by LDCs for their service territories

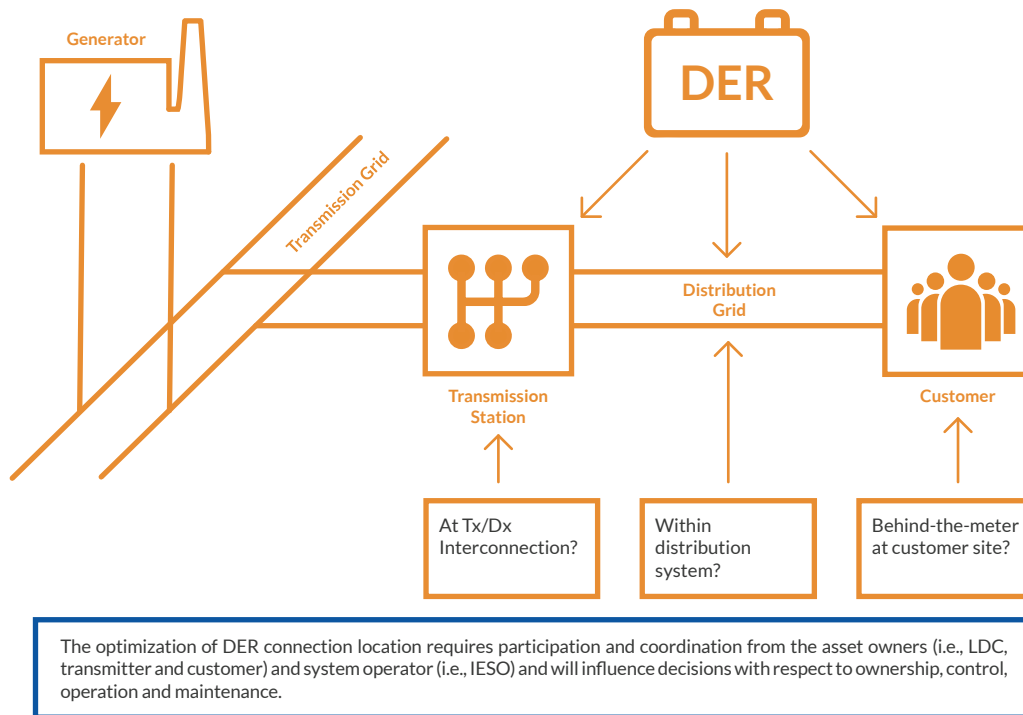


Figure 9. DER Planning and Optimization

For LDCs to become FINOs, the planning process will need to be appropriately decentralized to provide LDCs with the authority to engage in additional activities beyond the distribution of electricity, such as the procurement and management of the electricity products. LDCs will need to have more control in respect of the planning to meet resource needs within their service territories; this includes the possibility of removing restrictions on LDCs, which then enables them to function more like Load-Serving Entities (LSEs).

In summary, the root of the challenge within the current framework is that LDCs have had little input with respect to the optimization of siting resources centrally procured within their service territory. As a result, without LDC involvement in centralized procurement, the installation of DERs may occur in regions of the grid that do not have optimal value to the distribution system.

Summary of Impact:

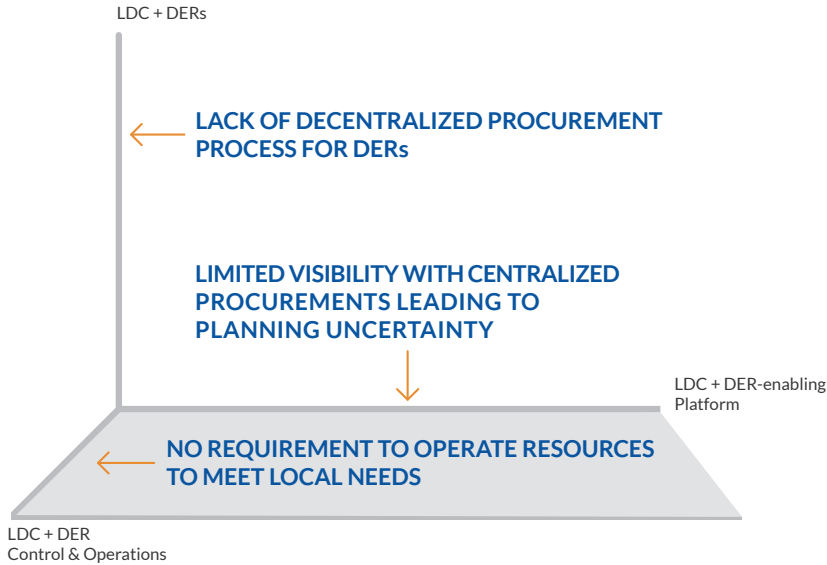


Figure 10. Impact of Uncoordinated Centralized Procurements

3.4 PERCEPTION OF LDC CAPABILITIES

Ontario's electricity sector has a unique organization of LDCs whose diversity can be beneficial in meeting the needs of electricity customers. The ownership and scale of the over 60 LDCs varies across the province, although most are municipally-owned with very little private sector ownership. As a result, LDCs will be on different trajectories in their evolution towards becoming FINOs.

Listed below are specific challenges and barriers regarding the perception of LDC capabilities and the evolution towards FINOs:

- **Varying structures of LDCs:** Although there is a need for a consistent and clear statutory framework to enable the transformation of LDCs to FINOs, each LDC will evolve independently of others and, therefore, the statutory framework must also be flexible enough to accommodate the unique characteristics of each LDC and the communities they serve.
- **Coordination with and amongst LDCs:** Many of the functions within the current statutory framework are centralized through the IESO and the OEB, who are required to coordinate with a wide range of LDCs, each with unique characteristics. LDCs also need to coordinate with each other. Coordination is required for planning functions (e.g., development of IRRPs), IESO operations, and the administration of government programs, etc.

Transfer and Departure Tax: It has been generally acknowledged that the Ontario transfer tax and departure tax rules have inhibited consolidation of LDCs and may, in some cases, have limited the ability of LDCs to access private capital that could fund upgrades and expansion of distribution networks, including enabling DERs.

The Premier's Advisory Council on Government Assets⁷ report recommended that the province alleviate some of the applicable tax barriers. These recommendations were introduced by way of the Provincial Budget in 2015. Until December 31, 2018, the Ontario Government has reduced the transfer tax rate from 33 to 22 per cent, and exempts Municipal Electricity Utilities with fewer than 30,000 customers from the transfer tax. In addition, the measures include an exemption for any capital gains arising under the PILs deemed disposition rules.

The EDA's recent submission to the Ministry of Energy regarding the development of the 2017 LTEP recommended that the government consider extending the tax relief to enable further voluntary consolidation.

In Ontario, and as demonstrated in the Vision Paper, LDCs of all scales and sizes are investing in smart grid pilot projects, renewable energy, and other DERs. To move forward in their evolution to FINOs, LDCs will need to take on more obligations that are associated with broad-scale deployment of DERs, investment in DERs, as well as develop tools for the control and operations of DERs within their systems.

⁷ Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First. <http://www.energy.gov.on.ca/en/ldc-panel/>

With a wide range of industry stakeholders, Ontario’s legislators and regulators will need to develop the appropriate framework that both encourages and rewards LDCs for taking steps towards changing business models, without penalizing those that might be on a different trajectory. Furthermore, the framework will need to consider the customer experience, particularly with respect to customers operating within the service territories of multiple LDCs, as the service availability and approach among LDCs may vary.

Summary of Impact:

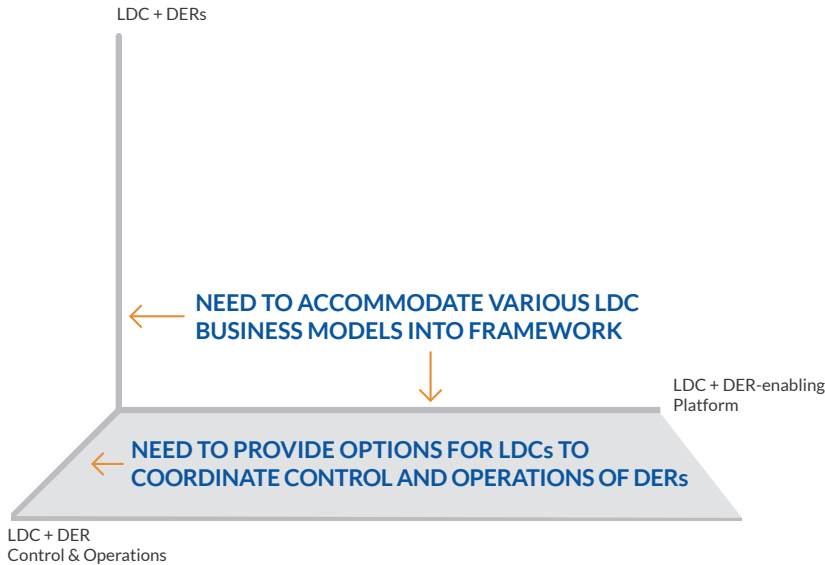


Figure 11. Impact of Perception of LDC Capabilities

3.5 PRICING AND RATE DESIGN

If LDCs are to make the transition to FINOs, wholesale electricity prices for energy, capacity and ancillary services need to provide accurate price signals to drive effective investments in DERs. Since some Ontario market entities are not settled directly based on actual wholesale electricity prices and instead based on regulated rates, the rates themselves will need to provide sufficient approximations of electricity costs. These inputs will also help accurately justify the need for DER-enabling infrastructure, development of DERs, and other FINO investment requirements.

- Efficient wholesale electricity pricing recognizes the locational supply and demand balance and considers the value of energy, ancillary services, and capacity.
- LMPs reflect the value of electric energy at different locations (i.e., nodes) on the grid and accounts for the patterns of load, generation, and the physical limits of the transmission system.

The IESO's Market Renewal Program is a set of the most ambitious enhancements to Ontario's wholesale electricity market design and rules since the market opened in May 2002. The Market Renewal Program will deliver design changes that will: 1) send transparent price signals to meet different system needs by improving utilization, scheduling, and dispatch of existing resources in the day-ahead and real-time time frames; 2) increase competition amongst resources with the goal to deliver greater efficiency and flexibility; and 3) achieve resource adequacy in more cost-effective and transparent ways. The Market Renewal Program is being designed to work effectively within Ontario's policy framework while also preparing for further changes in the sector. Design of these enhancements are being discussed with stakeholders now and are planned to be implemented over the course of the next two to 10 years.

Economically efficient wholesale electricity prices and effective rate design can enable timely investment in DERs and DER-enabling infrastructure by providing an accurate valuation of these resources versus other options. Currently in Ontario, changes to wholesale electricity prices are being considered, which will then require electricity rates themselves to be re-designed. This includes the IESO's Market Renewal Program which includes the implementation of LMP for energy - replacing today's uniform pricing, the Hourly Ontario Electricity Price (HOEP) and the five-minute Market Clearing Price (MCP). This change will also result in changes to the calculation of the Regulated Price Plan (RPP) for default supply customers. Similar changes are being contemplated through the planned implementation of Incremental Capacity Auctions (ICAs), which will likely impact the calculations of Global Adjustment (GA).

It is important to recognize that enabling DERs and their development could be impacted by the outcome of the IESO's Market Renewal Program, how energy pricing and capacity auctions are implemented, and how they impact rate design. Regardless, the evaluation of DER-related investments needs to reflect the total cost of electricity supply (generation, transmission and distribution) and not just the distribution component of rates.

Challenges related to efficient pricing and rate design impacting the deployment of DERs and optimization include the following:

- **Inefficient and non-transparent prices:** Wholesale electricity prices (i.e., energy, ancillary services, capacity, etc.) should be locational and reflect actual demand/supply conditions at that location on the grid. If wholesale electricity prices do not reflect locational values and are not transparent, DERs may be developed in sub-optimal locations.
- **Ineffective rate design:** Regulated rates need to be based on both efficient and transparent wholesale electricity prices and should be designed to provide efficient pricing. That is, the closer regulated rates approximate wholesale electricity prices, more effective decisions will be made regarding maintenance and development of distribution assets including DERs.

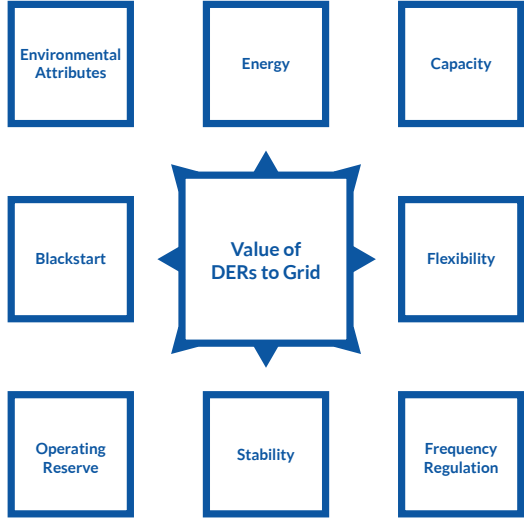
Today, most generation facilities in Ontario either have long-term contracts with the IESO or are rate-regulated by the OEB (i.e., Ontario Power Generation's (OPG's) nuclear and baseload hydroelectric generation including pump storage). As a result, Ontario's electricity market has been characterized as a 'hybrid market' with a province-wide wholesale market for energy and contracted capacity, both of which are administered and managed mainly by the IESO. Given

that the contracted portion of the supply costs are largely recovered through the GA as a fixed monthly charge, there are no price signals to customers for this portion of the cost of electricity.

Ontario’s LDCs pass through wholesale costs (i.e., wholesale market price, GA, etc.) to their customers as part of their billing and settlement responsibilities. The large portion of costs attributed to GA through contracted and rate-regulated resources limits the ability of LDCs and all actors to determine the long-term value of DER resources and DER-enabling infrastructure.

For LDCs to actively control and manage electricity usage within their distribution systems, location-based price signals - or LMPs - will help inform economic investment and operation. Locational need, constraints, and generation availability information would be provided to a control room and would actively inform how DERs are optimized within the network. This active visibility and control of resources would also inform DSPs with respect to when resources should be maintained, retired, or replaced.

Furthermore, transparent wholesale market prices would help to derive the maximum benefit of DERs, and should include various value attributes DERs may be able to provide to the bulk electricity system, as demonstrated in Figure 12 below.



<p>Energy (MWh): Real-time delivery of electricity to meet demand needs</p> <p>Capacity (MW-year): Availability to provide capacity to meet peak electricity demand needs for a season (e.g., winter or summer)</p> <p>Flexibility (MW/min): Ability to adjust output at each dispatch interval to match changing load patterns during ramping periods (i.e., morning ramp-up and evening ramp-down of load) and load-following periods (i.e., overnight or midday)</p> <p>Frequency Regulation or Regulation Service (+/- MW & MW/min): Load balancing services between the market dispatch intervals</p>	<p>Stability (MVAR): Voltage regulation or reactive power to maintain system stability for transfer capability throughout the power system</p> <p>Operating Reserve (MW): Ability to deliver electricity upon demand after an outage event has occurred (e.g., transmission line outage, generator-forced outage, etc.)</p> <p>Blackstart (MW): Ability to start up and deliver electricity to the grid without synchronization. In addition, ability to maintain stability, frequency regulation and energy to allow other power system resources (i.e., generators) to restart the power system.</p> <p>Environmental Attributes (EA): Value attributed to clean or renewable generation that offset GHG emissions and/or other pollution (e.g., NOx, SOx, PM2.5, etc.)</p>
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Figure 12. Potential Value Attributes of DERs to the Bulk Electricity System

Efficient pricing would reflect the potential value streams of DERs investments, and would inform where these resources could be optimized on the electricity grid.

In terms of the evolution of LDCs towards becoming FINOs, efficient price signals will help identify locations within the distribution network where investment in DER-enabling infrastructure will be economic. Efficient price signals would inform the business case for LDC ownership of DERs and would provide a framework for control and operation of DERs. A FINO would take more responsibility in controlling and operating DERs.

Summary of Impact:

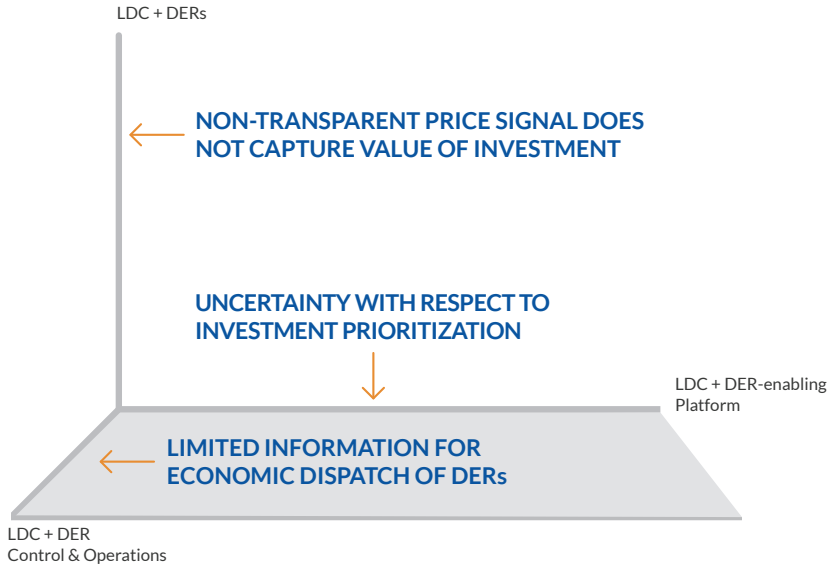


Figure 13. Impact of Pricing and Rate Design

3.6 SUMMARY OF CHALLENGES AND BARRIERS

The Vision Paper defined new roles, responsibilities, and obligations for LDCs in Ontario, with customer benefits central to decision making. Although the statutory framework for the electricity sector in Ontario has evolved and changed in recent years, it is designed to accommodate traditional 'poles and wires' LDCs.

In summary, there are five key challenges that need to be addressed for LDCs to take on a greater role with enabling, integrating, and controlling/operating DERs:

- The rules and provisions governing LDCs have not been updated to reflect an increase of DERs within distribution networks (e.g., priority access), there is a lack of definition for certain DERs (e.g., energy storage), and LDCs' licences are limited to distribution services limiting their ability to operate DERs;
- There is increased complexity with respect to DERs and distribution planning and a need for additional guidance with respect to rate-basing DERs and deployment of smart grid, and the current RRFE scorecard evaluates LDCs based on the traditional utility model;
- Centralized procurements do not necessarily align with LDC planning and LDCs do not have a requirement to serve load;
- A wide range of LDCs must be accommodated in Ontario's statutory framework; and
- Current wholesale electricity prices (e.g., HOEP, MCP) do not accurately reflect the locational cost and value of electricity supply, which in turn does not allow the benefits of DERs to be realized.

The Vision Paper describes FINOs with more responsibilities and obligations to customers compared to LDCs as they operate today. In this transition, the linkages and relationships to other entities within the electricity sector will also shift. For example, FINOs will have more interaction with the IESO through increased planning and the operation of DERs in response to wholesale market price signals. LDCs would also have more autonomy to make decisions about resources connected into their systems. Similarly, LDCs would have different obligations with respect to reporting to the OEB; rate filings would consider investments beyond the traditional utility model. In that sense, the role of the OEB is to establish a clear framework and ensure that LDCs are acting in the best interest of their customers.

Each of the challenges discussed in this report, while presented separately, is interconnected with each other. For example, the need for augmented distribution planning is interconnected to the need for coordinating centralized procurements. Further, efficient pricing of electricity products will help inform distribution planning priorities. The grouping of each of the challenges has been done to concisely convey the nature of each challenge, and to help identify specific potential solutions.

Summary Table:

Theme	Challenge or barrier	Description	Statutory references
1. Updates to Rules and Provisions	Rules for access to distribution system	Grid access currently grants renewables priority, with other DERs not provided the same guidance for access to the grid	<i>Electricity Act, Green Energy and Green Economy Act</i>
	Define additional DER services	Only load and generation clearly defined, and uncertainty with respect to valuing various services from DER resources	<i>Electricity Act, Ontario Energy Board Act</i>
	Limits with respect to distribution services	LDCs limited to providing distribution services, which does not include operations of DERs	<i>Ontario Energy Board Act</i>
2. Augmented Distribution Planning	DERs increasing complexity of DSPs	Evaluation of potential “non-wires” resource options	RRFE
	Uncertainty with respect to rate-basing DERs	No framework defined for the approval of LDC investment in DERs	RRFE
	Updates to the RRFE Scorecard	RRFE scorecard focuses on traditional LDC services	RRFE
	Uncertainty with respect to smart grid deployment	Need for guidance to facilitate investments in smart grid	RRFE
3. Uncoordinated Centralized Procurements	Limited consideration of local impacts	IESO centralized procurement does not consider LDC planning	<i>Electricity Act</i>
	No specific obligation to serve load	No requirement to plan for electricity supply within service territory	<i>Electricity Act, Ontario Energy Board Act</i>
4. Perception of LDC Capabilities	Varying structures of LDCs	Statutory framework must accommodate a variety of LDC business models and approaches	<i>Electricity Act, Ontario Energy Board Act</i>
	Coordination with and among LDCs	LDCs must coordinate planning and operations with IESO, OEB and transmitter	IRRP, DSC, TSC
5. Pricing and Rate Design	Inefficient and non-transparent prices	Wholesale electricity prices do not value attributes of DERs	<i>Electricity Act, IESO Market Rules</i>
	Ineffective rate design	Rates are not based on efficient wholesale prices	<i>Ontario Energy Board Act</i>

Figure 14. Summary of Challenges and Barriers

The next section of this report proposes potential solutions to the challenges and barriers that have been identified.

4. SOLUTIONS AND RECOMMENDATIONS

The categorization of the challenges and barriers that LDCs face in transitioning their businesses through enabling, owning, and controlling/operating DERs has been a necessary step to developing the solutions for consideration to facilitate the transition of LDCs to FINOs. To this end, the EDA and Power Advisory have reflected on changes that could be made to Ontario's statutory framework based on Ontario's unique policy context. This has been done from both holistic and practical implementation standpoints. Moreover, any potential change to the statutory framework needs to be evaluated in the context of benefits to electricity customers and other policy goals, such as reducing costs, improving reliability, creating choice, improving the environment, and reducing GHG emissions.

CHALLENGES	SOLUTIONS
1. UPDATES TO RULES AND PROVISIONS <ul style="list-style-type: none"> Rules for access to distribution systems Define additional DER services Limits with respect to distribution services 	1. Levelling the playing field for DERs 2. Improved definition of DERs and potential services
2. AUGMENTED DISTRIBUTION PLANNING <ul style="list-style-type: none"> DERs increasing complexity of DSPs Uncertainty with respect to rate-basing DERs Updates to RRFE Scorecard Uncertainty with respect to smart grid development 	3. Improving DSPs through investments in grid-visibility 4. Remove restrictions on LDC ownership of resources 5. Guidelines for rate-basing of DERs and DER-enabling assets consistent with DSPs
3. UNCOORDINATED CENTRALIZED PROCUREMENTS <ul style="list-style-type: none"> Consideration of local impacts No specific obligation to serve load 	6. Coordinating and decentralizing procurement of resources and DERs 7. Allowing LDCs to control and operate DER assets
4. PERCEPTION OF LDC CAPABILITIES <ul style="list-style-type: none"> Varying structures of LDCs Coordination with and among LDCs 	8. Shared services of LDCs with respect to control and operations
5. PRICING AND RATE DESIGN <ul style="list-style-type: none"> Inefficient and non-transparent prices Ineffective rate design 	9. Eventual development of LMP+D

Figure 15. Summary of Proposed Solutions

To address these issues, the following nine high-level solutions have been identified:

- Levelling the playing field for DERs;
- Improved definition of DERs and potential services;
- Improving DSPs through investments in grid visibility;
- Remove restrictions on LDC ownership of resources;
- Guidelines for rate-basing of DERs and DER-enabling assets that are consistent with DSPs;
- Coordinating and decentralizing procurement of resources and DERs;
- Allowing LDCs to control and operate DER assets;
- Shared services of LDCs with respect to control and operations; and
- Eventual development of LMP+D.

The remainder of this Section 4 provides an overview of these nine recommendations, and Section 5 outlines the suggested steps to implement the recommendations.

4.1 LEVELLING THE PLAYING FIELD FOR DERs

Resolution for: Updates to Rules and Provisions

Ontario needs to update the rules for DER access to distribution systems to reflect the needs of the future electricity grid and recognize that current rules reflect a point in time with respect to the integration of renewables. LDCs should have an explicit obligation to plan for DERs on their system in response to changing market conditions and customer requests for different technologies.

In Ontario, renewable energy projects have legislated priority access to distribution systems, whereas the relative priority of other DER resources is unclear. As an example, it is unclear how LDCs should prioritize a customer's request for the installation of EV charging infrastructure versus other connection requests.

While we are not suggesting that renewable energy be de-prioritized, we recognize that if everything is a 'priority', then nothing is priority. A level playing field will improve LDC planning capabilities, as LDCs are able to select the best resources to meet specific needs and objectives (such as reducing GHG emissions), as opposed to, for example, expanding the grid to accommodate more renewables. In other words, a level playing field would enable LDCs to more holistically plan their distribution system, considering a variety of assets such as EVs, energy storage, and solar – all of which contribute to lowering GHG emissions, rather than solely focusing on renewables on their own.

This change would be accomplished through amendments to the *Electricity Act*, and subsequent alignment of other codes and policies, such as the DSC.

4.2 IMPROVED DEFINITION OF DERs AND POTENTIAL SERVICES

Resolution for: Updates to Rules and Provisions

While it may not be feasible to list or define every type of DER within regulations and codes, greater definition is required for energy storage services, which act both as generation and load, within Ontario's electricity statutory framework. A second recommendation would be to outline provisions for enabling EV charging infrastructure, given the increase in customer demand expected for the coming years.

For example, the Smart Grid Advisory Committee developed provisions for energy storage,⁸ but the OEB's codes were not updated to reflect this work. Energy storage is effectively treated as a generating resource, which ignores the grid balancing, power quality, and system stability services it can provide (e.g., ancillary services). This change would recognize the ability of resources (like energy storage) to provide benefit to both individual customers and the electricity grid.

LDCs have indicated that energy storage and EVs are immediate term priorities, given customer demand and policy focus on reducing electricity costs and decreasing GHG emissions. This change would be accomplished through changes to the *Ontario Energy Board Act*, and subsequent alignment of other codes and policies, such as the DSC.

4.3 IMPROVING DSPs THROUGH INVESTMENTS IN GRID VISIBILITY

Resolution for: Augmented Distribution Planning

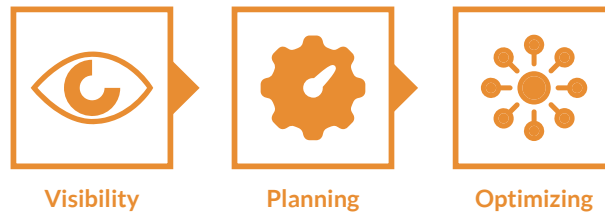


Figure 16. Grid Visibility

Ontario needs to empower LDCs to make the investments in grid visibility to benefit fully from the value of DERs. In this context, 'visibility' refers to the ability to monitor, record, and analyze historic and real-time load flow patterns and customer/resource actions, and includes digitization of distribution assets. Ontario has already taken significant action in this regard through the deployment of smart meters, and the next step would leverage this investment.

DER implementation should be integrated both as part of LDCs' investment plans and their performance measurements. The OEB and LDCs have had mandates to ensure that there is investment in smart grid infrastructure since 2010, but relatively little investment has taken place to deploy smart grid technologies outside of pilot programs. Given that more DERs are anticipated, improving visibility of distribution assets and utilization of real time is becoming increasingly essential. A lack of visibility also creates a risk that expansions and/or upgrades of distributed resources may be over- or under-built, adding costs to the system.

⁸ Smart Grid Advisory Committee. Storage Working Group Report. 2013. https://www.oeb.ca/oeb/_Documents/EB-2013-0294/SGAC_Storage_Report.pdf

Improving electrical visibility will also ensure that DSPs are developed with greater certainty and prudence. Furthermore, additional visibility of the distribution system would enhance the ability of LDCs to coordinate with the IESO in respect of DERs on the grid (e.g., forecasting and dispatch). Grid visibility is enabled through greater digitization of distribution networks, and the ability to leverage software to provide on-the-ground access to information about customers, resources, and other assets operating at the distribution level. LDCs will have access to more data that will justify the needs assessment for additional DER-enabling infrastructure. Increased visibility and digitization will help LDCs identify where DERs themselves might provide benefits to the network (i.e., integrated resource planning), which could support OEB rate applications.

Enhanced planning in this way will ultimately provide significant benefits to customers. Instead of over-building the system to meet peak system needs plus reserve, resources can be deployed more precisely and with greater ability to manage system peaks.

Furthermore, LDCs should also be encouraged to coordinate consultation efforts and engage with electricity customers so that there is an improved understanding of the expected DER uptake that might be driven by customer choice.

This change could be implemented in one of two ways. The OEB could provide guidance with respect to grid-visibility investments through rate filings, or centralized province-wide funding could be made available to LDCs. For example, proceeds from Ontario's Cap-and-Trade program could be a potential source of province-wide funding. Ontario's Climate Change Action Plan clearly demonstrates the role of the electricity sector in helping to meet overall emissions reduction targets. Improving grid visibility enables LDCs to connect more non-emitting DERs, such as solar and energy storage, and operate these resources more efficiently to reduce emissions.

Moreover, as discussed, the RRFE scorecard should be revised to measure the extent to which LDCs have visibility and digitization of their networks, which would provide a clearer incentive for LDCs to plan for these investments.

Smart Meters: Ontario has already taken significant steps to improving grid visibility through early investments in Smart Meters. These investments, driven by province-wide policy, have led to the ability to provide time-differentiated rates and have enabled greater digitization through the Green Button.

4.4 REMOVE RESTRICTIONS ON LDC OWNERSHIP OF RESOURCES

Resolution for: Augmented Distribution Planning

Ontario needs to make amendments to the statutory framework for distribution-integrated resource planning to support the flexibility of LDCs to own DERs, behind-the-meter DERs, and eliminate restrictions based on capacity.

Section 71(3) of the *Ontario Energy Board Act* states that LDCs may own and operate: 1) a renewable generating facility 10 MW or less; 2) a thermal generating facility; and 3) an energy storage facility. An OEB compliance bulletin (July 2010) stated that LDCs are not restricted to owning one qualifying facility. Furthermore, LDCs are required under section 80 of the *Ontario Energy Board Act* to file a notice to the OEB prior to constructing or purchasing a generation facility, and the OEB considers the transaction to mitigate against any anti-competitive behaviours.

These provisions have permitted LDCs to proceed with projects that are part of IESO centralized procurements, such as the FIT program. However, restricting ownership to projects 10 MW and less has put LDCs at a disadvantage in other procurements, such as the IESO's previous Large Renewable Procurement (LRP) Request for Proposals (RFP), which are competitive in nature. While projects greater than 10 MW may not be typically considered 'distributed', the ability of LDCs to participate in such procurements provides the LDC an additional source of revenue that could provide an LDC additional financial stability, freeing up capability to invest in DERs and DER-enabling investments. This, in turn, benefits customers as savings and higher quality services are passed down to customers.

Consistent with the recommendation above, Section 71(3) of the *Ontario Energy Board Act* should also be expanded to include other DER resources, such as EV charging infrastructure and load control devices. Ownership of assets provides LDCs additional options to meet the needs of customers directly and ensure that the benefits of the assets are shared with the rate-base.

The point of demarcation for "ownership" and "operation" will need to be clarified within the DSC with respect to LDC ownership of DERs behind-the-meter. Restricting LDCs to DERs in-front of the meter limits the services and options that LDCs may be able to provide to a customer and could limit cost-effective options that may be considered within their plans. For example, in emergency situations, LDCs could use an asset located behind the meter, such as energy storage, to respond. Or, LDCs could use a behind-the-meter resource to respond to economic market signals.

Outside of a centralized procurement, the path for ownership of DERs should be clarified, as discussed in the next section.

4.5 GUIDELINES FOR RATE-BASING OF DERs AND DER-ENABLING ASSETS

Resolution for: Augmenting Distribution Planning

Ontario needs to develop specific resource integration criteria to guide LDCs in the evaluation of ‘non-wires’ solutions, including DERs and DER-enabling investments. The criteria would provide guidance in respect of how various, and potentially uncertain, benefits can be combined to justify investment by LDCs. The criteria may include integrated resource planning as a key component of DSPs to approve investments and recovery of DER infrastructure costs. Alternatively, DER-enabling infrastructure could be built based on specific policy objectives (e.g., Ontario’s smart meter deployment).

For example, an LDC could in their DSP identify that they have transformer station (TS) capacity issues, a power quality issue, and/or customers requesting higher levels of reliability. These problems could be solved separately through wires solutions (e.g., new or expanded TS, new tap on transformer, new feeder line), or through different DER solutions (e.g., energy storage, peak shaving, automatic load regeneration, etc.).

The criteria should articulate what ‘case’ the OEB requires to support its decision, and why an LDC has chosen one investment over another. The evaluation of DERs should reflect the total cost of electricity and not just the distribution system costs.

This recommendation is consistent with the 2017 LTEP in that the OEB was instructed to evaluate opportunities for cost-effective grid modernization, identify measures for LDCs to facilitate deployment of residential EV smart charging, and consider opportunities to encourage a culture of conservation. This further emphasizes the importance of foundational investments to enable DERs and augmenting coordination with LDCs in the delivery of province-wide programs.

4.6 COORDINATING AND DECENTRALIZING PROCUREMENT OF RESOURCES AND DERs

Resolution for: Uncoordinated Centralized Procurements

Ontario needs to expand the role of LDCs within procurement initiatives. Today, the centralized IESO-led procurement processes (e.g., RFPs, standard offers, auctions, etc.) may require proponents to consult with LDCs, and little other local considerations are evaluated. There is a need to improve coordination and obtain input from LDCs within future procurement processes. Improved coordination will help ensure that DERs are geographically located in areas of a distribution network that maximize benefits to customers and are consistent with respective DSPs.

This can be achieved as follows, where appropriate and applicable:

- For centralized procurements, consider prioritizing projects that have ‘LDC support’ in conjunction with other project evaluation criteria and requirements; and
- Develop decentralized mechanisms for LDCs to procure DERs and DER-enabling infrastructure that meet local needs and/or objectives, consistent with either IRRPs and/or DSPs.

The former could be accomplished through revisions to the various program rules, procurement mechanisms (e.g., RFPs) and/or application processes of the IESO or other body administering programs. In past procurements, the IESO awarded priority points to projects that have municipal support or Indigenous support (e.g., FIT program, LRP RFP, etc.). In future procurements, where projects connect to distribution systems, support provisions from LDCs could be incorporated in the IESO's procurement processes (e.g., DR auctions, or the planned ICA per the IESO's Market Renewal Program) or program design criteria for other government incentive programs (e.g., Green Ontario Fund).

Developing a decentralized model for procurement of DERs would be a longer-term initiative since it will require broader changes to Ontario's statutes. For example, the IESO funds out-of-market costs of its procurements and programs through the GA, and costs are then passed on to customers. LDCs today do not have the ability to flow through applicable costs in this manner. Furthermore, the procurement of DERs through a decentralized, LDC-led model would necessitate enhanced coordination with the IESO with respect to bulk power system planning and regional planning initiatives.

More fundamentally, LDCs are restricted by the *Ontario Energy Board Act* from performing duties outside of the distribution of electricity – in other words, LDCs may not be able to 'procure' resources in this manner until necessary regulatory and legislative amendments are made. This is notwithstanding Bill 112, which provides the ability for LDCs to propose new business activities for the OEB's approval under "special circumstances".

Following the release of the 2017 LTEP, the IESO has been instructed to develop a program to support innovative renewable distributed generation demonstration projects, strategically located and paired with other DERs and smart grid technologies, as well as virtual net metering demonstration projects. This upcoming demonstration program could provide an opportunity to 'pilot' concepts for DER procurement with increased LDC participation and coordination.

Virtual Net Metering: Several jurisdictions across North America have implemented net metering programs with virtual net metering eligibility. Virtual net metering allows customers to offset their electricity consumption based on generation that is produced at a different location. For LDCs, this can pose both an opportunity and a risk. It is an opportunity in that virtual net metering requires distribution system assets and could be a service offered by LDCs to customers. On the other hand, it could be a risk if virtual net metering is implemented without consideration of LDC involvement with respect to siting, interconnection and settlement.

As announced in the 2017 LTEP, Ontario will be exploring virtual net metering demonstration projects. This would be an ideal opportunity to explore various LDC ownership, operation and control mechanisms for distributed renewable generation.

4.7 ALLOWING LDCs TO CONTROL AND OPERATE DER ASSETS

Resolution for: Uncoordinated Centralized Procurements

Ontario needs to ensure that foundational investments, such as DERMS, are made once a reasonable threshold of DERs has been achieved within a given distribution network. DERMS are the fundamental building block that would enable LDCs to control and operate DER assets within their networks. Consistent with the previous recommendation, specific criteria for investment in DERMS should be established to guide LDCs and the OEB.

Furthermore, LDCs could control and operate DERs for two primary purposes:

- Coordination and/or aggregation of DERs to respond to IESO-led procurements pertaining to addressing province-wide system reliability needs (e.g., DR auctions, ICAs).
- Coordination and/or aggregation of DERs to address local reliability within distribution networks.

In this capacity, LDCs would work with their customers, third parties, and/or leverage their own DER assets. For example, LDCs could enter into agreements with DER owners to operate DERs in response to wholesale market price signals. Enabling this capability may require a change to the *Ontario Energy Board Act* because LDCs are not permitted to operate assets that they do not own. This amendment is also consistent with the other changes that may be made with respect to updates to rules and provisions per Section 3.1.

4.8 SHARED SERVICES OF LDCs WITH RESPECT TO CONTROL AND OPERATIONS

Resolution for: Perception of LDC Capabilities

Rather than a one-size-fits-all set of requirements, Ontario needs to recognize the difference in the organization and structure of LDCs, both for their ability to create differing innovative solutions and find avenues for sharing that save implementation costs.

LDCs need to make wise ‘make or buy’ decisions with respect to DER control and operations. This can effectively be achieved if a framework is established for LDCs to share DER control and operations.

LDCs across Ontario have various scale and ownership structures, and each will have their own strategy to transform for evolving their business model towards becoming FINOs. Investing in the skills, resources, and infrastructure required to control and operate DERs may not be feasible for all LDCs and may not be cost effective for others. For cost efficiency, many of these LDCs may seek out opportunities with other LDCs for shared services.

Therefore, it is reasonable to consider mechanisms that would further enable LDCs to coordinate with one another to develop service agreements for the optimization of DER assets within their service territories. This is potentially a new area of business that might be considered as part of the *Strengthening Consumer Protection and Electricity System Oversight Act*, which the OEB may consider.

The Vision Paper suggested it is unclear which tests the OEB may utilize in the evaluation of new business activities for LDCs. Therefore, it would be reasonable for the OEB to develop a framework to provide regulatory certainty, and it is recommended that activities pertaining to operations of DERs should be permitted.

4.9 EVENTUAL DEVELOPMENT OF LMP+D

Resolution for: Pricing and Rate Design

Ontario could look to other jurisdictions for best practices, for example, New York, that are incorporating the value of local distribution into the formulas for LMP.

Through the Market Renewal Program, the IESO is planning for the implementation of LMP. LMP is a way for wholesale energy prices to be reflective of the value of energy at different locations and account for load patterns, generation availability, and congestion at different points on the transmission system. While this would provide the basis for more efficient energy prices, it does not in and of itself reflect the value of energy supplied within a distribution network.

New York REV

The changes currently taking place in New York state through their Reforming the Energy Vision (REV) initiative provides a good example. New York state is transitioning to a compensation model for distributed solar projects that would move away from the traditional net-metering model and would compensate generators based on LMP+D+E, where 'D' represents the value of the energy to the distribution system and 'E' represents any external societal value (such as environmental attributes).

Sending clear price signals will improve planning and will help justify DER asset development for both third-party developers as well as the LDCs themselves. This pricing information could also be used within development of DSPs, as the value of DER assets would be clearly communicated through the price signal. Furthermore, LDCs would be provided with appropriate information to cost effectively control and operate DERs within their networks in response to price signals.

It should be recognized, however, that in some cases the LMP+D amount may be less than what a facility would receive under traditional net metering with uniform prices. Market variability may create uncertainty for investment. That said, there could be means to resolve these concerns through robust design of the mechanism and linkages to other programs, such as those that might be offered through the Green Ontario Fund.

While the development of "D" in LMP considers the value of energy on a locational basis, not all DER providers will be settled based on wholesale electricity prices. Therefore, for DER providers not settled on wholesale electricity prices and are settled through regulated rates, these rates should change in the future to better reflect or approximate LMP and other wholesale electricity prices, as applicable. The OEB, LDCs, customers, and other stakeholders will need to work together to determine how to best design rates in accordance with the changes being planned for within the IESO's Market Renewal Program.

The 2017 LTEP also referenced that Ontario would be exploring opportunities to enable peer-to-peer transactive energy and potentially leverage Blockchain technology. The transition from LDCs to FINOs would not put undue barriers or constraints on advancing such technology and opportunity for electricity customers.

5. IMPLEMENTATION PLAN

Implementation plan

The following sections outline the implementation pathway for the recommendations and solutions proposed in this report. Consistent with the Vision Paper, the roadmap outlines specific milestones for the industry to achieve in the near-, medium- and long-term.

CHALLENGES	SOLUTIONS	
1. LEVELLING THE PLAYING FIELD FOR DERs	Amendments to Section 26 (1.1) of <i>Electricity Act</i>	Near Term
	Amendments to DSC	Near Term
2. IMPROVED DEFINITION OF DERs AND POTENTIAL SERVICES	Amendments to Section 57 of <i>Ontario Energy Board Act</i>	Near Term
	Amendments to the DSC	Near Term
3. IMPROVING DSPs THROUGH INVESTMENTS IN GRID VISIBILITY	Establishment of Advisory Committee	Near Term
	Revisions to RRFE scorecard	Medium Term
4. REMOVE RESTRICTIONS ON LDC OWNERSHIP OF RESOURCES	Amendments to Section 71 (3) of <i>Ontario Energy Board Act</i>	Near Term
5. GUIDELINES FOR RATE-BASING OF DERs AND DER-ENABLING ASSETS CONSISTENT WITH DSPs	Establishment of Advisory Committee	Medium Term
6. COORDINATING AND DECENTRALIZING PROCUREMENT OF RESOURCES AND DERs		
A) REVISIONS TO CENTRALIZED PROCUREMENTS ("LDC SUPPORT")	IESO Stakeholder Engagement	Near Term
B) DEVELOPMENT OF LDC-LED PROCUREMENT MECHANISMS	Establishment of Advisory Committee	Medium Term
7. ALLOWING LDCs TO CONTROL AND OPERATE DER ASSETS	Amendments to Section 71 (3) of <i>Ontario Energy Board Act</i>	Near Term
8. SHARED SERVICES OF LDCs WITH RESPECT TO CONTROL AND OPERATIONS	Establishment of Advisory Committee	Medium Term
9. EVENTUAL DEVELOPMENT OF LMP+D	New Market Renewal Stream (LMP+D)	Medium Term
	Amendments to Net Metering Regulation	Long Term

Figure 17. Recommended Solutions and Actions

To build a solid foundation for the medium- and long-term actions, the most urgent actions are set out as near-term priorities. To lay the foundation that would enable transformation of LDCs towards becoming FINOs, many of the actions would need to take place within the first 10 years (i.e., near-term and medium-term) as illustrated in Figure 17 and described in the following sections.

5.1 NEAR-TERM (0-5 YEARS)

Vision Paper milestones

- Alternative regulatory framework established
- Initial integration of DERs into DSPs
- DER-enabling platform at limited scale

Several of the recommendations outlined in this report will require amendments to Ontario's statutory framework for full implementation. To lay the framework for the emergence of FINOs in Ontario, the following amendments are required during this timeframe.

Electricity Act:

- Section 26 (1.1), which prescribes priority access of renewables, should be amended to reflect broader priorities of DER deployment and consideration of non-emitting resources

Ontario Energy Board Act:

- Section 57, which prescribes activities that require OEB licences, should be amended to add a new class of licence for “energy storage services” and “electric vehicle charging infrastructure”
- Section 71(3) should be amended by changing “own and operate” to “own and/or operate”
- Section 71(3) should be amended to add other DER assets such as EV charging infrastructure and load control devices
- Section 71(3) (a) should be amended to remove the 10 MW capacity restriction regarding LDC ownership of renewable energy

DSC:

- Updated to include provisions for the treatment of “energy storage services” and other services that act as a combination of “load and generation”
- Updated to include specific provisions for EV charging infrastructure
- Updated to include clarity for “ownership” and “operation” point of demarcation related to behind-the-meter DERs

Other recommendations do not require a change in law or code but would necessitate revisions to IESO procurements and other government programs for the prioritization of ‘LDC support’ where applicable and warranted. For example:

- IESO’s DR auctions;
- IESO’s planned ICAs;
- Future RFPs for grid products and services (regulation, etc.);
- Programs led through the Green Ontario Fund; and
- Ministry of Energy’s Smart Grid Fund.

During this time frame, LDCs should be encouraged to participate in centralized or IESO-led procurement programs for energy services. Likewise, during this time frame LDCs should also be making investments in improving grid visibility. Developing a database of information that will support the development of DSPs will help provide justification for DER investments in the future. Changes to the RRFE scorecard to include new metrics with respect to grid visibility should also be implemented.

Finally, consultation efforts must begin with industry stakeholders with respect to the development of transparent criteria the OEB would use to evaluate the potential rate-basing of DERs and DER-enabling assets to provide regulatory certainty.

It is recommended that an Advisory Committee be established, which includes representatives from the OEB, the Ministry of Energy, the IESO, the Electrical Safety Authority, the EDA and LDCs, to assess:

- OEB criteria for investments in grid visibility; and
- OEB criteria for rate-basing DERs and DER-enabling assets.

Such investments in grid visibility and other DER-enabling assets are considered foundational with respect to the transition from an LDC to a FINO. This discussion could also be included as part of the OEB modernization panel.

5.2 MEDIUM-TERM (5-10 YEARS)

Vision Paper milestones

- DER-enabling platform increased scale
- Initial integration of DER into markets and operations
- Evaluation of new business models

In the medium-term, it will be expected that LDCs have clearly developed DSPs that outline DER-enabling investments and DER deployment. LDCs may also be developing their own DER assets in response to IESO-led procurements and other government programs (e.g., Green Ontario Fund, Smart Grid Fund, etc.). Procurements and programs will also have greater alignment with DSPs and IRRPs.

It is also anticipated that certain streams of the IESO's Market Renewal Program will have concluded or nearly concluded, resulting in the implementation of LMP and other changes to the wholesale energy market (e.g., implementation of a Day-Ahead Market) and the establishment of ICAs and other mechanisms for the procurement of resources. Therefore, it will be appropriate during this period to commence further consultation with respect to the implementation of "LMP+D" (or LMP+D+E) which would improve the transparency of price signals with respect to the value of DERs. This would require a new stakeholder engagement initiative in coordination with the IESO regarding potential changes to Market Rules and other regulations that govern rate-making in Ontario.

Likewise, as new LDC business models are emerging, it would be reasonable to commence additional stakeholder engagement with respect to the types of business activities that may be considered by the OEB in relation to DER ownership, control, and operation. The review would leverage the *Strengthening Consumer Protection and Electricity System Oversight Act* which enables the OEB to approve new business activities of the LDC. This may include, for example, the potential for LDCs to offer shared services with respect to operating and controlling DERs.

Finally, to continue with the evolution of the regulatory framework, consultation with respect to the development of mechanisms for LDC-led procurement of DERs will need to be explored.

During this timeframe, the Advisory Committee would make recommendations with respect to:

- Shared services for operating and controlling DERs; and
- Development of LDC-led procurement mechanisms for DERs.

5.3 LONG-TERM (10-15+ YEARS)

Vision Paper milestones

- DER-enabling platform at full scale
- Limited value-added DER products and services
- Some real-time visibility at the distribution level
- Limited integration of DERs into markets and operations

As described in the Vision Paper during this timeframe LDCs will have implemented DER-enabling platforms at full scale and will regularly be interacting with customers in respect to DER deployment and operations.

During this period, LDCs may have the ability to control DERs on their grid to operate them cost effectively and for system optimization, as they have made foundational investments. Provided that an LMP+D pricing regime (or similar) along with applicable changes to rate design based on LMPs are implemented to provide price transparency and accuracy reflective of locational value of electricity, LDCs may have the ability to economically dispatch DERs. Therefore, it would be necessary to consider changes to the IESO's Market Rules that may be required to coordinate LDC dispatch and IESO dispatch of resources.

Furthermore, Net Metering regulations may be revised to reflect LMP+D price signals. These new transparent price signals may also provide input to any LDC-led procurement that might be implemented to meet local or regional needs as identified by DSPs or IRRPs.

5.4 SUMMARY OF PROPOSED ACTIONS AND TIMELINES

In summary, certain amendments to the statutory framework would be required to enable LDCs to progress to FINOs through deployment of DER-enabling and foundational investments, increased integration of DERs, and control and operation of DERs. Changes to the *Electricity Act* and the *Ontario Energy Board Act* would create a level playing field for DERs and establish a clear framework for DERs in LDCs' networks. Subsequently, amendments to the DSC would be implemented to ensure consistency between the legislation, regulation, and codes.

SUMMARY OF ACTIONS	
AMENDMENTS TO LEGISLATION	<ul style="list-style-type: none"> Level playing field of DERs (Section 26 (1.1) of <i>Electricity Act</i>) Clearly defining DERs and clarifying obligations (Section 57 of <i>Ontario Energy Board Act</i>) LDC control and operate DERs (Section 71(3) of <i>Ontario Energy Board Act</i>) LDC ownership of DERs (Section 71 (3) of <i>Ontario Energy Board Act</i>)
AMENDMENTS TO THE DSC	<ul style="list-style-type: none"> Level the playing field for DERs and clearly defining DERs and clarifying obligations
ESTABLISHMENT OF ADVISORY COMMITTEE	<ul style="list-style-type: none"> Development of LDC-led procurement Grid-visibility investments (OEB Criteria / government funding) OEB Criteria for rate-basing DERs and DER-enabling investments OEB Criteria for shared services (control and operation)
IESO STAKEHOLDER ENGAGEMENT	<ul style="list-style-type: none"> Revisions to centralized procurements ("LDC Support")
REVISIONS TO RRF SCORECARD	<ul style="list-style-type: none"> Grid-visibility investments
NEW MARKET RENEWAL STREAM (LMP+D)	
AMENDMENTS TO NET METERING REGULATION	<ul style="list-style-type: none"> Locational value (LMP+D)

Figure 18. Summary of Recommended Actions

It is also recommended that an Advisory Committee be established. The scope of the Advisory Committee would be to evaluate and consult on the implementation of the key initiatives outlined in this report, such as the development of LDC-led procurement, and the development of criteria to facilitate investments in grid visibility which will, in turn, inform more complex DSPs and provide justification for additional investments in DERs.

Additional consultations would also be held with the IESO on two measures. The first with respect to the development of new processes which could be built into existing IESO-led procurement processes to improve coordination with LDCs in the near-term – such as ‘LDC Support’ where a proposed project has additional local benefit. In the medium-term, as the scope of the IESO Market Renewal Program moves to implementation, the second measure that LDCs should be engaged in is additional discussions about local distribution value being added to LMP (the OEB should also participate within discussions relating to locational distribution value for energy).

Should LMP+D be implemented, it would be reasonable to consider additional amendments to Ontario’s Net Metering regulation that align with locational value of electricity supply. Locational values also provide a platform for optimizing the economic operations of local resources and would also inform DSPs and LDC investments.

A proposed implementation time frame is provided below:

		YEAR														
ACTION		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Amendments to <i>Electricity Act</i> and OEBA		■	■	■												
Amendments to the DSC			■	■												
IESO Stakeholder Engagement - LDC support in procurements			■	■	■											
Advisory Committee Tasks	■ OEB criteria for grid-visibility investment				■	■										
	■ Review of potential government funding mechanisms for grid-visibility investments				■	■										
	■ OEB criteria for rate-basing DERs and DER-enabling assets					■	■	■								
	■ OEB criteria for shared services (e.g., control and operation)								■	■						
	■ Development of LDC-led procurement mechanisms										■	■				
	Changes to RRFE Scorecard (grid visibility)					■										
New Market Renewal Stream (LMP+D)							■	■	■							
Amendments to Net Metering Regulation (pricing)													■	■		

Figure 19. Proposed Timeline

5.5 SCENARIO ANALYSIS

As discussed in Section 2.2 of this report, the Vision Paper provided a proposed trajectory for LDC evolution to FINOs (i.e., a ‘baseline’ vision for LDCs as shown in Figure 20). The recommendations in this report have been prepared to help ensure that LDCs have the capability to move forward along this proposed baseline.

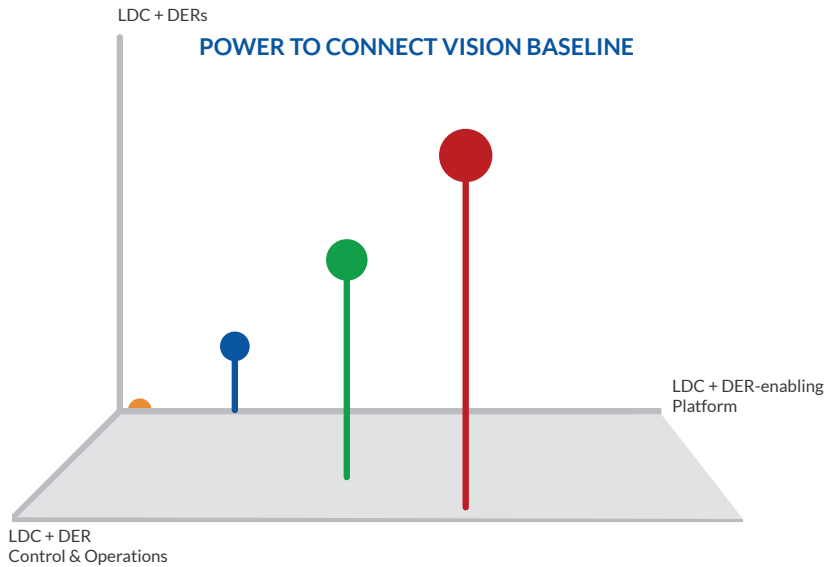


Figure 20. The Power to Connect Vision Paper Baseline

If the challenges and barriers presented in this report are not addressed, the ability for LDCs to evolve their business models and service offerings will be diminished.

For example, if proposed changes to the *Ontario Energy Board Act* and the *Electricity Act* are not implemented, it would be expected that LDCs’ potential for evolving to FINOs would be lessened, as shown in Figure 21. While LDCs would be able to continue to integrate distributed renewable energy systems and could continue to invest in DER-enabling infrastructure, the ability of LDCs to own and operate DERs would be restricted by Section 71(3) of the *Ontario Energy Board Act*, as other specific DERs are not identified (e.g., EV charging and load control), and LDCs remain restricted by their inability to operate assets they do not own.

Without regulatory certainty, there is a risk that LDCs would also be restricted from progressing towards FINOs, as illustrated in Figure 22. LDCs may not invest as extensively in DER-enabling infrastructure, such as grid visibility and digitization, which are foundational investments per the Vision Paper. As noted, increased visibility will help justify DERs investments consistent with DSPs, therefore DER integration would be slowed. Furthermore, LDCs may not control and operate DERs to the extent possible without coordination of shared services in this respect.

The integration of DERs within LDCs is also expected to be diminished if centralized procurements continue to be uncoordinated with local needs and if LDC-led procurement mechanisms are not developed as demonstrated in Figure 23.

Without clearer price signals, as illustrated in Figure 24, LDCs would experience a slower integration of DERs in the later years due to lack of price transparency that could be used to inform DSPs and justify DER investments. Furthermore, LDCs would have less information that could be used to inform the economic operations of DERs.

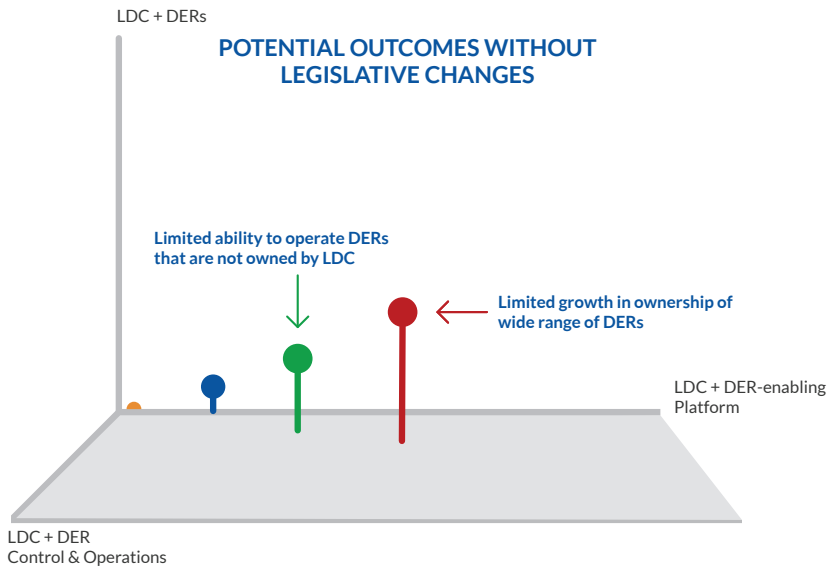


Figure 21. Potential Outcomes Without Legislative Changes

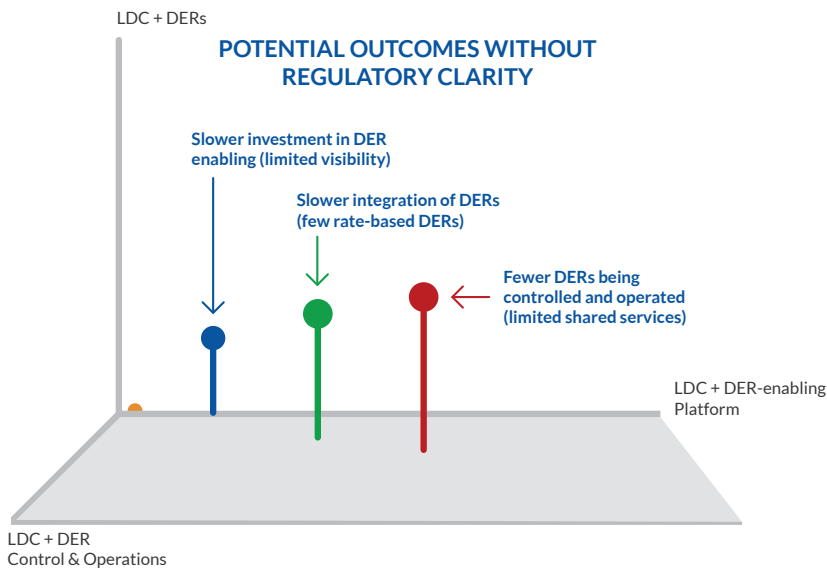


Figure 22. Potential Outcomes Without Regulatory Clarity

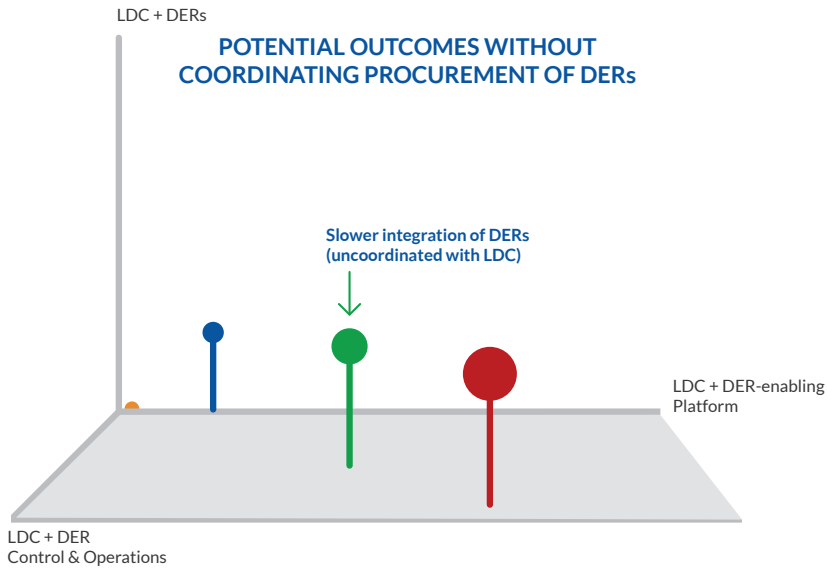


Figure 23. Potential Outcomes Without Coordinating Procurement of DERs

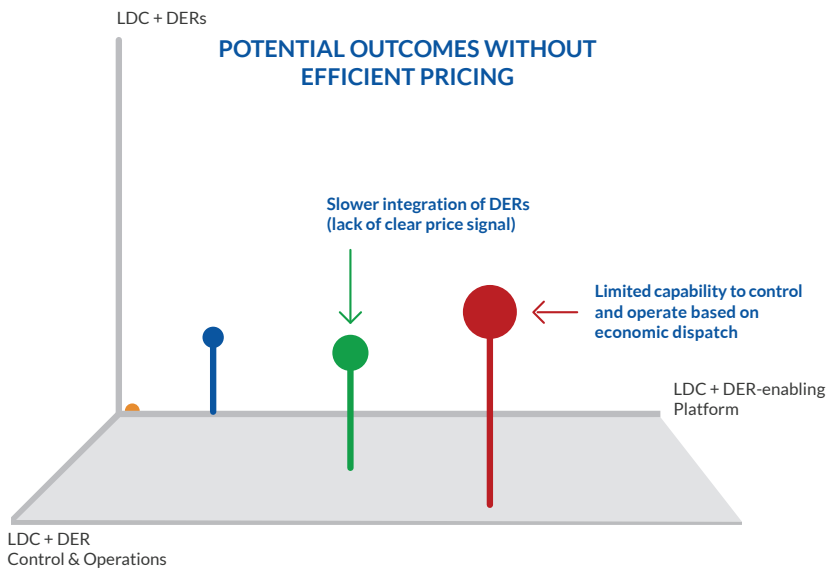


Figure 24. Potential Outcomes Without Efficient Pricing

The adoption of DERs is expected to grow significantly in the future. The distribution system must be prepared to accommodate DER growth, and more importantly be prepared to maximize the potential benefits of integrating DERs. These benefits include providing consumer choice, offering enhanced system flexibility, increasing the penetration of renewable energy in the supply mix, among many others. If investments are not made in a prudent and planned approach to support the evolution of the distribution system, the result will be increased costs to customers. Delayed investments that are made only in reaction to DER uptake limit the options available and result in ad-hoc planning and decision making.

Reflecting again on experience from the recent past, when a rapid increase of renewable energy deployment occurred through the FIT Program, the distribution and transmission systems were not fully prepared. Transmitters and distributors were not provided enough time to plan and make prudent investments. In some cases, the government had to issue directives to the regulator and to Hydro One to address bottlenecks in the system. To address short-circuit fault limitations, Hydro One had to make upgrades to three major transmission network stations (i.e., Hawthorne TS, Hearn SS, and Allenburg TS) along with 10 other regional transmission stations. This experience supports the need for the system to start investing now so that DERs can be integrated in a prudent and beneficial manner for all ratepayers.

6. CONCLUSION AND SUMMARY

The EDA's Vision Paper outlined the evolution of LDCs towards FINOs. This companion report has identified the challenges and barriers to achieving the EDA's vision and proposes solutions that are in-line with achieving greater value for customers and Ontario Government policy objectives, such as reducing costs to customers and lowering GHG emissions.

In summary:

- **Levelling the playing field for DERs** – provides options for customers and helps achieve GHG emissions reductions through the adoption of new technologies (e.g., EVs);
- **Improved definition of DERs and potential services** – provides guidance to LDCs which in turn will provide customers with choices to manage electricity costs, and will improve the deployment of energy storage and EVs;
- **Improving DSPs through investments in grid visibility** – augmented planning will help ensure investments are right-sized to meet customers' needs;
- **Remove restrictions on LDC ownership of resources** – improves the economic sustainability of LDCs;
- **Coordinating and decentralizing procurement of resources and DERs** – better alignment of procurement activities will help reduce costs to customers overall;
- **Guidelines for rate-basing of DERs and DER-enabling assets consistent with DSPs** – allows a mechanism for LDCs to invest in non-wires alternatives that are the best and most cost-effective option to meet local needs;
- **Allowing LDCs to control and operate DER assets** – more efficient use of resources could help reduce costs to customers;
- **Shared services of LDCs with respect to control and operations** – reduces costs to customers through shared services that will also be designed to optimize distribution assets; and
- **Eventual development of LMP+D** – more efficient prices and rates will appropriately incent investments and provide input into distribution system planning.

Like many other segments of the economy, the electricity sector is undergoing a transformation given the potential for new technologies and services. The most transformative companies in today's economy not only leverage new technologies but have redefined how services are provided to customers and maximize the latent value of existing infrastructure. Uber is the most obvious example of this new type of entrepreneurship – they are the largest new provider of taxi services without owning any taxis. Likewise, LDCs should maximize the latent value of resources within their networks (e.g., energy storage system that help customers mitigate electricity costs may also be able to provide grid services cost-effectively, benefitting electricity consumers more broadly).

The EDA's Vision Paper provides a goal for LDCs that want to become an active facilitator in a transformed electricity market, one that puts customers first and maximizes the utilization and value of electricity assets. This companion report has identified the challenges and barriers and can be used as a roadmap for consultation activities going forward through its proposed recommendations and solutions to facilitate LDCs transforming to FINOs.

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