PowerShare DSO Pilot Lessons

Essex Powerlines Corporation

2025-07-11

This project is supported by the financial contribution of the Independent Electricity System Operator (IESO), through its Grid Innovation Fund. However, the views, opinions and learnings expressed in this report are solely those of Essex Powerlines Corporation .

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Executive Summary

The PowerShare DSO Project, spearheaded by Essex Powerlines Corporation (EPLC), marked a pioneering step toward integrating Distributed Energy Resources (DERs) into Ontario's electricity system through a local flexibility market. The project successfully demonstrated the feasibility and effectiveness of Distribution System Operator (DSO) capabilities with existing infrastructure, showcasing a practical pathway for managing grid constraints with Non-Wire Solutions (NWSs).

Central to PowerShare's success were EPLC's partners NODES, Essex Energy, and Utilismart, along with the innovative flexibility market design featuring capacity reservation via LongFlex and near real-time flex activations via ShortFlex. This structure enabled a high level of flexibility responsiveness, with participants consistently delivering flexibility that could be translated into considerable infrastructure investment deferrals through a similarly subscribed business-as-usual program. Such a program could provide an estimated deferral of approximately $2 million at the distribution level, with additional benefits at the transmission level.

Throughout the project lifecycle, valuable insights emerged around barriers and challenges, each translating into constructive lessons for future implementations. Participant recruitment highlighted the initial complexities associated with onboarding stakeholders into novel flexibility markets. High-touch educational processes and uncertainty around financial returns initially slowed participant commitment, suggesting that future programs would benefit from clearer revenue guidance, streamlined onboarding processes, and simplified contractual frameworks. Furthermore, PowerShare provided essential lessons in operational and regulatory domains, particularly highlighting challenges around metering accessibility and real-time data visibility. These challenges underscored the critical importance of accessible, standardized, and timely metering data for effective market participation and operational oversight.

Regarding local and bulk coordination, the sequential Transmission-Distribution (T-D) coordination approach proved not only practical but also strongly aligned with evolving regulatory frameworks. This sequential approach effectively reduced complexity and minimized risk, while ensuring clear operational boundaries and efficient resource allocation between local and provincial markets. This experience suggests a robust foundation for future regulatory refinements, supporting the continued development of scalable DSO markets across Ontario.

Looking forward, the insights gained from the PowerShare pilot position Essex Powerlines and the broader Ontario utility sector to advance confidently toward more expansive and sophisticated DSO market implementations. By addressing identified barriers, refining coordination mechanisms, and continuing stakeholder engagement, Ontario stands to significantly enhance its grid resiliency, sustainability, and responsiveness to future energy challenges through the continued practical implementation of DER-driven non-wires solutions such as PowerShare.

Introduction and Goals

Essex Powerlines has been on a more than decade-long journey toward becoming a "Digital Utility", characterized by progressive investment in advanced technologies, digital transformation, grid modernization, and innovative practices for operations management. Over the years, significant milestones like the deployment of sophisticated capabilities such as a digital twin of our distribution system, implementing a self-healing grid, and developing an array of software-enabled abilities like Electric Vehicle (EV) detection and distribution-level forecasting through our tools -particularly SmartMAP- have firmly established EPLC as a proactive leader in utility innovation.

Inspired by the successful implementation and outcomes of flexibility markets operating in Europe and internationally, EPLC initiated the PowerShare project embodying EPLC's strong proactive and solution-oriented spirit to demonstrate the practicality and viability of advanced local flexibility markets within Ontario's regulatory environment. At the core of the project was the belief that Ontario's small and mid-sized utilities, with sufficient digital capabilities, could today build and operate their own flexibility markets, immediately providing both operational value and significant infrastructure investment deferral opportunities.

Partners

To realize this ambitious vision, EPLC strategically partnered with **NODES**, a Norwegian flexibility market platform provider. NODES brought critical expertise in flex market operations and design, greatly accelerating the effectiveness of the PowerShare initiative.

Furthering EPLC's digital capabilities, **Utilismart** was engaged as a key technology partner to enhance existing DSO functionalities within the SmartMAP toolkit. By integrating advanced forecasting, near real-time analytics, and operational integrations, Utilismart significantly empowered PowerShare to effectively manage and dispatch local energy flexibility resources. Their market enabling tools provided essential operational data and decision support, facilitating seamless near real-time flexibility market operations.

The partnership with **Essex Energy** also played a crucial role in the success of the PowerShare project. Leveraging their experience as a Metering Service Provider in Ontario's wholesale energy markets, Essex Energy offered critical insights in bridging existing assets into the flexibility market.

Goals

The overarching goal of PowerShare was to practically demonstrate that a digitally enabled, mid-sized utility could effectively implement and operate a sophisticated flexibility market, activating real-world (i.e. not simulated) DER-based NWS programs. This included engaging distribution customers, many of whom were non-traditional market participants, fostering a wider spread of DER market participation and sophistication. Additionally, the project aimed to conduct price discovery for distribution-level services to provide economic data to better understand and articulate the value of distribution-connected DER flexibility.

Further goals included:

- Establishing DER market liquidity,
- Prioritizing the continued safe, efficient, and reliable distribution of electricity to customers,
- Improving operational responsiveness and DSO readiness,
- Garnering Ontario-specific insight to operational or regulatory challenges to Local Energy Markets (LEMs), and
- Directly addressing local grid constraints through cost-effective market-driven solutions.

Ultimately, the insights gained from PowerShare were intended to shape future regulatory and market development discussions at the provincial level, ensuring that the practical experiences from this project meaningfully inform Ontario’s ongoing energy evolution.

Approach and Methodology

At its inception, PowerShare was a recognition of the importance and potential of evolving the electricity distribution system toward greater digital sophistication and flexibility. To responsibly explore this evolution, Essex Powerlines adopted a prudent, iterative approach designed to efficiently operationalize the end goal of a local flexibility market. EPLC's confidence in the technical readiness of our staff and tools to deliver supported this decision. Our methodology emphasized practical experience and real-world operation, recognizing that direct engagement in market activities would yield valuable insights beneficial to ratepayers.

Building upon existing distribution infrastructure was central to our approach. We strategically integrated digital platforms and advanced analytics tools, notably linking the NODES market platform with SmartMAP's sophisticated forecasting and digital twin capabilities. This integration enabled the continued reliable and safe management of distribution assets, ensuring ongoing reliability and enhancing the flexibility of the distribution system.

Understanding the critical role policy and regulatory frameworks play in shaping market effectiveness, our methodology prioritized proactive and structured engagement with provincial regulatory and market bodies. Throughout the project, we maintained continuous dialogue with the Ontario Energy Board (OEB) through regulatory applications and meetings with staff. Additionally, we actively participated in the Independent Electricity System Operator's (IESO) Transmission-Distribution Working Group (TDWG). This collaborative approach ensured our real-world experiences aligned closely with evolving policy developments and regulatory requirements.

Overall, PowerShare's approach was characterized by a pragmatic, iterative nature and deep commitment to extracting actionable insights through direct market implementation, supported by an unwavering commitment to safety and reliability. Our approach facilitated a comprehensive understanding of the operational realities and strategic potential of Distributed Energy Resource (DER) flexibility markets, laying a robust foundation for future market scalability and the continued prudent exploration of Local Energy Markets (LEMs).

Results and Quantifiable Outcomes

This section distills the headline figures from PowerShare's seven-month period of live market operation. Over that market operation period, Essex Powerlines contracted meaningful LongFlex capacity and frequently dispatched ShortFlex when local system conditions warranted. Although seven months is a comparatively brief run-time in the lifecycle of a distribution-level market, the aggregate megawatts enrolled, dispatched, and successfully delivered compare favourably to the results reported by other Ontario and international distribution flexibilty programs.

International experience shows that once a clear price signal is established, early successes like PowerShare's quickly strengthen the investment case for additional DERs and attract fresh participation that build momentum for when programs transition from pilot to standing offer. Against that backdrop, the capacity and energy figures that follow demonstrate that a thoughtfully designed, distribution-level market can deliver dependable megawatts and measurable customer value in remarkably short order.

Summary of Flexibility Created, LongFlex and ShortFlex[1]

Table 1 | ShortFlex Dispatched and Delivered (MW, MWh)

ShortFlex:	MW	MWh
Dispatched	474.15	237.08
Validated Delivered	449.30	244.65[2]

Table 2 | LongFlex Reserved (MWh)

LongFlex:	MWh
Reserved	694.61

[1] Note: that figures in the section are sourced from NODESmarket platform-generated settlement reports and may be rounded.
[2] Includes instances of over-delivery.

Quantifiable Outcomes

All-Time ShortFlex Delivery Rate: 95%

The ShortFlex delivery rate of 94.7% represents the delivery performance of all activated offers, calculated by comparing the validated delivery quantity against the committed capacity for all dispatches. This metric includes cases where participants overdelivered (i.e., reduced more load or injected more generation than offered), which demonstrates responsiveness of resources beyond minimum obligations.

The metric excludes instances of negative delivery, such as when a participant's net load increased during a dispatch period, instead counting them as zero. These negative outcomes were tracked separately and not included in the delivery rate calculation, consistent with the payment and settlement framework. This approach was chosen to prevent a small number of outlier events from skewing the overall delivery rate and to reflect the typical, net-positive value provided by participating DERs.

Average ShortFlex Delivery Per Activation: 80%

Median ShortFlex Delivery Per Activation: 89%

ShortFlex Interval Deliverability >0: 92-94%

Across all ShortFlex activations, 92% of dispatch intervals resulted in positive validated delivery (greater than 0 MW) when including test activations. When test activations are excluded, the rate increases slightly to 94%. This metric reflects the proportion of activated intervals where participants delivered net flexibility (curtailment or injection) and is calculated as the ratio of periods with >0 MW validated delivery to periods with <0 MW delivery. Negative delivery intervals where a participant increased load or underperformed during dispatch are counted as zero.

ShortFlex Interval Deliverability >50%: 73%

Across all ShortFlex activations, 73% of dispatch intervals resulted in positive validated delivery greater than 50% of offered quantities when including test activations. When test activations are excluded, the rate remains steady. This metric reflects the proportion of activated intervals where participants delivered net flexibility (curtailment or injection) and is calculated as the ratio of periods with >50% validated delivery to periods with <50%. Negative delivery intervals where a participant increased load or underperformed during dispatch are counted as zero.

ShortFlex Interval Deliverability >90%: 50%

Across all ShortFlex activations, 50% of dispatch intervals resulted in positive validated delivery greater than 90% when including test activations. When test activations are excluded, the rate remains steady. This metric reflects the proportion of activated intervals where participants delivered net flexibility (curtailment or injection) and is calculated as the ratio of periods with >90% validated delivery to periods with <90%. Negative delivery intervals where a participant increased load or underperformed during dispatch are counted as zero.

ShortFlex Pricing

Average Price >0 ($/MWh): 261.39
ShortFlex Median Price >0 ($/MWh): 200
ShortFlex Minimum Price >0($/MWh): 47.22
ShortFlex Maximum Price >0 ($/MWh): 1000

LongFlex Availability Fulfillment Rate: 98%

Percentage of scheduled periods where the resource was available (not withdrawn) for 100% of contracted capacity. Of the remaining 2% (72 periods) with less than 100% available capacity, 45 were caused by a discrepancy in LongFlex signing and settlement logic which created orders previous to the current date at LongFlex signing. If these availability failures are excluded, the Availability Fulfilment Rate approaches 99.3%.

Time from Onboarding to First Activation

To roughly benchmark the ramp up time and friction to local market entry, FSPs are compared from their completion of the Intake Form, the date the Participant Contract was signed, and the date of their accepted test activation. For protection of participant privacy, FSPs are given a number according to a legend which is retained by EPLC. See additional discussion on this Outcome in *Lessons Learned, 1.1.1 Participant Recruitment and Market Maturity*.

Table 3 | Time from First Interest to Contract Signing and First Activation, by FSP

FSP#	First Interest (A)	Contract Signing (B)	First Activation (C)	Length A-B (Days)	Length A-C (Days)
028	2023-09-09	2023-11-15	2024-02-06	67	150
029	2023-09-14	2024-07-10	2024-07-30	300	320
041	2024-02-06	2024-05-22	2024-07-11	106	156
042	2024-03-04	2024-08-21	2024-10-29	107	239

Lessons Learned

This section is organized by broad themes including barriers, value, regulatory takeaways, and market design learnings. Within each theme we highlight representative takeaways that illustrate where PowerShare succeeded, where it encountered friction, and what those experiences mean for future flexibility markets. These summaries are intentionally concise; they are meant to signpost the most consequential insights rather than catalogue every detail uncovered during the pilot.

A more granular record of challenges, mitigations, and qualitative results can be found in PowerShare's public Milestone Reports filed on Essex Powerlines' website: https://essexpowerlines.ca/about/innovation/powershare/. Where relevant, individual lessons in this section reference those documents so readers can trace back to the source material. The narratives that follow therefore represent only the surface layer of PowerShare's learning, interested readers are encouraged to consult the Milestone Reports for the full depth and context behind each lesson.

1.1 Barriers Encountered Across the PowerShare Project Lifecycle

Throughout the PowerShare project, barriers emerged at nearly every stage from early market design and participant recruitment to activation, settlement, and regulatory coordination. While many of these were anticipated in the pilot's original scope, their persistence and interrelation revealed key insights about the institutional, operational, and technical realities of launching a first-of-its-kind DSO-led flexibility market in Ontario. This section groups those barriers into five themes that spanned the entire project lifecycle.

Review additional learnings related to this section in the Milestone 3 Report, by ID and challenge:

- 3, DSO commercial responsibility for assets in IAMs; DSO and platform provider hesitant
- 4, Defining Maximum/Ceiling Price
- 7, Territory Expansion Lesson
- 17, Embedded Distributor Considerations
- 20, Aggregator Portfolios, Prevention of Double Counting
- 23, Technology Aggregators, like EV OEMs are interested in programs like PowerShare but scale poses challenge to integration
- 25, Finding Candidates for participation is the biggest challenge
- 27, Technical barriers to IoT and residential technology aggregators
- 44, Validating Forecast Capabilities - Stress testing how granular the process could go while keeping its efficiency and reliability
- 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
- 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
- 69, Flexibility services are not core business for most FSPs

Overall, any of the barriers PowerShare faced were the expected symptoms of launching a new market in an as-of-yet mature policy and technology landscape. Importantly, each barrier yielded actionable learnings that shaped refinements to the platform, onboarding processes, and market design. Together, these lessons have provided significant value by developing internal competency in DSO activities and T-D coordination, among other benefits.

1.1.1 Participant Recruitment and Market Maturity

From the outset, the project faced difficulty converting participant interest into committed enrollment. Despite a broad intake process, only a fraction of those initially contacted ultimately participated. Barriers included:

- Unfamiliarity with flexibility markets and the PowerShare model, especially among non-traditional participants.
- Lack of firm revenue estimates or historical pricing to support internal business cases.
- High internal lift required from participants to evaluate metering, performance, and contract requirements in the absence of proven incentives.

The team responded with tailored onboarding and education, but it became clear that Ontario's DER ecosystem is still maturing, and many parties remain reluctant to invest time or resources in pilots without clearer return expectations.

Qualitative indicators of these barriers can be found in the onboarding timelines displayed in Table 3, *"Time from First Interest to Contract Signing and First Activation"*. The timelines reflect the early-stage, high-touch nature of launching a first-of-its-kind distribution-level flexibility market. Below are the averages of intake timelines across the four participating FSPs, including non-working days like holidays and weekends:

> Average length from initial interest to contract signing was 161 days, just over 5 months.
>
> Average length from initial interest to first activation was 216 days, roughly 7 months.
>
> Average length from contract signing to first activation was 55 days.

At first glance, these durations may seem lengthy. However, they are expected and explainable given the novelty and structure of the PowerShare pilot. Below we explore some contextual drivers behind the onboarding timeline:

A. Novelty of the Local Market Model

PowerShare represents Ontario's first operational DSO-led flexibility market. Unlike more familiar programs like the IESO's Capacity Auction or ICI, PowerShare asked participants to engage with new products (ShortFlex, LongFlex), uncertain activation patterns, and a platform-based interface (NODES) that was unfamiliar to most. As a result, FSPs required time to learn, consult internally, and assess fit with their portfolios and operations.

B. Lack of Historical Revenue Data

Because the market was designed for price discovery and flexible participation, there was no upfront guarantee of revenue. Several prospective participants asked for detailed modeling of expected returns, activation frequency, and risk exposure. This led to an extended information exchange process where EPL and NODES worked to explain revenue logic, payment structures, and performance obligations, often through multiple onboarding calls and draft contract iterations.

C. Complexity of Metering and Site Readiness

Participants, especially larger greenhouses and aggregators, needed time to confirm telemetry capabilities, metering access, and operational availability. In some cases (e.g., FSPs 029 and 042), multiple rounds of internal coordination and site-level validation significantly delayed readiness, even after initial interest was expressed.

D. Program Design as a "High-Touch Program"

Given its pilot status, PowerShare operated on a case-by-case onboarding model, prioritizing participant understanding and relationship-building over speed. This meant that participants were given detailed walkthroughs of LongFlex and ShortFlex processes, and in some cases, had customized intake pathways based on asset type, load shape, or aggregation model.

Proceed to Lesson 1.1.1 for learnings regarding Recruitment Challenges and related timelines.

1.1.2 Metering and Data Access Challenges

Access to reliable, real-time or near-real-time meter data was one of the most consistent technical obstacles. Lack of visibility into real-time usage also limited many participants' abilities to confidently size offers or track delivery. This reinforces the need for a standardized, participant-facing metering interface in future programs that can provide nearer to real time insight to the DSO and Participants and perhaps can be an item for development in ongoing AMI 2.0 planning.

1.1.3 Coordination Between DSO and TSO Systems

The original project design included both sequential and coordinated T-D market models, but only the sequential model was tested. While ultimately a strength given its alignment with the IESO's Transmission-Distribution Working Group (TDWG) protocols, the process of coordinating with IESO market structures highlighted challenges:

- Lack of formal guidance on stacking or simultaneous participation in IESO and DSO programs.
- Unclear commercial responsibility for DERs when surfaced to the IESO by a DSO (i.e., the "superaggregator" problem).
- Technical hurdles in simulating Availability Declaration Envelopes (ADEs) and gate-closure processes with non-IESO-qualified assets.

1.1.4 Operational and Platform Complexity

Participants reported that while the NODES platform was generally effective, the day-to-day operation of ShortFlex trading introduced appreciable (but not overwhelming) overhead:

- Changing market conditions, short ShortFlex notice windows, and mid-day rebalancing required full-time monitoring that some FSPs could not provide.
- High-frequency dispatch notifications (every 30 minutes) became burdensome during long service windows.
- Some FSPs missed MW opportunities due to offer refresh or scheduling windows that weren't well aligned with their daily routines.

1.1.5 Administrative Burden and Program Layering

Finally, the accumulation of administrative requirements such as contracts, baseline validations, availability declarations, metering approvals, settlement reviews, could outweigh the potential revenue during low price periods or for low-capacity FSPs. For participants operating at the 250–500 kW level, this made PowerShare difficult to justify unless paired with additional value (e.g., stacking, energy savings, operational benefits). This led to the conclusion that smaller FSPs may not be scalable without in-house or aggregator-controlled automation to interface more directly with the market and following user-defined bidding logic to reduce the operational overhead of participating in a flexibility market.

1.2 Non-Wires Solution Value to Essex Powerlines

Across the project term, PowerShare illustrated how dispatchable DER flexibility could help defer infrastructure upgrades, mitigate local and upstream constraints, and offer a scalable operational tool for managing grid growth in areas like Leamington.

At the height of participation, PowerShare secured a total of 9.7 MW of participants, with a maximum of 4.4 MW simultaneously activated in live trading. These volumes represent a meaningful share of the flexibility needed to manage constraints on several feeders in EPL's service territory. Based on avoided infrastructure cost models and drawing from the Ontario Energy Association's 2023 DSO study ("the Study") and internal EPL costing assumptions, 4.4 MW of programmatically available flexibility represents approximately $2.2 million in avoided distribution system investment, equivalent to deferring construction of a new 3-phase circuit across 7 km of territory. If the full 9.7 MW were available and activated simultaneously, the estimated deferral value of the program would rise to $4.85 million.

This flexible demand also contributed measurable benefit at the transmission level. The 4.4 MW curtailed through ShortFlex activations equated to a reduction of 11.1 amps at the 230 kV transmission level, or 5.5% of the total loading on an 80 MVA station rated at 200 amps. Under full activation scenarios, the system could achieve a 24.3 amp reduction; roughly 12% of total constraint relief at the station. Given the Study's valuation methodology, the unit rate of avoided transmission infrastructure cost ranges from $0.1 M/MW to $0.2M/MW. Therefore the operational benefit translated to a transmission-level cost avoidance estimate of $330,000 to $660,000. These figures emphasize the dual benefit of DER flexibility in both distribution deferral and provincial system support.

Operationally, the project confirmed that a 2–3 MW curtailment window during peak conditions is enough to meaningfully reduce feeder load, improve voltage profiles, and avoid overloading station assets. Particularly in growth-sensitive areas like Leamington, where greenhouses and commercial customers place unpredictable demand on infrastructure, flexibility validated a pathway for EPL to 'buy time' on congested assets without immediately committing to capital-intensive upgrades.

However, realizing the full potential of PowerShare as a Non-Wires Solution will require addressing several key barriers identified through the pilot. Recruitment limitations driven by unclear revenue expectations and stacking restrictions meant that participation never reached its full theoretical ceiling. Many DER owners remained on the sidelines due to lack of historical price signals or concerns about market complexity. Metering and data access challenges also prevented some participants from confidently sizing or validating their offers. And while PowerShare's sequential T-D coordination model proved well-aligned with emerging Transmission-Distribution Working Group (TDWG) protocols, broader policy clarity is still needed to support multi-market stacking and reduce concerns over commercial responsibility for DERs surfaced to the IESO. Without these challenges the PowerShare team is confident that the value of a reliable distribution-connected flexibility program would be even more pronounced.

Despite these challenges, PowerShare has demonstrated that local DER markets are a real, dispatchable, and valuable resource. The pilot delivered measurable cost avoidance, enhanced operational control, and laid a practical foundation for future grid planning. With continued investment in participant onboarding, telemetry, and coordination mechanisms, PowerShare has the potential to become a cornerstone in EPL's long-term strategy to manage growth and maintain reliability without always building more wires.

1.3 Regulatory Learnings

PowerShare's market operations provide a meaningful first look at how distribution-level flexibility can offer quantifiable system value while operating within an emerging regulatory framework. From both an operational and financial perspective, the pilot demonstrated that DERs can provide location-specific capacity relief in constrained parts of Essex Powerlines' service territory, particularly on feeders 393M27 and 393M24 and the Leamington Transmission Station, where load growth and greenhouse expansions continue to present localized reliability challenges.

During the demonstration period, PowerShare procured 695 MWh of contracted flexibility through LongFlex tenders and approximately 237 MWh of activated energy via ShortFlex activations. These services were priced dynamically through the NODES platform, resulting in a per-unit average cost of activated flexibility of approximately $240/MWh, excluding platform fees.[3]

From a ratepayer perspective, the pilot imposed minimal direct cost burden. All participant payments and platform integration work were partially funded by the Grid Innovation Fund. If replicated under business-as-usual (BAU) conditions, the total flexibility procurement cost could translate to less than $0.10 per customer per month.[4]

The cost of EPL's contract with NODES, which included platform licensing, onboarding, expertise, and settlement functionality since March 2023 totaled roughly 30% of the cost of a conventional DERMS or SCADA upgrade. We argue that the benefits of the pilot have achieved significant value at relatively low cost. For a fraction of traditional hardware or software solutions, the PowerShare platform enabled automated validation, invoicing, and T-D coordination logic, demonstrating a low-barrier, scalable entry point into non-wires alternatives (NWA) without requiring sweeping internal system overhauls.

Beyond financial metrics, PowerShare aligned closely with regulatory and technical directions from the sector, such as from the IESO's Transmission-Distribution Working Group (TDWG). Particularly in the sequential coordination model, PowerShare ensured DSO-first visibility and decision-making before any DERs were surfaced to the provincial market. This design preserved operational integrity, avoided double-commitment risk, ensured technical deliverability, and demonstrated a viable T-D workflow (see Section C, T-D Coordination Reflection).

In summary, PowerShare demonstrates that a local flexibility market designed around DSO control, participant accessibility, and incremental cost discipline can function as a credible, regulator-aligned Non-Wires Alternative. The pilot not only proved potential deferred capital expenditure but did so at low cost and with growing participant interest. As such, it provides a strong foundation for integrating flexibility into future Distribution System Plans (DSPs) and supports the case for DER enablement within the OEB's ongoing proceedings.

1.4 Recruitment Challenges, Drivers and Overcoming Them

Recruiting participants for PowerShare proved more time-consuming than originally forecast, underscoring how much lead time a first-of-its-kind DER market requires. As detailed in Quantifiable Outcomes "Time from Onboarding to First Activation," the average journey from a prospect's first expression of interest to contract signature was about five months (161 days), and the interval to the first validated activation stretched to roughly seven months (216 days). These timelines are not unusual for programs that demand technical validation, contract review, and operational alignment, yet they illuminate four structural hurdles the pilot had to overcome.

First, market immaturity meant each prospective participant needed high-touch coaching to understand ShortFlex and LongFlex products, baseline logic, and the graduated payment-reduction curve; many had never sold flexibility before.

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[3] Advisory numbers. Combined ShortFlex and LongFlex costs divided by activated MW. Excluding test activations.

[4] Noting that rate impacts of a local flexibility market are more complex than this calculation, and BAU would be supported by infrastructure/capital deferral, potential bulk value, and other factors explored in the OEB's Benefit-Cost Analysis

Second, because the market was intentionally price-forming, EPL could only share broad revenue ranges which proved an uncertainty that dampened commitment, especially when early prices sat below familiar wholesale benchmarks.

Third, technical frictions such as metering system data access, identifying proper meter numbers and engaging with Metering Service Providers (MSPs) added weeks of back and forth.

Finally, stacking restrictions and perceived conflicts with IESO programs made several aggregators hesitant to dedicate portfolios to a local-only pilot.

Looking ahead, shortening this recruitment cycle will hinge on three improvements:

- Clear, upfront revenue examples drawn from real market prices will let prospects gauge returns without exhaustive modelling.
- A standardized intake toolkit combining contract templates, metering guides, and communication material in visual or video format can streamline technical and administrative steps that now require bespoke support.
- Realizing the potential benefit of 'Technology/Type Approvals', introducing pre-qualification tiers or "Fast-Track" onboarding for assets that already meet technical specifications (or that arrive through established aggregators) would allow straightforward participants to move quickly while more complex sites take the time they need.

Taken together, these adjustments should compress the onboarding timeline, reduce friction for first-time DER entrants, and help PowerShare scale from a promising pilot to liquid local flexibility market.

Review additional learnings related to this section in the Milestone 3 Report, by ID and challenge:

- 7, Territory Expansion Lesson
- 8, Defining Participant Payment Cycles within Milestone Payment Structure
- 10, Appropriate incentivization of service delivery, following the "least cost, no penalties or deposits" principle: Availability and Activations Payment Reduction Schedules
- 13, Clear Participant preference for ICI eligibility
- 22, Onboarding Lessons
- 23, Technology Aggregators, like EV OEMs are interested in programs like PowerShare but scale poses challenge to integration
- 26, Finding Candidates for participation is the biggest challenge
- 45, Battery Energy Storage System (BESS) Business case difficult for partners, even with funding contribution
- 47, Battery Energy Storage System (BESS) timelines, unexpected delays in deployment
- 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
- 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
- 60, Large users were interested, wanted multi-MW participation beyond pilot cap
- 61, Continuous allocation of Seasonal LongFlex may reduce competition.
- 69, Flexibility services not core business for most FSPs
- 76, Challenges/Lessons Informed by Participant Interviews (Set 1)
- 77, Challenges/Lessons Informed by Participant Interviews (Set 2)

1.5 Learnings from Sequential Market Design Approach

> As PowerShare progressed, it became increasingly clear that the sequential coordination 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.

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 coordination 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. Once these local needs were addressed, the NODESmarket platform generated simulated Availability Declaration Envelopes (ADEs) and gate closure submissions to the IESO that included any remaining flexibility. 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 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.

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 intraday 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

Review additional learnings related to this section in the Milestone 3 Report, by ID and challenge:

- 2, TD interoperability; how/when do communications with IESO happen
- 16, Adapting the Availability Declaration Envelope alongside DSO purchases, "LDC-directed quantities"
- 30, Defining DSO Gate Closure vis-à-vis IESO Gate Closure

1.6 Learnings from 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 DistributedEnergy 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 at a floor price 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.

A structured, sequential process with clear timelines and role definitions is both achievable and aligned with regulatory expectations, today.

Key learnings emerged from this process:

A. Platform-driven coordination is feasible and replicable

The pilot proved that a DSO can 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.

B. 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.

C. 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.

D. 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.

E. 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.

Review additional learnings related to this section in the Milestone 3 Report, by ID and challenge:

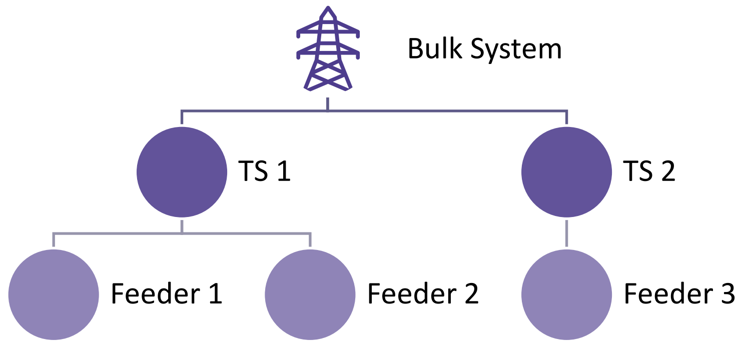
- 2, TD interoperability; how/when do communications with IESO happen
- 15, Defining Wholesale Simulation: triggers for purchases, qualification of offers
- 16, Adapting the Availability Declaration Envelope alongside DSO purchases, "LDC-directed quantities"
- 30, Defining DSO Gate Closure vis-à-vis IESO Gate Closure
- 32, IESO-DSO integration: Discussions related to integration between the EPL market and the simulated IESO Real Time Energy Market (RTEM)
- 33, IESO-DSO integration module in the NODES Platform: Development activities in line with the T-D Coordination Methodology
- 57, IESO dispatch visibility; without knowing Tx dispatches, local flexibility need can be mis-estimated.
- Milestone 3, Achievement 3: Wholesale Demonstration and Coordination Methodology Successfully Developed

Appendix 1 – Market Design Features

This table summarizes principal market design features that shaped PowerShare. Each element, ranging from gate-closure windows and product durations to pricing, was selected to balance operational reliability with participant accessibility. Presented in a simple discussion format, the table offers a concise description of the decision. A more granular record of market design features and the decision making process can be found in PowerShare's public Milestone Reports filed on Essex Powerlines' website: https://essexpowerlines.ca/about/innovation/powershare/.

Element	Discussion
ShortFlex (Energy) Product Duration	Product duration set to 30 minutes, balancing the current energy service durations of 5 minutes and 1 hour and allowing granular dispatch to meet distribution needs.
LongFlex (Capacity) Product Duration	Product duration set to 60 minutes to provide flexibility to participants in defining capacity availability windows. One LongFlex period automatically translates to two ShortFlex periods at ShortFlex market open.
Local Gate Closure	Default expiry time for local ShortFlex sell offers set at 125 minutes prior to delivery. Also a feature of sequential coordination; 120 minutes respecting wholesale timelines to update market offers/bids and an additional 5 minutes for DSO tools to format and submit qualified offers from participants. After Local Gate Closure, offers/bids are available to the wholesale market and are no longer available to the DSO.
ShortFlex Market Open	The ShortFlex market opens 7 days before delivery day. Participants and DSO can submit buy/sell orders any time during that timeframe. Buy/sell orders can be matched any time within the 7 days and become binding contracts for delivery upon matching. For the PowerShare project, ShortFlex buy offers by the DSO were restricted to same-day or day-ahead.

Element	Discussion
Editing ShortFlex Buy/Sell Orders	Buy/Sell orders that have not matched may be edited or withdrawn at any time.
Cancelling ShortFlex Contracts	The DSO and Participant must request cancellation of a matched buy/sell order via email to NODES technical support.
LongFlex Tender Periods	LongFlex can be issued with any period or duration such as seasonal, monthly, or weekly. These are configurable per-tender, and PowerShare featured mostly seasonal tenders but demonstrated short, bi-monthly tenders for test cases and price discovery.
Forced Outage Notifications	Any outage or disruption affecting a matched ShortFlex contract was considered a Forced Outage. Participants were required to provide notice as soon as possible: 48 hours prior to the event if foreseeable, 24 hours following the event if unforeseeable.
Dispatch Notification Frequency and Method	Participants were able to set custom dispatch notifications to text, email, or API methods. They also set the notice timeline, such as upon matching, 2 hours prior to dispatch, 5 minutes prior to dispatch, or any permutation thereof to match operational needs. In PowerShare, most participants opted for 2 hour pre-dispatch notifications.
Continuous Matching	The ShortFlex market was cleared via continuous matching. When a technically qualified sell order met a buy order's criteria, it was automatically matched and scheduled by the platform and removed the matched portions of the orders.
ShortFlex Provides Activation Price Only	ShortFlex orders are for activation price only, availability of resources is implicit in the order's existence. LongFlex obligations automatically create ShortFlex offers for participants.
Nodal Hierarchy	The electricity system was modelled in hierarchic zones or "Nodes". Each node can have parent or children nodes. Assets are registered at the lowest level node and are available to all 'ancestor' nodes. For example, Feeder Nodes < Transmission Station Nodes < Bulk System Node.

Element	Discussion
	Figure 1; Example Nodal Hierarchy 
Resource/Portfolio Logic	Participants register discrete assets for approval by the DSO. When approved, participants self-organized and managed portfolios of assets. Sell orders are published at the portfolio level. Assets may only exist in one portfolio. Portfolios had access to the lowest common orderbook of all assets within it. For example, following **Figure 1; Example Nodal Hierarchy**, if assets were sited across Feeders 1 and 2, the lowest common orderbook would be TS 1. If assets were sited across Feeders 1 and 3, the lowest common orderbook would be the Bulk System.
Portfolio May Have Multiple Concurrent Sell Offers	Portfolios were not restricted by the platform on the quantity, price, or frequency that could be offered. Participants were expected to manage obligations and offers within their available flexibility. Each sell order from a portfolio published to the same period in the ShortFlex market would create concurrent obligations.
Participant-set Expiry Timeline	ShortFlex sell offers allowed participants to set up custom expiry timelines for the offers, in hours or minutes. 2 hours was the default expiry. Unmatched offers at time of expiry would be removed from the ShortFlex market.
Payment Frequency	Participants were paid monthly.
Collateral Requirements, Participation Charges, Non-delivery Fees	Participants were not required to provide collateral or other participation fees. Participants were not charged a fee for underdelivery or non-delivery.

Element	Discussion
ShortFlex Delivery Payment Reduction Schedule	For ShortFlex Contracts, including those arising out of LongFlex Contracts, activated before Local Gate Closure, NODES compared metering data to the Baseline Capacity across 15-minute intervals, regardless of the metering granularity being 5 or 15 minutes (i.e. 5 min intervals are summed three by three to 15 minutes intervals). For each 15-minute interval: Where Delivery is validated for 90% or more of the Contract Capacity of a ShortFlex Contract, the Seller will receive 100% of the Activation Price. Where Delivery is validated for 80% or more, but less than 90%, of the Contract Capacity a ShortFlex Contract, the Seller will receive 65% of the Activation Price. Where Delivery is validated for 70% or more, but less than 80%, of the Contract Capacity a ShortFlex Contract, the Seller will receive 45% of the Activation Price. Where Delivery is validated for 60% or more, but less than 70%, of the Contract Capacity a ShortFlex Contract, the Seller will receive 30% of the Activation Price. Where Delivery is validated for 50% or more, but less than 60%, of the Contract Capacity a ShortFlex Contract, the Seller will receive 20% of the Activation Price. Where Delivery is validated for 40% or more, but less than 50%, of the Contract Capacity a ShortFlex Contract, the Seller will receive 15% of the Activation Price. Where Delivery is validated for less than 40% of the Contract Capacity, the Seller will receive 0% of the Activation Price.
Sequential Design	DSO purchases flexibility first, with remaining technically qualified flexibility passed to simulated IESO.