GIF Milestone Report Part A

Project Title: DSO Pilot Project (PowerShare)
Organization: Essex Powerlines Corporation
Milestone: 3
Project ID #:

SUBMISSION DATE: MAY 28, 2025

Milestone Due Date (from the Contribution Agreement): February 28, 2025
Contract Termination Date: December 31, 2025

Connecting Today.
Powering Tomorrow.

1. Project Description

Project Title	Essex Powerlines DSO Pilot Project (PowerShare)
Organization	Essex Powerlines Corporation
Milestone Number	3
Total Number of Milestones	3
Milestone Payment Amount *must match amount on invoice (before HST) and cannot exceed contracted amount	$258,890.10
Submitter Name	Anthony Clavet
Contact information	[redacted]
Milestone Submission Date	April 30, 2025; Amended May 28, 2025
Milestone Due Date (in original/amended contract)	February 28, 2025
Contract Termination Date (in original/amended contract)	December 31, 2025

Provide 1. A description of your project, and 2. State why you are doing this project.

The project ("PowerShare") will enable Essex Powerlines Corporation ("EPLC") to perform as a Distribution System Operator ("DSO") with a scalable market design for activation of DER flexibility in near real-time. Using the NODES platform, DER owners will be able to monetize their investments by selling excess or stored generation as flexibility to support grid resilience.

PowerShare will harness existing, and incentivize additional, DER flexibility in the grid as a non-wires alternative ("NWA"). Constraints in the Leamington area will be used to benchmark NWA performance of a DSO market while maintaining reliable service delivery to customers. Higher geographic and grid levels will be considered for market participation or simulation to demonstrate T-D coordination between DSO and IESO markets.

Essex Powerlines and partners propose to solve two major issues or barriers with this project: first, it will resolve local constraints on Essex Powerlines' grid and second, it will remove existing barriers related to DERs and assess their potential impacts on distribution system assets and market participation. Moreover, the project will test the coordination of DSO/IESO markets, helping solve grid constraints at a local, regional, and provincial level.

Milestone Description: Copy and paste the text from your Contribution Agreement below.

Once the market design is set and aligned with the IESO/OEB, development of the NODES platform will have to be configured to work within Ontario jurisdiction. Likewise, SmartMAP development will take place to ensure buying signals from the LDC can be automated within NODES platform.

2. Milestone Submission Attachments

The deliverable description must match milestone deliverables as outlined in the Contribution Agreement Table and Proposal. If multiple deliverables are contained in a single document, specify the page numbers/sections that reflect the specific deliverable.

ID	Deliverable Description	File Attachment Name	Section/Page Number
1.1	Summary of DSO Market Activities and Associated Costs	D1. Summary Report of DSO Market Activities and Costs.pdf	NA
1.2	Appendix A – Summary of Trading Activities	D1. Appendix A – Summary of Trading Activity.xlsx	NA
2	Final Report	D2. Final Report Addendum.pdf	NA
3	Milestone Report Part A	Essex Powerlines – GIF Milestone 3 Report Part A.docx	This document
4	Milestone Report Part B	Essex Powerlines – GIF Milestone 3 Report Part B.xlsx	NA
5	DER Integration Demonstration Framework	Essex Powerlines – DER Integration Demonstration Framework.xlsx	NA

3. Project Technical Progress and Lessons Learned

In the following tables, summarize the key lessons learned. This information is intended to inform future work in the same area. The lessons generated will be used to inform the success of future GIF projects by identifying areas of concern / unknown barriers, inform broader industry to enhance success and avoid failure. Do not delete entries from previous milestones, rather, add new rows for the new milestone and populate the fields. Please be detailed in your description.

MS (Milestone): Milestone Number

Category (Cat): Cat 1=Customer/Participation Reach, 2=Data, 3=Process, 4=Project Management (Budget, Scope, Timeline), 5=Technology Interoperability/Integration, 6=Other

ID: Unique ID for each lesson learned

Challenge Description: A detailed description of the challenge and how it impacted the project

Resolution: A detailed description on how the challenge was resolved, the thought process behind the resolution and describe the resources used to resolve the challenge.

MS	Cat	ID	Challenge Description	Resolution (if applicable)
1	5	1	Meters Used; Required Metering or Telemetry Equipment availability in-field, sufficiency for DSO purposes, and accessibility to participants	Wholesale metering is not available nor accessible for most distribution-connected participants. IESO required telemetry is a major barrier to service provision by distribution-connected DERs. EPL decided to leverage existing AMI systems and set the maximum metering granularity to 15 minutes - metered intervals longer than 15 minutes are not considered for the project. The sampling rate of a Flexibility Service Provider's ("FSP") meters will be increased to 5 minutes, subject to EPL's metering infrastructure capabilities and constraints. In cases where an FSP cannot have a 5-minute sample rate, but otherwise needs to be evaluated at 5-minute granularity, the 15-minute sample rate will be averaged over the three 5-minute intervals. Reference to 5-minute metering granularity shall include the three 5-minute interval average metric (35IA, 15/3, other notation). The 15-minute granularity applies to all ShortFlex and LongFlex settlements such that delivery for a 30-minute product interval is the average of the two 15-minute intervals' delivery percentage. For regularity, where 5-minute metering is available it is summed to 15-minute for purposes of settlement.

				This design is supported by NODE's experience in European markets where a combination of DSO meters and FSP-provided sub-meters are used in settlement. Additionally, all metering activities are supported by existing systems provided to EPL by Utilismart. NODES uses data submitted by Utilismart from EPL's meters to validate delivery of the service against the offered amount on the NODESmarket Platform. Note: the use of existing metering was of particular interest in engagements with the Ministry of Energy throughout Milestone 1.
1	3	2	TD interoperability; how/when do communications with IESO happen	With the intention to implement and inform ongoing exploration of the Transmission-Distribution protocols, including through the TDWG, this project simulates submission of DSO activity and qualified participant offers following the Availability Declaration Envelope (ADE) submission process and the IESO gate closure 2-hours ahead of dispatch. NODES simulates a submission to the IESO at 10:00:00 day-ahead of dispatch of: the quantities of DSO contracted services (also called "LDC-directed") at a 'floor price', and the remaining available Qualified offers from each portfolio in price/quantity pairs. The DSO gate closure is at 125 minutes prior to dispatch. NODES has 5 minutes to prepare, and at 120 minutes prior to dispatch (respecting the IESO's Mandatory Window), NODES simulates a final submission to the IESO of: LDC directed quantities at the floor price, and remaining Qualified offers from each portfolio that were submitted prior to the ADE submission. Data submissions to the IESO will occur on-request, during live demos, and during milestone submissions.
1	3	3	DSO commercial responsibility for assets in IAMs; DSO and platform provider hesitant	EPL and NODES share a hesitance to represent assets in IAMs. This function is termed as a 'superaggregator', a top-level aggregator for an area or local market which represents an additional layer of aggregation of direct assets and aggregations, potentially from different FSPs, to IAMs. A superaggregator would bear commercial responsibility for these assets. The T-D protocol in the project was designed with wholesale eligibility being an additional qualification that participants can opt in to test and demonstrate. (See T-D Coordination

				Methodology section 3.3 and NODES Schedule 5 section 2.4 for more on qualification for wholesale demonstration) Offers from qualified portfolios are then 'forwarded' to the simulated IESO for evaluation against purchasing scenarios rather than represented or 'superaggregated' by the DSO. EPL and NODES are interested in exploring combining offers across portfolios and potentially FSPs in later market designs and consider this to be an element to explore with the IESO and OEB since this will be affected by the concerns of commercial responsibility taken on by an LDC in an IAM. In this model, the commercial responsibility could be forwarded from the IESO market participating flexibility platform to the FSPs with aggregated assets. If this is solved in a satisfactory way, superaggregation would allow smaller portfolios and FSPs to access the IESO market, thus enhancing their potential revenue. This would contribute to further volumes and increased competition in the market for both DSO and the IESO.
1	4	4	Defining Maximum/Ceiling Price	To capture the full range of potential prices offered by distribution-connected DERs, the maximum price is undefined in the market rules. However, for procurements such as LongFlex tenders, the maximum activation price is set default at $2000/MWh whereas the budgetary allotment for ShortFlex activation is average $300/MWh less 5% for platform fees per the Budget.
1	4	5	Moving activities from planning/design milestones into demonstration milestones to reflect work, carry over of development work throughout the project	Working with NODES and Utilismart, the project benefits from spreading development through the market operation phases of the project. Particularly, activities that have been split between Milestones 3 and 4 were done so to reflect the second round of development necessary to implement the "Integrated Coordination" and other program or software enhancements which will come to the fore after use by end-users (participants and EPL staff). Continued development and user feedback marked as a lesson learned for future project submissions.
1	5	6	Identifying voltage regulation and thresholds for non-exporting and <10kW exporting DERs on the Distribution System, difficulty applying Conditions of Service of the LDC as a default standard like the IESO's "Voltage Variations" Grid Connection Requirements (Chapter 4)	Identifying the source of the standards or ranges for voltage variations as first the project-specific CIA/SIA study, then any connection agreements with LDC, then an LDC-accepted site/facility owner-approved DER Operation Plan if voltage ranges are an unresolved concern.

1	1	7	Territory Expansion Lesson	PowerShare's expansion to the entire service territory of EPL is driven by two factors: capacity constraints are existing or forecasted in all areas of our territory, and a market scale constraint. The scale constraint emerged from focusing specifically on EPL's service area in Leamington, which excludes many large load or generator customers that exist on shared EPL feeders ("hybrid feeders" per TDWG definitions).
1	4	8	Defining Participant Payment Cycles within Milestone Payment Structure	The Milestone-based payment cycle of the GIF leads the default payment of participants to follow milestones. However, from feedback from participant candidates that provided letters of support during application, advice from NODES from European markets, and from the dedication to accessibility of the market, EPL decided to conduct settlement and payment of participants on a monthly cycle. It was EPL's view that extended periods of service provision (and thus accrual of costs) by participants without payment would be a significant barrier to non-traditional market participants. This extends only to participants, whereas market-related invoices from project partners will align with Milestone submission. For example, the 5% market fee will be invoiced at the end of the milestone rather than monthly.
1	2	9	Baseline methodology and custom baseline methodology, considering IESO baseline methodology	NODES has a basic and accessible default baseline methodology of the five preceding weekdays based on EPL's meter data which is provided daily to NODES by Utilismart for each approved asset's meter. Baselines are evaluated at 15-minute granularity (see "meters used" lesson for more). Participants may nominate an alternative baseline capacity to better reflect their particular operations or asset type. EPL must agree to the proposed alternate baseline. EPL and NODES may conduct spot checks on alternate baselines and may suspend the participant from the platform until the baseline may be verified. From engagement with participant candidates that provided letters of support during application and with candidate aggregators, there was a clear desire to test alternatives to the IESO baselines. EPL and NODES intend to conduct variance analysis on the IESO baselines against the default baselines for settlement, to the extent appropriate.

				NODES' settlement formula from Schedule 5 of the Platform Rules: $BL_d^h = \begin{cases} \sum_{i=1,\mathrm{d-i} \notin [\mathrm{sat,sun}]}^{7} \frac{MD_{d-i}^h}{5} & if\ d \notin [\mathrm{sat,sun}] \\ MD_{d-7}^h & if\, d \in [\mathrm{sat,sun}] \end{cases}$ *where BL_d^h is the baseline value of day d and interval h* *and MD_d^h is the metered value of the day d and interval h*
1	3	10	Appropriate incentivization of service delivery, following the "least cost, no penalties or deposits" principle: Availability and Activations Payment Reduction Schedules	It is a leading goal of the Project to reduce to the extent possible any fees or charges required of Participants. This is prioritized to incentivize participation and enable relatively small DERs to participate with a minimal structural deficit. This determination was informed by stakeholder engagement with EPL customers and participant candidates which routinely discussed the cost barriers to wholesale market participation as a major concern. The Activation Payment (ShortFlex/energy) reduction schedule provides 100% payment for 90%+ delivery of the ShortFlex Contract Capacity. The reduction schedule drops quickly under 90% delivery, such as between 80-89.99% which provides 65% payment. Delivery of less than 40% of the ShortFlex Contract Capacity provides 0% payment. This schedule is designed to incentivize participants to deliver while also respecting the absence of penalty fees for under delivery. The Availability Payment (LongFlex/capacity) reduction schedule is calculated monthly on average delivery percentage of ShortFlex offers arising from a LongFlex contract. Unmatched ShortFlex offers provide full credit, matched ShortFlex provide credit depending on average delivery percentage, and unavailable ShortFlex offers provide no credit. This schedule is designed to incentivize participants to ensure ShortFlex offers are available for each contracted half hour Delivery Period. Availability payments are more drastically affected by unavailable ShortFlex periods than under delivery of particular periods. This schedule follows the same payment reduction as Activation Payment. Regular or repeated under delivery by a participant will prompt questioning from EPL, and potentially escalate to termination of the participant's eligibility to the Project market if it cannot be addressed.
1	3	11	Grid Nodes identification / Grid Node Representation Granularity; how to represent the Distribution	NODES provided examples of common hierarchies in European markets, which are often voltage or jurisdictional boundaries.

			System in a nodal hierarchy, informing the NODES Platform map and assignment of resources to the nodes	EPL originally planned to model granular portions of the distribution system as 'sections' created by automatic reclosers and to dynamically reassign those sections to a distribution feeder parent node. Challenges to this approach were appropriately representing the complex 'sections' of the distribution system in the platform in a simplified visual manner, and that the live reassignment is overly complex without automated checks between SCADA/SmartMAP/NODESmarket. SCADA integrations are dependent on EPL's ongoing Digital Utility and Joint Control Room projects. The resolution is to use feeders as the lowest node level which provides the benefits of being logistically manageable when network switching takes place and easy to understand visually on the platform. Live switching is an item marked for future exploration.
1	4	12	Participant Contracts: how to define eligibility or ineligibility, defining the role of the DSO versus Platform/Settlement Provider in intake and operation	PowerShare builds on the learnings from the publicly available York Region NWA contracts and program rules. Despite major differences in program design such as York having an auction-based procurement process versus PowerShare's open intake process, many elements were transferable. In particular, participant eligibility and ineligibility. PowerShare rules build further in defining the roles of the DSO (EPL) and the Platform/Settlement Provider (NODES). The PowerShare contract does not provide for payments to participants, which are instead conducted under NODES membership agreement. PowerShare's contract manages eligibility to access or offer services to the NODES Platform and this forms the primary method for the DSO to manage Flexibility Service Providers (FSP) and their assets. An asset may only make offers if they fulfil the requirements under the DSO contract. PowerShare also positioned the DSO to be in control of the registration process, where once an FSP has signed the DSO contract they are then connected with NODES to set up payment details and sign the platform membership agreement.
1	1	13	Clear Participant preference for ICI eligibility	An important lesson from the intake process with various participant candidates is their nearly universal interest in whether PowerShare participation is 'stackable' with ICI eligibility/activities. It is, and the team will be examining to the extent possible any coincidence of DSO needs with ICI peaks.

				In addition, many participant candidates expressed interest or curiosity in stacking market participation between DSO and IESO markets.
1	3	14	Asset Approval, Flexibility of Platform to enroll/disenroll or assign assets	Related to the learning on grid node identification, the flexibility of the Platform was harnessed to reinforce the discretion of the DSO in the approval, assignment, or removal of an asset from the platform. Once contracts are signed, each asset and its meter number must be approved by the DSO when assigning it to a node before it can begin trading with that asset. This ensures DSO control and visibility to the assets before they are added to existing portfolios.
1	3	15	Defining Wholesale Simulation: triggers for purchases, qualification of offers	Given that there is no integration with IESO tools and all activities are on a simulated basis, the PowerShare team endeavoured to capture the life cycle of simulated offers from qualification of assets to formation of offers and activation. Following engagement with GIF and IESO staff, PowerShare defines a two-step "qualification" for IESO offers. First, a portfolio must be tagged as 5-minute dispatchable. That portfolio must then offer at least 2 consecutive half-hour blocks of 100kW to meet the IESO's hourly offer duration and to simulate FERC 2222 compatibility. These offers are then forwarded, or 'seen' by the simulated IESO at T-2 hours. Activation can happen at any time after T-2 (IESO "Mandatory Window"). Engagement with IESO staff helped to identify price as the best trigger for activation rather than outages or capacity/quantity needs, since these are generally reflected in the prices. PowerShare has defined variable price triggers based on forecast Shadow Prices and a Market Clearing Price proxy adapted to the half-hourly market. More information is available in the Transmission-Distribution Coordination Methodology document. PowerShare noted that the $100 Shadow Price trigger used in the York Region NWA pilot did not result in a simulated wholesale activation and thus adapted to variable price triggers in an effort to capture more simulated IESO activity.
1	3	16	Adapting the Availability Declaration Envelope alongside DSO purchases, "LDC-directed quantities"	For the resources in PowerShare, the ADE is established such that real-time schedules will not exceed the quantity offered in the day-ahead timeframe. This principle is managed by the simulated IESO observing a limit on the qualified offers by qualified portfolios at the quantity offered in the ADE. The DSO also submits its "LDC-directed" quantities alongside the ADE submissions. These are submitted to reflect the total quantity of DSO purchases at ADE, regardless whether those

				portfolios or offers were qualified to be forwarded to the simulated IESO. If an otherwise qualified offer is made after the ADE, it is not made available to the simulated IESO to respect the assumed ADE submission of zero.
1	6	17	Embedded Distributor Considerations	It is a general learning of the project that being an Embedded Distributor is a confounding (though surmountable) challenge to Transmission-Distribution coordination for local energy markets. Connection Agreements must be leveraged to the extent they allow any flexibility-related activity and are a first step towards Host-Embedded distributor coordination since they must cooperate at the Connection Impact Assessment stage of connecting an asset. This step typically inserts delays into the process of connecting a new asset and may be a stage where the distributors may share information or availability of flexibility services from the asset, respecting negotiated limits or characteristics.
1	3	18	Adapting Outage Notifications for Forced and Planned Outages in a flexibility market	The Outage Notification process in PowerShare is managed by the DSO contract, as NODES does not have a forced/planned outage logic outside of managing them during contract formation. PowerShare adapted to this process by defining a forced outage as any outage affecting a 'matched' contract (in ShortFlex or LongFlex), with planned outages managed by refraining from making offers. Since participants are free to withdraw their unmatched ShortFlex offers, the DSO is only expecting the availability of matched offers to be delivered. Participants are expected to provide up to 48 hours notice of a Forced Outage, or to notify the DSO of it within 24 hours of its occurrence. Participants are not charged a fee for an outage; however the affected portions of the contract will be settled at zero percent delivery. The DSO may request additional information regarding a reported or suspected Forced Outage. The extent and frequency of Forced Outages may be considered in a future development of a 'reliability ranking' for local market participants but this will be manually tracked for purposes of the demonstration. Such a ranking could serve as a weighted parameter for selection of tender or service responses by FSPs.
1	3	19	Aggregator Portfolios / Flexibility of Approved Assets - differences	Using the NODESmarket functionalities, each Participant places their asset(s) in a Portfolio, which is the level used to generate

			of an Aggregator and a Direct Participant's portfolio management	baselines and make offers to the market. Functionally, Participants are free to arrange their assets as they like since they are held to the quantity of their offer rather than an assigned capacity of their assets. The enduring difference between Direct or Aggregator Participants would be the application of a Type/Technology Approval for their assets. This would be a sample of assets of the same technology selected by the DSO to demonstrate the dispatchability and market acceptance of that technology which the DSO can apply to other assets of the same type. The DSO must still approve each asset before it can be assigned to a portfolio, but it may simplify expanding an Aggregator's roster by leveraging the previously conducted testing.
1	3	20	Aggregator Portfolios, Prevention of Double Counting	Given the flexibility of Portfolios and the ability to transfer approved assets seamlessly between them, NODES implemented a check to prevent double-counting of assets via the Meter Point ID. This is used to prevent gaming or double-counting of services provided by an asset which might have appeared in multiple portfolios without that check, since it would contribute its asset baseline to the Portfolio baseline. A weighted delivery factor was considered as an alternate solution which would preserve the ultimate flexibility of portfolios while respecting the relative size of the concurrent offers (i.e. 5 MW, 3 MW, and 2 MW offers from three Portfolios which share an asset, the asset provides 50%, 30%, and 20% of its delivered flexibility to the Portfolios respectively). This is noted as a potential future enhancement for technology aggregators.
1	3	21	Testing, Standby and Activation Instructions adaptation to DSO platform functionalities	The NODESmarket platform does not provide 'standby notices' for activation. The only pre-matching information a participant would receive is whether they have a LongFlex obligation or a scheduled test. Notifications upon matching or X minutes before delivery is entirely defined by the Participant. For instance, if for operational reasons the Participant only wants to be notified 15 minutes before delivery, but not upon matching, that is possible for them. The test process is aligned to be the platform's "Market Acceptance" testing and the DSO's delivery test. The DSO and Participant agree on the time and quantity of the test, matching in the ShortFlex market. The Participant ensures they receive the notification of activation per their set preferences and then responds with delivery. This verifies the deliverability of the Participant's flexibility to the requirements of the DSO,

				and further testing may occur to confirm the ability of the Portfolio to be dispatchable with less than 2 hours notice for purposes of simulated IESO purchasing.
1	1	22	Onboarding Lessons	General learnings from recruitment discussions and onboarding processes include that many potential candidates were interested in the extent a Local Energy Market could help with justify net-new energy assets. This included interest from OEM or service providers in expanding their portfolio and local businesses interested in reducing energy expenses or to generate new revenues. Timing of onboarding in NODES' experience is that it takes approximately a month from the first meeting. This generally holds true in PowerShare, but can be as long as three months if a Participant requires accommodations to the process or the DSO contract.
1	1	23	Technology Aggregators, like EV OEMs are interested in programs like PowerShare but scale poses challenge to integration	There is a great interest in Technology Aggregators like EV charger and electric water heater OEMs in programs like PowerShare. The challenge seems to be developing integrations by the OEMs is limited by scale; one in particular remarked that Windsor-Essex County would be a scale better suited to develop a Demand Response program.
1	5	24	Hydrogen is not mature enough to source hydrogen-fuelled generation units or a reasonably priced supply in appropriate quantities for Local Market Demonstration	Despite the acceleration and interest in hydrogen projects, hydrogen is uneconomical in our modelling of a H2 fuelled unit operated on a rental basis and offering into PowerShare. The price of Hydrogen transportation and storage is a major impediment, since the points of supply are so far from the potential generation unit.
1	1	25	Finding Candidates for participation is the biggest challenge	Participation candidates like small and medium-sized businesses often do not consider energy/flexibility services as a main component of their business, and thus poses a challenge for recruiting capacity to a local energy market until capacity building or maturation can occur in the market. Although we assume this will come with time, NODES' European market experience has shown that the true scaling opportunity for flexibility is in residential. Large commercial/industrial assets want to be a small player in a national market rather than a large player in a local market; traditional capacity reservation is more aligned with their activation expectations since it minimizes interruptions to business. This notion is also discussed in the learning on Flexibility First. That said, large commercial/industrial assets are participating in local markets and have learned to use the activation price as a mechanism to illustrate their willingness to offer flexibility. A typical bidding profile could be comprised of a low/average reservation price

				and a high activation price. This would in turn reflect the FSPs expected frequency of activations (more information in the next section). Aggregations of residential "Internet-of-Things" demand response capable devices and their business models require maturation of machine learning/automation-based aggregators, given the high volume of devices and relatively small capacity. In other markets, NODES has explored the concept of a Flex Register which allows for the prequalification of technology and assets for flexibility services, serving also as a touchpoint to monitor or control data between TSO and DSO.
1	6	26	Flexibility First; application to distribution grid services	Informed by lessons from NODES' European markets, Flexibility First is an approach to Non-Wires Solutions which centers consumer choice and benefit. Value is captured in an open market based on the degree of voluntarism with which the grid service is provided, which sorts solutions into tiers which can sequence tool use in solving constraints or issues. The sequence where severity of the constraint/distribution issue increases: - 'Yellow Issue', solved with low-cost, highly voluntary flexibility such as a residential aggregator (thermostats, electric hot water systems, EVs). - 'Orange Issue', solved with higher cost, less voluntary flexibility such as C&I. - 'Red Issue', solved with all available flexibility and regulatory tools such as non-firm connections, interruptible rates. Emphasizing voluntarism in program design will lead to scaling and sorting of services into these tiers and will reduce the number or severity of involuntary flexibility provision such as through a non-firm connection. Ultimately there is a cost to solving grid constraints and by relying on involuntary solutions from customers, that cost is downloaded to them such as through lost production for C&I resources. See also the Regulatory Lesson re: Flexible Connection Agreements. A risk noted in this approach is that programs which allow a utility to access cheap or no-incremental-cost flexibility such as through traditional thermostat programs may reduce the liquidity in the market for those flexible assets. If these solutions form the lowest rung of the solution ladder, it may

				create a more difficult path towards maturation of other technology aggregators as they are directly competing with a DSO or TSO for those services.
1	5	27	Technical barriers to IoT and residential technology aggregators	Supported by learnings from Flexibility providers in Norway (i.e. Tibber), there are a number of challenges in the path to enabling residential flexibility at-scale. First is that the aggregators of these IoT technologies believe it is unreasonable to expect 1-second or other high granularity from a 1 kW scale asset the same as grid scale resources. Second is a suite of technical barriers: lack of data transparency and open protocols from device manufacturers, grid technical requirements being poorly matched to new kinds of assets, lack of standardization and scalability between markets, lack of investment certainty specifically for local flexibility which need to move from pilots to attract this kind of aggregator investment. Third is a "UX trilemma" where these aggregators must handle the grid service complexity with simple language to the end user, ensure ongoing engagement, and providing value. Ultimately making the customers understand the service and demonstrating the value for them to participate is a difficult balancing act.
1	1	28	Disseminating Results, Designs, and Principles to Industry including LDCs	LDCs are highly interested in PowerShare, publicly and privately. Industry conferences such as EDA's EDIST, CanREA's Energy Transition Hub Summits, and DistribuTECH have been integral to sharing the messaging and principles of PowerShare such as Flexibility First, the ability of LDCs to create and support Local Energy Markets, and the transition to DSOs.
1	3	29	Ramp Rate considerations	Given the market design and the under-delivery reduction methodology, Project decided to not consider ramp rate and the participant is expected to provide 100% of their offer at the contracted time regardless of ramp rate. Participants are encouraged to manage the ramp rate and consider any impacts on costs in their price and payment expectations.
1	3	30	Defining DSO Gate Closure vis-à-vis IESO Gate Closure	Defining the gate closure, or default 'expiry' of ShortFlex offers in PowerShare was a debate in the market design stages between two and three hours whether to mirror the IESO Mandatory Window or to provide additional time between DSO gate closure for the simulated IESO to receive the qualified dispatch data. The project settled at 125 minutes before dispatch hour, respecting the Mandatory Window and providing the time for NODES to provide the simulated IESO with the qualified offers and DSO information. Per TDWG, the DSO submits at some

				time prior to the Mandatory Window an "LDC-directed quantity" for all the local market activity within this period. Wholesale-qualified offers are also prepared and made visible to the simulated IESO in the 5-minute period. This is possible only because of the simulated nature of T-D coordination, and we expect that live coordination may have a longer time period unless reliably automated and technically integrated. NODES has experience with the latter in Sweden and Norway markets.
1	2	31	Identify Deadband for Dispatches/Activations	Reference to the 'Dispatch Instructions in Real Time Market' PDF shared by the IESO on March 1, 2023, facilities in this pilot that are less than 30 MW, the IESO expects facilities to operate as close as possible to the dispatch instruction. PowerShare hopes that findings from this project will help inform what a reasonable deadband for DER facilities would be, noting the IESO's interest in a +/-2% deadband. Operation as close as possible to the dispatch instruction will be supported and incentivized by the stepwise reduction of payment by % delivery.
2	2	32	IESO-DSO integration: Discussions related to integration between the EPL market and the simulated IESO Real Time Energy Market (RTEM)	During the initial project and design discussions, it became clear to EPL and NODES that wholesale integration would be simulated rather than directly integrated into the IESO's operational market(s), as initially outlined in the application. Consequently, NODES shifted its development focus from technical integration to designing and building a new module within the NODES Platform. This module would establish a connection between the local market and the IESO's wholesale market. The revised objective necessitated process adjustments. Rather than primarily focusing on integration documentation and development, NODES initiated design discussions with EPL and the IESO. The project team collectively decided to integrate the local market with a simulated IESO Real Time Energy Market (RTEM). Qualified and unused portfolio sell orders would be forwarded to the simulated IESO RTEM for evaluation against purchasing scenarios. An iterative process followed with all stakeholders contributing to a Transmission-Distribution (T-D) coordination design document. This document outlined the conceptual and technical link between EPL's local market and the NODES platform. Expert resources from the IESO and the Ontario Energy Board (OEB) reviewed the documentation and actively participated in discussions to improve its applicability. The combined approach, including review of existing integration

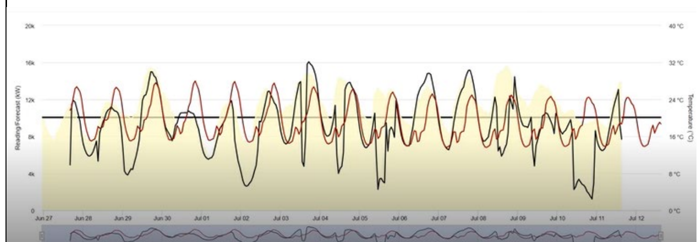
				documentation and iterative planning for new integration frameworks, culminated in the creation of a robust T-D Coordination Methodology. Additionally, NODES and EPL closely monitored ongoing discussions within the Transmission Distribution Working Group (TDWG) to inform the development of the T-D Coordination Methodology. Given the focus on sequential coordination during the initial trading period, aspects from the Total DSO model were particularly relevant for PowerShare. These considerations addressed broader discussions in Ontario's evolving market design discussions. Overall, it was agreed that PowerShare will trial three T-D Coordination areas: 1) Sharing information on Essex Powerlines' purchases with the IESO (the Information Service). 2) Passing unmatched sell orders to the IESO's simulated RTEM after NODES market closure (Sequential Coordination). 3) Having Essex Powerlines and the simulated IESO purchase flexibility at the same time on NODES (Integrated Coordination). Developments and conceptual discussions related to this module will be part of milestone 3 and 4. See T-D Coordination Methodology and NODES Schedule 5 for more on the final protocol.
2	5	33	IESO-DSO integration module in the NODES Platform: Development activities in line with the T-D Coordination Methodology	The new integration module in the NODES Platform was developed to connect the local market with the simulated IESO's RTEM. The development was carried out concurrently with the T-D Coordination Methodology designed by the project team (including representatives from the IESO and the OEB). Throughout the process, the NODES technology team considered the eligibility requirements for RTEM participation and technical links between local (EPL) and wholesale (RTEM) market rules. As an example, NODES will only pass on orders from the local market (30 minutes) if the order is preceded or followed by another order, so that the orders together form one hour. Meaning orders will be transmitted as a consecutive half hour pair to the RTEM. Despite the challenges inherent in aligning the criteria of EPL as a Distribution System Operator (DSO) with the existing RTEM, the simulated integration service has been developed successfully. The development demanded substantial resources

				and time, but the result - the coordination module - now facilitates seamless communication between the local and simulated wholesale market.
				
				In short the result of the T-D coordination module is developed as follows:
				
				- A module to submit and approve portfolios based on the DER's/asset's characteristics such as ramp up/down rates.
				- A set of rules that dictate the requisites and shape of the orders to be transferred from the DSO market to the simulated RTEM
				  • Only approved portfolios can participate.
				  • 2 hours before activation time, orders from the same portfolio are aggregated to hourly blocks and then split into 5-minute intervals.
				- A module to transfer orders from the DSO market to the simulated RTEM.
				  • NODES submits simulated Availability Declarations to the IESO by the IESO's day ahead deadline (10 am day ahead). The Availability Declarations will be equal to the volume of unmatched sell orders that meet the criteria shortly before 10 am day ahead. Meaning every day, an email is sent with an excel report detailing all the orders that will be sent to the simulated RTEM the following day, provided they do not get bought by EPL in the local market.
				  • Every hour, 2 hours before activation time (Mandatory Window), aggregated orders are cancelled in the EPL market and created in the simulated RTEM (separate market in the NODES Platform).
				- A module to view orders in the simulated RTEM before orders are transferred.
				  • When viewing an orderbook in the simulated RTEM before the 2-hour mark, a view is created on the spot to visualize how the simulated RTEM orderbook will look like at the current state of the market.
				- A communication channel between the DSO and the simulated RTEM.
				  • In the simulated RTEM orderbooks, trades from the DSO market are also aggregated up and visualized so the simulated IESO can know how much flexibility that has already been procured by the DSO.

				• Overall, the development went well, adhering to the project timeline. Notably, the highest complexity arose from ensuring compliance with the IESO market rules while respecting the differences in the EPL market. • A point of discussion revolves around the strict requirements, particular the element of vertical aggregation only (as opposed to allowing horizontal aggregation of FSP order pairs as an addition). It's worth considering whether relaxing this restriction would bring additional liquidity in the simulated RTEM market, as this would allow smaller portfolios to access it. • More information can be found in the T-D Coordination Methodology and NODES Schedule 5.
2	2	34	IESO-DSO integration module in the NODES Platform: Development of the information service	To bridge the market design disparities between Europe and Ontario, NODES adjusted its 'Balance Responsible Party Role' and introduced an "information service". This transparent service will keep the simulated IESO informed about trading activities in the local market. The collaborative effort involved close coordination among the IESO, EPL, and NODES. In short, the technical service facilitated the IESO' registration as the recipient of trade data (assuming the Balance Responsible Party role within the NODES Platform) for all assets participating in the EPL DSO market. This streamlined approach ensures efficient communication and alignment across markets. More information can be found in the T-D Coordination Methodology and NODES Schedule 5.
2	5	35	SmartMAP integration the NODES Platform: metering data submission	As part of the PowerShare initiative and EPL's transition to a distribution system operator (DSO), a critical undertaking involved integrating the SmartMAP tool with the NODES Platform. The collaborative effort between the Utilismart/SmartMAP team and the NODES technology team followed a hybrid approach, combining technical meetings, email correspondence, in-person sessions during NODES' presence in Canada or the US, and thorough review of documentation within the NODES developer portal. Despite minor challenges, the overall integration proceeded according to plan. NODES made necessary adjustments in the registration process for Distributed Energy Resources (DERs) to enable accurate identification by the SmartMAP tool. Assets

				are identified by their meter number which allows SmartMAP to poll the NODESmarket API for a list of all active meters and missing meter intervals on NODESmarket. The Submission Task uses the active meter list to collect the previous day's metering data alongside any missing intervals from previous submissions. This is submitted to the NODESmarket API and registered to the appropriate DERs. Subsequently, testing by the technical and operational teams ensured seamless submission of meter readings to NODES, culminating in the generation of baselines at the portfolio level for participating FSPs. This integration enhances the overall market facilitation capabilities and reinforces EPL's commitment to advancing DSO operations within the PowerShare framework See challenge "Integration Obstacles between SmartMAP and NODES" for more information on the Meter Data Submission process.
2	2	37	Consulting for DSO design expertise: experience sharing, strategic workshops, knowledge transfer and tool adoption	NODES consistently offers consulting services in DSO design expertise as part of its ongoing collaboration with PowerShare. In this specific task, NODES concentrated on core capabilities and the adoption of essential tools. Leveraging insights from experienced grid companies in Scandinavia, NODES facilitated knowledge sharing regarding operational tools. - Experience sharing and insights: NODES leveraged its experience working with DSOs across Europe. Best practice, lessons learned, and insights specific to DSO operations was shared through collaborative sessions. Sessions drew on real scenarios, context and practical knowledge and aimed to facilitate Essex Powerlines' decision-making. - Strategic workshops and knowledge transfer: NODES facilitated targeted workshops and meetings with one of the most mature DSOs in Norway. These sessions focused on critical aspects of DSO design, including grid planning, DER/asset management, and regulatory compliance. By engaging directly with their team, the idea was to foster knowledge transfer, encourage open discussions and identify areas for improvement. - Tool adoption and resource support: Recognizing the importance of efficient DSO tools, NODES introduced EPL to software solutions relevant to their operations. NODES provided comprehensive documentation, training materials, and direct access to key resources of tools used by the Norwegian DSO. By providing insights to the DSO tools used in

				operations, NODES enabled EPL to plan for new developments in SmartMap to thereafter optimize grid management processes and enhance reliability. Despite the challenges posed by time zone differences and geographical distance, EPL and NODES believe that we are not only providing valuable DSO insights to the PowerShare initiative, but also to the broader DSO discourse in Ontario.
2	4	38	Consulting – project management	During the implementation phase, weekly project meetings between EPL and NODES continued in order to coordinate work and discuss implementation topics. In particular, topics included the rules about and implementation of eligibility to the simulated IESO market, and of bundling orders from the DSO market to be forwarded to the simulated IESO market. Discussions of these topics ensured consistency between market rules and the implementation, and in particular that all possible cases were carefully described both in the software implementation and in the market rules. This project touchpoint continues to be a critical connection between the EPL and NODES teams and the weekly cadence has often been required to follow up on project design or stakeholder concerns.
2	2	39	Develop algorithm to recognize when flexibility is needed based on set of parameters	A Load Forecasting tool was identified as the primary development item for flexibility need recognition. EPL and Utilismart undertook to create a prediction of demand in the next 24 (later increasing to 48) hours. This provided insights to the demand patterns and was iterated upon to become more accurate as the results were evaluated in the pre-market period. For more information on this activity, see Lesson 40: "Forecast Accuracy vs. Simplicity", Lesson 41: "Operationalizing Forecast vs. Real-time and Visualizing constraints", Lesson 42: "Database (back-end) build out", Lesson 44: "Validating Forecast Capabilities", and commentary in forthcoming Milestone reports related to operationalization and use in market periods.
2	3	40	Forecast Accuracy vs. Simplicity – How to define a reliable time frame while maintaining efficiency	The main challenge in the pre-market operations period was to find the ideal balance between having enough data to secure consistent accuracy and reliability and not being detrimental to the overall process. The initial thought consisted in utilizing historical load readings data for a specified period (last 2 weeks of data, prior to the desired date, from a year ago) and use that to forecast the next 24 hours consumption aiming to anticipate a strain on the network. As the initial idea was being developed, several attempts were made to improve its

				accuracy and efficiency without causing any negative impacts to the system. It was noticeable that by also adding the "last 2 weeks of data prior to the desired date" to the consideration contributed to the initial goals, but also the reliability of the forecast was greater without compromising the system's performance despite factoring more data. This lesson is used in future milestones when fine-tuning and expanding the functionality of the forecast. For more information, see Lesson 42: "Database (back-end) build out"
2	3	41	Operationalizing Forecast vs. Real-time and Visualizing constraints	The obstacle after defining the optimal time frame for the data was to define the proper process and how to plot that in a graph in a clean and intuitively way. The final process became like the following example:  - Actual date: July 11th, 2024. - Desired date of forecasting: July 12th, 2024. - Historical load readings periods used to calculate the forecasted data: (June 27th, 2023, to July 11th, 2023) + (June 27th, 2024, to July 11th, 2024). - In a graph, the maximum demand DSO can provide, the actual load readings curve (1) for the last 2 weeks (June 27th, 2024, to July 11th, 2024) and the forecasted load curve (2), which will derive from averaging the historical load data from both periods, will be plotted with the addition of the calculated forecast for the next 24hrs (July 12th, 2024) With the information provided, DSO will be able to make an informed decision, in almost real-time, whether it will need to action DERs and which deviations should be investigated to future enhancements to the baseline. *Future enhancements and interaction of wholesale market activity with the forecast will be discussed in future milestones*.
2	2	42	Database (back-end) build out – Improve the database to support the forecasting algorithm while maintaining performance	During the conceptualization and development of the forecasting algorithm, the project team faced a critical question: "How can the database be improved to support the implementation of the forecasting algorithm while maintaining its overall performance?" To address this, multiple brainstorming sessions were held to discuss various scenarios

				and solutions. These sessions focused on practical considerations, such as how far back the system should retrieve historical data to ensure reliable forecasts, ways to address potential data gaps, and strategies to prevent overloading the system. Several iterative build-out attempts were proposed, tested, and debated. For instance, an early design suggested running the forecast process daily, clearing out older data each time to minimize system strain. However, this approach was ultimately discarded. It became evident that preserving historical forecast data was essential not only for showcasing the algorithm's accuracy but also for generating stakeholder trust in its reliability and transparency. By retaining this history, the team could provide valuable insights into how the forecasts evolved and were used over time. The final database design was updated to process forecasts every five minutes, calculate results for the next 24 hours, and retain both the forecast history and the actual values for comparison. This robust system allowed stakeholders to measure the accuracy and effectiveness of the forecasts, providing a clear demonstration of how the system could reliably inform operational and market decisions. The iterative process of refining the database and algorithm highlighted the team's commitment to delivering a solution that balanced performance, reliability, and scalability for future milestones.
2	5	43	Integration obstacles between SmartMAP and NODES	Meter data process and data adaptation had to be made to enable the Meter Data Submission to NODES. To start, a variety of translations had to occur; such as readings being published as Power (MW or kW) instead of Energy (MWh or kWh), ensuring EST-to-EDT accuracy, but also the logic applied to "Delivered" (Positive for SmartMAP) and "Received" load readings (Negative for SmartMAP) had to be reversed to accommodate NODES. Another large lift towards integration was publishing the readings to NODES. Initially for the process to happen an asset would be added to the platform and to a portfolio to accept meter data submissions. During the publishing, if at least one asset from the set of all assets (meter numbers) on the NODESmarket Platform was not part of a portfolio, the whole process would fail/crash. The solution devised by the team enabled publishing per device where when it identifies a failure, a log is created with that asset and the process moves on to the next asset from the batch instead of crashing/breaking the whole process. Those logs are reviewed

				to ensure the devices included for the next publishing round. This submission is confirmed prior to the Platform/Market Acceptance testing.
2	3	44	Validating Forecast Capabilities - Stress testing how granular the process could go while keeping its efficiency and reliability	To validate the performance functionality of the system after the algorithm implementation, the initial test had the process running the forecast once a day and analysed how the system behaved. As no issues emerged from the first test, the frequency was increased to run the process every hour, then every 30 minutes, until the final point where the forecast process ran every 5 minutes. That final stage was defined because there were no reads smaller than 5 minutes readings, rendering any smaller interval attempts irrelevant, as well as keeping accuracy, efficiency and performance at optimal levels.
2	1	45	Battery Energy Storage System (BESS) Business case difficult for partners, even with funding contribution	This and following BESS lessons are informed by engagement with host site candidates (multiple businesses and municipalities), BESS developers, and operator/proponents. BESS larger than 1 MW are more practical for business cases due to the fixed costs of installation (foundations, connection costs, etc.) in addition to the existing potential of participation in permanent IESO-Administered Market programs (being >1 MW it is presently qualified for IAMs) and roles in Industrial Conservation Initiative plans. Importantly, the role of a BESS in ICI savings plans are the most critical justification of the resource at nearly all evaluated sites. A concern surfaced from engagement for BESS was Global Adjustment (GA) misbalance. Where the BESS may incur GA fees when charging during off-peak hours, the savings achieved during discharge may not fully offset the additional GA costs. This is an uncertainty in cost/benefit planning that businesses require before agreeing to a BESS business case and proved a barrier in at least one proposed behind-the-meter development. Additionally, the uncertainly of continued Local Energy Market (LEM) revenue due to PowerShare's status as a time-limited innovation project contributed to concerns about the continuing business feasibility of the BESS investments. Revenues for the proposed BESSs from PowerShare's LEM capacity and energy services would have been secondary to the revenues from ICI-related savings but proved definitive for at least two proposed developments.

2	1	46	Battery Energy Storage System (BESS) municipal approval, community readiness to host	General uncertainty and hesitancy around the environmental and emergency risks of BESS were a challenge. Insurance considerations deterred at least two potential host sites. Fire department resources in engaged municipalities were ready with knowledge on BESS and provided helpful recommendations on development plans. Generally, they recommended signage warning against contact with the BESS and siting it a prescribed distance from flammable structures. In the case of a BESS fire, it would be contained rather than extinguished.
2	1	47	Battery Energy Storage System (BESS) timelines, unexpected delays in deployment	The deployment of a larger BESS system at a municipal site faced significant delays due to unexpected factors including challenges with host agreements, timeliness of developer site review and communication, and unforeseen technical hurdles. For instance, there were protracted negotiations over contract terms, particularly around the saving materialization timeline and addressing site-specific issues such as zoning and environmental considerations. BESS development timelines in the project exceeded 1-2 years, impacting project milestones. Additionally, a business host site declined the BESS development due to a misalignment with their expected energy investment horizons, where the BESS would be at least a 10-year operation, the business preferred a 5-year or less life for an energy investment.
3	5	48	LongFlex auto-generation bug - initial contracts only issued ShortFlex orders for the first 30-min of each hour, risking settlement errors	Patched NODES hourly LF obligation to half-hourly SF obligations logic. Added visual contract review before publishing live tenders and implemented test script for all future market parameter changes. NODES developed necessary adaptions to the code.
3	2	49	Lack of real-time load visibility for FSPs: participants could not see their real-time meter data inside NODES, complicating day-of offering / performance validation	Built daily CSV-push from Utilismart to NODES “Meter Data” hub; roadmap item for 15-min near-real-time API feed. Future programs should budget early for nearer to real time participant dashboards or other form of day-of performance validation. One FSP suggested a notification at the end of a delivery period with a preliminary delivery result.
3	3	50	Under-delivery experience from NODES Norway, a real case in Southern Norway where the DSO purchased 5 MW but received 3.2 MW prompted concern that DSO	PowerShare adopted a 10-20 % “operational head-room” rule: LongFlex tenders automatically include an approximate 10% surplus in the target volume, rounded up.

			markets need a procurement buffer.	
3	5	51	Baseline Overlap (FSP upload vs default) edge case when an asset uploaded an approved baseline.	A code change in the settlement process was implemented in response to an event which will prioritize FSPs' approved uploaded baselines if there are overlapping baselines during the trade period.
3	3	52	Participant interest in alternate baselines. Multiple FSPs requested alternative baseline formulas (e.g. last 10 days, exclude trade days)	Created custom baseline nomination. EPL reviews methodology; once approved, NODES calculates settlement based on approved methodology. No FSPs elected to submit a custom methodology.
3	1	53	Trade-compensated baseline preference by FSPs	FSPs regularly asked about trade compensation in baselines in intake discussions. NODES implemented this and it became the default for PowerShare. This is a methodology which credits the FSP for the flexibility activity in their baseline, adding ShortFlex settled quantities to the actual metered load when calculating baseline.
3	1	54	Technology /Type Approval of small assets	Given the potential challenge of qualifying many small technically identical assets (e.g. a particular brand of DER), NODES suggested a type/tech approval to approve small assets for aggregators mirroring processes in other NODES markets. Technology/Type approval was included in the Intake process but was not used due to lack of small resource aggregation.
3	1	55	CACP-equivalent payments may not be sufficient an availability payment for the additional lift to integrate into business procedures for aggregators/traditional IAM participants	A high availability price LongFlex tender with a low activation price ceiling was tested and achieved minimal enrolment. FSPs commonly stated that availability prices should be sufficiently above CACP prices to incent participation in local markets.
3	3	56	Participants commonly ask about standby notices prior to activations	A common question from prospective FSPs likely more familiar with IAMs or Toronto Hydro Local Demand Response programs. These are common features in DR or flexibility-type markets, but in PowerShare this was managed by customizable expiry of ShortFlex offers in the market. For instance, if an FSP needs to know whether they will be called by 10am day of, they can set a custom expiry time to remove the offers from consideration for activation. No Standby Notices were provided to FSPs in regular market operation.
3	3	57	IESO dispatch visibility; without knowing Tx dispatches, local flexibility need can be mis-estimated.	IESO market activity in Leamington affects the need for local flexibility - visibility into IESO dispatches would inform the Local market activity. Visibility to local activity will be required by DSOs to avoid operational violations, particularly when coordinating DERs between IESO/DSO.

3	2	58	IESO activity affects the accuracy of forecasts.	This can be mitigated with notification of action or ad-hoc 'fixes' to compensate for specific meter activity such as in the case of an IAM participant. Data sharing arrangements will be critical to improve visibility of market activity and refining forecasts in future LEMs.
3	3	59	LongFlex offers are not commonly reduced from the FSP's tender-defined Activation price; meaning that FSPs set their activation price at LF tender issuance and did not change in day-to-day market operations	Although LongFlex $/MW activation payments are commonly reduced at tender stage lower than the Maximum Activation Price ($2000 in July/August LF, otherwise $1000), the Activation price accepted in the tender remains the offer price day-of despite the ability of FSPs to reduce the price to capture DSO buy offers. The cause of this is unknown, potential solutions are whether the participating FSPs were sufficiently aware of the ability to the change the price, or if they were not willing to lower the price. Supported generally by the July/August, September/October, HighAvail, and Winter Seasonal LongFlex.
3	1	60	Large users were interested, wanted multi-MW participation beyond pilot cap	Large users/assets have interest in local programs like PowerShare which are out of the scope of a pilot market. Large asset owners (manufacturing, generation) showed interested in offering thousands of MWhs in a year and are interested in what investments can allow them to do that (while benefitting the business through power quality, etc) such as BESS. Although untapped in PowerShare, this potential can be informative to future flexibility procurement initiatives and provincial discussions on flexibility availability.
3	4	61	Continuous allocation of Seasonal LongFlex may reduce competition.	Continuous allocation of the LongFlex contracts may prevent competition by reducing the likelihood of tenders competing to achieve an allocation. Despite the "continuous allocation" of Seasonal LongFlex capacity, FSPs were observed to set reasonable "Maximum Activation Prices" in response to the market prices seen in platform (both purchase by DSO and sell by other FSPs). Interest in competition was expressed by nearly every FSP in intake discussions. An alternative approach to continuous allocation of LongFlex contracts could have been enabled with a one-time allocation post a pre-determined tender close time.
3	3	62	Trade cancellation manual and slow	Cancellation of trades was considered a feature to accommodate user error or enact emergency grid override. This was managed as a manual process by contacting NODES support when contracts needed to be cancelled. In a future operationalized market, a formal cancellation process needs to be available to the DSO without manual intervention by platform staff. This lesson was valuable feedback for NODES. NODES entered PowerShare as an independent market operator and, over the

				course of the initiative, pivoted its model to a technology provider that can assign more responsibilities to a DSO. One such example is providing a systematized cancellation process to DSOs in future markets.
3	2	63	Participant performance validation a challenge in near-real time (particularly for small DERs which may not affect the load curve drastically),	Reducing the time delta from activation to confirmation of delivery is noted as a future development item (particularly for future AMI capabilities) to provide advisory performance data nearer to real-time. Future programs should consider how FSPs will be able to monitor site load and flexibility delivery. It should be considered whether this should be a requirement for all DERs (e.g. small DERs like EV chargers) or if it should be limited to DERs based on installed capacity, portfolio volume. DER type, product delivery, etc.
3	3	64	Weekend Trading disabled to allow manual oversight	Trading on weekdays was a choice to manage participant outages, rather than implement fully automated or unsupervised weekend-trading. In future stages weekend trading is feasible with moderate computer automation and 24/7 Control Room access to override/cancellation tools. Weekday-only rule kept for M3, flagged as scalability item.
3	1	65	Steep learning curve rapidly overcome; users became proficient after ~1 week.	Participants, once acquainted with the platform, quickly became proficient despite the complex nature of handling active flexibility concepts. Confirms effectiveness of onboarding webinars, platform documentation, and play-sandbox.
3	3	66	High notification frequency (every 30 min) tedious in long Service windows.	Many participants when asked about their experience with the platform would remark more on the frequency of notifications from the Platform (every half hour) which can be tedious for long continuous service periods. Noted as a future improvement to notify for each full activation window rather than product period or perhaps to implement set point/event-based notifications. It was found that the use of text/email dispatch notifications enables rapid deployment and quick integration to existing business operations.
3	3	67	Uncapped number of activation events in PowerShare	Proved successful as a design decision to not impose a ceiling on numbers of activations in any given period (such as 5 activations per season) - validated emphasis on voluntary provision of flexibility. Participants were able to impose their own cap on activation frequency by proposing a minimum rest period between ShortFlex activations.
3	3	68	Testing LongFlex Obligations in-market	Exceptional Trades used to confirm deliverability of LongFlex obligations. Dispatches successful. Examples: - September 27 - Market Quantity Test 4-6PM 0.5 MW@$1000, had Participants offer at the Seasonal LF maximum, and was

				decided to take the small quantity risk of 0.5 MW for two hours to test the participants at the high activation price. Also benefit of testing dispatch avoidance. - October 30 - Market Quantity Test, .25 MW@$1000, Seasonal LF Maximum to test LF obligations.
3	1	69	Flexibility services not core business for most FSPs	Interviews confirm that providing flexibility is not the primary business line and FSPs appreciated the flexibility inherent in the program to provide a low-risk entrance to energy services. The absence of fines, the ability to self-define participation/availability windows, and the availability of the PowerShare team were noted in interviews as mitigating this challenge.
3	3	70	LongFlex automatic provision of ShortFlex offers	Automatic ShortFlex submission from LongFlex contracts reduces error. A feature provided by the platform effectively provided 'Standing Offer' automation with no instances of failure to be available in ShortFlex caused by FSPs.
3	1	71	Participants value flexibility in defining availability windows	Given a LongFlex availability window (eg. 2pm-10pm), FSPs can nominate any hour or include discontinuous hours to fit their operational needs. This was noted in FSP interviews as a valuable option and one FSP favourable contrasted this availability scheme to the Capacity Auction's availability windows.
3	3	72	Defining a ceiling price encourages bidding at ceiling	Default pricing ceilings help prevent budget overrun but may inhibit price competition by providing a signal FSPs can naturally offer if they are not concerned with competitive forces.
3	5	73	LongFlex QA lapse (past periods incorrectly counted)	A LongFlex settlement bug occurred where periods prior to the signing of the LongFlex contract (but after the bid submission date) were counted against an FSP as unavailable periods. This was solved, highlighting the need for robust QA in market software in cases of logic oversights like counting delivery periods in the past on time of signing against monthly delivery percentage of LongFlex.
3	1	74	Multiple FSPs were interested in whether they could stack participation with IAMs	Participants are wary of obligations (e.g., IESO IAM vs. DSO market) and expressed interest in being able to provide both local and wholesale services.
3	1	75	Providing market education sessions helps reduce onboarding friction.	Public sessions promoted business understanding, public interest.
3	1	76	Challenges/Lessons Informed by Participant Interviews (Set 1)	• Scale matters: for Greenhouses, programs like PowerShare become economically attractive the larger the greenhouse operations (particularly into the multi-MW lighting loads). Single range sites (250 kW or less) may not have the requisite revenue potential, but 2-4 MW is feasible and attractive for a >10MW total load.

				• Meter consolidation: having all ranges or site load on a single meter would have made baseline management and bidding easier; multiple meters can complicate participation and reduced potential MW offered. • Need for Real-time Usage Visibility: no simple/default way for sites to see current load in real-time, FSP suggested that programs like PowerShare should bundle or recommend metering/load monitoring solutions. • Staff Attention / Market Windows: trade posting times and intra-day changes required continuous monitoring. Smaller teams need longer response windows or better automation/notification options to avoid missed revenue.
3	1	77	Challenges/Lessons Informed by Participant Interviews (Set 2)	• Operational Flexibility Valued: ability to remove specific hours, vary volumes, and face no penalty fees for partial delivery was cited as a key advantage over IESO HDR/CA programs for some kinds of DR sites. • Price Point Barrier: LongFlex Availability Payments were viewed as too low to attract significant additional aggregator customers; higher availability rates are needed for aggregators business cases. • Stacking Restrictions: prohibition of Capacity Auction participants limited resource pool; aggregators want clarity on legitimate and permanent future stacking pathways. • Baseline Adequacy Varies by Asset Type: the five-day rolling baseline works for steady commercial loads but not for highly variable industrial loads (e.g. arc furnaces); in-day adjustments may be needed for variable asset types. • Data Transparency Tools: FSP requested a meter data and baseline dashboard on the market platform to validate performance without requiring external systems. Platform Endorsement and Future Intent: NODES-type platform seen as an effective single portal, FSP would definitively join future DSO markets provided prices and stacking rules improve.
3	5	78	Baseline calculations and associated surveillance	Baseline prognoses algorithms used in PowerShare and generated by the market platform are technically quite straightforward and in principle possible to calculate manually. There are two situations where this could be useful:

				1. A customer wants a detailed explanation for a given result after settlement delivery calculations. 2. To check for possible errors or to manually confirm correct calculations after code changes. However, exact manual calculations can be hard and time consuming to do correctly. Especially for case 1, where metered data or portfolio composition could have changed after settlement calculations were triggered. Even if data hasn't been changed, correct calculation can be a challenge because of details on how time zones are handled and how prognosis start hour effect which historical data is included. An unexpected edge case where a baseline didn't match expectations for certain hours was explored during operations in PowerShare. A significant amount of effort went into figuring out why we got a certain baseline result. This was partly due to a complex scenario that couldn't easily be debugged and because it was challenging to consider whether manual attempts at calculations were correct and based on the same set of data as the algorithm. To make these calculations easier in the future, a "data-snapshot" feature was implemented. Post the findings, a document containing the actual data being used for the prognosis and all prognosis-relevant settings continued to be generated and stored in the database whenever a prognosis is triggered.
3	3	79	Shared settlement between EPL and the simulated IESO	The TD Coordination module was designed and scoped to allow shared settlement (both Bulk and Local levels settling for distribution services) but this feature was not developed due to the simulation-only role of IESO activation and data sharing. The concept of partial activations and 'split payments' were ready to be implemented in the invoicing module to test scenarios where the DSO partially activated a DER and the Simulated IESO activated a portion of the outstanding capacity.
3	3	80	Participation in the simulated IESO RTEM	PowerShare managed to test and validate simulated submission of trades in the simulated IESO RTEM. The NODES Platform packaged qualified DER offers and, at 10:00 day-ahead, generated a simulated Availability Declaration Envelope (ADE) file that mirrors IESO processes. The developed module for sequential coordination between EPL's Distribution Flexibility Market and the simulated IESO RTEM was available for FSPs throughout the trading phase in M3, but many of the

				participants were not able or willing to meet IESO-level telemetry, metering, and registration requirements. Even after relaxing many of the original market participation constraints, the number of DERs that could be considered wholesale-eligible remained low. This highlights the need for stacking protocols and eligibility exemptions that reflect the operational distinctions between local and provincial needs, as well as the willingness FSPs have to invest in capabilities that is limited to a pilot project. Detailed reflections can be found in the "Looking back" section

4. Project Regulatory/Policy Considerations and Lessons Learned

Projects with an electricity distributor as lead proponent or partner: please ensure that the electricity distributor completes – or provides input – to this section.

In the following tables, summarize regulatory lessons learned, including any unanticipated legislative or regulatory barriers that were encountered and if/how any barriers were addressed in the project. The lessons generated may be used to inform regulatory and policy initiatives associated with innovative actitivies. Do not delete entries from previous milestones, rather, add new rows for the new milestone and populate the fields. Please be detailed in your description.

MS (Milestone): Milestone Number

ID: Unique ID for each lesson learned

Challenge Description: A detailed description of the challenge and how it impacted the project.

Response: A detailed description on how the challenge was addressed or resolved (if applicable), the thought process behind the response and describe the resources used to respond to the challenge.

MS	ID	Challenge Description	Response (if any)
1	1	Reporting of DSO activations in embedded generation categories	Essex Powerlines continues to include all embedded generation injections in monthly submissions if those injections offset the LDC's internal load. This portion of the LDC's load would not be accounted for by IESO upstream wholesale meters, and therefore the IESO depends on the LDC's submission to determine total monthly load (which is used as an input to calculate their Class B GA charges and IESO admin fee charges as well). While the embedded generator's participation in the pilot program may impact how they operate, it would not have an impact on the LDC's submission requirements.
1	2	Resource Exclusivity with IESO Markets	It is recognized that this is an understandable provision for the purposes of the Grid Innovation Fund, given concerns of double-dipping or subsidizing market participants unfairly. However, this was a challenge to recruitment where a significant constituency of mature energy market participants are unable to continue their regular business processes within the IAMs if they want to provide local flexibility. There is one example of a <100kW site that was part of an IAM aggregation which reallocated their portfolio to participate, largely driven by an interest in DSO models and local flexibility market learnings. Participant candidates were commonly interested in the extent of 'stacking' local and wholesale markets, such as capacity commitments outside of the IESO Capacity Auction availability windows.

1	3	DSO concerns representing assets to the Wholesale market in a "Superaggregation" model	EPL and NODES share a hesitance to represent assets in IAMs. This function is termed as a 'super aggregator', a top-level aggregator for an area or local market which represents an additional layer of aggregation of direct assets and aggregations to IAMs. A super aggregator would bear commercial responsibility for these assets, which is a risk to distributors. See technical learning "DSO commercial responsibility for assets" for more. In a theoretical design discussion, the IESO proposed that it would be possible to "translate" non-performance penalties to resource owners in a 'super aggregation' model. The LDC retains a preference for not being commercially responsible for IAM participants given the current risk models. EPL and NODES are interested in exploring combining offers across portfolios in later market designs and consider this to be an element to explore with the IESO and OEB since this will be affected by the concerns of commercial responsibility taken on by an LDC in an IAM.
1	4	Defining a mechanism for recovery of cost of energy and capacity services within Local Energy Market Demonstration	This is a pending matter with the OEB and may be subject to change. With legal counsel, EPL has made Application (EB-2024-0096) to the OEB for a deferral and variance account (DVA) to record the cost of grid services within the PowerShare local energy market, net of GIF funding and of HOEP. For discussion, LDCs incurring a cost of power for LDC-procured grid services for energy is unaccounted for in the current settlement processes. This will require investigation and maturation of the settlement pathways between the IESO and LDCs. Also for discussion, there is an attribution question which asks to whom the cost and benefits of operating a local energy market should be assigned. Whether it is entirely localized within the LDC, if it includes Host Distributors, the region, or the province as a whole is an important design for the use of DERs as NWSs - particularly within local energy market structures.
1	5	"Non-firm" Connection Agreements are becoming the “silver bullet” but become regulatory tools or ‘free flexibility’ which reduces the incentive to procure voluntary flexibility (potentially reducing liquidity)	Supported by learnings from European markets where non-firm connection agreements are becoming more popular, involuntary actions such as 'non-firm' disconnections compete with development of voluntary flexibility options. Non-firm connections are not 'free flexibility' as they asymmetrically impose the costs of grid management actions on the

			customer/business which may have had no choice but to accept the non-firm agreement to receive a connection. These management costs should be borne more equally by all customers rather than imposed upon individual customers. In addition, the use of non-firm connection agreements, contrarily to market-based flexibility, gives no guarantee of dispatching the asset with the lowest dispatch cost, due to the absence of a prices signal. These solutions can form an important rung in the active management ladder, but the place for non-firm agreements should be after market-based processes to encourage growth and confidence in the 'lower' more voluntary flexibility services. Alternatively, non-firm connections could be coordinated with market, enabling the non-firmly connected grid user to pay for other grid users to provide flexibility instead of itself, and thus creating a price signal. See also learning on 'Flexibility First' for more on emphasizing voluntarism in grid service provision.
2	6	Complexities in Global Adjustment (GA) Fee Imbalances: uncertainty whether GA savings during discharge would outweigh GA fees incurred during charging presented a barrier to business case development	Unresolved, proponent withdrew.
3	7	IESO telemetry standard (5-min revenue meter & ICCP) is a barrier for distribution-connected DERs.	PowerShare proved that 15-min AMI data is workable for DSO needs. Recognized that a policy path needed to accept AMI-based validation for sub-100 kW assets on the road to DSO activity. Another possibility (alternative but not excluding) would be to (also) allow the use of embedded submeters or dedicated measuring devices, in order to allow a more fine-tuned measuring of delivered flexibility directly on the asset (e.g. EV, heat pump, battery), and thus avoid the noise of other assets behind the same meter.
3	8	Milestone-based public-funding cycles conflict with monthly settlement expectations.	Program solved this via internal float, but future funding designs should consider DER revenue timelines as many prospective participants noted that they would prefer monthly settlement.
3	9	Better Price-cap guidance to correct absence of pricing for local markets.	Participants often defaulted to high ceiling offers; regulators could issue indicative value-of-flexibility bands to accelerate price discovery in nascent LEMs. Also, increased liquidity would over time lead to more competitive pricing from FSPs. On the LDC side, further analysis on the value of flexibility, which would depend on the cost of alternative measures of each case (technical rerouting,

			cost of not connecting new assets, grid investment…), would also provide guidance to LDCs as to a ceiling for each particular bottleneck or situation.
			[Reserved for NODES]

5. Project Victories

This section captures project victories that you wish to celebrate. For example, increasing head count, securing additional project funding or even a successful technology demonstration from your organization that is outside the scope of this project. Do not delete entries from previous milestones, rather, copy the table for the new milestone and populate the fields.

Milestone 1

Achievement 1: Developing the Market Rules Package

The preparation of the Market Rules Package was a showcase in collaboration between Essex, NODES, IESO staff, and many stakeholders like the OEB and Ministry of Energy. The staff engaged in developing the rules received exposure and context to many elements of the energy sector, deepening their competencies in exciting ways. Some learning elements include aspects of the IESO Market Rules, the Transmission-Distribution Working Group's DSO-TSO coordination protocols, OEB processes such as RRR and licensing, and the important learnings from foundational demonstrations like the York Region Non-Wires Alternative project.

Completing the Package required a clear understanding of the roles of a DSO, a platform service provider, and the customer/Flexibility Service Provider (FSP).

For NODES, the biggest challenge related to the Market Rules achievement was to reconcile two markets (the DSO and simulated IESO) with different metering and dispatch granularities and qualifications into a single market pathway for FSPs. This was a novel addition to NODES' markets.

Achievement 2: Developing Internal Competency on DSOs and Transmission-Distribution Coordination

Developing internal competency on DSOs and Transmission-Distribution Coordination has been a significant achievement in PowerShare which showcases the collaborative efforts of Essex Powerlines, NODES, the Independent Electricity System Operator (IESO), and other stakeholders. The project team engaged deeply with the IESO's Transmission-Distribution Working Group to develop essential T-D coordination protocols, ensuring the project aligned with regulatory and operational standards.

By seeking to resolve local constraints and addressing barriers related to Distributed Energy Resources (DERs), the project is set to demonstrate effective coordination between DSO and simulated IESO markets. Understanding this coordination is crucial for enhancing grid resilience and reliability. The integration of the NODES platform enables DER owners to monetize their flexibility, contributing to grid stability and market efficiency.

Moreover, the project team gained valuable insights into the complexities of market design and rules, enhancing their understanding of the roles and responsibilities within a DSO framework. This experience has equipped Essex Powerlines and its partners with the knowledge and skills necessary to navigate and influence the evolving energy market landscape in Ontario, positioning them among leaders in the transition towards more dynamic and responsive energy distribution systems.

Achievement 3: Presenting the PowerShare Initiative at EDIST for the Energy Industry in Ontario

The PowerShare initiative marked a significant milestone when it was co-presented by the Independent Electricity System Operator (IESO), Essex Powerlines, and NODES at the Electricity Distributors Association's (EDA) 2023 EDIST conference. This collaborative presentation showcased the innovative aspects of the PowerShare project, emphasizing its potential as a scalable model for local distribution companies (LDCs) of all sizes.

The presentation highlighted the success of PowerShare in addressing local energy constraints through a dynamic and flexible market model. By detailing the coordination efforts between DSOs and TSOs, the presenters were able to demonstrate how the project integrates distributed energy resources (DERs) to enhance grid reliability and efficiency. This was supported by insights from the IESO on the Grid Innovation Fund, the provincial energy outlook, and a remark that "PowerShare is key to understanding how to unlock DERs" as well as testing coordination protocols.

Feedback from the conference attendees underscored the perceived scalability of the PowerShare model. Participants from various LDCs expressed interest in adopting similar approaches within their jurisdictions, recognizing the potential for widespread application. The warm reception and interest garnered from attendees was certainly an achievement. Overall, the presentation at EDIST served as a major moment for the PowerShare project by reinforcing its position as a forward-thinking solution and cementing wider industry interest in the project.

Achievement 4: Perceived as a Scalable Model for Small, Medium, and Large LDCs, as well as Beyond Ontario

PowerShare has been widely recognized for its scalability and adaptability, making it a model for local distribution companies (LDCs) of all sizes. The project has been presented to global audiences at DistribuTECH 2023 and 2024, European audiences at Nordic Flexibility Day and Nordic Energy Day 2023, Canadian audiences at the CanREA Energy Transition Hub and EDIST 2023, as well as represented at conferences in Los Angeles, Montreal, and others.

The collaborative efforts between Essex Powerlines, NODES, and the IESO were pivotal in crafting a comprehensive market rules package that can be scaled and replicated across different jurisdictions. This foundational work ensures that LDCs can work towards adopting similar models, benefiting from shared insights and best practices. Feedback from the various conference attendees reinforced the perception of PowerShare-like markets as a versatile and scalable solution – with PowerShare serving as a Flexibility Market touchpoint in North America. Representatives from various LDCs expressed interest in implementing the model within their regions.

Milestone 2

Achievement 1: Demonstrating Local Energy Markets with Existing Grid Capabilities

One of the greatest achievements of the PowerShare initiative during Milestone 2 was the creation of a fully functional local energy market using only existing grid assets and infrastructure. By leveraging Advanced Metering Infrastructure (AMI), SCADA devices, and other field-deployed technologies already in operation, Essex Powerlines demonstrated that local flexibility markets are not only possible but also practical within the current technological and operational capabilities of Local Distribution Companies (LDCs). This approach eliminated the need for costly infrastructure additions while showcasing how existing systems can be optimized to support new market dynamics.

The success of PowerShare's metering, settlement, and operational workflows underscored the maturity of current technology to measure and validate DER activity effectively. SCADA systems provided vital real-time data for operational decision-making, while existing AMI offered granular-enough insights into participant energy use for settlement and baseline calculations. These existing assets enabled market settlements, proving that distribution-level markets can operate reliably without major additional hardware investments. As technology advances and distribution grids become more observable towards the grid edge the opportunities to expand market opportunities and include even more participants will only grow.

This achievement highlights the readiness of LDCs to support local energy markets and the feasibility of such markets when local businesses and stakeholders are engaged and capable. The project also illuminated that the biggest challenges for a DSO future may not lie in technical feasibility but in ensuring seamless communication and coordination between DSOs, the IESO, and other stakeholders. Essex Powerlines' success sets a benchmark and reinforces the potential of local markets as a solution within Ontario's energy transition. This victory is a clear signal that the integration of DERs into distribution systems can be a collaborative and achievable goal.

Achievement 2: Gaining Future-Ready Insights for DSO Evolution

PowerShare has provided Essex Powerlines with a forward-looking lens into the evolving role of DSOs in managing local energy markets (LEMs). By leveraging existing grid technologies such as SCADA systems and AMI infrastructure, the project highlighted how LDCs can support distributed energy resources (DERs) and facilitate dynamic grid operations without significant infrastructure additions. These insights have directly informed EPL's product development roadmap and its strategic collaborations with partners like Utilismart, ensuring alignment with the long-term demands of a high-DER energy system.

One of the key areas of development driven by PowerShare is the integration of LEM platforms with advanced control room operations. Utilismart's SmartMAP plan has evolved to include insights from PowerShare, such as dynamic assignment of resources to zones based on real-time switching configurations of the grid. This capability would allow for efficient sectionalization, enabling DSOs to respond flexibly to local constraints while maintaining operational reliability for distribution-connected market participants. These advancements also set the stage for further enhancements, such as embedding LEM operations directly into control room dashboards, allowing operators to oversee and manage market activities seamlessly alongside traditional grid operations.

Looking further ahead, the development roadmap includes staged plans for increasing automation and intelligence within market and grid operations. Initial steps involve implementing human-supervised automation, allowing the grid to propose execution of predefined actions based on switching events or market triggers. As the system matures, machine learning (ML) capabilities could be introduced to further automate grid switching, market trading, and optimization activities. These ML-ready features will allow the grid to make predictive adjustments, optimize DER participation, and execute trades in local markets with minimal operator intervention.

The engagement with the sector through PowerShare has highlighted how future DSOs must be equipped to manage real-time grid visibility, optimize local energy dispatch, and facilitate market integration with minimal reliance on new infrastructure. These findings have directly influenced the development roadmap for EPL and its partners, addressing emerging challenges in areas like automated grid control, SCADA expansion, and the scoping of AMI 2.0. Through PowerShare, EPL and its partners have not only validated the feasibility of current grid technologies but also laid the foundation for a future-ready distribution system.

Milestone 3

Achievement 1: Participant Engagement, Communication, and Interest in Continuing Participation

A key success of PowerShare has been being widely viewed by participants as approachable, flexible, and overall well-communicated. Both aggregators and direct participants described the PowerShare team (EPL, NODES) as responsive, approachable, and clear in explaining program details, rules, and expectations. FSPs noted that the ease of participation, clear communications, and low administrative burden were among the most valuable features of the program.

In feedback interviews, Participants rated the communication and support provided throughout the program as excellent (5 out of 5). Several participants directly credited the high-touch engagement approach including onboarding sessions, walkthroughs of contract terms, and open lines for questions and troubleshooting as a key factor in their willingness to participate.

Notably, the program's ease of understanding was highlighted as a strength even among participants newer to energy services or markets. The combination of straightforward contract language, clear product definitions (ShortFlex and LongFlex), and supportive platform demonstrations helped participants feel confident navigating the offer structure.

Feedback gathered during the FSP feedback interviews emphasized that PowerShare's communications and structure helped remove uncertainty and reduce perceived risk. Selections from interviews:

- A greenhouse Participant described the experience as "fun" and "like playing the market," reflecting how clear instructions and good market interfaced turned participation into an engaging process rather than a bureaucratic hurdle.
- Another Participant confirmed that the program's onboarding and support were "very good" and that the availability of the team to answer questions quickly helped keep participation smooth.

Importantly, nearly all participants indicated that they would participate again if PowerShare were to continue. Many also shared that, with more time and experience, they would seek to increase their participation quantities or enrol additional assets. Aggregators noted they had other customers ready to participate but that the program's planned trading length and stacking constraints were limiting factors.

Participants viewed PowerShare as a program they could build into their long-term operational planning - a strong indicator of trust in both the model and the team facilitating it. This outcome highlights the critical role of communication and education in the success of local flexibility markets and stands as one of the key victories of the project.

Achievement 2: Successful Demonstration of Distribution-Level Flexibility Procurement

PowerShare moved beyond theory and executed live, meter-validated trades on Essex Powerlines' (EPL's) distribution grid. Over the approximately 315 ShortFlex activations representing nearly 475 MW, PowerShare successfully demonstrated that a local flexibility market can operate reliably at the distribution level through real, validated trades without relying on traditional procurement models like annual auctions. Using the NODES platform, the project executed live activations through both energy and availability products. These activations were metered, validated, and settled through automated processes using existing LDC systems and the NODES Platform, ultimately delivering monthly payments to participants for their flexibility services.

Importantly, the project maintained a no-penalty, payment-reduction curve structure, which provided a fair and accessible on-ramp for non-traditional resources while still incentivizing delivery performance. This approach contrasted with the 'all-or-nothing' penalty models of wholesale DR programs, helping to de-risk participation for small and medium-sized DERs and confirming the viability of market-based flexibility procurement at the local level.

The outcome confirms that distribution-level flexibility can be procured reliably through open, continuous allocation tenders and automated ShortFlex offers. The successful delivery of services under this model provides a scalable template for other Local Distribution Companies (LDCs) seeking to harness distributed resources as non-wires solutions (NWSs) and contribute to system resilience and local constraint management.

Achievement 3: Wholesale Demonstration and Coordination Methodology Successfully Developed

While full wholesale participation ("stacking") was out of scope, the team nonetheless implemented a credible Transmission-Distribution (T-D) coordination framework informed by the IESO TD Working Group draft protocols. NODES packaged qualified DER offers and, at 10:00 day-ahead, generated a simulated Availability Declaration Envelope (ADE) file that mirrors IESO processes. At T–120 minutes to dispatch (respecting the IESO mandatory window) the platform issues a second, gate-closure submission containing updated price/quantity pairs and any LDC-directed volumes at a floor price. This end-to-end rehearsal demonstrates how local markets could surface distribution-connected flexibility to provincial operators without transferring commercial risk to the DSO.

Achievement 4: Scalable Software Integration with NODES and Utilismart for DSO Activities with Existing Infrastructure

A major technical victory was achieving automated settlement using EPL's existing Advanced Metering Infrastructure (AMI) rather than installing new 5-minute revenue meters. Utilismart now delivered daily CSV extracts (15-minute granularity) into the NODES "Meter Data Hub," where they are translated into settlement reports. Custom logic averages each 15-minute read into three 5-minute proxies when finer granularity is required. This light-touch integration enabled monthly invoicing directly from the NODES Platform and a clear scalability path by which future DSOs can implement a similar market with zero additional hardware so long as they are sufficiently enabled with forecasting and meter data submission tools. The success of a software-first approach lowers adoption costs for small resources and positions PowerShare as a replicable model for other utilities that wish to unlock flexibility without an overhaul of their metering.

The next generation of AMI is expected to enhance the DSO's capability even further. Prospective DSOs should be encouraged by the success of PowerShare to consider AMI as a major enabler for NWS programs, and to incorporate DSO-enabling functions to forthcoming procurements.

Achievement 5: Continuous Participant Intake Enabled Market Growth and Increased Liquidity

The decision to allow continuous participant intake throughout the trading period, rather than restricting onboarding to a pre-trading registration window, proved to be a significant success. This enabled the market to evolve organically as interest grew and allowed the project team to respond to real-time constraints and emerging opportunities during active operations. As a result, the project was able to onboard progressively larger resources over time, including the direct enrolment of a large greenhouse facility into a LongFlex contract during the market's operational phase.

This continuous intake model allowed for flexibility in participant recruitment and supported the enrolment of new Flexibility Service Providers (FSPs) in a way that increased market liquidity and competitive dynamics. As more participants joined, including aggregators and commercial operators, the range and volume of offers expanded, resulting in a deeper pool of available flexibility and greater responsiveness to procurement signals. The team also observed increased day-to-day interest and engagement from FSPs, particularly as they became more familiar with the "daily trading game" through the ShortFlex product. This demonstrated that allowing new participants to enter the market during its operational window not only improved scalability but also contributed to an ongoing learning and engagement cycle.

6. Looking Back

Knowing what you know now, what specific decisions/actions would you have changed/taken differently? Do not delete entries from previous milestones, rather, copy the table for the new milestone and populate the fields.

Milestone 1

Reflection 1: Balancing Technical and Regulatory Focus

During the initial stages of work the project team initially concentrated heavily on technical details such as the setup of market rules and operational integrations in SmartMAP, which is the DSO operational tool hub for Essex Powerlines. This focus on the program framework and technical infrastructure was necessary to support DSO functionalities like the meter data submission to NODES or to manage the intake process.

However, this intense focus on technical details resulted in the team not immediately recognizing the requirement of submitting a request for a Deferral and Variance Account (DVA) to the Ontario Energy Board for the specialized circumstances of PowerShare. Perhaps the team understood the OEB's May 31, 2022 letter confirming PowerShare is considered distribution activity by OEB Staff as sufficient regulatory guidance; allowing the team to so intensely focus on the technical and rule design of the project. However, once the DVA application was proven essential for regulatory compliance and the financial arrangement of the project, the manner of structuring the DVA was not clear to the team.

The PowerShare team recognizes that while their focus on the technical aspects was necessary, an earlier submission of the DVA could have garnered more timely regulatory feedback and possibly accelerated regulatory approval processes to recover the cost of power. This insight has been incorporated into the project's ongoing and future phases, ensuring a closer alignment between technical development and regulatory submissions to enhance project execution and scalability.

See Regulatory/Policy Lesson "Defining a mechanism for recovery of cost of energy and capacity services within Local Energy Market Demonstration" for more discussion of the DVA.

Reflection 2: Expanding project area, overly focused on Leamington constraints

PowerShare was designed with a focus on existing constraints in the Leamington area. The highly localized approach was beneficial for focusing the project team on specific issues but inadvertently limited the scope of the project market and its applicability to the larger, notably constrained Essex County region.

Given the immediate needs and significant constraints of Leamington, the area was a logical starting point for deploying the Local Energy Market demonstration. However, the narrow focus restricted the integration of numerous and diverse Distributed Energy Resource (DER) assets across Essex Powerlines' service territory. Additionally, Project learnings and engagement with aggregators highlight that aggregators require a larger market scale to begin effective integration. Additionally, according to the learnings of NODES in European projects, aggregated residential resources are essential for scaling Local Energy

Markets and integrating electrified resources. The limited geographic area posed a challenge for attracting and incorporating these aggregators.

Looking back, the team acknowledges that an expanded geographic scope could have provided valuable insights into the scalability of the DSO model and its applicability to regions experiencing similar constraints earlier. A wider market area would have facilitated better integration of diverse DER assets, enhanced market competition, and improved market liquidity at the early stages of PowerShare. This lesson is essential for future iterations of Local Energy Markets where a more inclusive, regional, or cross-LDC approach could enhance the attractiveness and effectiveness of a Local Energy Market.

Reflection 3: Transforming Initial Interest into Active Participation

PowerShare made a specific effort to engage potential participants and stakeholders during this Milestone. We held detailed discussions and engagements early on to ensure all participant candidates understood the market design and the participant-facing technical aspects of the platform. Cross-team market design work covered permissive asset participation requirements, metering requirements, product duration, and minimum bid sizes to enable a diverse array of distribution-connected assets. These early meetings highlighted the importance of engaging DER asset owners in the Leamington area - a focus that remained central throughout the market design process.

During the project application phase, we received many letters of support from potential participants indicating strong initial interest. However, these expressions of support did not always translate into active participation. Despite our extensive groundwork, there is always room for improvement. This experience highlights the importance of continuous and wide participant outreach, not just for initial engagement but throughout the project lifecycle.

Looking back, we recognize the opportunity to further enhance participant outreach. Engaging a broader range of participants earlier and increasing the frequency of our engagement activities might have facilitated earlier trading and attracted more candidates. Nonetheless we recognize the significant effort put forth understanding that we operated at our highest capacity given the constraints.

Milestone 2

Reflection 1: Intentions and Learnings from the Inclusion of BESS Development in PowerShare

The inclusion of Battery Energy Storage Systems (BESS) in the PowerShare project was a strategic decision aimed at showcasing the role of customer-owned flexible Distributed Energy Resources (DERs). From the outset, BESS integration was seen as an opportunity to demonstrate how these systems could provide critical grid services (LongFlex and ShortFlex in PowerShare but including future services such as frequency regulation or energy arbitrage) while also offering direct economic benefits to municipalities and businesses. The project envisioned BESS acting as a cornerstone for the local flexibility market, capable of dispatching stored energy during high-demand periods and addressing grid constraints in areas like Leamington. Beyond their technical potential, the BESS installations were expected to encourage local investment in energy services, serving as a public example of the opportunities and value DERs present to businesses and municipalities.

While the eventual removal of BESSs from the project's scope represented a shift in priorities, the effort still yielded valuable insights and paves the way for future deployments. One of the most promising BESS candidates was a Mobile BESS (MBESS) solution which was owned by an affiliate of an Ontario Local Distribution Company (LDC) for a since-concluded innovation project. The MBESS was designed as a containerized solution which could easily be moved between sites to meet temporary or transient demand. It had concluded its use in the innovation project and its use in PowerShare represented a promising second life for the solution. The plans for connection, transportation, and contractual arrangements for its PowerShare operation were in place and nearing completion when the BESS activities were ultimately taken out of the amended scope and timeline for the project.

The lessons from the BESS development activities underscored broader structural and regulatory hurdles facing DER integration, such as difficulties securing host commitments and navigating complex permitting and insurance requirements. For instance, the extended timelines required to align stakeholder interests with the project's goals often exceeded the capacity of local businesses to engage, particularly given the investment horizons required. Similarly, municipal readiness issues—such as the need for clearer environmental assessments and emergency response protocols—highlighted gaps in the ecosystem supporting large-scale DER adoption. Despite these obstacles, the team remained focused on extracting learnings to refine future approaches, including improving business case development and stakeholder engagement strategies.

Crucially, the PowerShare team prevailed in demonstrating market design and flexibility principles despite the removal of BESS from the project. By leveraging other DER types, such as demand response assets and lighting curtailment, the team was able to test and validate the functionality of the NODES platform and the local market structure. The inclusion of BESS, remains an optimistic and bold initiative that strengthened the foundation of future DER integration efforts, informed the path forward for flexibility markets, and strengthened the capacity of local stakeholders to consider DERs as investments in the future.

Milestone 3

Reflection 1: Reevaluating the Minimum Participation Threshold

A key principle of PowerShare's design was to promote inclusivity by setting a minimum participation threshold as low as 1 kW with the intent of allowing broad access to the flexibility market, including small-scale DER owners and aggregators with micro-assets. However, experience of participant recruitment, intake, and operations demonstrated that no participants ultimately engaged at this scale.

While philosophically aligned with the goal of enabling wide DER participation, the administrative and operational effort required to support small-scale offers was not justified by actual market interest. The low threshold also introduced unnecessary complexity in participant outreach and created confusion in industry communications, where the perception of wide eligibility did not align with the practical realities of system needs or aggregator business models.

As recruitment progressed, several aggregators expressed interest primarily in larger aggregated portfolios and consistently focused their engagement around multi-hundred-kilowatt to megawatt-scale opportunities. None of these potential participants expressed intent to operate down to 1 kW, even in an aggregated format. Feedback from an aggregator during intake discussions confirmed that they were unlikely to pursue resources below their existing minimum portfolio thresholds due to the overhead costs of managing small-scale assets relative to the revenue potential.

Similarly, direct outreach to growers and commercial participants reinforced this finding. This group of participants' curtailment or generation offers consistently exceeded several hundred kilowatts. None of the participant intake discussions, nor the intake forms received, indicated serious interest at the sub-100 kW level, let alone at 1 kW. Scale was also noted as a primary enabler for greenhouse grower participation, where the multi-MW scale of one participant allowed them to balance operational needs while still receiving an appreciable revenue for the flexibility service.

Additionally, early outreach materials and the marketing strategy referenced the low eligibility threshold, requiring clarification in multiple participant conversations and leading to additional effort to realign expectations. In several cases, prospective participants misunderstood the flexibility market as being designed for individual household-scale DERs rather than aggregated, commercial, or industrial assets. This led to follow-up explanations and, in some cases, disengagement from candidates who were initially curious but ultimately not equipped to offer flexibility at scale.

Future flexibility programs should reflect on this learning by adopting a higher minimum participation floor, likely in the range of 50 kW to 100 kW for individual offers, and potentially higher for aggregators depending on the service. This adjustment may promote onboarding efficiency, reduce administrative complication, and improve clarity in public and industry communications. Recruitment efforts and participant education should also emphasize realistic participation thresholds to align with the market segments most likely to engage.

This learning reinforces that although accessibility and inclusion remain important goals, success depends on matching program structure to the operational realities and business models of the flexibility providers who can most effectively contribute to system needs.

Reflection 2: Incentive Design and Non-Penalty Approach to Underdelivery

Another major design decision for PowerShare was to lower participation barriers by the intentional absence of punitive penalties for underdelivery. This fostered early engagement from a wide range of DER owners and aggregators and was critical to the success of the fledgling flexibility market. It encouraged initial participation from growers and aggregators who may not have otherwise engaged in a flexibility market due to concerns about risk exposure, unfamiliarity with market operations, or technical uncertainty regarding their ability to consistently deliver.

The Activation Payment reduction curve, which provided 100% payment for 90%+ delivery and scaled down payments for lower delivery percentages, was structured to balance incentive without penalization. This ensured that even partial delivery was compensated in relative proportion to performance, while also providing the space for participants to build confidence with the operational and settlement processes.

However, experience during the project highlighted a behavioural risk that should be addressed in the design of future Local Energy Markets (LEMs): the strategic alignment of offers to periods where participants anticipate lower than usual demand due to operational factors unrelated to the market signal. For example, in interviews and intake discussions with greenhouse participants, there was recognition that certain production cycles or operational decisions (e.g., shutting off lighting ranges for multiple days due to favourable growing conditions) would naturally result in lower demand relative to their historical baseline. Offering into the market during these known low-demand windows would enable these participants to achieve demand reduction payments without requiring any additional curtailment action, essentially receiving compensation for conditions that were already planned or incidental.

While no deliberate exploitation of this feature was observed during the pilot, the structure of the baseline methodology and payment reductions could (if left unchanged in a formalized market) create incentives for "strategic baseline management" rather than genuine flexibility delivery. Participants might selectively offer during periods where baseline demand is elevated but expected actual demand is temporarily low due to operational plans, thereby optimizing payments without contributing meaningful responsiveness to grid conditions.

Despite the abovementioned risks of "strategic baseline management", this type of activity resembles another product used in some of NODES' European flexibility markets - the "maximum usage" contract. Even without demand response (or other dispatchable resources') activations, knowing the ceiling of a participant's demand remains valuable for system operators. This insight could inform future product development, such as maximum usage contracts that support forecasting and planning without structurally enabling non-delivery-based participation in a market.

The baseline approach of a five-day average of prior weekdays was accessible and easy to administer -- appropriate for the demonstration phase. However, the interviews and operational feedback also highlighted that this method may not fully account for variability driven by growing schedules, weather conditions, or automation overrides in systems such as greenhouse lighting controls. For instance, a grower noted challenges in predicting their own demand in real-time due to the complexity of their automation systems and a lack of granular visibility into current usage. This underscored both the risk and opportunity of strategic offer timing.

For future LEM design, we recommend evolving the non-penalty underdelivery structure toward one that:

- Further tightens performance-based payment scaling to reward actual delivery more robustly, respecting market maturity.
- Implements optional in-day adjustments or other baseline mechanisms to avoid strategic alignment of offers to known low-demand periods.
- Considers introducing a performance score, rolling average, or other appropriate incentive mechanism to boost delivery effectiveness and/or baseline accuracy as a precondition for maintaining eligibility for higher availability payments.
  (Note: A "reliability score"-type metric has been noted as successful at incentivizing participation/response in event-based customer-side flexibility programs in Ontario)
- Explores structured availability products separate from activation-based products, clearly differentiating between true flexibility provision and operational insight (e.g. forecasting, planning inputs) services.

This learning demonstrates the value of the pilot's low-barrier approach while pointing to necessary evolutions in incentive or baseline design to support credible, reliable, and efficient market outcomes in a fully operational LEM.

Reflection 4: Price Discovery and Maximum Activation Pricing

A challenge identified in trading was setting an appropriate maximum activation price in the absence of historical pricing data for local flexibility services. To balance market realism with budget control, LongFlex included a maximum activation price of $1000/MWh to $2000/MWh though offers were expected to land closer to $300/MWh on average to align with the project's planning assumptions.

This ceiling was meant to cap budget exposure while allowing participants the freedom to test the market. However, several participants submitted offers directly at the maximum price. This validated an expectation where participants uncertain about the true market value of their flexibility would default to the highest allowable price to avoid undervaluing their capacity.

Discussions with participants suggested that this may have been driven by several factors:

- Inexperience with flexibility markets or price-setting strategies.
- Uncertainty about how competitive the offer stack would be, particularly during the early stages of recruitment.
- Perceived operational risk or opportunity cost, where participants may have been reluctant to commit to lower prices without a clear understanding of the frequency of activations or potential value of their service.

While price ceilings were necessary to manage risk and test participation behaviours, the experience highlighted the importance of providing clearer price guidance and education on competitive offer strategies. Future markets may benefit from including:

- Indicative price ranges or historical data (once available) shared transparently with participants.
- Education sessions on bidding behaviour, price discovery mechanisms, and market competitiveness.

- Consideration of graduated ceiling pricing for different products or seasons to reflect system need more accurately.

The market operation phase confirmed that without clear price signals, some participants will err on the side of caution and offer at the cap. While this behaviour is understandable, a formalized market should aim to foster competitive price discovery that reflects true cost and willingness to deliver, rather than uncertainty or strategic ceiling bidding.

Reflection 5: Participant Recruitment and the Need for Clearer Revenue Signals

Participant recruitment for PowerShare was one of the most challenging and instructive aspects of the project. While the project team engaged in targeted outreach across multiple customer classes - greenhouses, aggregators, commercial facilities, battery operators, among others- overall participation volume remained lower than anticipated during the early phases of market operation. Despite strong support from early adopters and positive feedback from active participants, many prospective Flexibility Service Providers (FSPs) chose not to proceed past initial interest. In hindsight, there are several factors that limited recruitment and which future programs should aim to improve.

One of the most frequent requests from prospective participants (particularly aggregators and mid-sized commercial customers) was for a firm estimate of expected revenue. While PowerShare was designed with pricing flexibility to encourage a real market dynamic, and while participants were given maximum and average activation prices ($2000/MWh for LongFlex activations, $300/MWh average for ShortFlex), many prospective participants found this too abstract or hypothetical to base an investment or staffing decision on. The project team emphasized the market's flexible design and the pilot nature of procurement, but in retrospect, this may have contributed to a sense of uncertainty among candidates.

Even when we were able to provide modelled examples, this information was often too general. For instance, a modelled possibility of a 250 kW resource receiving $300–$600 per month in LongFlex availability payments, plus per-MWh activation revenue. Prospective FSPs frequently asked: "How many activations can we expect?" or "How much will I actually make each month?" Without historical data or a guaranteed revenue floor, some businesses found it difficult to prioritize participation amidst other internal demands. Aggregators expressed that they could not justify the time required to enrol customers without greater clarity on potential returns.

Additionally, while we conducted several outreach rounds including onboarding webinars, targeted greenhouse meetings, and aggregator consultations, we now believe there were missed opportunities to engage participants with stronger customer-facing collateral including more tailored revenue scenarios, case studies, and video explainers. Likewise, several interviewees expressed that availability pricing was not competitive enough relative to wholesale programs such as the IESO Capacity Auction, further dampening interest from those with flexibility experience.

Ultimately, we did what was feasible at the time given the pilot constraints, the absence of prior local market data, and the evolving status of regulatory spending approvals. However, we believe that future programs can improve recruitment by:

- Offering clearer pricing benchmarks, with modelled revenue ranges by asset size and service type.

- Publishing real-time or cumulative market insights, such as average cleared prices, activation frequency, and paid volumes over a longer term of active trading. Cumulative market insights, such as volumes and average prices down to weekly aggregation are publicly available on NODES website.
- Creating streamlined onboarding tools and readiness guides tailored to different customer profiles (e.g., growers, BESS, aggregators).
- Coordinating with trusted intermediaries such as sector associations to co-promote participation.
- Providing, as far as possible, realistic forecasts on number of activations, presumed necessary volumes over a given time-period or similar, together with indicative prices. This could be done by functions like the NODES constraint publication service.

Building a local market from the ground up inevitably involves an element of uncertainty. But with greater transparency, targeted tools, and stronger onboarding incentives, we believe future recruitment efforts could convert a higher percentage of initial interest into active participation.

Reflection 6: Learnings from the Sequential Market Design Approach

At the outset of PowerShare, the project design included two market demonstration phases with differing coordination pathways: a coordinated market design, in which DSO and TSO scheduling activities would occur simultaneously, and a sequential market design, in which the DSO would evaluate and act on local flexibility needs before surfacing any remaining technically qualified DER capacity to the TSO. Although both models were included in the project design, ultimately only the sequential model was implemented for a single demonstration phase.

In practice, this proved to be a valuable and well-aligned decision. As PowerShare progressed, it became increasingly clear that the sequential model was not just easier to implement in the pilot setting, but it was also more directly aligned with the evolving policy and technical frameworks emerging from the IESO's Transmission-Distribution Working Group (TDWG). TDWG draft protocols consistently emphasize the application of local system needs, articulating a process where the DSO evaluates and reserves flexibility for its own purposes before making outstanding technically qualified capacity visible to the IESO. This mirrors PowerShare's structure almost exactly, validating the foundational design of the project and reinforcing its relevance as a practical model for future DER integration.

Under PowerShare's sequential design, flexibility procurement began at the DSO level, with EPL identifying local constraints, issuing Seasonal LongFlex tenders to secure availability in advance, and then running daily ShortFlex activations based on SmartMAP congestion indicators and identified price signals. Only once these local needs were addressed did NODES generate simulated Availability Declaration Envelopes (ADEs) and gate closure submissions to the IESO, including any capacity not already reserved. This one-way, staged communication model minimized integration complexity while maintaining clear operational boundaries between the DSO, the TSO, and market participants.

Importantly, this model also reduced risk to DERs and aggregators, who could offer into PowerShare with the assurance that they would not be over-committed or subject to conflicting dispatches from both system levels. Participants were only surfaced to the simulated IESO layer if they had not already been activated or contracted by EPL. This improved trust in the platform and streamlined contract management. Moreover, it validated a key principle for DER alignment across systems: distribution-first visibility and override authority must precede any TSO-level scheduling.

The sequential model further reinforced the practicality of PowerShare's layered product architecture, where LongFlex served as a mechanism for local reservation and ShortFlex enabled day-ahead or intra-day dispatch. This separation of availability and activation allowed market operations by the DSO and TSO clearly separate and definable. In coordinated market designs, the merging of procurement timelines often results in opaque optimization logic and increased dependency on shared real-time data. In contrast, PowerShare's staged process enabled maximum benefit with minimal communication overhead.

While testing a more integrated or coordinated model may be a valid direction for future pilots, the experience in PowerShare suggests that a sequential design is not only sufficient, but in many cases preferable, particularly for first-mover utilities and pilot-stage DER markets. It offers a lower-friction path to integrated grid operations, supports participant confidence, and aligns cleanly with current regulatory expectations. As such, the sequential model should be seen not as a simplified solution, but as a foundational structure for operationally sound and policy-ready DSO-led flexibility markets.

Reflection 7: Learnings from the Transmission-Distribution (T-D) Coordination Approach

A central learning from the PowerShare pilot was the importance and complexity of defining a workable Transmission-Distribution (T-D) coordination approach that reflects local operational realities, emerging provincial market frameworks, and best practices from more established flexibility markets in other jurisdictions. One of the project's original goals was to explore how a Distribution System Operator (DSO) could surface Distribution Energy Resource (DER) flexibility to the provincial system operator (TSO) in a structured, transparent, and non-conflicting way. Through the design and testing of a simulated T-D interface, PowerShare contributed meaningful insights into how distribution-connected flexibility can participate in wholesale markets without compromising local grid reliability or participant accountability.

PowerShare adopted a sequential coordination model (described in the previous reflection), but critically, this included the development of a simulated interface between the NODES market platform and IESO market processes, modeled on the Availability Declaration Envelope (ADE) and gate closure procedures used in IESO operations. The platform was configured to package and submit simulated offers to the IESO at two defined points:

- 10:00 AM day-ahead: Submission of the ADE with total available flexibility, including LDC-directed quantities priced at a floor and all other qualified offers in price-quantity format.
- 120 minutes prior to dispatch: Final update of offers, reflecting any changes due to local constraints, DSO overrides, or participant withdrawals.

This structured approach ensured that the DSO retained visibility and operational control over its own system, reserving the right to override or withdraw offers prior to wholesale submission. This mechanism also avoided the need for a DSO to act as a "superaggregator" bearing commercial risk, instead simulating a pass-through of qualified bids while respecting local capacity requirements and operational constraints.

Key learnings emerged from this process:

1. <u>Platform-driven coordination is feasible and replicable</u>
   The pilot proved that a DSO could use platform-based scheduling logic to isolate and forward DER offers to a TSO in a consistent, recognizable, and TSO tool-consumable format. The use of SmartMAP for congestion detection, coupled with NODES for qualified offer assembly, demonstrated that DSO-

to-TSO handoff can be systematized without continuous real-time integration.

2. Wholesale eligibility requirements are a major barrier for DERs
   Many of the participants recruited during the pilot were not able or willing to meet IESO-level telemetry, metering, and registration requirements. Even after relaxing many of the original market participation constraints, the number of DERs that could be considered wholesale-eligible remained low. This highlights the need for stacking protocols and eligibility exemptions that reflect the operational distinctions between local and provincial needs.

3. Coordinated messaging reduces duplication of offers and conflicts
   By allowing the DSO to perform the first evaluation of DER offers (including LongFlex reservations), the system avoided the risk of over-committing a resource to both the DSO and the TSO. Participants were never required to make a judgement call about which offer to prioritize; PowerShare ensured they were only surfaced to the IESO once local needs were satisfied.

4. The IESO-TDWG draft frameworks are moving in this direction
   PowerShare's coordination model reflects the Transmission-Distribution Working Group's emerging principles, especially the emphasis on DSO-prioritization, structured data handoff, and role clarity between the system levels. The pilot provided a real-world illustration of how those principles can be implemented using commercially available tools and standard operational timelines.

5. The simulation approach avoided regulatory barriers while testing integration logic
   Rather than attempt live IESO integration, which would have triggered compliance obligations and added procedural complexity, the project focused on mock submissions and reconciliation reports, allowing EPL and NODES to validate the technical and procedural elements of T-D coordination without the risk or delay of formal market registration.

Looking ahead, these learnings suggest that T-D coordination does not require a fully co-optimized or deeply integrated system to be effective. A structured, sequential process with clear timelines and role definitions is both achievable and aligned with regulatory expectations, today.

Reflection 8: A coordinated T-D market as an alternative to Sequential Coordination of Flexibility Procurement

Building on the insights from Reflections 6 and 7, we recognize that a coordinated market structure - where distribution and wholesale actors clear flexibility simultaneously- remains a viable alternative to the sequential coordination demonstrated in PowerShare. A coordinated model could identify clear patterns and potential synergies between local and provincial flexibility needs, leading to deeper insights on desirable grid operations or configuration.

In practical terms, an always-on link between a distribution level market and the Real Time Energy Market (RTEM) or other wholesale services could harness DER value more effectively than sequential hand-offs. Though PowerShare demonstrated the sequential coordination, international experience supports this direction. In Finland, Fingrid (TSO) and Helen Sähköverkko (Helsinki DSO) are piloting a fully coordinated congestion management market that clears 400 kV and 110kV bottlenecks in a single process. Their early results suggest that simultaneous trading can address real constraints more efficiently than separate, sequential procedures. A comparable trial in Ontario would help determine whether similar benefits materialize here and what data sharing or procurement roles are required to support them.

Reflection 9: Recognizing that time is essential to build liquidity in a new market, especially in a small grid area

Outreach for PowerShare was a years-long process, beginning prior even to the Grid Innovation Fund application. Following our continuous-intake process, it continued through to the end of Milestone 3. PowerShare began live, non-test trading in July 2024 and reached 10 MWh of monthly activations by October 2024 following the onboarding of several new FSPs. In NODES' experience, this trajectory is consistent with other LEMs, where it typically takes time to recruit FSPs and bring them to a state of operational readiness for trading flexibility.

This challenge is particularly pronounced when the recruitment area is geographically limited and relatively low on number of potential participants. Smaller areas inherently exclude many potential FSPs and aggregators - some of whom may manage large portfolios of DERs/assets, but not enough within the target area to justify participation. As such, expanding the geographic scope for flexibility procurement and allowing sufficient time for FSP recruitment and operational onboarding is critical, especially when both the LDC and FSPs are relatively new to the domain.

While one could argue that solving local grid constraints naturally requires a narrow recruitment area (an observation reflected in the PowerShare experience), a more mature market would likely see faster and broader participation. The FSPs who ultimately engaged in PowerShare were early movers and first time adopters in the Leamington area. Future projects could benefit from recruiting early adopters and first movers across a wider grid area, using their positive experiences to attract more cautious FSPs in subsequent phases. This approach could significantly increase market liquidity in future seasons.

7. Collaboration & Acknowledgement

In the table below, acknowledge exceptional individual contributions from the project team and partners. For example, acknowledging the individual contributor that conceived and implemented a solution to a challenge applicable to this milestone, ideation of novel methodology/process that improved the success of the project, or contributed valuable domain knowledge that mitigated a problem in the future. Do not delete entries from previous milestones, rather, copy the table for the new milestone and populate the fields.

Milestone 1

Contributor 1 Name & Organization: Jacob Godfrey, Essex Power Corporation

In this milestone we would like to acknowledge Jacob Godfrey who played a crucial role in the success of the project through his meticulous preparation and coordination efforts. Jacob's dedication in crafting agendas, spearheading meetings, and preparing minutes for nearly all project meetings reveals the work of a phenomenal coordinator. His diligent work provided a clear and consistent record of our progress and decisions, ensuring that our discussions were organized and documented thoroughly.

Despite onboarding to PowerShare well after the GIF submission and design, Jacob hit the road running as the primary drafter and coordinator of the market rules package - a fundamental component of our project. His efforts in organizing and reflecting the outcomes of design workshops in the rules package were instrumental in shaping the project's framework between the DSO and Platform Rules. Jacob's ability to coordinate between various stakeholders and ensure that all points were captured and addressed significantly contributed to the project's success thus far, and the primary achievement of Milestone 1.

Jacob's diligent work not only facilitated smoother project operations but also ensured that we maintained a high level of organization and clarity throughout our efforts. His contributions exemplify the collaborative spirit and commitment to excellence that drive our project forward.

Contributor 2 Name & Organization: Guro Grøtterud, NODES

We would like to acknowledge the exceptional contributions of Guro Grøtterud, whose expertise and project management skills have been invaluable to the PowerShare initiative. Guro brought extensive regulatory experience in European flexibility markets and distribution-transmission coordination, which significantly informed and enriched our project and approach to the energy transformation in Ontario.

Guro's insights into the development and implementation of Flexible Connection Agreements and the Flexibility First approach were particularly impactful. Her deep understanding of these areas helped us navigate complex challenges and align our strategies with proven practices from European markets. By

sharing her experiences and lessons learned from NODES' projects, Guro provided us with a broader perspective that enhanced our planning and execution.
Moreover, Guro played a crucial role in NODES' project management side following the example of her colleague, Sofia Eng, who provided great value as a NODES' Project Manager during the inception of PowerShare.

Guro's expertise and leadership have been crucial in advancing our project. Her contributions not only improved our regulatory and operational strategies but also fostered a collaborative environment through her willingness to share her knowledge.

Contributor 3 Name & Organization: IESO Staff

Our team would like to make a special acknowledgement of the IESO Staff which have had a hand in supporting this project. Not only the Grid Innovation Fund team, who have contributed greatly to the visibility and successful growth of PowerShare thus far, but also a few notable contributors to PowerShare-IESO coordination (non-exhaustive):

- Angeli Jaipargas; for expert insight to IESO market operations and how best PowerShare can identify and simulate the most impactful elements, as well as guidance in capturing the market metrics with the greatest value to the IESO.
- Ali Golriz; for significant contributions to the understanding of Transmission-Distribution coordination design in PowerShare as well as presenting informed and thoughtful questions on the design of the project.

The contributions of all IESO and GIF Staff cannot be entirely enumerated here, but the PowerShare team would like to recognize their efforts in support of the project.

Milestone 2

Contributor 1 Name & Organization: Jorge Vecino Rodriguez, NODES

In this milestone we would like to acknowledge Jorge for his outstanding leadership in the technical development and implementation of the T-D Coordination Module within the NODES Platform. His expertise and dedication have been pivotal in the successful integration of this complex system, which is now a core component of PowerShare.

Drawing upon extensive experience from T-D integrations in Scandinavia, the NODES team has adeptly applied lessons learned and best practices to the T-D module. Their proficiency in incorporating concepts from discussions across European countries has enriched the initiative, ensuring a comprehensive approach to market integration.

The NODES development team navigated the eligibility requirements for RTEM participation and the intricate technicalities linking local and wholesale market rules. Jorge's collaborative efforts with Svein Jørgen Sønning and other technical resources at NODES, alongside the team's ability to translate concepts from our partners at EPL, the OEB and the IESO, have culminated in a robust solution that bridges local market operations with the simulated IESO's RTEM. The resulting coordination module facilitates seamless communication and aggregation between the local and simulated wholesale markets. This milestone achievement reflects Jorge's commitment to innovation and excellence.

We recognize the immense effort invested by Jorge and the team. Their dedication has been instrumental in achieving this significant milestone.

Contributor 2 Name & Organization: Corey Cornellier, Utilismart Corporation

Corey Cornellier emerged as a pivotal contributor during the latter stages of Milestone 2, supporting the integration of PowerShare functions into SmartMAP and advancing SCADA system development. His efforts focused on ensuring that SmartMAP and NODESmarket integrations can react in conjunction with grid infrastructure, enabling near real-time data flows and dynamic decision-making. Corey's contributions to SCADA development played a critical role in sectionalizing grid zones for forecasting, an important capability for the PowerShare market to operate efficiently.

Corey's work bridged the gap between operational grid management and market activities, particularly through the integration of virtual SCADA points. This innovation allowed for interim solutions to real-time metering challenges, enabling the PowerShare platform to visualize local grid constraints effectively. His forward-thinking contributions also laid the foundation for a long-term vision of evolving a self-healing grid with real-time feedback, demonstrating how SmartMAP could evolve to meet the needs of a dynamic grid featuring an active energy market.

His contributions have strengthened the project's technical capabilities, ensuring scalability and resilience as PowerShare continues to evolve. Corey's dedication underscores the collaborative spirit and innovation that have defined the success of Milestone 2.

Contributor 3 Name & Organization: Essex Energy Corporation Staff

Making a special acknowledgement of the Essex Energy Corporation Staff which were instrumental in maintaining momentum in Battery Energy Storage System (BESS) development despite significant headwinds and complexity. Though BESS projects were later removed from the scope of the Grid Innovation Fund, the team recognizes a few notable contributors from Essex Energy to BESS activities and PowerShare generally (non-exhaustive):

- Patrick Casey; for his significant contributions to the technical integration of potential BESSs and to the project generally with his expertise in Wholesale Metering and as an operator of Market Resources. He also sourced a promising candidate BESS in the form of a Mobile BESS (MBESS), then served as a liaison with the MBESS-owning partner. For all these and more, Patrick has been a consistently valuable resource within the PowerShare team.
- Imtiaz Ahmed; for accomplishments in identifying constraints across the Essex Powerlines service territory (existing and forecasted), for managing discussions with alternative energy source proponents such as suppliers of Hydrogen and Hydrogen-fuelled generators, and for valuable analytical insights throughout the PowerShare project.
- Eric Freeze; for his pivotal role in coordinating with potential Battery Energy Storage System (BESS) hosts, developers, and related stakeholders. Eric worked tirelessly to align developer timelines and communications with host expectations, where his proactive communication helped build trust and maintain momentum at crucial stages.

Milestone 3

Contributor 1 Name & Organization: Anthony Clavet, Essex Powerlines

The success of the PowerShare Project owes greatly to the leadership, commitment, and technical expertise of Anthony Clavet, whose contributions have been central across all facets of project design, execution, and engagement.

Anthony has served as the primary project lead on behalf of Essex Powerlines Corporation (EPLC), providing consistent direction and coordination across internal teams, project partners, and stakeholders including the IESO, NODES, Utilismart, DER owners, and aggregators. His leadership has ensured alignment across the multiple working groups—Engineering, Regulatory, Communications, and Software—and facilitated the navigation of complex technical and regulatory landscapes associated with emerging DSO models.

A key strength of Anthony's contribution has been his ability to translate global best practices and emerging learnings into tangible outcomes for the PowerShare project. His participation in international forums, such as the Nordic Energy Day and NODES workshops in Norway, allowed him to bring back valuable insights on flexibility markets, DSO models, and aggregator engagement strategies from leading European jurisdictions. These global perspectives were not only shared with the PowerShare team but directly informed the engineering and market design approach of the project, ensuring that PowerShare was grounded in proven concepts while responsive to local conditions.

Anthony's role as a representative of PowerShare at industry conferences including EDIST, CanREA, and other sector events has been a cornerstone of the project's notability. Through these engagements he has positioned PowerShare as a thoughtful and scalable demonstration model, effectively communicating the project's potential and learnings to a broad audience of utilities, policymakers, and solution providers. His participation in these forums has also created channels for two-way knowledge exchange bringing new ideas into the project while sharing PowerShare's innovations with the wider industry.

Beyond these external-facing roles, Anthony's technical leadership has been demonstrated through:

- Recruitment and relationship-building with key DER owners and aggregators.
- Development and refinement of the PowerShare registration processes and eligibility criteria, balancing accessibility with rigor.
- Oversight of engineering activities including BESS integration, site assessments, and metering strategies.
- Coordination of settlement approaches and resolution of operational challenges, including LongFlex contract execution, invoicing, and participant onboarding.

His hands-on approach, technical competence, and willingness to directly engage with participants have been critical in de-risking project milestones and adapting strategies in response to on-the-ground conditions. Anthony's ability to pair engineering excellence with strategic foresight and stakeholder collaboration continues to be a key factor in the PowerShare initiative's progress and its positioning as a replicable model for DSO frameworks in Ontario.

Contributor 2 Name & Organization: Svein Jørgen Sønning, NODES

The success of the PowerShare Project has also been significantly shaped by the strategic insight, domain and technical expertise, and collaborative spirit of Svein Jørgen, whose contributions on behalf of NODES have been instrumental in aligning the project's market design with emerging flexibility models and international best practices.

As a key representative of NODES, Svein Jørgen has played a multifaceted role encompassing conceptual design, strategic advisory, and cross-stakeholder alignment. His deep understanding of flexibility markets and distributed energy resource (DER) integration has helped ensure that PowerShare's architecture is not only technically robust but also future-ready and scalable.

Svein Jørgen's involvement has been particularly impactful in shaping the market coordination framework, drawing on his experience with European flexibility platforms and regulatory environments. His ability to bridge the gap between high-level market concepts and practical implementation has enabled the project to adopt a more integrated and dynamic approach to T-D coordination.

Through his participation in workshops, bilateral sessions, and strategic planning meetings, Svein Jørgen has provided critical input on:

- The design and evolution of the flexibility market interface.
- Alignment of PowerShare's procurement mechanisms with international methods.
- Integration of the NODES Platform capabilities into the broader Ontario energy ecosystem.
- Strategic positioning of PowerShare within the global conversation on DSO models and local energy markets.

Svein Jørgen's collaborative approach and commitment to knowledge-sharing have also helped foster strong working relationships across project partners, including EPLC, IESO, Utilismart, and DER stakeholders. His contributions have not only enhanced the technical and strategic quality of the project but have also reinforced PowerShare's role as a pioneering demonstration of coordinated flexibility markets in North America.

8. Additional Information

Please provide any information here that is not covered elsewhere in this report (include photos where available).

9. Administration (IESO STAFF USE ONLY)

Report & Submitted Attachments Approved	☐ Yes	☐ No

Payment Amount

Amount:

Signature of Fund staff (IESO)

Name:
Date:

Name:
Date:

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/IESO

Connecting Today.
Powering Tomorrow.