IESO York Region

Non – Wires Alternatives Demonstration Project

Evaluation Report

July 2024

Table of Contents

Acknowledgements

ICF would like to thank Alectra Inc. and IESO for their openness, collaboration, and strong commitment to the success of both the York Region Non-Wires Alternatives Demonstration Project and the effort to develop this report and findings. During the assessment process, their teams were very active participants, provided all requested data and assumptions, shared operational insights, explained their approach and internal perspectives, and ensured that the analytical approach and findings benefited from prior work and overall market dynamics. Without their guidance and partnership this report would not have been complete or provided the robust understanding needed to prepare for future program success.

About IESO

The IESO manages the province's power system so that Ontarians receive power when and where they need it. It plans and prepares for future electricity needs. The IESO administers, settles, and evolves Ontario's wholesale electricity market to foster competition and ensure affordable electricity pricing. The IESO works closely with municipalities, regional governments, Indigenous communities, and other partners to understand local electricity requirements and priorities and identify the best options to meet growing needs. A not-for-profit entity established by the Government of Ontario, IESO fees and licenses to operate are set by the Ontario Energy Board.

About Alectra

Alectra is the Local Distribution Company (LDC) serving approximately one million homes and businesses across a 1,924 square kilometer service territory comprising 17 communities including Alliston, Aurora, Barrie, Beeton, Brampton, Bradford, Guelph, Hamilton, Markham, Mississauga, Penetanguishene, Richmond Hill, Rockwood, St. Catharines, Thornton, Tottenham and Vaughan. Alectra holds Ontario Energy Board (OEB) Electricity Distributor License No. ED-2016-0360 for its licensed service territory and is the acting Distribution System Operator (DSO) for this Demonstration. Alectra contributes to the economic growth and vibrancy of the communities it serves by investing in essential energy infrastructure, delivering a safe and reliable supply of electricity, and providing innovative energy solutions.

About NRCan

Natural Resources Canada ("NRCan") is a department of the Canadian Government that is "committed to improving the quality of life of Canadians by ensuring the country's abundant natural resources are developed sustainably, competitively, and inclusively."[1] NRCan's Green Infrastructure Smart Grid Program provided funding for smart grid demonstration projects to reduce greenhouse gas emissions, better utilize existing electricity assets, foster innovation, and create jobs in the cleantech sector. The Non-Wires Alternatives Demonstration Project was supported by funding from this program.

[1] Natural Resources Canada (2024)

Executive Summary

Significant technological advancements are transforming electricity systems in Ontario and beyond. Grid operators, resource developers, policymakers, and customers are embracing new capabilities that can help maintain grid reliability and meaningfully contribute to the energy transition. Advances in electricity resource technologies as well as new information and communication technologies (ICT) are leading to more complex planning, operation, and marketplace processes that enable consideration of new types of solutions. Distributed energy resources (DERs), including solar panels, electric vehicles, and smart thermostats, have potential to provide services to the grid in novel ways. DERs can expand the options and strategies available in addition to traditional infrastructure solutions, such as distribution, transmission, and central generation. In Ontario, the Independent Electricity System Operator (IESO), local distribution companies (LDCs), the Ontario Energy Board, communities, and stakeholders are developing new approaches to integrate and procure services from DERs, while ensuring the electricity system remains safe, reliable, and cost-effective. In recent years, the IESO has engaged stakeholders across several initiatives aimed at enhancing the integration of DERs as part of its DER Roadmap[2], including the York Region Non-Wires Alternative Demonstration.

The Demonstration Project

The IESO and delivery partner Alectra Utilities undertook the York Region Non-Wires Alternatives Demonstration ("the Demonstration") project to explore market-based approaches to securing local energy and capacity services from DERs[3].

The Demonstration focused on using DERs as non-wires alternatives (NWAs), which are resources that provide electricity services as alternatives to delivery infrastructure investments[4]. Deliver infrastructure include transmission poles and wires, substations, distribution poles and wires, distribution transformers, and other infrastructure. By using cost-effective DERs as NWAs, investments in major distribution and transmission can be deferred or avoided, while also potentially offering value to the bulk electricity system[5]. The connection, capabilities, and operations of DERs provide opportunities to foster innovation that supports reliability and affordability of the overall electricity system.

[2] Distributed Energy Resources Roadmap
[3] In the context of this report, the term "market" refers to structured procurement mechanisms that facilitate competition and transactions among parties for services. Markets are characterized by the principles of supply and demand, where prices are determined through the interactions of buyers and sellers. These mechanisms may be continuous or periodic.
[4] While the project focused on using DERs as NWAs, NWAs can also include conservation and demand management (CDM), advanced grid controls, and transmission-connected resources.
[5] The overall value of using DERs as alternatives includes a range of benefits and costs. This report captures the major components to provide a substantial understanding of the impact. However, to develop a more holistic and comprehensive understanding of costs and benefits, future evaluations of similar projects may consider additional factors, which were beyond the scope of this study.

Since 2020, IESO and Alectra have been actively involved in the Demonstration aiming to thoroughly explore competitive procurement and operation of DERs as NWAs in southern York Region ("the Demonstration area"). With York Region's growing electricity demand, which is projected to surpass the existing system capability over the next decade, the Demonstration also sought to provide insight for regional planning processes.[6] Throughout the project, Alectra demonstrated the role of a distribution system operator (DSO), playing a central role in operationalizing and delivering the Demonstration.[7] IESO played a significant role in designing of the Demonstration as well as developing the rules and contracts documents that were used. The demonstration sought to demonstrate DERs providing services to both distribution and transmission level through local auctions. Specifically, Local Capacity Auctions and Local Energy Auctions were used to procure services to secure and operate the participating DERs.

Summary of Findings

Overall, this evaluation finds that the Demonstration was successful and met its primary objectives. The findings validate the approach to and benefits of using DERs as NWAs for distribution-level needs and potentially for transmission-level benefits. The process and tools that were developed, tested, and refined provide the groundwork for future exploration of the demonstrated concepts to increase the potential for DERs to support the energy transition as an alternative or deferment for traditional electricity system infrastructure.

DER Interest and Capabilities:

The Demonstration uncovered insights based on the participants and DER technologies that took part in the auctions, how the DER operated throughout the Demonstration, as well as feedback provided in participant interviews. Through extensive outreach, the Demonstration secured participation from a diversity of participant types (residential, commercial, and industrial load customers as well as aggregators) and DER technologies. The amount of DERs registered during the two years ('Year 1' and 'Year 2') of the Demonstration significantly exceeded the capacity targets for procurement, as detailed in Table 1. This reflects the strong interest from DER participants in delivering services to the grid.

[6] IESO (2020) – IESO York Region Non-Wires Alternatives Demonstration Project

[7] DSO activities involve new and advanced functions to integrate and actively manage DERs in distribution systems with high DER penetration. These functions include managing the distribution network to support DER, utilize DERs for various distribution system services, and operational coordination with bulk system operators like the IESO. It is important to note that distribution services facilitated by DSOs extend to a broader range of services, tools, and processes than this in this Demonstration.

Table 1: *Local Capacity Auction-Based Market Mechanism Results*

	2021	2022
Number of Bids	37	33
Capacity Bid (kW)	19,000	22,775
Capacity Target (kW)	10,000	15,000
Total Cleared Capacity (kW)	10,000	15,000

The eligible resource categories in the Demonstration were: Demand Response (DR), Thermal Resource, and Storage Resource. Table 2 summarizes the amount of capacity that awarded to each resource class. Most of the DER in the Demonstration consisted of demand response, which is consistent with the general expectation that most DER potential is comprised of customer-sited devices or customer load flexibility. The Demonstration was agnostic to the demand response strategies participants employed and did not collect information about the specific methods used. The evaluation process that ICF undertook included interviews with some of the participants, which revealed that the methods employed to achieve demand response varied, encompassing load curtailment strategies, behind-the-meter storage, and behind-the-meter gas-fired generation. One of the participants made use of an aggregation of residential smart thermostats as the demand response resource. The single successful Thermal Resource consisted of a combined heat and power (CHP) facility. Out of the ten participants in the Demonstration, six made use of aggregations of smaller, contributor DERs, while four participants made use of larger, individual DERs.

Table 2*: DER Capacity by Resource Type*[8]

Resource Type	2021	2022
Demand Response	7.1 MW	13.2 MW
Thermal Resource	2.9 MW	1.8 MW
Storage Resource	0 MW	0 MW

The participating DERs demonstrated the ability to provide local capacity and energy services to the distribution system without safety incidents, generally meeting activations and fulfilling distribution needs that simulated the use of DER as NWAs. When their impact was taken together, the diverse portfolio of DERs

[8] The demonstration rules and contract did not collect information regarding the assets and methods used by demand response providers to achieve their demand reductions. Through participant interviews, it was identified that a mix of load curtailment, gas-fired generation, and battery storage was used, with mixed-resource participants contributing 3.4 MW in 2021 and 2 MW in 2022.

participating in the Demonstration provided a more consistent response to activations compared to the performance of any one of the participating DERs in isolation.

While the Demonstration was designed to facilitate the dispatch of DER to meet transmission-level needs, such activations did not explicitly take place. This was because the wholesale market price for the area (i.e., "shadow price" at the closest transmission node) did not reach levels that would trigger these activations.

Auction-Based Market Mechanism:

The project's auction processes successfully secured the targeted level of local capacity and energy services (as well as local reserves[9]) from DERs. Fewer high price capacity bids were observed in Year 2 compared to Year 1 of the Demonstration, suggesting that the participants applied strategies learned from Year 1's Local Capacity Auction. These adjustments highlight the participants' willingness to submit improved bids in response to competition. With respect to the Local Energy Auctions, some participants shared in post-demonstration interviews that their strategy was to bid at the auction ceiling to maximize the payment per activation while minimizing the frequency of dispatches. This led to clearing prices in the Local Energy Auctions being at or close to the auction ceiling price throughout both years of the Demonstration. Nevertheless, Alectra was able to successfully activate DERs based on distribution system conditions by employing the Local Energy Auction mechanism.

The market operations activities in the Demonstration were successfully completed by Alectra, including administering auctions, executing contracts, coordinating DER activations, and completing contract settlement functions. The web-based software platform developed to facilitate the Demonstration and interface with internal Alectra processes to implement the Demonstration operated effectively. DER participants were able to effectively bid capacity to be available, bid/offer to deliver energy, receive activation notices, and view settlement information for the services they provided.

DER Performance:

Over the two operational years of the Demonstration, participating DERs were activated on 15 different occasions, providing a total of 366 MWh in energy services. A major difference between the two years was that the participating DERs experienced material capacity de-rates in the second year, mainly due to supply chain delays and other impacts of the Covid-19 pandemic, as described further in the report.

The operation of the DERs participating in the demonstration exhibited both strengths and areas for improvement. Across the two operational years, the average availability metric was 83%, and when activated,

[9] Local reserve was defined in the demonstration as a distribution service intended to manage unplanned distribution system conditions, including activation when other DERs failed to follow their activation instructions or were insufficient. However, the service was deemed too experimental to incorporate in the analysis and discussed only briefly in this report.

the overall performance metric was 85% on a collective, portfolio basis[10]. However, substantial over and under deliveries by different DERs during activations were observed. While these variations partially balanced out, resulting in good portfolio performance, they indicate reduced performance at the individual DER level. These operational results informed the assumptions for the illustrative cost-benefit analysis to ensure that the performance metrics of the DERs were considered and that enough DER capacity was assumed to be procured.

Costs-Benefit Analysis:

The illustrative cost-benefit analysis conducted as part of the evaluation of the Demonstration suggests that strategically targeting procurement of services from DERs in areas where they can provide multiple benefits can be highly advantageous. Table 3 provides a summary of the costs and benefits associated with using DERs as an alternative to avoid or defer to traditional infrastructure for the years 2027 and 2032. The avoided costs of generation, transmission, and distribution are compared with the costs of procuring DERs, illustrating the overall financial impact across three scenarios. As shown in the projections in Table 3, DER costs and benefits vary depending on input assumptions, such as availability of DER capacity and future energy and capacity costs. In high growth scenarios with more favorable DER inputs and assumptions, significant value can be realized, driven by avoided generation capacity and transmission and distribution investment deferral. For the full benefit of DERs listed in in Table 3, to be available, it is necessary for the IESO and DSOs to enable DERs to provide "stackable" distribution and transmission level services rather than limiting them to "single service" procurements. Effective transmission-distribution coordination is also needed to ensure that DERs are used in a reliable manner and so that the value is realized for both DSOs and IESO.

Table 3: *Summary of Net Benefits of using DERs as NWA*

Year	DER Cost and Benefit Streams ($/MW-year equivalent[11])	Slow Growth	Base Case	High Growth
2027	Avoided Generation Energy Value	$720	$720	$860
	Avoided Generation Capacity Value	$81,000	$192,000	$297,000
	Transmission Deferral Value	$96,000	$98,000	$160,000
	Distribution Deferral Value	$12,000	$67,000	$80,000
	DER Procurement Cost	$(239,000)	$(167,000)	$(156,000)
	Net (Cost)/Savings for DER as Alternative	$(49,000)	$191,000	$382,000

[10] The availability metric indicates the proportion of a DER that is available for activation compared to the original capacity obligation and considers unavailability. The performance metric is an indicator of the DERs' over- or under-deliveries compared to the activation instructions to provide energy services.
[11] Specifically, MW of installed capacity.

2032	Avoided Generation Energy Value	$880	$880	$1,060
	Avoided Generation Capacity Value	$99,000	$257,000	$398,000
	Transmission Deferral Value	$104,000	$112,000	$174,000
	Distribution Deferral Value	$57,000	$70,000	$144,000
	DER Procurement Cost	$(282,000)	$(213,000)	$(202,000)
	Net (Cost)/Savings for DER as Alternative	$(21,000)	$227,000	$515,000

Scope and Limitations:

This evaluation report summarizes the design, experiences, and lessons learned from the York Region NWA Demonstration project. The analysis conducted is applicable to the specific context of the Demonstration at the time that it was conducted (2021-2022). This report is not intended to make projections about future marketplace conditions or infrastructure requirements in York Region or in Ontario broadly. The conclusions presented in this report may have limited direct applicability to other time periods, geographic regions, and/or mix of DER types.

Furthermore, a Total-DSO (T-DSO) model informed the project design, aimed at minimizing the required interfaces and environments for DER participants. This model involves the DSO coordinating all services for DER or aggregations for DERs in both wholesale and distribution markets, thereby eliminating the need for these resources to participate directly in the wholesale market. Different DSO models are possible and under discussion and consideration in Ontario and other jurisdictions. It is important to note that many elements of the Demonstration and observations in this report are not exclusive to the T-DSO model. This evaluation report is not an assessment of the viability or benefits of one model over another and similar approaches and outcomes may be attainable using different coordination models. While the T-DSO model represents a viable approach, most of the principles and mechanisms described can be adapted and applied within the context of other models.

Several key limitations impact the broader applicability of the evaluation's findings:

- The DERs participating were largely existing resources. Therefore, the prices observed in the demonstration should not be understood as indicative of the price of future deployment of DERs.
- The value DERs can provide in York Region are exceptional and result from the area's specific infrastructure needs. The local value in many other regions of the province is not expected to be as high.
- The capacity of the DERs in the demonstration was relatively small (10 to 15 MW in total). For large scale NWA projects that require substantial numbers of DERs, the availability of DERs must be investigated.
- The evaluation provides an illustrative cost-benefit analysis only and does not assess current planning options in York Region, including key considerations like implementation timelines or associated risks.

Additionally, it should be noted that the DERs in the Demonstration were not being used to address an actual reliability need, which would be the case in a full-scale NWA implementation. Rather, the Demonstration utilized actual forecasted and current load information from the Demonstration Area, but in a simulated environment that was not connected to the operational tools and processes for the acting DSO and IESO. This approach allowed the Demonstration to be conducted in a low-risk environment while being informed by real-world conditions.

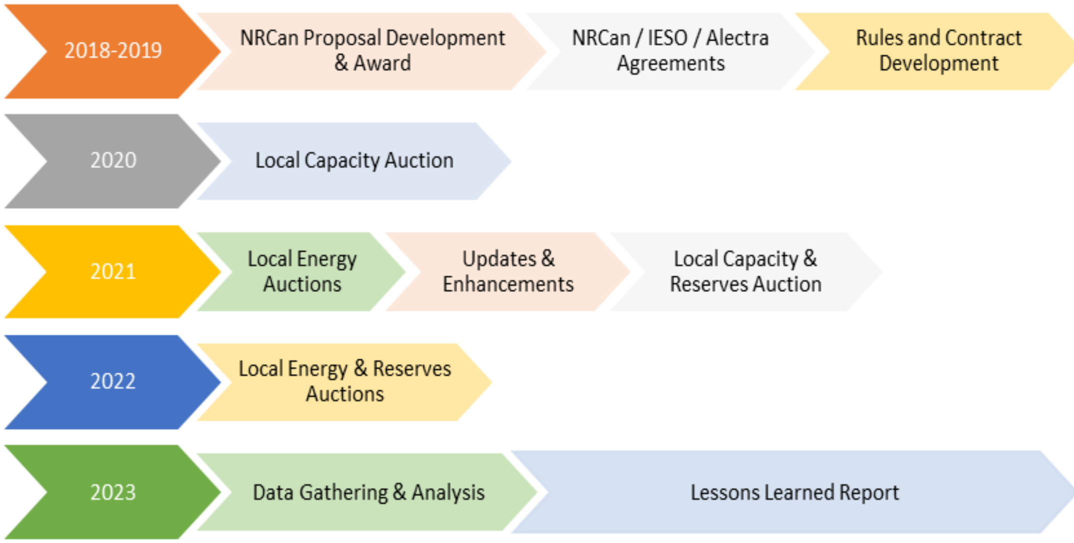
1 Introduction

Funded by the IESO and NRCan[12] and delivered by Alectra, the Demonstration established North America's first local electricity market. A key objective was to procure services from DERs - such as battery storage, thermal generation, and demand response – to support local distribution areas. These services were employed during peak demand periods in a manner that simulated the use of DERs as alternatives to traditional distribution, transmission, and generation. The project examined how DERs could meet the growing electricity demands of York Region and the province, offering services at both distribution and transmission levels.

The Demonstration sought to advance the understanding of the market-based procurement of DER services in a real-world, multi-year effort. Local auctions were trialed for procuring services within the Demonstration area. The timeline for the development and implementation of the Demonstration is shown in Figure 1. The project was structured into two operational years (Year 1 and Year 2). The first commitment period, during which the DERs were subject to activations, extended from May to October 2021. The second period spanned from May to October 2022. The auction processes in the Demonstration were organized around these periods. Local Capacity Auctions were held in advance to secure the availability and participation of DERs. During the commitment periods, Local Energy Auctions were used to select and activate DERs. Local Reserve Auctions were introduced during the commitment periods in Year 2.

[12] The Demonstration was conducted as part of NRCan's Smart Grid Fund Program and the IESO's Grid Innovation Fund.

Figure 1: *Timeline for IESO York Region Non-Wires Alternatives Demonstration Project*[13]



Another goal of the Demonstration was to explore the potential of using DERs as alternatives to traditional electricity infrastructure. The selection of the Demonstration area was informed by the IESO's regional planning process, which had identified infrastructure needs in southern York Region. As shown in Figure 2, the Demonstration area is focused on southern York Region, and includes Richmond Hill, Markham, and Vaughan.

Figure 2: *IESO Planning Regions and Southern York Region*

For the Demonstration, Alectra acted as a DSO, managing auction processes that secured and activated participating DERs provided by third-party customers or DER aggregators. To limit reliability impacts, the Demonstration was administered in a simulated test environment that was separate from the IESO's and Alectra's operational systems.

[13] Graphic adapted from IESO: Independent Electricity System Operator, 2021, [IESO Presentation to OEB's FEI Working Group: IESO York Non-Wires Alternatives Demonstration Project]

ICF was retained by the IESO to review, analyze, evaluate, and summarize the operational outcomes and participants' experiences of the Demonstration. Through this analysis, the IESO and Alectra sought to better understand how DERs can be used as NWAs as well as meet bulk system needs. Insights have the potential to inform the development of future markets or programs and transmission-distribution (T-D) coordination, helping better capture the potential of DERs across Ontario's distribution and transmission electricity systems.

This report is structured as follows: Section 1 provides a detailed description of the project, including the planning context, demonstration rules and software platform. The objectives outlined during the project's design phase are used to evaluate whether the demonstration achieved its intended goals in Section 2. Section 3 provides a brief overview of the approach applied in the analyses detailed in Sections 4, 5, and 6. Economic analyses are presented in Section 4 for the Local Capacity Auction, the Local Energy Auctions, and the settlements in the demonstration. Section 5 summarizes the performance of the DER that participated in the Demonstration, including capacity offered and delivered. In Section 6, an illustrative cost-benefit analysis is outlined, including methodology, assumptions, costs as well as distribution and transmission level benefit streams. Section 7 synthesizes participant feedback and Section 8 offers practical recommendations for using DERs as NWAs based on insights from the Demonstration. Finally, Section 9 concludes the report by reflecting on the demonstration concepts and the potential of DERs as NWAs.

1.1 Planning Context

As the momentum for electrification and decarbonization picks up, there will be a growing need to better integrate DERs in the electricity system, potentially presenting opportunities to use them as NWAs. The following sections outline relevant planning frameworks and summarize the needs in southern York Region that informed the demonstration project.

Ontario's Regional Planning Process

The current Regional Planning Process was formalized by the OEB in 2013 and is performed at least every 5 years for each of the 21 planning regions in the province. This process is carried out by the IESO, in collaboration with the transmitters and LDCs in each region.

The main objective of Ontario's regional planning process is to assess the near, medium, and long-term needs of a given region. A robust infrastructure plan is developed that ensures cost-effective and reliable electricity resources, taking into account existing electricity infrastructure, forecasted growth, and customer reliability as key inputs. The process supports distribution and transmission infrastructure investments, regulatory processes, and electricity resource acquisitions. It also serves as a forum for the IESO, LDCs, transmitters, communities, and stakeholders to coordinate local electricity priorities with provincial electricity needs.

When NWAs are identified as a potential solution, the Integrated Regional Resource Plan (IRRP) process is triggered to determine the preferred mix of infrastructure (i.e., wires), Conservation and Demand Management (CDM), DERs, and transmission-connected generation, storage, or demand response. A recently published report, Guide to Assessing Non-Wires Alternatives, presents an overview of the IESO's current methodology in IRRPs[14].

The latest IRRP for York Region was published in 2020 and included a variety of recommendations and action related to NWAs. York Region was seen as an appropriate area for a demonstration project due to the specific resource capacity needs in the area. The next regional planning cycle for York Region began in 2023 and is scheduled to be complete in 2025.

Distributor Use of DERs as NWAs

From the perspective of electricity distributors, DERs offer benefits that can improve the resilience, sustainability, and efficiency of the grid. The integration of DERs play an important role in modernizing distribution systems and in enabling a broader range of participants, such as homeowners and small businesses, to contribute to supporting the electricity system. Under certain conditions, distributors can use DERs as NWAs, offering a potential cost-effective alternative or deferment to costlier distribution network infrastructure upgrades.

In the recent past, the Ontario Energy Board (OEB) has taken several important steps to clarify the regulatory treatment of DERs to facilitate their adoption in ways that enhance value for customers. In the 2023 report "Framework for Energy Innovation: Setting a Path Forward for DER Integration", the OEB outlined policies and next steps regarding the integration of DERs in the province's electricity distribution systems, as well as the use of DERs by electricity distributors as NWAs. Subsequently, the OEB set out to develop a Benefit Cost Analysis Framework (BCA Framework) that distributors can use to develop business cases for DERs as NWAs. In 2024, the OEB issued the "Non-Wires Solutions Guidelines for Electricity Distributors", which provides guidance on the role of NWAs and addresses their treatment in distribution rate applications.

Regional Need in Southern York Region

The southern part of York Region was identified by system planners as a location well-suited for the Demonstration. York Region is part of the Greater Toronto Area and is a densely populated and industrialized area, experiencing rapid growth and extensive ongoing urbanization, driving the need for new electricity infrastructure over time. The demonstration was specifically focused on the townships and municipalities of Richmond Hill, Markham, and Vaughan within southern York Region.

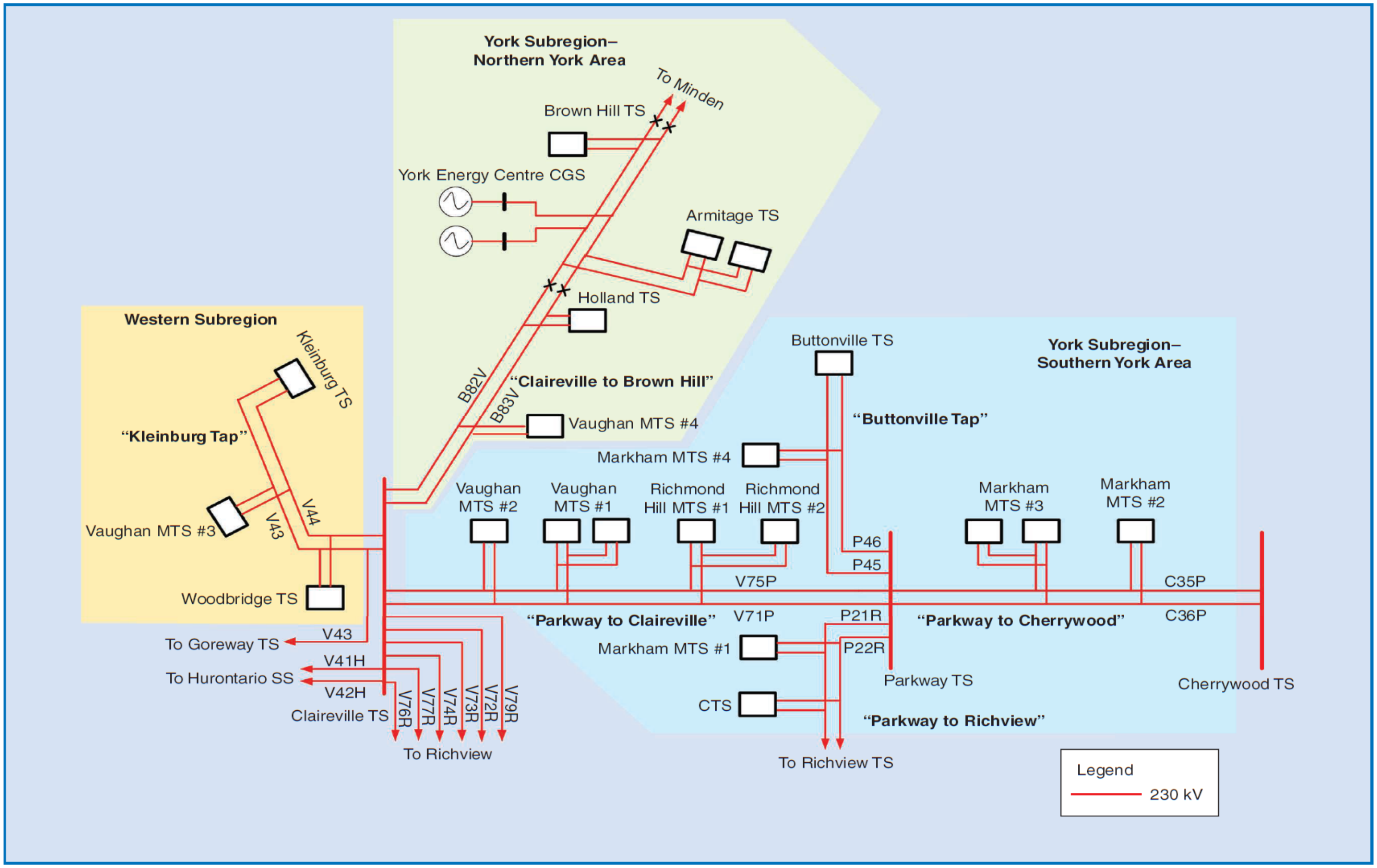
The 2020 IRRP for York Region highlighted that DERs or other non-wires options have the potential to defer the need for medium-term step-down stations and, consequently, have the potential to defer a large longer-term transmission need in the region as well. A recommendation was made to conduct work between regional planning cycles to collect more information on potential future NWA and other opportunities in York Region

[14] The guide is posted on the IESO's Planning Information and Data webpage.

to inform the next IRRP. This was a key factor that led to the initiation of the York Region NWA Demonstration.

For the purposes of the demonstration, a specific region within southern York Region was designated as the 'Demonstration Area'. This area is visualized electrically in Figure 3 below, specifically covering Markham Municipal Transformer Stations (MTS) 1 to 4 and Vaughan MTS 1 to 4. The Demonstration Area experiences demand exceeding 1,300 MW during summer peak hours, with a load mix that includes residential, commercial, and industrial loads. Given the existing DER penetration in this area, it was identified as the ideal location to conduct a demonstration to evaluate the value of DERs as NWAs.

Figure 3: *The York Region transmission system*[15]



15 MTS: municipal transformer station; CGS: customer generating station; CTS: customer transformer station.

1.2 Project Rules

The building blocks for the Demonstration were laid down through the design of the market processes, which were captured in detail in the Demonstration's rules and participant contracts documents. The IESO and Alectra teams collaborated with a team from the law firm Borden Ladner Gervais (BLG) to develop the documents. The rules laid out certain business processes, including eligibility criteria, registration rules, the DER qualification process, the local capacity auction process, and summarized the demonstration's contract. The contracts captured the terms and conditions of participating in the Demonstration, including details on the local energy auctions, metering and baselining, and settlements processes. Following Year 1, an updated version of the Demonstration rules and contract documents were developed with changes to integrate a local reserve auction. These updated documents were employed for Year 2 of the Demonstration.

Eligibility of DERs

A minimum size threshold of 100 kW was used for eligibility to participate in the Demonstration. Participation was permitted either with an individual DER or an aggregation of DERs, as long as the 100 kW requirement was met. For context, the size threshold to participate in the IESO's wholesale market is currently 1 MW and the IESO's DER Market Vision Project (MVP) has proposed a reduction of the threshold to 100 kW, over time. The lower requirement in the Demonstration opened opportunities for smaller DERs to participate, allowing Alectra and the IESO to better access the available DER potential. Table 4 provides a list of the DER types that participated in the Demonstration. The Demonstration focused on using dispatchable or responsive DERs as NWAs at the distribution level, while also enabling access to their services in the wholesale market.

Table 4: *Participating DER Resource Types*

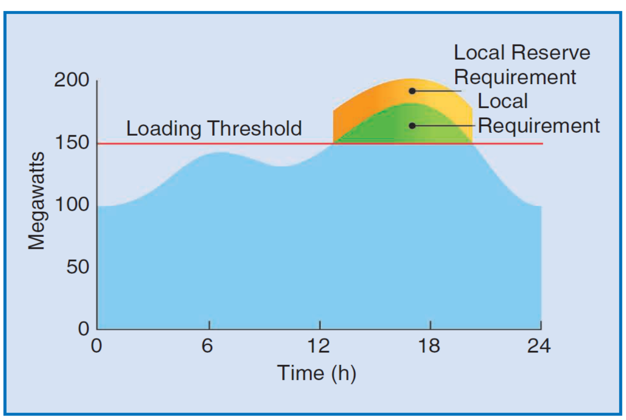
DER Type	Description
Thermal Resource	Generates electricity from natural gas, biomass, or biofuel.
Demand Response (DR)	Customers who curtail their demand or use behind-the-meter DERs to reduce energy consumption.
Storage Resource	Capable of withdrawing electricity at a controlled rate, storing such electricity for a controlled period, and then injecting stored electricity at a controlled rate.

Local Auction Mechanisms

To demonstrate how a local market-based approach can avoid or defer distribution system needs, two Local Capacity Auctions were held to secure DER capacity in advance of the Year 1 and Year 2 commitment periods. Participants provided offers with one or more price-quantity (P-Q) pairs for their DER or their aggregation of DERs. Each price-quantity pair indicates the price at which the participant was willing to provide a specific quantity of capacity services, effectively setting a cost for each increment of capacity offered. After the deadline for submitting capacity offers to the software platform passed, the platform ranked the offers from least to most expensive. It then accepted the lowest priced bids until reaching the target capacities of 10 MW for Year 1 and 15 MW for Year 2, respectively. The Local Capacity Auction clearing price was determined by the price associated with the last cleared price-quantity pair accepted. Participants that cleared the Local Capacity Auction were awarded a Demonstration contract. The capacity obligation under the contract required participants to be available from 12:00 EST to 21:00 EST on business days throughout the commitment period for participation in the Demonstration's Local Energy Auctions. DER participants submitted price-quantity pairs to the Local Energy Auctions to indicate the price above which they were willing to provide energy services.

Local Energy Auctions were held when the forecasted demand in the Demonstration Area exceeded a pre-established demand threshold, simulating the limits of distribution infrastructure[16]. This demand threshold, shown in Figure 4, served as a signal to activate DERs as NWAs in an effort to ensure capacity limits were not exceeded. The threshold was determined based on two-year historical peak demands for the Demonstration Area and set such that it would be exceeded coincident with peak demand in the Demonstration Area. When the local load forecast exceeded the demand threshold a "local requirement" was identified in the software platform, and an automatically issued standby notice was sent at 7 AM EST to all participants with bids/offers for the Local Energy Auction.

Figure 4: *Loading Threshold and DER Dispatch Requirement Stacking*[17]



[16] Details outlined in Appendix E – Activation and Scheduling of the Demonstration rules document
[17] Figure from IEEE Power and Energy Magazine article [Auctions for Nonwires Alternatives: Securing and Operating Dispatchable Distributed Energy Resources](), which describes the auction processes used in the demonstration project.

Participants whose offers/bids cleared in the Local Energy Auction were given at least 2.5-hour notification of activation. Participants whose bids/offers cleared in the Local Reserve Auctions were scheduled to provide local reserves and required to deploy and begin operations within 30 minutes of notification. This service allows for a rapid response to contingencies identified by the DSO. The majority of DERs that cleared the auctions were called upon to provide energy, and a smaller amount were scheduled as reserves. Different thresholds were used throughout the commitment period to help spread out activations in the Demonstration across different months. The Demonstration contract limited the number of activations to 10 times during a commitment period, to limit performance fatigue and allow for a balanced activation frequency for the participants.

Over the two commitment periods, a total of ten participants took part in the Demonstration operations. A summary of Participants and their cleared capacity is shown in Table 5. In the second commitment period, capacity obligations were adjusted after the Local Capacity Auction due to DER unavailability and capacity derates, which was flexibility that the Demonstration rules and contracts allowed for.

Table 5: *Demonstration Project Cleared Capacity by Participant*

Participant Name	2021 Cleared Capacity (kW)	2022 Cleared Capacity (kW)*
Aggregators		
Demand Power Group Inc.	0	2,875
Edgecom Energy Inc.	3,000	0
Enel X Canada Ltd.	0	1,500
Rodan Energy Solutions Inc.	400	1,000
Energy Hub Inc.	1,200	2,525
GC Project LP	1,000	1,000*
Direct Participants		
Tycho Poly Inc.	500	300
Longo Brothers Fruit Markets Inc.	1,000	1,000*
Markham District Energy	2,900	1,800*
Sobeys Capital Inc.	0	3,000*
Total Cleared Capacity (kW)	**10,000**	**15,000**

* Qualified as Reserve Capable Capacity

1.3 Software Platform

To manage the local auctions for the Demonstration, Alectra, in collaboration with software vendor Util-Assist, developed an in-house software platform. The platform facilitated the different stages of the DER participation lifecycle, from DER registration to settlements. Alectra used the platform to administer the Demonstration and Alectra and the IESO used it to monitor. The software platform enabled the processes outlined in the Demonstrations' Project Rules and Participant Contracts. The design of the software platform was based on the project's design documentation and included multiple modules. Alectra, with support from the IESO, developed detailed user journeys based on the Demonstration's design and Util-Assist led the module software development to enable the identified user journeys. Detailed descriptions of the intended use and functionality of each module in the software platform, namely, registration, capacity auction, contracting, energy resources management, energy auction and M&V settlements were provided by Alectra for this report and are detailed in Appendix 2. ICF did not assess the functionality of the platform as part of the project review and therefore cannot comment on the effectiveness of the platform to meet its stated fitness for purpose or procedural timeliness and accuracy.

2 Summary of Findings for Project Objectives

In designing the demonstration project, IESO and Alectra identified nine objectives. ICF used these objectives to guide the assessment of the project. Table 6 provides a list of these objectives and a brief description along with unique identifiers that ICF assigned to be used throughout this report as a cross reference.

Table 6: *Demonstration Project Objectives*

Objective Number	Objective Description	Identifier
1	Exploring the use of auctions to secure local capacity and local energy services, including local reserve, from DERs to demonstrate their use as NWAs and alternatives to traditional wholesale-level resources	1AUCT
2	Exploring models of coordination and interoperability between the IESO, as the transmission system and electricity market operator in Ontario, and Alectra, acting as DSO in York Region for the purposes of the demonstration project	2COORD
3	Demonstrating the interest of parties in participating in and the potential for the creation of a Local Energy Price on Alectra's distribution system in York Region	3DLMP
4	Assessing the interest in, and ability of, different DERs to compete to provide capacity, energy and reserve services through the auctions	4DER
5	Assessing the operational impact of DERs on the local distribution system to facilitate the maintenance of safe, reliable and efficient system operations	5OPS
6	Identifying market and systems operations barriers to the use of DERs as NWAs and exploring potential solutions to such barriers	6BARR
7	Exploring how elements and benefits of the wholesale electricity market could be extended to the distribution system level	7MKTS
8	Drive community engagement and development by enabling local solutions to meet local needs	8LOCL
9	Assessing the unique operational and reliability characteristics of particular DERs as compared to traditional transmission-level system resources and transmission and distribution infrastructure	9COMP

1. Exploring the use of auctions to secure local capacity and local energy services, including local reserve, from DERs to demonstrate their use as NWAs and alternatives to traditional wholesale-level resources [1AUCT]

Background

The IESO employs auction-based processes in its markets to procure capacity, energy, and operating reserve across the province. Building on these mechanisms, the Demonstration showcases a novel approach that enables a DSO to procure local capacity and energy services from DERs through auctions. Auctions are an effective way of enabling competition and efficient outcomes, and removes barriers of entry for smaller participants[18], who were a key target group in the Demonstration.

Results

The Demonstration successfully secured the targeted amount of local capacity and local energy services, including local reserve, providing valuable insights into the feasibility and effectiveness of auctions at securing DERs as NWAs and alternatives to traditional wholesale-level resources.

In the first local capacity auction in November 2020, 13 participants placed 41 unique price-quantity pairs representing 25.2 MW of bid capacity. This surpassed the capacity target of 10 MW by more than 250%, indicating high interest in a local level market. The auction cleared at a price of $0.64/kW-day ($80,000/MW for the commitment period).

The second local capacity auction was conducted in October 2021 with a capacity target of 15 MW, of which 5 MW was sought to be reserve-capable. 11 participants placed 34 unique price-quantity pairs representing 25.8 MW, building on the strong outcomes from Year 1. The auction cleared 15 MW of local capacity at a price of $0.40/kW-day ($50,000/MW for 6-month period), of which 6.8 MW was also capable of providing reserve services.

The Year 1 commitment period took place from May to October 2021, during which participants submitted bids/offers for each availability hour - 12 PM to 9 PM on business days - in the Local Energy Auctions. Alectra activated resources during nine events in the 2021 commitment period. The Year 2 commitment period took place from May 2022 to October 2022 and had a total of six activation events. Participants in the Local Reserve Auction submitted separate bids/offers for being scheduled for reserve. Alectra deployed the scheduled reserve during two events in Year 2 of the Demonstration, instructing the DERs to operate on short notice.

[18] From article in Footnote 16 which was developed as part of the Demonstration

2. Exploring models of coordination and interoperability between the IESO, as the transmission system and electricity market operator in Ontario, and Alectra, acting as DSO in York Region for the purposes of the demonstration project [2COORD]

Background

Effective coordination between transmission and distribution systems requires implementing a model for how IESO, LDCs, and DER providers should work together. This involves streamlining information exchanges, aligning requirements, and integrating systems. Additionally, it is important to devise strategies for structuring and operationalizing this coordination to ensure reliability and effectiveness.

Results

The 2019 whitepaper "Development of a Transmission Distribution Interoperability Framework", prepared by ICF explored various coordination models. For the demonstration, the "Total DSO" model was adopted The Total DSO model allows DER participants to interface directly with Alectra, as the DSO, for both distribution and transmission-level services, simplifying the Demonstration by:

1. Decreasing development complexity by minimizing the number of platform environments needed.
2. Reducing participation complexity as DER participants managed only one interface (with the DSO).

To support the Demonstration, a web-based software platform was developed to manage participant registration, auction bid/offer submission, communication of activation instructions, meter management, demand response baselining, and providing settlement data. The platform was also used by Alectra to monitor forecasted demand, manage energy activations, and administer local reserve schedules.

Alectra activated DERs based on forecasted distribution level demand and a pre-determined loading threshold, simulating the management of a full-scale NWA project. All activations during the Demonstration were driven by distribution-level needs. Although a mechanism for transmission-level activations was included, activations were not triggered since the conditions for transmission-level activations were not met. Transmission-level activations would have been triggered if DER participant's bids/offers were economical compared to the closest wholesale market shadow price. In instances where both distribution and transmission level needs arose simultaneously, the DERs were first activated to meet distribution needs. Any remaining DER capacity was then to be available for transmission-level needs if conditions were met. Throughout the Demonstration, there were examples of transmission-level needs that coincided with distribution-level needs[19]. Given the relatively small capacity of DERs available, there was no opportunity to demonstrate activations driven explicitly by transmission-level conditions.

[19] DERs were also activated on five occasions over the two operational years in which the demand in the Demonstration Area peaked during the same hour as the provincial system demand. During these periods, DERs activated through the Demonstration potentially provided benefits to both the transmission and distribution systems.

3. Demonstrating the interest of parties in participating in and the potential for the creation of a Local Energy Price on Alectra's Distribution System in York Region [3DLMP]

Background

In implementing the Demonstration within the Demonstration Area, IESO and Alectra sought to reveal the availability and interest of DERs to participate in providing services to both the distribution and transmission levels, as well as to establish novel pricing mechanisms for these services. By administering capacity and energy auctions, the Demonstration created a market signal (the clearing prices). Another key aspect was the implementation of a simply derived distribution locational marginal price (DLMP) in the Local Energy Auctions.

Results

Throughout both years of the Demonstration, the oversubscription of registered bidders compared to the capacity targets in the Local Capacity Auctions indicated strong interest from customers and aggregators in delivering electricity services with DERs. In Year 1 of the Demonstration, 13 participants submitted 41 bids representing 25.2 MW of capacity, of which 10 MW cleared the auction. In Year 2, 11 participants submitted 34 bids representing 25.8 MW of capacity, of which 15 MW of capacity cleared the auction, with minor adjustments made at a later time due to operational challenges (the adjustments were made as described in the Demonstration project rules). Most participants engaged in both years of the Demonstration, indicating sustained strong interest throughout the entire period.

The participants in the Demonstration established a local energy price through the auction process. All participants who cleared the Local Capacity Auctions were then required to participate in the Local Energy Auctions. The local energy price consistently cleared at the ceiling price of $2/kWh. However, the average price of the bids/offers in the Local Energy Auctions, for the two years was $1.81/kWh and $1.19/kWh respectively, indicating a year-over-year decrease.

The Local Energy Auctions utilized a straightforward clearing process: bids/offers for the DERs were ranked and selected according to price until the distribution need was satisfied. The bid of the DER that was selected last set the clearing price in the auction, which was used as the DLMP for the settlement of the energy services provided. This method for deriving DLMPs included several simplifications, such as disregarding electrical losses and limiting its applicability to radial systems. Exploring DLMP within the Demonstration was an important step towards achieving more granular pricing for DERs.

The Demonstration attracted a diverse range of participants, including those experienced in IESO markets or programs as well as newcomers to grid services. This varied mix enriched the Demonstration and provided insights into the feasibility and attractiveness of local pricing mechanisms. Notably, the local capacity and energy prices established in the Demonstration were generally higher than similar prices at the transmission level, underscoring the potential value and dynamics of local prices.

4. Assessing the interest and ability of different DERs to compete to provide capacity, energy, and reserve services through the Auctions [4DER]

Background

The Demonstration sought to advance the understanding of market-based procurement of local services from DERs in a real-world, multi-year effort. Specifically, auction processes were employed to procure local capacity, energy and reserve services. Effective market-based processes facilitate competition among DER participants and enable discovery of prices for grid services. The Demonstration served as an opportunity to assess the interest and capability of DER participants to engage effectively in these processes.

Results

The Local Capacity Auctions demonstrated significant interest from DERs and were significantly oversubscribed, with registered capacity being much higher than the target capacity. This robust participation highlights DER participants' interest in competing to provide grid services. Additionally, the auctions effectively secured DER capacity and facilitated price discovery. Notably, there was a reduction in the number of high-priced capacity bids in Year 2 compared to Year 1 of the Demonstration, suggesting that participants refined their bidding strategies based on previous experiences. Despite the capacity target being higher in Year 2 than in Year 1, the clearing price decreased from $0.64/kW-day in Year 1 to $0.40/kW-day in Year 2, which represents a 38% decrease. However, neither the number of registered participants nor DER capacity increased from Year 1 to Year 2, highlighting the challenge of scaling up DER availability for larger, full-scale local service projects (particularly within the context of a short-term financial commitment as was offered through the Demonstration).

The Local Energy Auctions consistently cleared at the ceiling price of $2/kWh, despite receiving bids lower than this maximum. This pattern emerged partly because the forecasted demands that triggered the use of the Local Energy Auctions were substantial, leading to the activation of most, if not all, DERs. This outcome raises questions about the effectiveness of the auction mechanisms and the benefits of competition for local energy services. However, it is important to note that as DER penetration increases and local market frameworks mature, auctions are likely to become more effective at establishing dynamic energy prices.

Post-demonstration interviews revealed that some participants strategically bid low in the Local Capacity Auctions to improve their chances of participating in the Demonstration, and then subsequently bid at the ceiling price in the Local Energy Auctions to maximize payment per activation and minimize the number of activations. The Local Reserve Auction was deemed too experimental to incorporate in the detailed evaluation of the Demonstration.

5. Assessing the operational impact of DERs on the local distribution system to facilitate the maintenance of safe, reliable, and efficient system operations [5OPS]

Background

The Demonstration evaluated how DERs respond to activations by Alectra, focusing on their performance both individually and as a collective portfolio. The Demonstration focused on using dispatchable or responsive DERs as NWAs at the distribution level, while also enabling access to their services in the wholesale market. The consistent and predictable performance of DERs in providing local energy services directly impacts their reliability and viability in providing grid services. Performance metrics help shape decisions regarding system planning margins, economic evaluation, procurement strategies, operational tactics, and pricing models.

Results

Throughout the Demonstration, no system outages, disturbances, or reliability concerns occurred because of the operations of the participating DERs.

Over the two operational years, DERs effectively responded to activation instruction, providing a total of 366 MWh in energy services. In Year 1, participating DERs were available during 97% of the 'Availability Window' of each Business Day from noon to 9 PM during the commitment period – and delivered or reduced 81% of the activated energy. In Year 2, participating DERs were available during 69% of the availability window hours and delivered or reduced 91% of the activated energy quantity. The reduced availability in Year 2 was due to supply chain delays and resourcing challenges linked to the impacts of the Covid-19 pandemic. Please refer to Section 5 for additional details on the operational challenges in Year 2.

Operational results from the Demonstration informed the assumptions used for reliability planning margins in the illustrative cost-benefit analysis conducted as part of the evaluation of the Demonstration. These margins were intended to ensure that the performance metrics of the DERs were considered and that enough DER capacity was assumed to be procured to meet the planning needs.

To further investigate the reliability and system impacts of DERs on the distribution grid, EPRI analyzed eight Alectra feeders and two standard IEEE feeders, all modeled with additional load and DERs. The outcomes from this work were captured in the whitepaper 'Procuring Grid Services from Distributed Energy Resources (DER)'. Thermal limitations along the main feeder lines emerged as a primary constraint. While DERs of various sizes were technically capable of reducing peak demand, it was observed that smaller-scale DERs faced additional technical and economic challenges. The whitepaper also examined standard IEEE test systems and found significant differences in simulation results compared to the Alectra feeders. This observation emphasizes the importance of feeder-specific evaluation in the context of high DER penetration and DERs providing grid services. Furthermore, the whitepaper discussed the benefits of flexible interconnection agreements and advocated for detailed time-series studies.

6. Identifying market and systems operations barriers to the use of DERs as NWAs and exploring potential solutions to such barriers [6BARR]

Background

The Demonstration explored the use of DERs to provide services across the electricity system, aiming to identify and address market and system operations barriers. The Demonstration investigated barriers such as the underexplored nature of local market mechanisms and the need for robust coordination among DER participants, DSOs, and the IESO. To obtain real-world insights, the evaluation also included interviews with participants, aimed at collecting direct input on barriers and potential solutions.

Results

As part of the Demonstration, Alectra successfully ran the capacity and energy auctions, executed contracts, coordinated resource activations, and facilitated settlement payments. Participants effectively engaged in capacity offerings, bid/offer transactions, and energy delivery. The successful execution of the project, free from significant platform or process issues, demonstrates the effective management of a local market mechanisms for securing services from DERs.

The whitepapers developed as part of the Demonstration investigated methods for coordination in great depth. For example, the whitepaper titled 'Procuring Grid Services from DER' sought to better understand the technical potential of DERs to provide a range of grid services, and evaluate the market coordination, operational coordination, and data exchanges required among DER participants, DSOs and the IESO.

Demonstration participants were interviewed and shared the following feedback:

- The registration and enrollment processes were effective, and the customer portal was user friendly.
- The financial reporting functionality could be improved, including providing more detailed data.
- Activating ten times may be the upper limit for certain participants to minimize activation fatigue.
- Receiving longer advance notification of activations would be better for load curtailment DERs.
- Allowing aggregators to more easily access customer meter data from Alectra could simplify the settlement process.
- Participants interested in more flexibility for baselining methodologies tailored for their type of DER.
- A longer pilot duration (e.g., five years) would allow participants to plan and commit more resources.

7. Exploring how elements and benefits of the wholesale electricity market could be extended to the distribution system level [7MKTS]

Background

The Demonstration aimed to explore how elements of wholesale electricity market design could potentially be adapted to the distribution system level. For example, the project sought to incorporate elements such as auction mechanisms and location-based pricing, offering a more dynamic and granular approach to valuing and managing grid services from DERs. This approach contrasts with typical DER programs, which often rely on predetermined, fixed prices and lack competitive elements.

Results

In alignment with the principles of open access observed at the transmission level, the Demonstration facilitated the participation of third-party customers and DER aggregators. The project successfully adapted auction mechanisms from wholesale market design to the distribution system. The auction processes were detailed in the Demonstration rules and contract documents, which were collaboratively developed by IESO, Alectra, and the law firm Borden Ladner Gervais (BLG). These auctions were structured to procure local capacity, energy, and reserve services - mirroring service definitions used at the transmission level. The three services were combined to implement and manage the NWA component of the project. Each service featured its own auction process to clear DERs and establish granular locational prices for the services at the distribution level. These granular locational prices can help drive targeted investment in and operation of DERs in areas with higher demand than others within the electricity system.

Notably, several design elements of the Demonstration were directly adapted from the rules and requirements for Hourly Demand Response (HDR) in the IESO's Capacity Auction. This adaptation provided an established design foundation for the demonstration and a familiar framework for DER participants. Key operational procedures were adopted, including the issuance of standby notices by 7 AM on activation days and activation notices given 2.5 hours in advance. Additionally, the Demonstration adopted baselining methods from the Capacity Auction for accurately assessing the performance of demand response DERs. Similarly, the approach to non-performance charges in the Demonstration was also derived from the Capacity Auction.

The clearing price in the Local Energy Auctions in the Demonstration effectively represented a simply derived DLMP, extending the concept of Locational Marginal Pricing (LMP) at the transmission level to the distribution system with greater granularity. However, while the Local Capacity Auctions facilitated price discovery in the Demonstration, the Local Energy Auctions consistently cleared at the ceiling price of $2/kWh. As previously discussed, this recurring pattern raises questions about the benefit of energy auctions. Nonetheless, as DER penetration increases and DERs are increasingly used for grid services in the future, the Local Energy Auction process may prove more effective and beneficial.

8. Drive community engagement and development by enabling local solutions to meet local needs [LOCL]

Background

The Demonstration aimed to empower local community members to play a role in meeting local as well as provincial electricity needs. Effective outreach to customers and stakeholders is key in boosting interest and participation levels. The Demonstration was open to a diverse range of potential participants and retaining financial benefits within communities.

Results

The Demonstration represents a step forward in creating more opportunities for DERs to provide local grid services, paving the way for customers and communities to have greater choices in meeting their electricity needs. Mechanisms, processes, and tools to utilize DERs as alternatives to traditional electricity infrastructure were successfully developed and implemented. The project yielded valuable real-world insights into procuring granular, local grid services from DERs.

As part of the Demonstration, Alectra conducted an outreach campaign, engaging load customers and DER aggregators to broaden awareness of the project and its opportunities. The team developed outreach materials that clearly explained the demonstration and the financial benefits for participants in practical terms. Supporting these efforts, the IESO hosted a public engagement process, featuring a dedicated engagement webpage and periodic webinars. The Demonstration webpage served as a hub for background information, access to project documents, and webinar materials and recordings.

Webinars were conducted to present the project’s whitepapers and provide detailed information about the demonstration design and actively seek feedback from potential participants and other stakeholders. This feedback was essential in ensuring that the demonstration design, rules, contracts, and administrative processes were practical and aligned with participant needs. Furthermore, this evaluation report will be featured in a public webinar, aimed at disseminating the project's results and insights.

The Demonstration attracted a diverse group of participants, including small-scale manufacturers, supermarket operators, commercial aggregators, a district heating provider, and residential participants through an aggregation. This variety shows the broad appeal and opportunity offered by the project. The oversubscription of the Local Capacity Auctions further demonstrates the perceived value of participation. Additionally, positive interview feedback from participants indicated a desire to continue providing grid services and support for extended project timelines.

9. Assessing the unique operational and reliability characteristics of particular DERs as compared to traditional transmission-level system resources and transmission and distribution infrastructure [9COMP]

Background

The Demonstration explored the operational and reliability characteristics of DERs as an alternative or deferment to traditional distribution, transmission, and generation solutions. It aimed to understand how DERs can be effectively integrated into the grid to maintain operability and reliability. By examining the performance of the participating DERs, the study sought to provide insights into their availability and performance. Additionally, the Demonstration assessed the economics of DER integration, comparing the use of DERs to traditional infrastructure solutions and their costs.

Results

The operation and reliability of the DERs participating in the demonstration exhibited both strengths and areas for improvement. Across the two operational years, the average availability metric was 83%, and when activated, the overall performance metric was 85% of the energy activated on a portfolio basis. However, substantial over and under delivery by different DERs during activations was noted. While these variations partially balanced out, resulting in good portfolio performance, they indicate reduced performance at the individual DER level. The demonstration data also revealed varied performance patterns across activation hours and over time, with a notable trend of performance fatigue, particularly evident over extended durations and multiple activations. It is important to note that variability in performance does not suggest that DERs should not be utilized. The operational results from the Demonstration informed the assumptions used for reliability planning margins in the illustrative cost-benefit analysis conducted as part of the evaluation.

In addition to the evaluation of operational characteristics, the report presents an economic comparison to assess the effectiveness of DERs as NWAs. The illustrative cost-benefit analysis suggests that strategically targeting the procurement of services from DERs in areas where they can provide multiple benefits is highly advantageous. The analysis compared the avoided costs in generation, transmission, and distribution with the costs of procuring DERs, illustrating the overall financial impact across different scenarios. The analysis showed that DER costs and benefits vary depending on input assumptions, such as the availability of DER capacity and future energy and capacity costs. For scenarios with more favorable DER inputs and assumptions, significant value can be realized, driven by avoided generation capacity and transmission and distribution investment deferral. Conducting local achievable potential studies for DERs can be highly informative about the current and future available DER capacity, which is a key input into planning decision-making. These studies assess whether adequate DERs will be available to use them as an alternative or deferment to traditional electricity infrastructure.

3 Analytical Approach

ICF's approach to developing these findings and recommendations started with gathering all the program documents, holding initial discussions with IESO and Alectra staff, and reviewing, in detail, the project objectives described above. ICF utilized the Demonstration rules and contracts, which were detailed in a jointly authored document by the IESO, Alectra, and law firm Borden Ladner Gervais (BLG), to guide and structure the analytic approach.

The Demonstration rules governed the demonstration market mechanisms and included information on:

- Registrant and DER eligibility for both direct participants and aggregators
- Registration requirements
- Local capacity auction
- Local energy and local reserve auctions
- Changes to DER capacity and availability
- Demonstration review and amendments
- Confidentiality and other applicable rules

The Demonstration contract outlined terms and conditions for participation in and included information on:

- Participant and performance obligations
- Metering and baselining
- Financial settlements calculations
- Operational procedures
- Outage management and test activation
- Contract administration
- Confidentiality and other legal provisions

The Demonstration rules and contracts documents thoroughly and clearly outline the processes and mechanics for auctions for local services, serving as key products developed during the project. The documents were not only critical to the design and implementation of the demonstration but have subsequently also been adapted in other pilots with different approaches.

From this foundation, ICF developed an analytical pathway to address the overall project goals, systematically collecting and evaluating program participant and procurement data captured by Alectra. These data points were refined, integrated, and analyzed across multiple dimensions including time, DERs, participant, and activity categories. With input from IESO and Alectra, ICF developed a framework for an illustrative cost-benefit analysis. This analysis estimates the avoided costs associated with traditional distribution, transmission, and generation compared to the cost of procuring services from DERs.

ICF had regular meetings with Alectra and IESO throughout the project. Alectra was very responsive in providing data and relating the context to provide a comprehensive understanding of the program, sharing their experience as the DSO, and how data was collected and prepared for analysis. The IESO provided valuable insight into the design intent of the demonstration and helped identify key areas of innovation. Table 7 describes the data sources that were used in ICF's analysis for this report.

Table 7: *Demonstration Project Evaluation Data Sources*

Data Type	Data Source	Use and Objectives Mapping
Demonstration Local Capacity Auction bids	Provided by Alectra	Used to calculate local capacity auction summary statistics [1AUCT, 3DLMP, 4DER, 7MKTS,]
Demonstration Local Energy Auction bids/offers	Provided by Alectra	Used to calculate local energy auction summary statistics [1AUCT, 3DLMP, 4DER, 7MKTS,]
Demonstration M&V files	Provided by Alectra	Used to calculate operational and settlements summary statistics [2COORD, 3DLMP, 4DER, 5OPS, 6BARR, 7MKTS, 8LOCL, 9COMP]
Post-Auction Report for IESO Capacity Auction and Demand Response Auction	Downloaded from IESO (link) and (link)	Used to compare clearing prices in the Capacity Auction and Demand Response Auction as well as identify participants who participated [7MKTS]
IESO DER Potential Study	Downloaded from IESO (link)	Used to determine the maximum DER potential for southern York region [9COMP]
Hourly Ontario energy prices	Downloaded from IESO (link)	Used to calculate wholesale settlement value relative to demonstration settlement payments and charges [7MKTS]
Hourly zonal loads	Downloaded from IESO (link)	Used to calculate coincidence of province-wide load and Toronto load with southern York load [7MKTS]
York Region MTS capacity and peak demand forecast	Downloaded IRRP from IESO website. Supporting appendices / datasets provided by IESO. (link)	Used to calculate the avoided cost of MTS deferral [9COMP]
York Region transmission capacity and peak demand forecast	Provided by IESO	Used to calculate the avoided cost of transmission deferral [9COMP]

4 Analyses of Demonstration Auctions

To secure and operate DERs as alternatives to traditional electricity infrastructure, the Demonstration project utilized Local Capacity Auctions and Local Energy Auctions. The following sections detail the processes, results, and analysis of these auctions, highlighting participation, bidding strategies, and overall outcomes.

4.1 Local Capacity Action

Two Local Capacity Auctions were held during the Demonstration. The first auction, targeting a procurement of 10 MW of capacity, was held in November 2020 for the Year 1 commitment period of May to October 2021. The second auction, targeting a procurement of 15 MW, was held in October 2021 for the Year 2 commitment period of May to October 2022. In Year 2, a local reserve capacity category was added to the Local Capacity Auction with a procurement target of 5 MW of DERs that are capable of providing reserve capacity. Only eligible registrants with eligible DERs were allowed to participate in the Local Capacity Auction. Eligible DER technologies included: thermal generation, battery energy storage systems, demand response - commercial and industrial (C&I), or residential - as shown in Figure 5 below. Individual DERs or DER aggregations that were sized between 100 kW and 3 MW were eligible to participate. The cap of 3 MW was strategically selected to ensure broader participation, allowing multiple DER participants to engage in the Demonstration.

Figure 5: *Eligible Resource Types*

Prior to the Local Capacity Auctions, pre-auction reports were published to provide key information to potential participants, including target capacity, minimum and maximum capacity prices, and minimum and maximum energy prices (in the Local Energy Auctions). Additionally, as part of the marketing efforts to encourage participation in the demonstration and to illustrate how revenues would be calculated, a document outlining the revenue potential was published[20]. This guidance helped participants to evaluate and compare the economics of this program to the costs of providing grid services with their DERs.

The maximum local capacity price was $1,600/MW-day ($1.60/kW-day) and was based on initial estimates of the potential value of DERs as an alternative to distribution infrastructure, transmission infrastructure, and centralized generation. In setting the maximum clearing price, assumptions at the high end of the range were

[20] Alectra, IESO York Region Non-Wires Alternatives Demonstration Project: Revenue Potential for Participants, viewed on 06/14/2023

used to ensure sufficient incentive to drive participation in the Demonstration. The assumptions were informed by anticipated infrastructure investments in the Demonstration Area.

ICF received data on the Local Capacity Auction bids for each of the Demonstration years from Alectra. This data included participant information, quantity, price, and timestamps of all submitted bids. ICF conducted quality assurance/quality control (QA/QC) of the data and resolved any data quality issues with Alectra.

ICF performed descriptive analysis on the bid data in Excel to summarize the auction outcomes. This included the development of summary statistics of bids such as minimum bid price, maximum bid price, average bid price and weighted average bid price by year and participant. These findings are summarized and presented in this document, within the limits of the confidentiality provisions in the Demonstration rules and contracts.

Analysis

One of the key objectives of the Demonstration was to understand participant behaviors to inform lessons learned and identify participation barriers for customers and DER aggregators. This section discusses key characteristics of the Local Capacity Auction to examine participants' bidding decisions. Table 8 below summarizes the salient characteristics of each auction. A total of 41 bids were submitted and 10,000 kW (40% of capacity bid) cleared the Local Capacity Auction in Year 1. Six resources (33%) bid more than one price-quantity pair - a feature of the auction design intended to give participants the flexibility to specify the cost for different segments of their resources. This benefited some participants who received auction awards for a portion of their DER's capacity. The participant's bidding approach (one price-quantity pair price vs. multiple price-quantity pairs) may depend on the specific resource characteristics, the participant's experience bidding into markets, and the participant's unique bidding strategy.

Table 8: *Local Capacity Auction Summary*

Auction Characteristics	Year 1 (2021)	Year 2 (2022)	% Change
Quantity of Bidders	13	11	-15%
Quantity of Resource	24	17	-29%
Quantity of Bids	41	34	-17%
Total Capacity (kW)	25,200	25,775	2%
Cleared Capacity (kW)	10,000	15,000	50%
Maximum Bid Price ($/kW-day)	$1.60	$1.60	0%
Minimum Bid Price ($/kW-day)	$0.00	$0.00	-
Average Bid Price ($/kW-day)	$0.78	$0.56	-28%
Weighted Average Bid Price ($/kW-day)	$0.81	$0.40	-51%
Clearing Price ($/kW-day)	$0.64	$0.40	-38%

11 of the 13 bidders from Year 1 returned for the Local Capacity Auction in Year 2, indicating a high degree of continued interest from Year 1 participants. Of the total capacity bid in the capacity auction, 61% or 15,000 kW cleared the auction, of which 6,800 kW were reserve capable. Seven resources (70%) were bid with more than one price-quantity pair. The 37% increase in the number of price-quantity bid pairs for Year 2, compared to Year 1, suggests more sophisticated bidding strategies based on insights gained during the Local Capacity Auction for Year 1. Five of the 11 participants cleared all their bids. The Local Capacity Auction for Year 2 resulted in a clearing price of $0.40/kW-day, a 38% reduction from the Year 1 price of $0.64/kW-day. This substantial decrease reflects increased competition and further highlights the participation interest in the Demonstration year-on-year.

Figure 6: *Local Capacity Auction: Bids by Year*

Figure 6 above shows the number of bids received at each price in the Local Capacity Auctions for Year 1 and Year 2 of the Demonstration operations. The most notable difference between the two years is the reduction in the quantity of bids greater than $0.80/kW-day. This suggests that the participants were acting on learnings from the Year 1 auction strategies and shows their willingness to bid lower due to competition.

Another important aspect of the Local Capacity Auction was the diversity of participants that took part in the Demonstration. As seen in Table 5, the participant types spanned across various sectors, including small-scale manufacturing facilities, supermarket operators, a district heating provider, medium and large-scale aggregators, as well as residential contributors (through aggregated participation). This wide array of participant profiles, which included both new entrants and those experienced at providing grid services, demonstrates the broad interest in the Demonstration. It also highlights the technology types and participation strategies that it attracted.

4.2 Local Energy Auctions

The distribution locational marginal price (DLMP) for provision of energy service in the Demonstration was set through the Local Energy Auctions, representing a simplified approach to determining these prices. Participants that cleared the Local Capacity Auction were required to satisfy their local capacity obligation(s) by taking part in the Local Energy Auctions for each resource that cleared the auction. Participants had to submit bids/offers, provide information about resource unavailability, and respond to the activation instructions from Alectra. Participants submitted bids for each hour of the availability window, from noon to 9 PM on business days, and the software platform cleared the auction. The floor and ceiling prices for energy were provided in pre-auction reports to ensure transparency and help participants gauge revenue potential. The energy price ceiling of $2.00/kWh was set to be aligned with the IESO wholesale energy market price ceiling of $2,000/MWh. Participants who cleared the Local Capacity Auction were awarded a contract with Alectra, which outlined their performance obligations, operational procedures, metering requirements, baselining methodology, and settlement calculations. In Year 2, the Local Reserve Auction was added to the Demonstration, which generally ran after the Local Energy Auctions. In addition, periodic test activations were conducted to ensure the DERs were able to deliver on the contractual obligations.

Analysis

Table 9 below summarizes the Local Energy Auction results for the Demonstration. Each business day consisted of nine potential activation hours from noon to 9 PM.

Table 9: *Energy Auction Summary*

Energy Bid/Offer Characteristics	Year 1 (2021)	Year 2 (2022)
Energy Activations	9	6
Total Bids/Offers Accepted	468	657
Total Energy (kWh)	183,950	342,050
Percentage of Bids/Offers at Ceiling Price ($2/kWh)	88%	53%
Average Bid/Offer Price ($/kWh)	$ 1.81	$ 1.19
Weighted Average Bid/Offer Price ($/kWh)	$1.75	$1.41
Average Bid Reserve Price ($/kWh)	-	$0.91
Weighted Average Bid Reserve Price ($/kWh)	-	$0.78

The local energy price consistently cleared at the ceiling price of $2/kWh. However, the average price of the bids/offers in the Local Energy Auctions for the two years was $1.81/kWh and $1.19/kWh respectively, indicating a year-over-year decrease. This decrease seems to suggest that the participants were acting on learnings from Year 1 of the Demonstration and willing to bid lower due to competition. Regardless, the Local Energy Auction results show a strategic inclination towards many participants bidding at the auction ceiling price. The interviews reveal that some participants' strategy was to bid low in the local capacity auctions to improve their odds of being selected for the Demonstration, then subsequently bidding at the maximum in the Local Energy Auction to minimize activations across the commitment period. DER aggregators specifically noted a motivation to bid at the ceiling price to avoid activation fatigue for their contributor DERs, and to cover relevant costs[21].

4.3 Demonstration Settlements

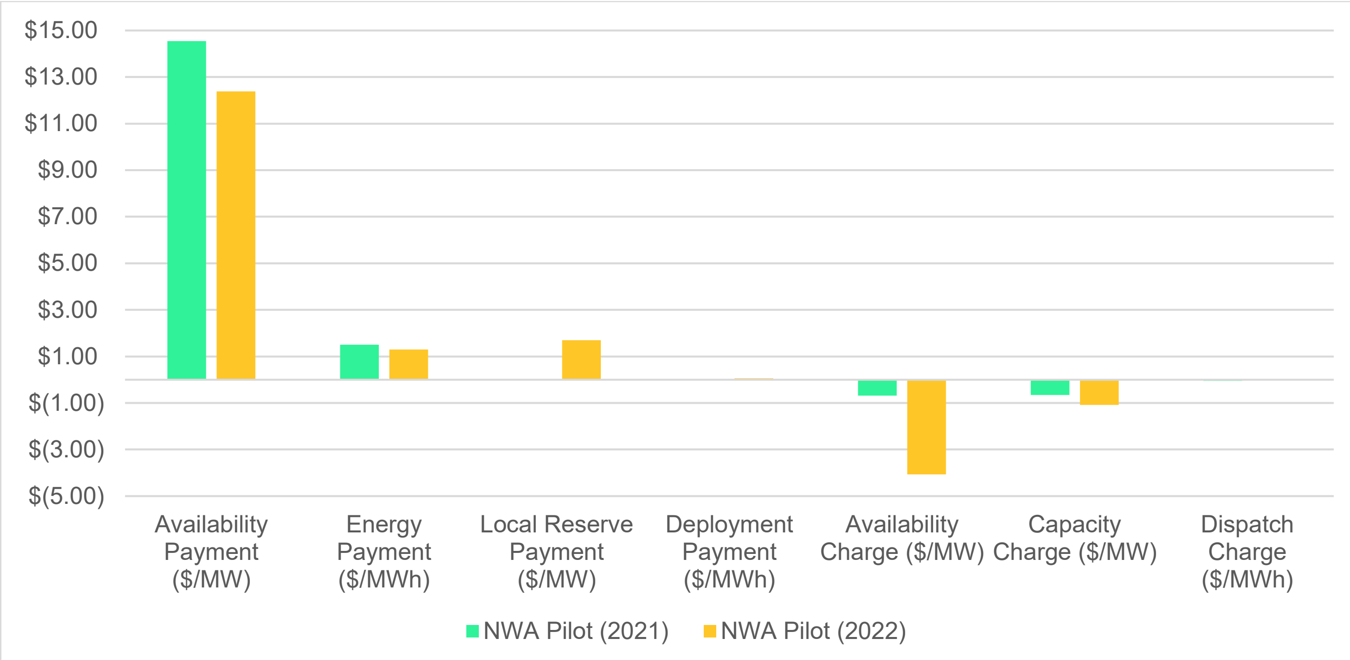
There were three categories of payments and charges, including capacity, energy, and those relevant to test activations. Within these three categories, there were five payment types and three charge types. The payment types compensated participants for capacity (Availability), reserve capacity, energy (DLMP), reserve energy, and test activations. The charges provided a mechanism to reduce capacity, reserve capacity, and energy payments if there were instances of non-performance where the specified performance thresholds were not met. Detailed information about metering requirements, baseline methodologies, and settlement calculations were included in the demonstration contracts[22,23] that were put in place between Alectra and DER participants.

Analysis - General Observations

Settlement payments and charges by type and year are displayed in Figure 7 below. Comparing Demonstration prices and wholesale market prices provides useful metrics, since participants may choose the opportunity that offers the highest financial benefit. However, significant inherent differences exist between transmission and distribution level services. Therefore, directly comparing prices from the Demonstration with those from IESO markets and programs requires consideration of numerous caveats.

[21] For context, the demonstration had a limit of 10 activations in one commitment period.
[22] Contract - Direct Participants (Year 2 DRAFT) – compare to Year 1
[23] Contract - Aggregators (Year 2 DRAFT) – compare to Year 1

Figure 7: *Comparison of Demonstration Project Payments and Charges*[24]



Generally, local capacity and local energy prices cleared higher in the Demonstration compared with capacity and energy prices at the transmissions level. This is to be expected, as more geographically restricted local electricity services typically are more expensive compared to wholesale market services that are sourced from broader areas with more participants. This aligns with the added system benefits and extra value that DERs can provide by offering services to the distribution system in addition to transmission level services.

Availability payments are a construct borrowed from the capacity auction designs at the transmission level. They incentivize participants to fulfill their obligations and ensure their DERs are available for activation. These payments constituted 71% of the total settlements in the Demonstration, highlighting their significance in the payment structure. Availability payments were fixed from month-to-month, in contrast to DLMP energy payments which were variable and were provided when activations took place. The design of the price and payment constructs in the Demonstration were intended to provide a stable and predictable revenue stream for participants. This design aligns with the underlying cost structure of resources, reducing uncertainty for participants and promoting more stable prices.

The Demonstration included three categories of non-performance charges, addressing specific concerns:

1. Availability charges: Applied when participants failed to submit bids/offers for the DER capacity they were obligated to make available. The charge was only for the unfulfilled portion of these obligations.
2. Capacity charges: Applied when a DER failed a test activation. After a first failed test activation, the capacity charge was applied. If a second test activation was failed, it could result in contract default.

[24] Deployment payment and dispatch charge are negligible

3. Dispatch charges: Applied when a DER does not meet activation instructions within a 15% threshold of the activated quantity. Demand response DERs were assessed against baselines.

Overall, these non-performance charges were established to reinforce the contractual obligations for participating and providing services in the Demonstration.

Throughout the Demonstration, settlement and payment trends varied across the months of the commitment periods, reflecting the operational and market dynamics. Total settlement peaked during the hotter summer months, aligning with increased activations, with the highest in August and the lowest in October for both Year 1 and Year 2 of the Demonstration. Availability payments remained consistent across the months, while DLMP energy payments fluctuated monthly, depending on the number of activations that took place. There was a notable decrease in the Local Capacity Auction clearing prices from Year 1 to Year 2, resulting in lower related settlements. Additionally, all Local Energy Auctions cleared at the ceiling price of $2.00/kWh.

5 Operational Performance Analysis

After participants in the Demonstration cleared the Local Capacity Auctions, they entered a contract with Alectra, and were assigned a capacity obligation based on the results of the auctions. Aggregators had a supplementary period (from November to March prior to each summer commitment period) after the Local Capacity Auctions to identify specific resources to meet their contractual obligation. Once the Local energy Auction began in the May to October commitment periods, participants entered their bids/offers in the software platform and were activated by Alectra when needs arose. This section provides an overview of how DERs performed throughout the Demonstration, taking various factors into consideration. This analysis aims to better understand when and how DERs were activated and how they responded to those activations.

The performance metric is one indicator of a DER's reliability, with higher values indicating more reliable performance. The over or under-deliveries when compared to activation instructions impact the performance metric. Another important metric is the availability metric, which reflects the proportion of a DER that is available for activation compared to the original capacity obligation. This metric considers unavailability and capacity derates of the DER.

Every business day before 7 AM, the software platform would evaluate Alectra's demand forecast for the Demonstration area to check for a 'local requirement' for DERs to operate. If a local requirement was identified, a standby notice would be sent to the participants. Subsequently, three hours before each hour in the availability window (noon to 9 PM on business days), the platform reassessed to determine whether the hour would be an activation hour, verifying the local requirement closer to real time. Should an activation be triggered, the platform would organize the bid/offer price-quantity pairs and activate the most cost-effective DERs to meet the local requirement.

If there was no local requirement or activation, or if available DERs exceeded the local needs, bids/offers would then be assessed against the shadow price of the nearest wholesale energy market node. Bids/offers that were economic compared to the shadow price would have been activated based on wholesale market needs. This approach was used to simulate participation in the wholesale energy market.

As shown in Figure 8, the software platform would issue an activation notice no less than 2.5 hours prior to an activation hour. An activation notice indicated the quantity activated for each activation hour. Each activated DER was paid the clearing price in the Local Energy Auction for energy delivered (or reduced for demand response). Under the Demonstration rules, a DER could be activated only once per day during the availability window, for up to four consecutive hours, with a maximum of ten activations allowed throughout the May-October commitment period.

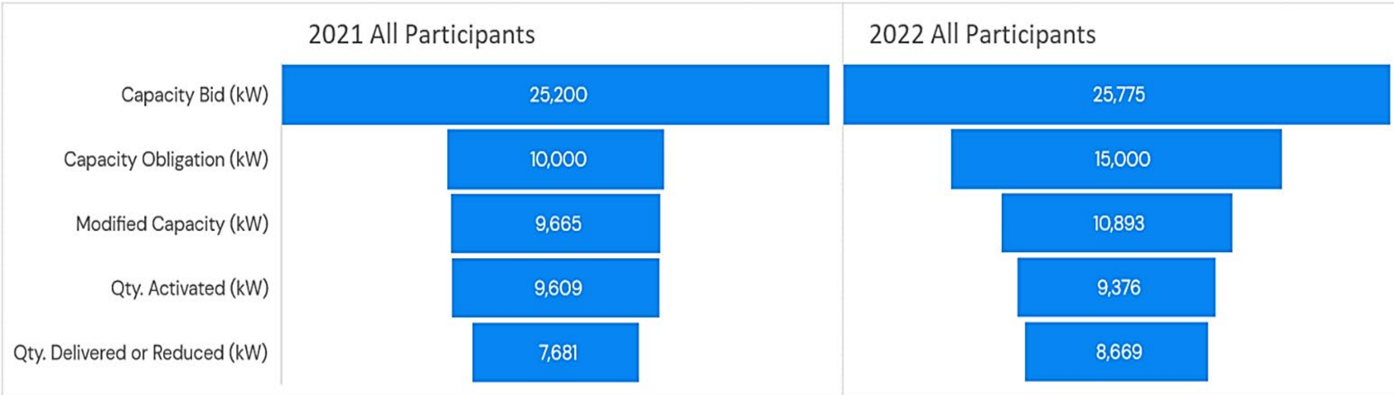
Figure 8: *Activation Event Sequence*

Analysis

In analyzing the operations of the Demonstration, the following discrete steps were examined: capacity bids, capacity obligation, modified capacity obligation[25], quantity activated, and quantity delivered or reduced. These five steps provide a helpful framework for understanding the key activities and outputs from the Demonstration. Figure 9 below illustrates these five analytical steps for Year 1 and Year 2 of the project.

[25] Modified Capacity Obligation: This value was created by ICF, starting with the Capacity Obligation, and then subtracting resource unavailability, capacity derates and energy auction derates.

Figure 9: *Capacity Offered and Delivered – All Participants*

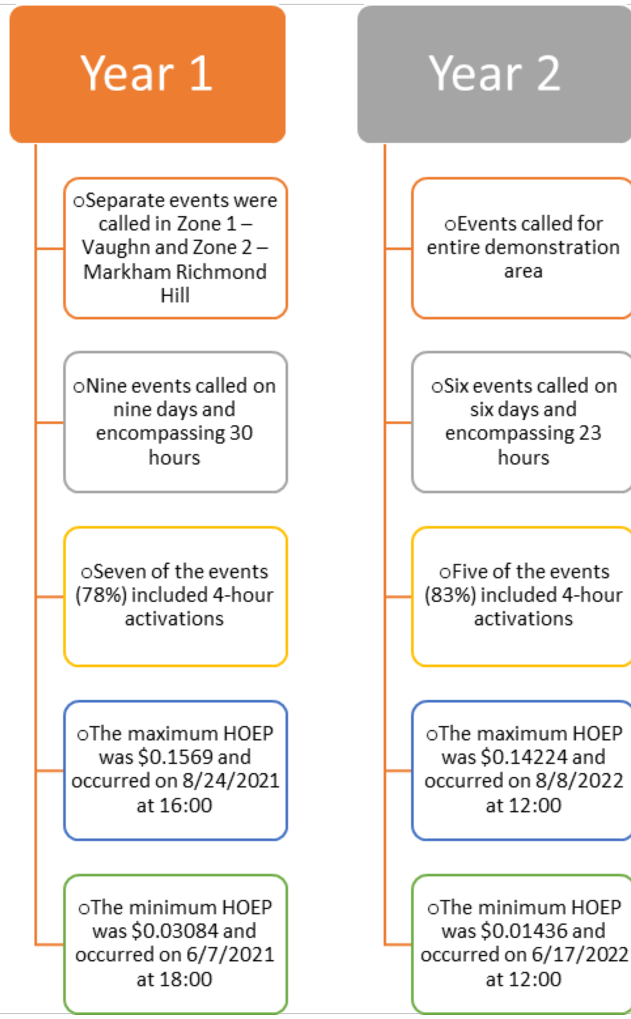


The figure highlights key differences from Year 1 and Year 2 for each step. The quantity of capacity bid was similar in both years (only 575 kW difference), but the capacity obligation that was contracted was larger (by 5,000 kW) in Year 2. Overall, in Year 1 there were small difference between the capacity obligation, modified capacity obligation[26], and quantity activated. Year 1 had a larger variation between quantity activated, and quantity delivered/reduced (1,928 kW) relative to Year 2 (707 kW), meaning that the performance metric for the DERs improved in Year 2.

The activations across the two operational years of the Demonstration had many similarities and some differences. For example, during the first year, distinct events were initiated for Vaughan and the Markham-Richmond Hill areas. However, in the second year, these two zones were merged, covering the entire area of the Demonstration. Figure 10 below summarizes the activations for the Demonstration.

[26] See footnote 26

Figure 10: *Activation Event Characteristics Comparison by Demonstration Year*



In Year 2 of the Demonstration, participants encountered challenges that necessitated modifications to the original capacity obligations cleared in the Local Capacity Auction. Participants shared various issues as part of their ongoing communications with Alectra. Some reported technical equipment failures, coupled with COVID-19 related supply chain delays and specialized staff shortages that limited the ability to repair equipment in a timely manner. Additionally, some aggregators working with contributor DERs, who had varying degrees of previous operational experience, faced difficulties in managing their contributors. From Alectra's perspective, several tools were available and utilized in the Demonstration to manage and enhance the performance of the participating DERs. Some of these included: test activations, non-performances charges, reserve deployment, and a consistent one-on-one communication plan to ensure participants were adequately informed on maintaining and improving their performance.

As seen in Table 10, the available capacity was close to the modified capacity obligations, achieving an average availability metric of 83% over the two operational years of the Demonstration. This indicates that 83% of the resources that were contracted were also available for activation. Moreover, when activated, the available DER capacity generally performed well, with an overall performance metric of 85% on a portfolio basis across. However, it is important to acknowledge the substantial over and under delivery by different DERs during the activations. While these variations partially balanced out, resulting in good portfolio performance, the observed variability indicates reduced performance at the individual DER level. Although not explicitly captured in Table 10, the Demonstration data also revealed varied performance patterns across activation hours and over time. A notable trend was performance fatigue, which was particularly evident during longer activation periods. The data suggested a decline in DER performance over extended durations and multiple activations.

Table 10: *Demonstration Project Operational Summary*

Operational Characteristics	Year 1 (2021)	Year 2 (2022)	Total	Equation
Sum of Hourly Capacity Obligation (kWh equiv.)	254,500	262,875	517,375	A
Sum of Hourly Quantity Activated (kWh equiv.)	246,550	182,549	429,099	B
Sum of Hourly Modified Capacity Obligation (kWh equiv.)	246,450	194,943	441,393	C
Quantity Delivered or Reduced (kWh)	200,471	165,943	366,414	D
Over/(Under) Delivered or Reduced (kWh)	40,676 (86,755)	48,646 (65,252)	89,322 (152,007)	D - B
Availability Metric	97%	69%	83%	B / A
Performance Metric	81%	91%	85%	D / B

One of the components for ensuring performance capabilities in the Demonstration was test activations. These tests, which were conducted at different times throughout the Demonstration, allowed Alectra to validate the performance of each participant, as needed. The design for the Demonstration allowed for a maximum of two test activations during a given commitment period. Test activations were strategically used by Alectra when it identified performance issues with the participating DERs. 15 tests were conducted over the two operational years of the Demonstration with a passing rate of 33%, as detailed in Table 11.

Table 11: *Capacity Test Results by Year*

	Year 1 (2021)	Year 2 (2022)	Total
Capacity Tests Performed	8	7	15
Capacity Tests Passed	3	2	5
Capacity Tests Failed	5	5	10
Passing Rate (%)	38%	29%	33%

The test activations served multiple functions for both the Alectra and the Participants. For Alectra, the test activation served as a good tool to assess the performance of the DERs, to ensure that the resources can deliver on their capacity obligation throughout the Demonstration. For participants, the tests provided an opportunity to demonstrate the performance of their DERs and address any identified performance issues to improve future activations.

6 Illustrative Cost-Benefit Analysis

One of the key objectives of the Demonstration evaluation was to assess the costs and benefits of procuring services from DERs and using them as alternatives. A holistic assessment is needed to understand the full value of DERs and compare them against traditional solutions. This section of the evaluation report presents an illustrative cost-benefit analysis, outlining the methodology, assumptions and outputs for cost and benefit streams at both the distribution and transmission levels.

6.1 Background and Methodology

To determine the net cost or benefit of procuring grid services from DERs, the avoided costs of traditional solutions need to be assessed. This assessment should be based on a logical connection between DER costs and infrastructure costs. Sited close to load, DERs can serve as alternatives to upstream infrastructure, including distribution, transmission, and central generation. They can be strategically procured and managed to defer investments in traditional infrastructure. For instance, a project aiming to avoid distribution infrastructure investments would seek services from DERs located in the downstream distribution area.

There are numerous on-going research efforts and pilot projects across the global electricity industry to clarify under what conditions exactly that DERs can and cannot provide “stacked” services and/or “stacked” value. The demonstration took the following approach:

- If there is simultaneous distribution and transmission level need, an operating DER is capable of supporting both.
- If there are distribution and transmission level needs in separate periods on separate days, the DER is capable of supporting both needs by operating in each of the periods.
- If there were “back-to-back” distribution and transmission needs (or vice versa) it was assumed that four consecutive hours of DER operation would be sufficient to cover both needs.

In particular, the IESO and Alectra teams acknowledged that the assumption that four hours of DER operation could address back-to-back needs is likely inaccurate and thorough investigations to determine the duration of operation required will need to be conducted in future projects. It is important to recognize that this issue primarily affects energy-limited DERs (e.g., battery storage) but does not apply to DERs capable of continuous operation (e.g., natural/hydrogen gas engines). [27]

[27] Determining the duration that energy-limited DERs need to operate to meet both distribution and transmission level capacity needs involves complex modelling and accounting for the variability and uncertainty at both levels of the system. Energy-limited DERs that offer stacked value may need to have capabilities beyond a 4-hour operation period – for instance 6 or 12 hours – to ensure reliability. The capability of maintaining extended operation would result in higher cost for services from the DERs than observed in the Demonstration.

ICF utilized the U.S. National Standard Practice Manual (NSPM) for Benefit-Cost Analysis of Distributed Energy Resources[28] to identify potential DER value streams to weigh against the costs of procuring services from DERs. Based on a review of each cost-benefit category and the data available from the Demonstration, ICF developed a methodology to calculate the net cost or benefit of utilizing DERs in the manner contemplated in the Demonstration. The complete list of the categories from the NSPM are available in Appendix 2.

Table 12 presents the specific benefit-cost categories and items from the NSPM that have been integrated into the forthcoming illustrative cost-benefit analysis. The benefits streams associated with the DERs providing grid services in the Demonstration are linked to avoiding the costs and impacts listed in Table 12.

Table 12: *NSPM value stream items included in the illustrative cost-benefit analysis*

Type	Utility System Impact	Description
Generation	Energy Generation	The production or procurement of energy (kWh) from generation resources on behalf of customers
	Generation Capacity	The generation capacity (kW) required to meet the forecasted system peak
Transmission	Transmission Capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably
	Transmission O&M	Operating and maintaining the transmission system
Distribution	Distribution Capacity	Maintaining the availability of the distribution system to transport electricity safely and reliably
	Distribution O&M	Operating and maintaining the distribution system
General	Financial Incentives	Financial support provided to DER host customer or other market actors, such as an aggregator

It should be noted that the overall value of DERs includes a range of benefits and costs. This report captures major components to provide a substantial understanding of the impact of using DERs as alternatives to traditional infrastructure. However, future evaluations of similar projects will need to consider additional factors, which were not considered in this evaluation due to limited availability of information and resources constraints, to develop a complete understanding. For example, the impacts of the reduction in transmission and distribution losses, a typical result of deploying DERs, were not explored in the cost-benefit analysis presented in this report.

[28] National Energy Screening Project, The National Standard Practice Manual

ICF calculated a range of illustrative avoided costs for the Demonstration for partially deferring an investment in two new MTS, as identified in the 2020 IRRP[29]. The MTS are needed to increase the capability to deliver electricity and meet load growth in the Vaughan and Markham areas, as depicted in Figure 2. In addition, the illustrative avoided costs include consideration for deferring a potential transmission solution upstream of the Demonstration area. The transmission solution is projected for the early to mid-2030s, due to the capacity limits being reached on the Claireville TS to Brown Hill TS 230 kV line.

A scenario-based approach was adopted for the illustrative cost-benefit analysis to help offer insights within uncertain and complex future conditions. Three scenarios were developed, 'Slow Growth', 'Base Case', and 'High Growth', each representing distinct future states of DER prevalence and their corresponding market values.

- The 'Slow Growth' scenario assumes limited DER deployment and growth in the region. This is expected to increase risks associated with a smaller pool of available DERs and increase prices for local capacity and energy prices due to fewer potential participants. This scenario also assumes lower costs for infrastructure and lower inflation rates resulting in lower avoided costs for NWAs.
- The 'Base Case' scenario considers a moderate presence of DERs that tracks most closely to Year 2 of the Demonstration.
- The 'High Growth' scenario anticipates significant deployment and growth of DERs. This scenario assumes that infrastructure costs grow faster and avoided energy costs are higher. Due to the larger pool of DERs in the region, there would be more resource availability that reduce performance risks and the price of energy and capacity services relative to the other scenarios.

The following sub-sections will discuss the scenario approach used in the analysis, the required DER capacity over time, the value of deferring distribution and transmission infrastructure, the avoided costs of centralized generation, and conclude with a summary of illustrative cost-benefit results.

It is cautioned that this evaluation report offers only an illustrative cost-benefit analysis, which should not be mistaken for an assessment of current planning options in southern York Region. Certain key considerations are not evaluated in this report, including implementation timelines and the associated risks of various options aimed at meeting the region's needs. The specific need selected for evaluation is also one with a higher expected transmission cost than most capacity based needs typically encountered in regional planning. This allows DERs to be explored in a case with larger than typical potential value from deferral.

The IRRP process relies on detailed, comprehensive analysis and close engagement with distributors, transmitter, and public stakeholders. The Demonstration and associated illustrative cost-benefit analysis in this report are intended only as proof of concept and to serve as input into future regional planning processes.

[29] The 2020 York Region Integrated Regional Resource Plan (IRRP) can be found on the York Region Regional Electricity Planning stakeholder engagement webpage.

The results presented in this section are calculated using a variety of assumptions, forecasts, and estimates. Values are rounded to reflect a lower level of precision and acknowledge the associated uncertainties.

6.2 Key Scenario-Based Parameters

Key financial and technical parameters for the illustrative cost-benefit analysis were carefully chosen across three scenarios - slow growth, base case, and high growth - to reflect different market conditions, as detailed in Table 13. The discount rates, both nominal and real, were used for determining the present value of future cash flows, with the nominal rate accounting for inflation.

The DER reliability margin is calculated by adding a grid planning margin, which functions similarly to a planning reserve, to a DER performance adjustment that accounts for how reliably DERs perform when activated. For the grid planning safety margin, ICF employed a proxy value of 10%, consistent with values typically used in grid planning and procurement analyses.

For the DER performance adjustment, ICF used a range of 8 to 14% across the three scenarios, which was within the range of performance metrics from actual DERs participating in the Demonstration. Cost assumptions for the MTS and the transmission solution identified in the IRRP are detailed Table 13.

Table 13: *Key Financial and Technical Parameters*

Parameter	Description/Rationale	Source	Slow Growth	Base Case	High Growth
Discount Rate (Nominal)	Sum of the real discount rate and inflation rate	N/A	8.00%	10.00%	10.00%
Discount Rate (Real)	Used to determine present value of a project/investment	IESO	4.00%	4.00%	4.00%
Implied Inflation Rate	Overall change in prices of goods and services, including a range of rates based on the last few years	Alectra	4.00%	6.00%	6.00%
Grid Planning Margin	Oversizing equipment or procurement of DERs to meet a given need, based on typical safety margin for wires solutions	ICF	10%	10%	10%
DER Performance Adjustment	Lower DER adoption requires a greater performance adjustment due to smaller portfolios of resources that may not be as	York NWA demo data	14%	12%	8%

	reliable as when there is a higher level of DER adoption				
DER Reliability Margin (Incl. Performance Adj)	Total reduction in DER available capacity, to increase reliability of DERs. This reliability margin can be lowered when there are more DERs performing more reliably.	ICF + demo data	24%	22%	18%
Max DER Potential multiplier	Multiplier used to create a range of DER growth relative to Alectra estimate, within the bounds of the DER Potential Study[30]	ICF	1.00	1.25	1.40
MTS Unit Cost ($2020 Millions)	Initial Municipal Transformer Station capital cost, based on IRRP MTS costs (inclusive of multiplier below)	Alectra	$50	$50	$62.5
Multiplier: Initial MTS Unit Cost	*Accounts for supply chain constraints and material cost increase*	*Alectra*	*0%*	*0%*	*25%*
MTS O&M Deferral Potential	Estimated industry average annual O&M costs	ICF	2%	2%	2%
Transmission Unit Cost ($2020 Millions)	Initial Transmission capital cost, based on IRRP transmission costs (inclusive of multiplier below)	IESO	$100	$100	$175
Multiplier: Initial Transmission Unit Cost	*Accounts for supply chain constraints and material cost increase*	*IESO*	*0%*	*0%*	*75%*
Transmission O&M Deferral Potential	Estimated industry average annual O&M cost	ICF	2%	2%	2%
Avoided energy ($2022/MWh)	Based on the IESO 2022 Annual Planning Outlook Marginal Cost (inclusive of multiplier below)	IESO	$30	$30	$36
Multiplier: Avoided energy	*Plausible energy price increase above forecast*	*ICF*	*0%*	*0%*	*20%*

[30] IESO, DER Potential Study

Avoided capacity ($2022/MW-Day)	Range of values between 2022 IESO capacity auction clearing price, the IESOs forecasted Net CONE reference price, and the weighted average clearing price for storage resources in the recent expedited Long-Term (E-LT1) RFP	IESO	$265	$570	$882
DER energy procurement ($2022 $/MWh)	Range of energy bids from Demonstration, cost reduces as market size increases (inclusive of multiplier below)	ICF + demo data	$2,000	$1,500	$1,000
Multiplier: DER energy procurement	*Represents range of energy bids from demonstration project*	*ICF*	*0%*	*-25%*	*-50%*
DER capacity procurement ($2022/MW-Day)	Range of capacity clearing prices from Demonstration, cost reduces as market size increases	ICF + demo data	$640	$400	$400

6.3 Modeling DER Over Time

Time is a critical element in financial and operational assessments of DERs as alternatives to traditional infrastructure. Changes in costs and deferrals over time have a significant impact on the outcomes of cost-benefit analyses and are dependent on the time period being evaluated and future assumptions.

An advantage of using DERs is their ability to be installed modularly and incrementally. DERs can be scaled and deployed to closely match demand, reducing the probability (and associated cost) of over procurement. On the other hand, new transmission and distribution delivery infrastructure is “lumpy” in nature. Typically, newly installed delivery infrastructure is oversized to accommodate future load growth, and therefore experiences relatively light usage in its initial years.

This inherent difference in development and scaling of DERs versus traditional infrastructure results in higher deferral value per unit of DERs because a smaller capacity of DERs can meet grid needs and offset a much larger capacity of traditional infrastructure. However, as the volume of DERs needed for deferral becomes higher in later years, the deferral value per unit of DERs decreases.

A key challenge lies in determining the approach and timing for supporting DERs and investments in traditional infrastructure to achieve the most economical outcomes. Addressing this challenge involves several considerations, including fostering the development of DER potential over time, balancing DER procurements with future grid needs, and ensuring stability with certainty in incentive structures for DERs participation.

Annual Capacity Requirement

Establishing the capacity requirement in future years is a key parameter of the illustrative cost-benefit analysis presented in this report. The capacity requirement is used to identify the timing of traditional infrastructure development as well as the capacity of DERs needed for deferral.

To calculate the capacity needed to defer an MTS, the analysis used year-over-year peak demand growth and currently existing MTS capacity, as outlined in the 2020 IRRP for York Region. The annual peak demand was compared to the existing MTS capacity to determine the specific year when a new MTS would be needed, and the incremental capacity gap in each subsequent year. Due to the interconnected nature of the distribution grid in southern York region, peak demand from the entire region was combined (Buttonville, Markham, Richmond Hill, and Vaughan).

Using the published IRRP load forecast from 2020, ICF's modelling identified 2025 as the first year that peak demand would exceed system capacity, requiring a new MTS[31]. A similar methodology was used to determine the timing for implementing a new transmission solution upstream of the Demonstration area. The illustrative cost-benefit analysis is presented for 2027, which focuses on deferring MTS infrastructure, and for 2032, which includes the need for both MTS and an upstream transmission solution.

Maximum DER Potential

The maximum potential of DERs plays an important role in the illustrative cost-benefit analysis, because sufficient DERs are required to meet the capacity requirement and enable deferral of traditional infrastructure. Maximum DER potential is effectively a constraint on the ability to support infrastructure deferral.

To estimate maximum DER potential presented in this report, Alectra developed estimates of near-term DER growth in their entire service area and then proportionally allocated the capacity to York Region. Long-term projections extrapolated the rate of change in DER growth from historical data to forecast DER potential in future periods. These estimates represented maximum DER potential in the slow-growth scenario of this analysis[32].

For the three scenarios, ICF utilized a multiplier to adjust the DER potential. The multiplier values utilized were within the range of potential modeled in the recent DER Potential Study published by IESO. Accurately forecasting the maximum potential of DER is essential for effectively modeling as alternatives to traditional infrastructure.

The level of DER needed to procure were based on the annual capacity requirement, adjusted using a reliability margin to account for the performance and forecasted availability as a resource for deferral planning. The margins used for each scenario were based on a range of values derived from actual DER

---

[31] While the analysis uses the latest published data for the York Region, it is important to note that the peak demand forecasts, which influence the need for new infrastructure, were developed in 2018 in advance of the 2020 IRRP release and do not reflect updated demand projections. This context should be considered when interpreting results.
[32] To accurately gauge the potential of DERs in a region or sub-region, a detailed local potential study is necessary. Conducting local achievable potential studies for DER can be highly informative about the current and future available DER capacity.

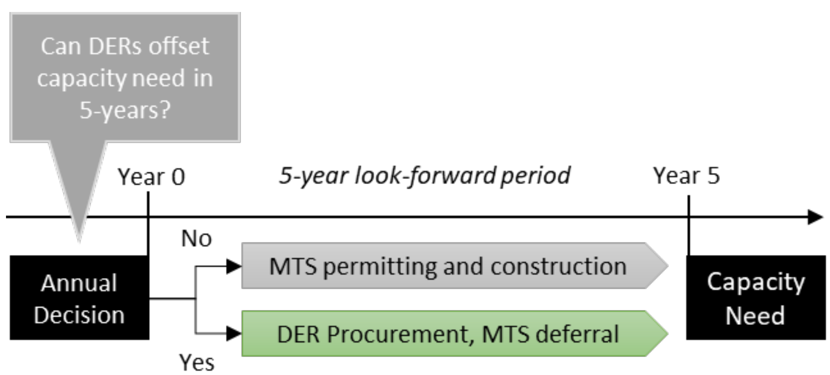
performance within the Demonstration and market estimates for average DER portfolios. This approach reduces risks for non-performance and creates a more realistic ratio of DERs needed to meet the capacity requirement.

Look-Forward Period

The illustrative cost-benefit analysis employs look-forward periods to strategically plan for the deployment of DERs and provide confidence to planners and grid operators in their decision to defer traditional infrastructure investments. Deferral was modeled only when the forecasted DER potential throughout the look-forward period was sufficient to meet the anticipated need for each forward-looking year, as illustrated in Figure 11. A 5-year look-forward period was chosen for deferring MTS to ensure there is enough time for permitting and construction before the reliability need arises. For transmission deferral, a 7-year look-forward period was selected for similar reasons.

These look-forward periods were also used to calculate the deferral value created by DERs using 5-year and 7-year rolling averages, which are presented alongside annual values in the cost-benefit analysis. Annual deferral values fluctuated significantly, with higher values when a small capacity of DERs can offset a large infrastructure investment, and lower values over time as more DERs are needed to offset the growing capacity requirement. The purpose of using rolling deferral value is to smooth out the variable annual values and provide more stability and certainty.

Figure 11: *Infographic of Rolling Deferral Value*



Supporting DER Potential

As previously discussed, maximum DER potential is effectively a constraint, limiting the possibility of infrastructure deferral. Therefore, to expand the situations in which DER can defer traditional infrastructure, efforts to expand DER capacity are warranted.

One example is the utilization of rolling deferral values to provide stable incentives for DERs throughout the look-forward period, ensuring certainty for investment and encouraging consistent growth and readiness. From a system planning perspective, this approach offers confidence that DERs will be available throughout the look-forward period.

An important aspect of using DERs to defer traditional infrastructure is the need to develop the DER potential before actual reliability needs arise. Relying on late procurement carries risks, as insufficient DER potential could significantly challenge to meeting electricity demands. Rolling deferral values support DER potential before deferral needs arise by capturing future deferral value and providing incentives throughout the look-forward period.

Similarly, the amount of DER needed for deferral fluctuates from year to year, subject to the dynamics between demand growth and system capacity. The approach taken in the illustrative cost-benefit analysis supports DER potential through these fluctuations, ensuring that the DER potential is supported and available throughout the look-forward period.

6.4 Distribution Delivery Deferral Value

ICF developed a methodology for analyzing the deferral of two new MTS in southern York Region to meet the projected peak annual demand growth through 2040. DER procurement for each year was based on the incremental capacity needed due to load growth plus a DER reliability margin, as outlined in the above Section 6.3. Table 14 provides a description of the methodology and source for key elements used in the analysis.

***Table 14**: Deferral Value Model Elements*

Elements	Description	Source
Peak Demand (MW)	Peak demand for Buttonville, Markham, Richmond Hill, and Vaughan	2020 IRRP
System Capacity (MW)	Capacity of MTSs serving Buttonville, Markham, Richmond Hill, and Vaughan	2020 IRRP
Capacity Requirement (MW)	Difference between System Capacity and Peak Demand	Calculated value
Max DER Potential in Region (MW)	Estimate for the total DER which could participate in an NWA program. Original estimate provided by Alectra, with multiplier implemented by ICF	Alectra and ICF
DER Need with Reliability Margin (MW)	Represents the Capacity Requirement DERs need to fill accounting for the additional capacity needed to meet the performance adjustment	Calculated value

Incremental DER (available for procurement)	The difference between Max DER Potential in Region and DER Need with Reliability Margin	Calculated value
Deferred Capacity (MW)	The MTS capacity which can be deferred by DERs, which occurs when the DER Need w/Reliability Margin is greater than the Capacity Requirement	Calculated value

The deferral values for 2027 and 2032 are highlighted in Table 15 and Table 16. The selection of these specific years was strategically informed to illustrate two distinct cases: 2027 focuses on a period where deferred infrastructure primarily involves MTS, while 2032 highlights a timeframe requiring both MTS and a large transmission solution in the region.

By 2027, the peak demand is expected to surpass the existing MTS capacity by 81 MW, requiring the procurement of DERs to defer the installation of the MTS. Each new MTS addition was modeled to provide 153 MW of new station capacity and enhanced electricity delivery capabilities.

The capacity requirement for DERs ranges from 95 to 100 MW across the scenarios, factoring in a reliability margin of 18% to 24%. Table 15 indicates that the maximum DER potential in the area is 118 to 165 MW across the three scenarios, which is greater than the DERs needed to address the capacity requirement. However, in the 5-year look forward-period for the Slow Growth scenario the DERs needed will exceed the maximum DER potential, therefore MTS deferral does not occur in this scenario.

The total annual value[33] of deferring the MTS with DER was found to be between $0 and $109,000/MW-year. The rolling average deferral value[34] calculated over the 5-year look-forward period ranged from $12,000 to $80,000 per MW-year, varying by scenario.

By 2032, the peak demand is projected to grow further, exceeding the existing MTS capacity by 218 MW, potentially requiring the installation of two MTS. However, the possibility of deferring the MTS is constrained as the maximum DER potential, varying from 132 to 185 MW across the scenarios, falls short of the capacity requirement.

Therefore, in 2032, it will be necessary to have built one MTS, while the remaining capacity requirement can be addressed with DER, allowing for the deferral of a second MTS. While not noted in Table 16, with the installation of one MTS, the additional capacity needed to defer the second MTS is 65 MW., The modeling approach indicated procurement of 132 to 185 MW - the full amount of available DER potential. This is reflected in in Table 16 with DER needs matching exactly with the maximum potential. As described in Section

[33] The annual MTS deferral value is a $/MW figure that reflects the total value of deferring the MTS by one year, divided by the DER capacity that would need to be procured in that year to realize the deferral.
[34] The rolling MTS deferral value represents the cost savings from deferring the MTS over a 5-year period, spread across the DER capacity that needs to be procured and aligns with the lookahead timeframe used for the MTS deferral.

6.3, this strategy supports the development of the DER potential in the area, helping ensure that DERs are available over the look-forward period to realize deferral opportunities.

The total annual value in 2032 derived from deferring the MTS installation was calculated to be between $57,000 and $75,000 per MW-year. The rolling 5-year deferral value varied from $57,000 to $144,000/MW-year depending on the scenario.

Table 15: *Distribution Deferral Value by Scenario for Deferral Year 2027*

Deferral Value (2027)	Slow Growth	Base Case	High Growth	
Capacity Requirement (MW)	81	81	81	A
Max DER Potential in Region (MW)	118	148	165	B
DER Need w/Reliability margin (MW)	100	99	95	C
5-year Look Ahead (DER Potential > DER Need)	No	Yes	Yes	
Deferred Capacity (MW)	-	153	153	D
MTS Total Cost ($Million)	65.8	75.2	94.0	E
Annual MTS Capital Deferral Value ($Million)	-	6.8	8.5	F
Annual O&M Deferral Value ($Million)	-	1.5	1.9	G
Annual MTS Deferral Value ($/MW-year)	**-**	**85,000**	**109,000**	H = (F + G) / C
Rolling 5-Year MTS Capital Deferral Value ($Million)	5.7	38.5	48.2	I = 5-yr. Avg (F)
Rolling 5-Year O&M Deferral Value ($Million)	1.5	8.5	10.6	J = 5-yr. Avg (G)
Rolling 5-Year MTS Deferral Value ($/MW-year)	**12,000**	**67,000**	**80,000**	K = (I + J) / 5-yr. Avg (C)

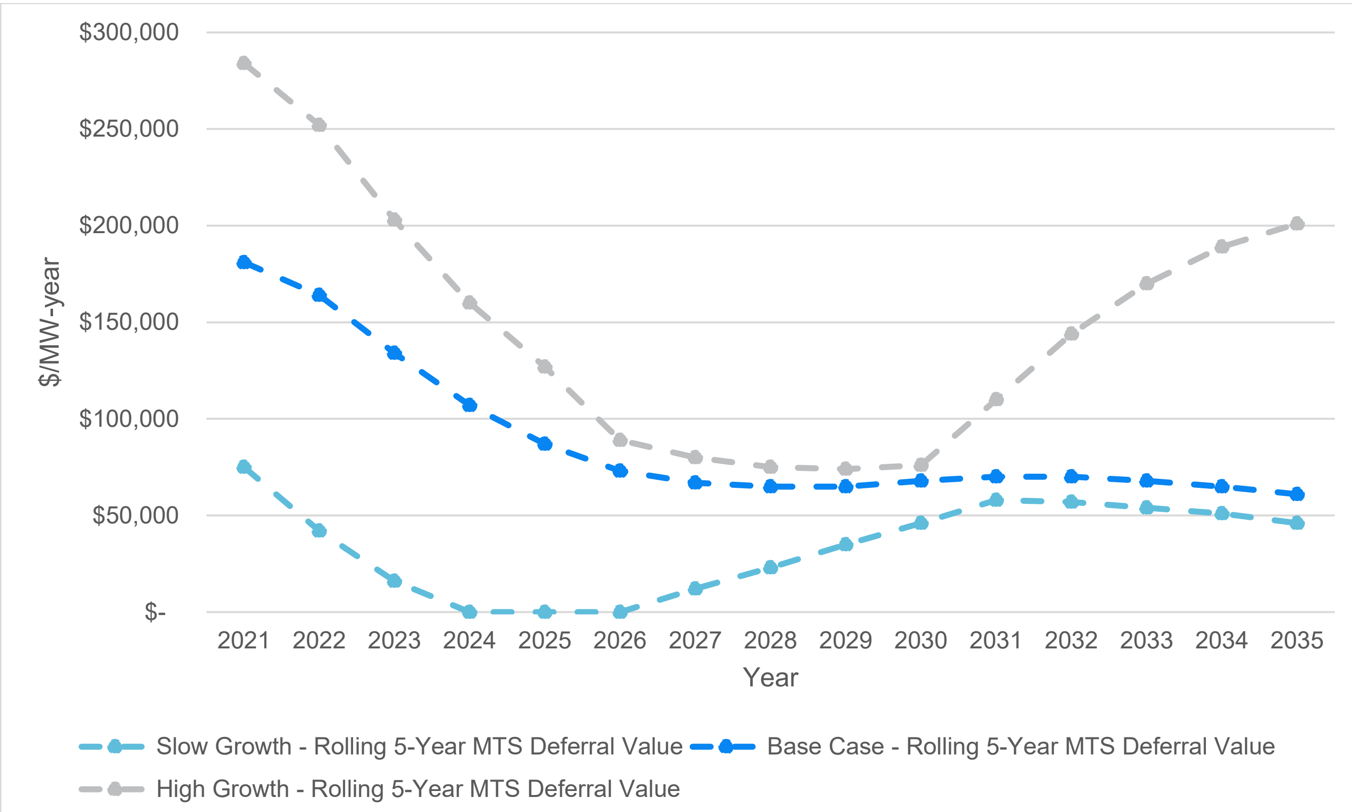
Table 16: *Distribution Deferral Value by Scenario for Deferral Year 2032*

Deferral Value (2032)	Slow Growth	Base Case	High Growth	
Capacity Requirement (MW)	218	218	218	A
Max DER Potential in Region (MW)	132	165	185	B
DER Need w/Reliability margin (MW)	132	165	185	C
5-year Look Ahead (DER Potential > DER Need)	Yes	Yes	Yes	
Deferred Capacity (MW)	153	153	153	D
MTS Total Cost ($Million)	160.1	201.2	252.5	E
Annual MTS Capital Deferral Value ($Million)	5.9	9.1	11.4	F
Annual O&M Deferral Value ($Million)	1.6	2.0	2.5	G
Annual DER Deferral Value ($/MW-year)	**57,000**	**68,000**	**75,000**	H = (F + G) / C
Rolling 5-Year MTS Capital Deferral Value ($Million)	32.1	48.6	120.6	I = 5-yr. Avg (F)
Rolling 5-Year O&M Deferral Value ($Million)	8.7	10.7	23.5	J = 5-yr. Avg (G)
Rolling 5-Year DER Deferral Value ($/MW-year)	**57,000**	**70,000**	**144,000**	K = (I + J) / 5-yr. Avg (C)

The variations in MTS deferral values across the scenarios highlight the crucial role of inputs and assumptions in the analysis. In instances where DER growth and performance are lower, as seen in the slow growth scenario for 2027, no deferral value materialized. This outcome supports the insight that it may be beneficial to adopt strategies that cost-effectively develop DER potential over time, to ensure that sufficient capacity is available to provide grid services.

Figure 12 below shows the changes in deferral values from 2021 to 2035. The 'Rolling 5-Year MTS Deferral Value' is calculated based on the MTS capital cost that can be deferred in the evaluated year, provided there are sufficient DERs available five years in the future to meet incremental peak load and defer the MTS at that time. If enough DERs are available for deferral, the DERs are modelled to be deployed, and the deferral value of the infrastructure is counted for that year. This process is repeated each year, and the deferral values are summed up over time. The 'Annual MTS Deferral Value' is highest initially because deferral can be achieved with a smaller amount of DER, leading to a significantly higher per unit value. This is evident in the 2032 High Growth scenario in Table 16, where the least amount of DER is needed to defer the MTS costs. Additionally, the deferral value increases further for years when the MTS would have been in service, as it includes both capital and O&M deferral. As the capacity need increases, more DERs are required to continue deferring the investment, which also grows with inflation. Consequently, the deferral values tend to decrease over time as the average approaches minimum annual values. However, depending on the rate of demand growth and inflation, it is possible that deferral values could increase again in the later years.

Figure 12: *DER Procurement and Distribution Deferral Value Across Scenarios*



6.5 Transmission Delivery Deferral Value

ICF developed a deferral analysis methodology for the transmission solution in southern York Region to meet the anticipated peak demand growth. The transmission avoided cost model extends from 2020 to 2040, with the first incremental demand need identified starting in 2032, as can be seen in Table 17 and Table 18. The transmission solution was modeled with a capital cost of $100M (in 2020 dollars) for the slow growth and base case scenarios and $175M (in 2020 dollars) for the high growth scenario. Additionally, operations and maintenance (O&M) costs were calculated as 2% of the transmission solution capital cost, which aligns with the average transmission O&M costs across the industry.

The transmission avoided cost methodology was very similar to the MTS avoided cost methodology and utilized the same scenarios. However, it focused on the peak demand growth specific to the transmission system connecting York Region to the bulk electricity system. This forecast, provided by IESO, included an hourly load profile from 2032 through 2037. As the load in the region increased, peak events were identified when the load exceeded the current transmission system capacity. The maximum incremental demand from these peak events was used for each year to identify the incremental capacity needed each year.

When the model determined that new transmission was needed, the cost was calculated based on the future year cost of the transmission solution. Since the incremental distribution capacity needs were greater than the incremental transmission capacity needs, the analysis assumed the same DER procurement for each year as in the distribution avoided cost model. The annual transmission deferral value was calculated by adding the deferred transmission capital and O&M costs and dividing this sum by the quantity of DER capacity required for that year. In 2027 the transmission line would not be in service and there would be no associated O&M. Therefore, while the transmission line is deferred based on the 7-year look ahead, and capital deferral benefits are captured based on the present-day value of the transmission infrastructure, O&M deferral is zero. For the rolling deferral value, a 7-year period using the same approach as the MTS deferral, to align with the lookahead timeframe for transmission deferral.

Table 17: *Transmission Deferral Value by Scenario for Deferral Year 2027*

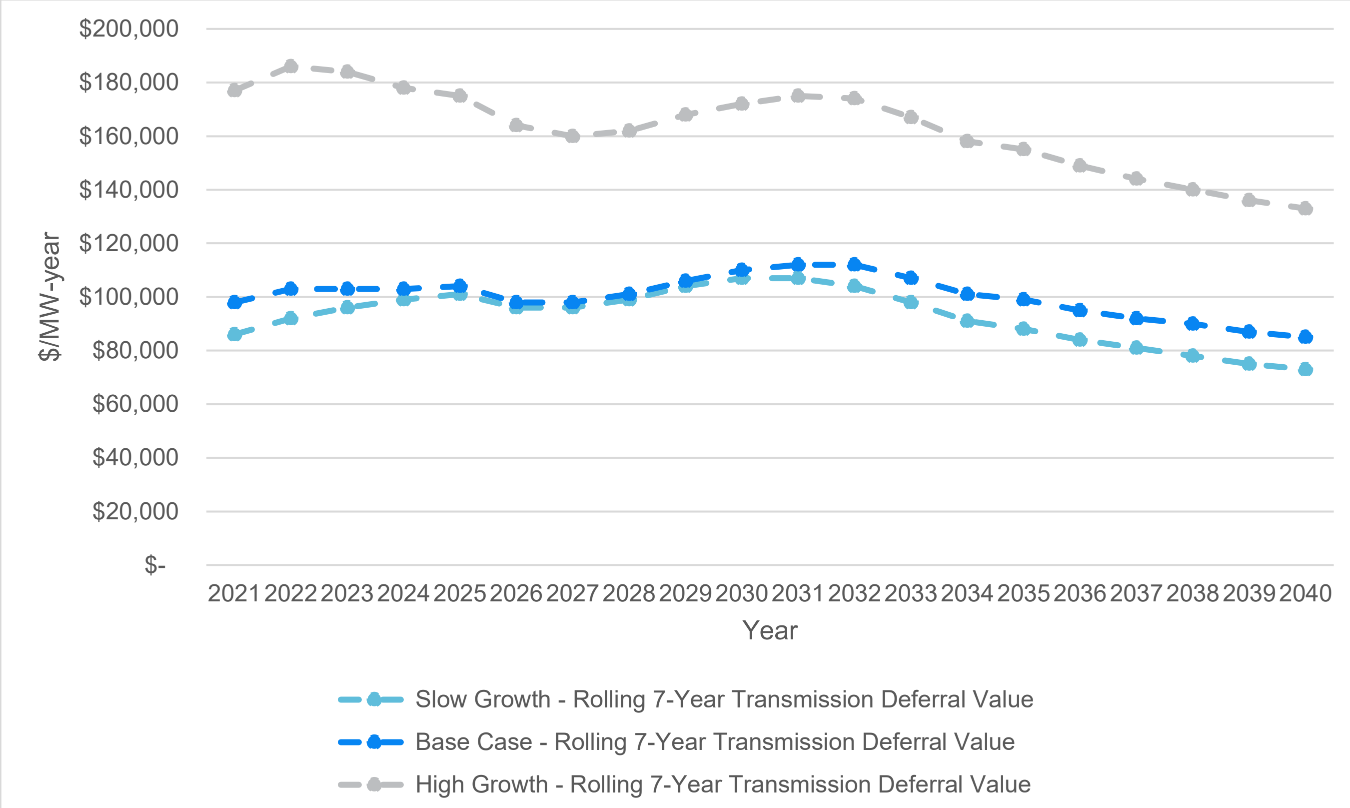
Deferral Value (2027)	Slow Growth	Base Case	High Growth	
Transmission Deferral Potential($Million)	131.6	150.4	263.1	A
Annual Transmission Capital Deferral Value ($Million)	9.7	11.1	19.5	B
Annual O&M Deferral Value ($Million)	-	-	-	C
Annual Transmission Deferral Value ($/MW)	**97,000**	**113,000**	**204,000**	**D = (B + C) / (C from Table 15)**
Rolling 7-Year Transmission Capital Deferral Value ($Million)	77.0	93.5	163.6	E = 7-yr. Avg (B)
Rolling 7-Year O&M Deferral Value ($Million)	6.5	8.3	14.5	F = 7-yr. Avg (C)
Rolling 7-Year Transmission Deferral Value ($/MW)	**96,000**	**98,000**	**160,000**	**G = (E + F) / 7-yr. Avg (C from Table 15)**

Table 18: *Transmission Deferral Value by Scenario for Deferral Year 2032*

Deferral Value (2032)	Slow Growth	Base Case	High Growth	
Transmission Total Cost ($Million)	160.1	201.2	352.1	A
Annual Transmission Capital Deferral Value ($Million)	11.9	14.9	26.1	B
Annual O&M Deferral Value ($Million)	3.2	4.0	7.0	C
Annual Transmission Deferral Value ($/MW)	**114,000**	**115,000**	**179,000**	**D = (B + C) / (C from Table 16)**
Rolling 7-Year Transmission Capital Deferral Value ($Million)	93.7	125.1	218.9	E = 7-yr. Avg (B)
Rolling 7-Year O&M Deferral Value ($Million)	25.3	33.8	59.1	F = 7-yr. Avg (C)
Rolling 7-Year Transmission Deferral Value ($/MW)	**104,000**	**112,000**	**174,000**	**G = (E + F) / 7-yr. Avg (C from Table 16)**

The transmission deferral value shows trends similar to the distribution deferral value, but with a higher initial value. The per unit value decreases each year as the incremental capacity need approaches the installed capacity of the transmission solution. Figure 13 below illustrates how the 7-year rolling DER procurement transmission deferral value changes over time for each scenario.

Figure 13: *DER Procurement and Transmission Deferral Value Across Scenarios*



6.6 System Resource Value

DERs can be strategically located close to load, reducing the incremental need for upstream distribution, transmission, and additional generation or storage resources in the right circumstances. Without DERs as an alternative, there may be a need for additional centralized generation capacity and energy. The costs listed in Table 19 and Table 20 below are generation-related costs that can be avoided with the effective use of DERs (or that DERs can earn, depending on the approach taken). The input assumptions for the avoided costs, along with IESO planning and procurement sources, are detailed for each of the three scenarios. The scenario inputs allow for a nuanced understanding of the cost implications and benefits under varying conditions.

Table 19 below provides the figures corresponding to the avoided generation cost assumptions, adjusted for inflation under each scenario. The avoided energy unit costs ($/MWh) are derived from an IESO forecast of the marginal costs of producing energy, reflecting the trajectory of energy market prices. The energy cost represents the weighted average of the cost across a year and is used as a direct input into the slow growth and base case scenarios. However, for the high scenario, the cost is adjusted up to recognize that the DERs are likely going to be operating in periods when the demand on the system and the energy prices are high.

Notably, the capacity costs listed in Table 19 and Table 20 are derived from reasonable data points but vary significantly. It remains important to further investigate and define appropriate capacity cost assumptions for future projects.

Table 19: *Avoided Generation Costs Across Scenarios for 2027*

Avoided Generation Costs (2027)	Slow Growth	Base Case	High Growth
Avoided Energy Unit Cost ($/MWh)	$34	$34	$40
Avoided Capacity Unit Cost ($/MW-day)	$320	$760	$1,180
Avoided Annual Energy Cost ($/MW-year equiv.)	$720	$720	$860
Avoided Annual Capacity Cost ($/MW-year)	$81,000	$192,000	$297,000
2027 Total Avoided Generation Cost ($/MW-year equiv.)[35]	$82,000	$193,000	$298,000

Table 20: *Avoided Generation Costs Across Scenarios for 2032*

Avoided Generation Costs (2032)	Slow Growth	Base Case	High Growth
Avoided Energy Unit Cost ($/MWh)	$41	$41	$50
Avoided Capacity Unit Cost ($/MW-day)	$390	$1,020	$1,580
Avoided Annual Energy Cost ($/MW-year equiv.)	$880	$880	$1,060
Avoided Annual Capacity Cost ($/MW-year)	$99,000	$257,000	$398,000
2032 Total Avoided Generation Cost ($/MW-year equiv.)[36]	$100,000	$258,000	$399,000

6.7 DER Procurement Cost

Projected DER procurement costs, representing costs for acquiring services from DERs in the demonstration's local auctions, were calculated for the years 2027 and 2032. Table 21 provides a breakdown of assumptions and input sources for the energy and capacity costs used. While the demonstration also included a local reserve auction, it was deemed too experimental to incorporate in this analysis. The procurement costs differ across three scenarios: slow growth, base case, and high growth. The capacity cost variations were based on the different local capacity auction prices observed in Year 1 and Year 2 of the demonstration, as detailed in Table 13, which outlines key financial and technical parameters used in the cost-benefit analysis.

[35] Based on 21.31 Activation Hours per MW-Year for avoided energy; 252 business days per year for avoided capacity.
[36] Based on 21.31 Activation Hours per MW-Year for avoided energy; 252 business days per year for avoided capacity.

In the slow growth scenario, energy service procurement costs from DERs are based on the wholesale market's maximum price of $2/kWh, aligning with the demonstration's trend of local energy auctions consistently clearing at this ceiling price. Conversely, the base case and high growth scenarios assume lower energy market costs, and capacity costs, anticipating increased competition and more advanced bidding strategies. Table 21 outlines the DER procurement cost assumptions, showing a decrease in total costs from the slow growth to the high growth scenario. Additionally, these costs are projected to be higher in 2032 compared to 2027, reflecting the impact of inflation.

Table 21: *Estimated Future DER Procurement Costs Across Scenarios*

Estimated Future DER Procurement Costs	Slow Growth	Base Case	High Growth
2027 Energy Unit Cost ($/MWh)	$2,000	$1,500	$1,000
2027 Capacity Unit Cost ($/MW-day)	$780	$540	$540
2027 Total DER Procurement Cost ($/MW-year equiv.)	**($239,000)**	**($167,000)**	**($156,000)**
2032 Energy Unit Cost ($/MWh)	$2,000	$1,500	$1,000
2032 Capacity Unit Cost ($/MW-day)	$950	$720	$720
2032 Total DER Procurement Cost ($/MW-year equiv.)	**($282,000)**	**($213,000)**	**($202,000)**

6.8 Summary of Total Net Benefit

This section provides a summary of the costs and benefits outlined earlier, culminating with an analysis of net benefits or costs associated with using DERs as an alternative to traditional infrastructure. Table 22 and Table 23 present the net results for the years 2027 and 2032, respectively. These tables compare the avoided costs in generation, transmission, and distribution with the costs of procuring services from DERs, illustrating the overall financial impact across slow growth, base case and high growth scenarios. The tables use rolling deferral values, which as previously noted are preferred for aligning with long-term DER planning perspectives of both participants and system planning.

The 2027 figures indicate lower avoided transmission deferral values as compared to 2032, reflecting the fact that the need for transmission infrastructure upgrades does not fully materialize until 2032. Nevertheless, the rolling 7-year deferral value provides some benefit for this in 2027. Overall, the cost-benefit analysis demonstrates significantly positive net benefits, indicating the economic viability of DERs as an alternative or deferment to traditional infrastructure, in the Base Case and High Growth scenarios. However, the net cost in the Slow Growth scenario, as well as the range of values across the scenarios, emphasizes results are highly sensitive to different market conditions and assumptions.

For the 2032 projections, with the full transmission need materialized, there is a marked increase in the deferral value. For this year, the Base Case and High Growth scenarios show substantial net benefits. However, the Slow Growth scenario still indicates a net cost, albeit smaller than the 2027 figure.

Table 22: *Summary of Net Benefits of using DERs as NWA for 2027*

Category	Cost/Benefit	Slow Growth	Base Case	High Growth	Source
A. Avoided Generation Energy Cost	Total Avoided Generation Energy Cost ($/MW-year equivalent)	$720	$720	$860	Table 19
B. Avoided Generation Capacity Cost	Total Avoided Generation Capacity Cost ($/MW-year)	$81,000	$192,000	$297,000	Table 19
C. Transmission Deferral Value	Rolling 7-Year Transmission Deferral Value ($/MW-year)	$96,000	$98,000	$160,000	Table 17
D. Distribution Deferral Value	Rolling 5-Year MTS Deferral Value ($/MW-year)	$12,000	$67,000	$80,000	Table 15
E. DER Procurement Cost	Total DER Procurement Cost ($/MW-year equivalent)	$(239,000)	$(167,000)	$(156,000)	Table 21
F. Net (Cost)/Savings for DER as alternative	($/MW-year equivalent)	$(49,000)	$191,000	$382,000	F=A+B+C +D-E

Table 23: *Summary of Net Benefits of using DERs as NWA for 2032*

Category	Cost/Benefit	Slow Growth	Base Case	High Growth	Source
A. Avoided Generation Energy Cost	Total Avoided Generation Energy Cost ($/MW-year equivalent)	$880	$880	$1,060	Table 20
B. Avoided Generation Capacity Cost	Total Avoided Generation Capacity Cost ($/MW-year)	$99,000	$257,000	$398,000	Table 20
C. Transmission Deferral Value	Rolling 7-Year Transmission Deferral Value ($/MW-year)	$104,000	$112,000	$174,000	Table 18
D. Distribution Deferral Value	Rolling 5-Year MTS Deferral Value ($/MW-year)	$57,000	$70,000	$144,000	Table 16
E. DER Procurement Cost	Total DER Procurement Cost ($/MW-year equivalent)	(282,000)	$(213,000)	(202,000)	Table 21
F. Net (Cost)/Savings for DER as alternative	($/MW-year equivalent)	$(21,000)	$227,000	$515,000	F=A+B+C +D-E

The illustrative cost-benefit analysis, summarized in the two tables above, demonstrates that DERs can offer substantial cost savings as an alternative or deferment to traditional infrastructure given the right conditions. As mentioned previously, York Region has unique local characteristics that make DERs particularly valuable, given the potential need for a large upstream transmission solution in the early to mid-2030s. While this aspect is less common outside of York Region, the deferral of MTSs is a more general benefit that holds relevance for many other regions in the province as well.

Insights from the illustrative cost-benefit analysis are highly relevant to the energy transition. A lower-cost electricity system can reduce barriers to electrification and decarbonization. When considering individual benefit streams like avoided generation, transmission, or distribution costs in isolation, the DER procurement costs may exceed the benefits, indicating a net cost. However, a more comprehensive assessment that considers several benefit streams together - often referred to as a "stacked" approach - can reveal that the combined benefits outweigh the costs of DER procurement, leading to net savings.

The analysis provides several key observations and strategic considerations:

- Strategic targeting of DER procurements is essential, with the greatest benefit likely to be realized by focusing on areas where DERs can offer distribution and transmission deferral value, along with avoided central generation costs.
- Developing appropriate rules, requirements, mechanisms, and processes is foundational to making the potential of DERs available.
- Enabling the stacking of services by the IESO and DSOs, rather than restricting DERs to "single service" procurements, is essential for maximizing benefits.
- Effective coordination between transmission and distribution is crucial to ensure reliable DER usage and that the stacked benefits are realized for both DSOs and IESO.

The demonstration project has made significant advancements in many key areas to enable DERs to be used as alternatives or deferment to traditional infrastructure, and continued efforts are needed to refine and improve the methods.

7 Project Participant Feedback

ICF partnered with Alectra to gather perspectives from 2021 and 2022 Demonstration participants. High level observations and recommendations are noted below. While these participant insights are important for shaping future programs, they should also be balanced with the requirements of the electricity system and program administration to achieve overall positive outcomes.

Common Observations

All organizations interviewed expressed their willingness to participate in the Demonstration project again if given the opportunity. Participants highlighted their positive experiences working with Alectra throughout the Demonstration, noting their consistent and supportive approach. Operationally, both the registration and enrollment processes were deemed effective, and participants found the software platform to be user-friendly.

Several participants noted that their energy bidding strategy involved bidding at the ceiling to maximize payment per activation while minimizing the frequency of dispatches, given the costs and complexities associated with responding to activations. Aggregators observed that while customers were willing to be activated up to ten times, this was considered at the higher end.

Some demand response participants in the Demonstration made use of combined heat and power (CHP) or natural gas-fired thermal generators to displace load at the customer site to participate in the Demonstration.

Three participants noted that they were part of other program offerings, such as the IESO Capacity Auction and the Industrial Conservation Initiative (ICI). Several participants opted to withdraw DERs from other programs to enroll in the Demonstration, seeking to support innovation and pursue new revenue opportunities. One participant expressed confusion about participating in both the Demonstration and ICI.

Common Recommendations

Many participants suggested improving the Demonstration's financial settlement reporting, including providing data in spreadsheet format per resource and adding more settlement details on the platform. Aggregators in the Demonstration manually sifted through PDF reports to generate individual customer statements.

Participants suggested extending the advance notification beyond the current timeframes in the Demonstration (i.e., standby notice by 7 AM and 2.5 hours of advance notice of activation) This would be especially beneficial for DERs involving load curtailment.

Two participants noted that direct access to customer meter data via Alectra would have streamlined the Demonstration's processes. However, they also recognized the complexities involved, such as data sensitivity and the necessity for secure connections.

Two participants expressed that the Demonstration could have achieved greater system benefits if participants had more flexibility to choose among baseline methodologies tailored for their type of DER. Additionally, multiple participants pointed out advantages of longer project commitment duration to four to five years in future projects.

8 Considerations for Using DERs as NWAs

During the review and analysis process for this report, ICF evaluated cross-cutting success factors for both this Demonstration and for future expansion or replication of this project across Ontario. These observations are related to and support the nine stated project objectives and are intended to describe key program design elements that can be considered when looking to the future of this effort. The considerations are divided into overall program administration and actual program design, although there is some overlap between these two categories. The considerations are intended to be representative of the major considerations for Alectra, IESO and other stakeholders when planning for future programs similar to this Demonstration and program evolution but are not intended to be comprehensive of all possible program elements.

8.1 Program Administration

Topic area: Participant engagement strategies

Considerations: Broad communication of program opportunities to DER owners and aggregators is essential to successfully gathering interest and participation. Clear articulation of procurement goals, program rules, contract terms and conditions, and opportunities for stakeholder engagement are strategies that build confidence and increase the pool of qualified resources. A comprehensive web-based platform for program resources, documents, rules, examples, prior lessons learned, and tailored contracts improves visibility and trust in the program. This topic area includes considerations related to Demonstration objectives 3DLMP and 8LOCL.

Rationale: Interviews with participants indicated that the Demonstration was open and transparent and developed a level of interest and confidence that yielded capacity bids in both years that exceeded target levels. Effective outreach and participant engagement becomes more important if the approaches in the Demonstration are expanded to include larger areas and greater capacity in regions, pulling from a larger pool of potential DERs. Participants also indicated that they needed a central, easy-to-navigate platform for finding program resources. Additional opportunities are available to increase participation by specific DER resource types and locations by targeted outreach to potential participants with existing resources or the potential to build new resources.

Topic area: Automating and scaling processes

Considerations: In projects with a limited number of participants, some processes, such as contracting and settlement processes, can be handled in a more customized, manual approach. However, when scaling a program, processes must be standardized based on contract terms and should be enabled within automated software, potentially as part of a web-based platform. This creates operational efficiencies and participant confidence for not only the individual DER resource providers but especially for the aggregated DER providers with potentially thousands of contributor DERs. A related consideration is the need for metering data that is made available closer to real-time and can be used by participants to quickly and accurately observe their response to activations and determine settlement impacts. This topic area includes considerations related to demonstration project objectives 3DLMP and 8LOCL.

Rationale: During the 2-year Demonstration, the contract terms and processes evolved toward a more standardized approach. This was recognized by participants and Alectra staff as moving in the right direction that would enable faster and more accurate settlements. However, the variety of meter data sources and their availability to provide timely data into the settlement platform required more time and effort than would be ideal in a full-scale program. Also, data exports for participant accounting, especially for those with multiple meters, was an issue that created additional work on the part of aggregator participants to be able to reconcile and share that data with the owners of the contributor DERs.

Topic area: Historical data for future evaluation

Considerations: Capturing and storing all relevant data during a project or program enables ongoing analysis, improvements, and adjustments to balance participant behavioral drivers and overall program costs. Stored data needs include all of the project/program-specific activity and external comparative data for baselines to demonstrate incremental impact. These data points are essential for assessing performance of the program and market impact, while building confidence in the ability for DERs to serve as a grid resource. This topic area includes considerations related to demonstration project objectives 5OPS, 6BARR, and 9COMP.

Rationale: The Demonstration project activity data was well organized and readily available for nearly all of the analyses that needed to be performed. However, during the data gathering and analysis phase, some of the historical baseline data was not readily accessible for comparative market settlements. This required the project team to invest additional time and effort in locating archived sources and examining methodology behind data.

8.2 Program Design

Topic area: Economic valuation of DERs as alternatives

Considerations: Conducting local achievable potential studies for DER can be highly informative about the current and future available DER capacity, which is critical to planning decision making. Distribution-level deferrals of new investments can be realized when DERs are procured in sufficient quantities and in the right locations, and then activated when needed to meet local needs. Value can also be derived from using DERs for transmission-level deferrals and as alternative to centralized generation. This becomes economically feasible particularly when the “stacking” of services is enabled, facilitated by effective coordination protocols and operational mechanisms. Multi-year program commitments can enhance DER procurement in targeted areas, helping ensure that adequate resources are available to defer traditional infrastructure investments. This approach provides planners, who typically need five to seven years' advance notice for investment decisions, with the necessary runway to make periodic deferral and procurement decisions. The financial value of these deferrals can be based on a multi-year valuation so that DER procurement prices are more stable, facilitating deployment of new DERs and lowering risks for all parties. This topic area includes considerations related to Demonstration project objectives 1AUCT, 2COORD, 4DER, 5OPS, and 9COMP.

Rationale: As seen in the illustrative cost-benefit analysis presented in this report, the potential benefits generated were well in excess of incremental DER procurement costs in most of the scenarios investigated. Distribution-level deferrals could potentially be sufficient to support the costs of a DER program and stacking the benefits of transmission-level deferrals and avoided centralized generation costs could significantly increase the benefits. The Demonstration underscored the importance for future projects to accurately determine the operational duration required for DERs (e.g., four hours, eight hours, etc.) to effectively realize the stacked value. Each periodic extension of the go/no-go decision to build either a MTS or new transmission solutions also provides more insight into load growth or changes in load profiles that enable better planning.

Topic area: Recognizing all DER cost and benefit streams

Considerations: The value of DERs as alternatives to traditional infrastructure can be quantitatively assessed, providing an understanding of their economic benefits. In addition to these benefits, DER deployment may also offer benefits that are challenging to quantify, including resilience and environmental advantages, which are important aspects of a comprehensive assessment. Recognizing and identifying these less tangible benefits where appropriate is important for program design and participant engagement, as they can contribute to the overall value created by DERs. Using DERs allows load customers, businesses, and communities to tailor their energy usage according to their goals and policies, reflecting their preferences and priorities. Finally, it is important to recognize that most DERs are independently developed and deployed with private capital, helping the financial benefits from the resource to remain with the customers and communities involved, increasing their participation in the energy transition. This topic area includes considerations related to demonstration project objectives 1AUCT, 4DER, 5OPS, and 9COMP.

Rationale: The illustrative cost-benefit analysis presented in this report is an example approach to valuating DERs as alternatives to traditional distribution, transmission, and generation infrastructure. Additional benefit streams were identified that could potentially improve the cost-benefit ratio, including dispatchability, resiliency, and greenhouse gas emission reductions, but these were not quantified as part of the project evaluation. While the demonstration saw participation from natural gas and CHP resources with emissions, it is expected that DERs will be predominantly non-emitting as the energy transition unfolds, including smart thermostats with heat pumps, electric vehicle chargers, stationary batteries, and clean hydrogen-fueled thermal generators. The demonstration participants represented a wide variety of local customers and businesses, including a district energy facility, supermarket stores, residential customers, and equipment manufacturers.

Topic area: DER planning and operation with portfolio approach

Considerations: A key facet of using DERs as a portfolio of resources is that they behave in patterns that are both related to their individual characteristics and somewhat independent due to a range of operational and participant drivers. Their performance metrics need to be incorporated into future DER procurements in a way that accounts for unexpected variances by potentially both "over-procuring" DERs in terms of capacity but also "over-activating" DERs in terms of energy. These approaches are similar in concept to market and operations approaches used at the transmission and bulk system levels where planning or reserve margins are often employed. Additionally, a portfolio approach to procuring multiple DER types, rather than relying on a limited set of DER types, provides greater robustness in activation and delivery of expected services. Exploring these topics as well as the need for related reliability standards further would be highly beneficial for the sector. This topic area includes considerations related to Demonstration objectives 1AUCT, 4DER, and 9COMP.

Rationale: This Demonstration met its objectives for capacity procurement but was by design limited in number of participants and DER technologies. As described in the section of the report on DER performance analysis, there were certain performance patterns that emerged based on participant and resource type over the two annual procurement cycles, but using a limited dataset to extrapolate for a larger participant pool can create an unreliable forecast for future performance. However, the portfolio approach to utilizing multiple resource and participant types did seem to reduce overall delivery risks. One strategy explored in the Demonstration was using some DERs as local reserve, where they are ready to be activated in short order in case other DERs do not follow their activation instructions. Certain participants and resources when activated over-performed while others under-performed due to a variety of factors and the range of overall performance was between 81% and 91%. As a group, the portfolio approach helped to mitigate performance issues and an increased number of participants and deeper pool of resources would enable more robust delivery of energy when activated.

Topic area: Reliability of individual DER performance

Considerations:

Using DERs as alternatives to traditional infrastructure requires not only reliable performance at the portfolio level but also reliable individual availability and performance metrics for DERs. Several strategies should be employed in the design of a local market to ensure reliable individual DER performance. It is essential to establish an effective framework that includes appropriate incentives for performance and effective disincentives for non-performance. Aligning financial incentives with the fixed and operational costs of using DERs ensures compensation on a per-usage basis that aligns with underlying costs, thereby reducing risk for participants. Test activations and clear rules for handling defaulting participants are important for preserving market integrity. Balancing the number of DER activations to reduce "dispatch fatigue" and increase DER participation, while ensuring that the number of activations are sufficient for grid operators to meet designated grid needs to enable asset deferral. Clarity on eligibility to stack services/programs and procedures for coordinating stacked operations is also critical. Finally, it is worth acknowledging that the reliability of future DER performance may vary compared to today, considering the evolving landscape of DER technologies. This topic area includes considerations related to Demonstration objectives 1AUCT, 3DLMP, 4DER, 6BARR, 7MKTS, 8LOCL.

Rationale:

The Demonstration project offered capacity and energy payments to DER participants. These payments were designed to align with the fixed and operational costs of the DERs, as well as the results of auction competitions. The Demonstration's rules and contracts provide a comprehensive framework for incentives, non-performance charges, test activations, and events of default. These documents were foundational in shaping the Demonstration’s local market for services and can serve as valuable templates and guides for similar projects. As discussed in the report, the non-performance charges and test activation mechanisms in the Demonstration were used effectively throughout the project. However, it should be noted that while the DERs demonstrated strong performance at the portfolio level, significant over-delivery and under-delivery was observed at the individual DER level. This highlights that there are opportunities to improve these mechanisms to achieve more consistent and reliable performance in future projects.

Topic area: Multi-year commitments on programs and DERs

Considerations: For DERs to be effective as NWAs to new distribution and transmission infrastructure, a multi-year program commitment is required to ensure that participants develop and make their resources available. Such commitment provides the necessary certainty and support for participants to develop, invest in, and deploy new DERs to provide electricity system services. Multi-year commitments are also helpful to system planners, as it allows them to align commitment periods with the durations for which DERs are to be used as alternatives to traditional infrastructure. For example, if the target range for deferrals is five years, then the procurement of DERs should be for at least that length of time. This approach provides participants and system planners with the assurance that DERs will be available throughout the deferral period and the deferral goals will be realized. It should be noted that multi-year commitments could involve gradual increase in DER capacity deployment to align with the growth in demand throughout the commitment period. Furthermore, as discussed previously, this approach allows for periodic decisions on whether to extend the deferral projects, informed by improved data on load growth and evolving needs. This topic area includes considerations related to Demonstration objectives 1AUCT, 3DLMP, 6BARR, 8LOCL, and 9COMP.

Rationale: As part of interviews to evaluate the Demonstration, participants expressed their interest in being part of the Demonstration both to understand how their DER assets would be valued and to help support IESO and Alectra in their innovation efforts. However, a general theme was that the participants would need a longer time horizon for the program to commit to bringing new DER capacity online and to feel more comfortable with the operational processes required to participate on an ongoing basis. All interviewed participants explained that they would be interested in seeing this Demonstration expanded and extended, indicating that their DERs could be made available in the future. To build confidence in DERs as a viable grid resource, a local program could be ramped up in advance of actual deferrals, which may entail additional costs in advance of the cost savings. However, as seen in the illustrative cost-benefit analysis, using DERs as alternatives to traditional infrastructure can generate substantial savings, which could be used to develop the DER potential in advance of the deferral needs actually materializing.

Topic area: DSOs, DER participants, and IESO coordination

Considerations: Simplifying the provision of services for DER participants, including across rules, processes, and interfaces, is essential to reducing barriers to entry and developing the potential of DERs to contribute meaningfully to the energy transition. For example, it would be simpler for DER participants to access a single web-based platform that consolidates all their service provision-related needs, instead of navigating through two (or more) different web portals. The responsibility of coordinating across different independently designed services should not fall on the DER participant. Instead, coordination should be facilitated by streamlined rules from DSOs and the IESO, specifically designed for "stackability". These rules should include clear coordination protocols, outlining the steps to be taken and the timing for data exchanges by all parties to ensure reliable use of the DERs. For the effective stacking of services, it is essential to establish coordinated efforts across various processes including planning, procurement, operations, and settlement. Exploring DER program designs that integrate stacked services into a singular offering with streamlined rules and processes for both DSOs and the IESO to activate the DERs may prove beneficial.

Rationale: The Demonstration made use of a Total DSO coordination model, where DERs interface exclusively with Alectra, acting as the DSO, to receive compensation and instructions for stacked services. The whitepaper titled "Development of a Transmission Distribution Interoperability Framework" prepared by ICF Consulting at the outset of the Demonstration, also discussed a shared platform concept that would similarly serve as a singular interface for DER participants (and also DSOs and the IESO). The Demonstration included several participants that were aggregators, which too can offer DER providers with a simplified interface while managing complex relationships in the background. As discussed extensively in this report, the Demonstration provided DER participants with an opportunity to provide stacked services, simulating their use at the distribution and transmission levels. In the Demonstration's local energy auctions the logic and processes facilitated activation for distribution needs and were also specifically designed to consider bids/offers for activating DERs in response to wholesale market needs. The Demonstration has informed other IESO initiatives, notably the Transmission-Distribution Coordination Working Group (TDWG), which is focused on developing protocols for reliable coordination among parties and continues to actively investigate these topics in detail.

9 Conclusions

This successful demonstration project introduced various new concepts, mechanisms, and processes, showcasing the potential benefits of employing DERs as substitutes for traditional infrastructure. The results and findings from the two-year effort to use local capacity and energy auctions to procure grid services from DERs support the achievement of the overall objectives for the project. The processes and tools that were developed, tested, and refined while identifying additional opportunities for improvement such as automated settlements to improve scalability. The economic value of DERs, both as a local resource and as an alternative investment to traditional distribution, transmission, and generation infrastructure, was found to be net-positive in most scenarios evaluated in this report.

Processes for improving coordination between transmission and distribution operations and wholesale and local markets are nascent. This demonstration project showed that auctions are a promising mechanism to secure local capacity and local energy services, including local reserve, from DERs. The project demonstrated a streamlined approach to procuring services from DERs to enable local pricing and participation by customers, businesses, and communities that is aligned with electricity system needs. Interestingly, the design and documentation of the Demonstration, including the rules and contracts, have been adapted in other pilots with different approaches, which highlights the impact that the project has had.

The future of local markets, including rules, roles, and administration of transmission and distribution-level programs remains an area for exploration both in Ontario and other jurisdictions. For example, regional markets in the United States are seeking to enable participation from aggregated DERs in wholesale service markets under FERC Order 2222. As the energy transition progresses and the penetration of DERs continues to rise, there is likely to be an increased focus on refining local market design and enhancing operational coordination. This demonstration project provides a promising local market option as system operators, regulators, policy makers, DER participants, and other stakeholders consider a broad set of strategies to advance integration of DERs in electricity system.

Appendix 1: Demonstration's Software Platform Modules

Module	Description
Registration	• Participants would sign up as Direct Participant or Aggregator on the platform, along with other key information (name, number, emails, resource address etc.) • As a Direct Participation, one would also register their DERs in this module. • As an aggregator, one had the option to register without resources at this stage. Resource registration would be permitted up until one month prior to the beginning of the Commitment Period. • A primary and secondary delegate can be selected at this module.
Capacity Auction	• For all registered participants, an option of submitting up to five price/quantity pairs during the Capacity Auction period was available. • A minimum and maximum Capacity Price was set within the platform (this information was also publicly available on the IESO and Alectra websites through a Pre-Auction Report). • The platform would clear all submitted bids, from least to most expensive, and resources that cleared the auction were selected to proceed. • Results are communicated on the platform and via email (this information was also publicly available on the IESO and Alectra websites through a Post-Auction Report).
Contracting	• During this stage, participants submitted meter numbers and other key information for contracted resources. For aggregators, this period allowed them to contract for resources to meet their capacity obligation.
Energy resources management	• All meter numbers were verified and approved by the DSO. • Once approved, the metering data for each resource will be pulled into the platform automatically via API connections with the acting DSO's Meter Data Management vendor.
Energy auction	• During the energy auction timeframe, participants could submit up to five price/quantity pairs daily. Alternatively, one could input the bids once and it would transfer over to each consecutive day automatically. • The platform had a built-in custom forecasting feature, which reflected the actual and forecasted need in the Demonstration Area for the next 24 hours. • Activations were called upon when forecasted need exceeded the pre-set threshold.

	• Resources received automatic potential event notifications at 7 am every morning for a potential activation, and 2.5 hours before an actual activation for the final details (time of activation, quantity activations etc.)
M&V and settlements	• The platform had built-in measurement and verification (M&V) functionality, which would compute the key performance metrics based on resource metering data (which was pulled into the platform's databases through automated API connections). For maximum accuracy, detailed Q&A processes were built by the acting DSO to ensure data verification at all stages. • The baselining methodology was used for all Demand Response resources, in accordance with the Demonstration's rules and participant contracts. • Settlement information was calculated automatically within the software platform. Detailed Q&A processes were built by the acting DSO to ensure data verification at all stages. • Settlement payments were issued on a consolidated monthly basis (the actual payment process occurred outside of the platform; the platform information was displayed for reporting purposes only). • All delivery and settlement information were available on the platform and shared via PDF statements by the acting DSO.

Appendix 2: NSPM Benefit Cost Table

Type	Utility System Impact	Description	Used in Avoided Cost Methodology? If not, why?
Generation	Energy Generation	The production or procurement of energy (kWh) from generation resources on behalf of customers	Yes
	Capacity	The generation capacity (kW) required to meet the forecasted system peak	Yes
	Environmental Compliance	Actions to comply with environmental regulations	No. Environmental regulations compliance not outlined in pilot goals or DER selection.
	RPS/CES Compliance	Actions to comply with renewable portfolio standards or clean energy standards	No. RPS/CES compliance not outlined in pilot goals or DER selection.
	Market Price Effects	The decrease (or increase) in wholesale market prices as a result of reduced (or increased) customer consumption	No. Due to the small size of the pilot, no anticipated impacts on wholesale market prices.
	Ancillary Services	Services required to maintain electric grid stability and power quality	No. Market mechanism doesn't currently exist for DERs.
Transmission	Transmission Capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably	Yes, this captures capital costs and value of optionality provided by DERs.
	Transmission System Losses	Electricity or gas lost through the transmission system	No. Transmission System Losses were not included in DER value calculations.
Distribution	Distribution Capacity	Maintaining the availability of the distribution system to transport electricity safely and reliably	Yes, this captures capital costs and value of optionality provided by DERs.
	Distribution System Losses	Electricity or gas lost through the distribution system	No. Distribution System Losses were not included in DER value calculations.
	Distribution O&M	Operating and maintaining the distribution system	Yes

	Distribution Voltage	Maintaining voltage levels within an acceptable range to ensure that both real and reactive power production are matched with demand	No. Data might be available, but was not specifically tracked as part of pilot performance.
General	Financial Incentives	Utility financial support provided to DER host customer or other market actors to encourage DER implementation	Yes, this captures capacity and energy payments based on DER performance.
	Program Administration	Utility outreach to trade allies, technical training, marketing, and administration and management of DERs	No. These activities occurred, but related costs not tracked as part of pilot performance.
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of DER programs	No. Utility performance incentives do not currently exist for non-wires alternatives.
	DG tariffs	Determine how a host customer will be compensated for distributed generation output	No. Existing DG tariffs for each DER not tracked as part of pilot performance.
	Credit and Collection	Bad debt, disconnections, reconnections	No. Credit and collections not tracked as part of pilot performance.
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks	Partial. Only DER operational uncertainty tracked as part of pilot performance.
	Reliability	Maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components	No. Data might be available, but was not specifically tracked as part of pilot performance.
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions	No. Data might be available, but was not specifically tracked as part of pilot performance.
Host Customer	Host portion of DER costs	Costs incurred to install and operate DERs	No. Host portion of DER costs not tracked as part of pilot performance.

	Host transaction costs	Other costs incurred to install and operate DERs	No. Host transaction costs not tracked as part of pilot performance.
	Interconnection fees	Costs paid by host customer to interconnect DERs to the electricity grid	No. Interconnection fees not tracked as part of pilot performance.
	Risk	Uncertainty including price volatility, power quality, outages, and operational risk related to failure of installed DER equipment and user error; this type of risk may depend on the type of DER	No. Host customer risk not tracked as part of pilot performance.
	Reliability	The ability to prevent or reduce the duration of host customer outages	No. Host customer reliability not tracked as part of pilot performance.
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions	No. Host customer resilience not tracked as part of pilot performance.
	Tax incentives	Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs	No. Host customer tax incentives not tracked as part of pilot performance.
	Host Customer NEIs	Benefits and costs of DERs that are separate from energy-related impacts	No. Host customer non-energy impacts not tracked as part of pilot performance.
	Low-income NEIs	Non-energy benefits and costs that affect low-income DER host customers	No. Low-income customer non-energy impacts not tracked as part of pilot performance.
Societal	Resilience	Resilience impacts beyond those experienced by utilities or host customers	No. Societal resilience not tracked as part of pilot performance.
	GHG Emissions	GHG emissions created by fossil-fueled energy resources	No. GHG Emissions were note used in the DER value calculations.

	Other Environmental	Other air emissions, solid waste, land, water, and other environmental impacts	No. Societal environmental impacts not tracked as part of pilot performance.
	Economic and Jobs	Incremental economic development and jobs impacts	No. Societal economic and jobs impacts not tracked as part of pilot performance.
	Public Health	Health impacts, medical costs, and productivity affected by health	No. Public health impacts not tracked as part of pilot performance.
	Low Income: Society	Poverty alleviation, environmental justice, and reduced home foreclosures	No. Societal low income impacts not tracked as part of pilot performance.
	Energy Security	Energy imports and energy independence	No. Energy security impacts not tracked as part of pilot performance.

twitter.com/ICF
linkedin.com/company/icf-international
facebook.com/ThisIsICF
#thisisicf

icf.com

About ICF

ICF (NASDAQ:ICFI) is a global consulting and digital services company with over 7,000 full- and part-time employees, but we are not your typical consultants. At ICF, business analysts and policy specialists work together with digital strategists, data scientists and creatives. We combine unmatched industry expertise with cutting-edge engagement capabilities to help organizations solve their most complex challenges. Since 1969, public and private sector clients have worked with ICF to navigate change and shape the future. Learn more at icf.com.