

A REPORT FOR THE ONTARIO ENERGY ASSOCIATION

DER COMPENSATION: ANALYSIS & RECOMMENDATIONS

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ABOUT THE AUTHOR

Kaleb Ruch is Director, Energy, at Sussex Strategy Group, with over 15 years of experience in Ontario's energy sector. Kaleb holds a Bachelor of Applied Science in Mechanical Engineering from the University of Waterloo and a Master of Public Policy from the University of Toronto's Munk School of Global Affairs & Public Policy.

EXECUTIVE SUMMARY

Ontario's electricity sector is at a pivotal crossroads, facing the urgent demands of reliability, affordability, economic growth, and decarbonization. Distributed Energy Resources (DERs)—including storage, solar PV, demand response, and managed EV charging—are essential to achieving these goals. While Ontario has laid strong foundations for DER compensation through unbundled tariffs and customer choice, significant opportunities remain to unlock the full value of DERs and modernize how they are rewarded.

This report delivers a rigorous, service-driven, and technology-neutral analysis of Ontario's DER compensation framework, benchmarking it against leading international jurisdictions such as New York, the United Kingdom, and Australia. These regions demonstrate the benefits of precise pricing, flexibility markets, and revenue stacking, offering valuable lessons for Ontario's path forward.

Through a detailed mapping of Ontario's compensation mechanisms across four key customer archetypes—from residential net-metered customers to grid-scale front-of-the-meter resources—the report reveals systemic gaps and opportunities for principled reform. It scrutinizes ongoing efforts by the Independent Electricity System Operator (IESO) and Ontario Energy Board (OEB), and incorporates insights from recent policy consultations and market initiatives.

The recommendations chart a practical and sequenced roadmap for reform, including:

- Advancing dynamic price signals and modernizing net metering and Global Adjustment frameworks.
- Introducing locational tariffs and flexibility services to enhance operational efficiency.
- Strengthening governance and market integration of DERs, with clear Distribution System Operator (DSO) roles.
- Accelerating grid modernization while safeguarding consumer interests.

By acting on these priorities, Ontario can transition from today's patchwork of compensation mechanisms to a transparent, financeable, and future-ready system. The proposed reforms will ensure DERs are deployed where they deliver the greatest system-wide value, benefiting ratepayers through a more efficient, reliable, and resilient electricity grid. This evidence-based approach aligns with Ontario's Integrated Energy Plan and positions the province to lead in DER integration and compensation.

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1.0 CONTEXT AND PURPOSE

1.1 Purpose and Framing

Ontario's electricity sector stands at a critical juncture, driven by the non-negotiable demands of reliability, affordability, economic development, and decarbonization. The province's Integrated Energy Plan (IEP) articulates a clear vision for Ontario's energy future that requires a system robust enough to meet today's needs and flexible enough to embrace technological evolution and changing consumer expectations. Within this framework, Distributed Energy Resources (DERs), including storage, solar PV, various forms of demand response and managed EV charging, are essential levers for realizing Ontario's strategic objectives.

DERs are unique in their ability to meet both bulk and local system requirements at once. In contrast to conventional generation, DERs offer capacity, energy, and ancillary services at the provincial scale and the potential to address local needs, such as peak management, congestion relief, and infrastructure deferral. This dual function produces two-way power flows, empowering customers to actively engage with short-term price signals and fundamentally reshaping the province's electricity paradigm—particularly for the distribution systems to which they connect.

The issue goes beyond the integration of DERs and includes the manner in which their value is acknowledged and rewarded. Where they outperform traditional resources, their compensation must transparently and fairly reflect their contribution, preferably without unjustifiably favouring specific technologies. Where DERs do not provide net system benefit, no compensation is warranted.

Through the Minister's Implementation Directives, the province's Integrated Energy Plan (IEP) establishes an unequivocal mandate for the Ontario Energy Board (OEB) and Independent Electricity System Operator (IESO) to construct a robust framework that accurately values and compensates DERs. The OEB must advance implementation of prior recommendations, promote non-wires alternatives, and ensure utility incentives align with whole-system benefits. The IESO is directed to integrate DERs into market and out-of-market opportunities, including participation in capacity auctions, and markets for energy and ancillary services. These directives underscore the imperative to modernize regulatory and market structures, guaranteeing that DERs receive compensation commensurate with the full spectrum of benefits they deliver.

1.2 Ontario Policy Context: Foundations and Gaps

Ontario has already established many foundational elements needed to support a leading DER compensation framework.

Unbundled tariffs separate energy, transmission, and distribution, improving cost transparency and laying the groundwork for more granular price signals. Customer choice under the Regulated Price Plan (RPP), including time-of-use (TOU), tiered, and ultra-low overnight (ULO) rates, permits optional movement toward more dynamic pricing for customers, while preserving predictability for those who prefer simpler rates.

Building on this, IESO is undertaking reforms to enable DERs. The IESO’s Capacity Auction provides a platform for short-term capacity for Demand Response, the Enabling Resources Program (ERP) is opening pathways for storage, hybrids, and aggregated DERs to provide energy and ancillary services; and the forthcoming Local Generation Program (LGP) has the potential to re-contract expiring distribution-connected assets and incorporate consideration for local needs. The Transmission-Distribution Coordination Working Group (TDWG) made concluded its work to avoid conflicting dispatch instructions and to support revenue stacking across wholesale and distribution opportunities. Complementary market rule changes under Market Renewal are modernizing scheduling, pricing, and participation models.

Regulatory initiatives are also advancing with purpose. The OEB’s Electricity Demand-Side Management (eDSM) Stream 2 framework will drive local, utility-led programs that deliver measurable system-wide *and* local benefits. The Benefit-Cost Analysis (BCA) Framework requires distributors to evaluate non-wires solutions on an equal footing with traditional solutions. The Distribution System Operator (DSO) Capabilities consultation is clarifying essential roles, market participation, and whole-system optimization. These coordinated efforts, reinforced by ministerial direction, signal Ontario’s commitment to a coherent valuation and compensation framework for DERs.

Despite this momentum, there is room for improvement. As the OEB notes, capacity, energy, emission avoidance and infrastructure deferral are all at issue for a robust DER valuation framework. The absence of locational and temporal granularity in retail frameworks leaves DERs undervalued, particularly where they could defer capital spending or relieve local constraints. Short-term capacity signals, such as annual capacity auctions, lack the investment certainty required for multi-year assets—especially for distribution-connected storage or aggregated portfolios. Longer-term signals in capacity auctions could attract and retain cost-effective DERs with firm deliverability. Fragmented governance and coordination between transmission and distribution operations, while improving, still risks undermining efficient deployment and fair compensation of DERs.

The diversity of tariff structures across customer classes and segments further complicates Ontario’s policy landscape. Residential and small commercial customers under the RPP are primarily compensated through net metering, offsetting consumption at retail rates, yet broader system benefits remain unrecognized. Medium-sized commercial and institutional customers access demand response programs, but compensation for DER contributions beyond peak reduction is limited. Large industrial customers participating in the wholesale market can capitalize on energy arbitrage and ancillary service revenues, yet they face constraints in valuing locational and reliability benefits. These disparities clearly illustrate the urgent need for an integrated and equitable approach to DER compensation that recognizes value wherever it is delivered.

1.3 Objectives and Analytical Approach

This report issues clear recommendations for immediate and long-term reforms to Ontario’s tariffs, markets, programs, and governance structures—reforms essential to credibly valuing DER services while driving down total system costs. The approach is deliberately service-driven and technology-neutral, ensuring compensation reflects actual system benefit rather than resource preference. Drawing on mechanisms from

jurisdictions such as New York, the United Kingdom, and Australia, the analysis examines the conditions under which these approaches deliver results. Ontario's current compensation landscape is systematically mapped across key customer archetypes to illuminate aspects where value is acknowledged and where critical gaps remain.

The structure of the report is as follows:

- **Section 2** sets out the methodology, including the jurisdictional scan and archetype mapping.
- **Section 3** distills jurisdictional lessons into compensation mechanisms that support accountable performance and whole-system efficiency.
- **Section 4** assesses Ontario's current arrangements and identifies gaps in recognizing capacity, locational value, and ancillary services for each customer type.
- **Section 5** recommends and prioritizes actions that improve Ontario's DER compensation mechanisms over short and longer-term horizons, and addresses governance and enabling actions that help more DERs benefit from these incentives.

In sum, this report seeks to provide a clear, evidence-based approach for reforming DER compensation in Ontario, grounded in the objectives of the IEP and informed by lessons from leading jurisdictions. The recommendations are designed to be practical, actionable, and aligned with the province's broader energy strategy, ensuring that DERs are deployed where they deliver the greatest system-wide value and that ratepayers benefit from a more efficient, reliable, and resilient electricity system.

2.0 METHODOLOGY

Ontario’s electricity sector is not unique in its challenges, nor in its opportunities, but its energy system governance and market structure has few immediate comparables. Despite this, lessons from other jurisdictions can illuminate pathways forward, while a careful mapping to local realities ensures recommendations are both relevant and actionable.

2.1 Jurisdictional Practices Scan

To anchor Ontario’s DER compensation framework in best practices elsewhere, the report begins with a systematic scan of leading international jurisdictions—New York, the United Kingdom, and Australia. These regions were selected for their advanced approaches to DER integration, their willingness to experiment with market-based and regulatory innovations, and the practical relevance of their experiences to Ontario’s evolving policy landscape.

The scan proceeds in three stages. First, it identifies the full spectrum of value streams that DERs can provide, collectively known as the DER value stack. This includes commodity services—energy, capacity, ancillary services, and loss reduction—as well as network benefits such as locational relief, demand reduction, and grid stability. Societal contributions, including resilience, reliability, power quality, and avoided transmission costs, are also considered, even where compensation mechanisms remain nascent.

Second, the analysis catalogues the mechanisms by which these value streams are compensated. Tariffs, market products, and programmatic incentives are reviewed for their transparency, granularity, and flexibility. Special attention is paid to the ability of these mechanisms to enable revenue stacking across markets, an essential feature to unlocking the full potential of DERs.

Third, the scan distills enabling actions that support DER integration. These include investments in grid modernization, frameworks for aggregator participation, and protocols for transmission-distribution coordination.

2.2 Customer Archetypes and Compensation Mechanism Analysis

Building on the jurisdictional scan, the report turns to a detailed mapping of Ontario’s DER compensation mechanisms across four representative customer archetypes. This approach recognizes that the value and compensation of DERs are shaped by customer type, market participation status, and tariff structure.

- **Class B RPP Customers:** Residential or small business customer on a Regulated Price Plan (TOU, Tiered, or ULO) with rooftop solar or other renewable generation. Compensation is primarily through retail energy offsets and net metering credits.
- **Class B Non-RPP Customers:** Medium commercial or institutional customer not on RPP, facing market-based commodity charges but ineligible for the Industrial Conservation Initiative (ICI) program. May deploy behind-the-meter storage or participate in demand response programs through an aggregator.

- **Class A Market Participants:** Large industrial customer eligible for the ICI program, paying Global Adjustment (GA) based on peak contribution. May operate dispatchable load or large-scale storage and participate directly in wholesale markets.
- **Front-of-the-meter (FTM) DERs:** A non-customer-hosted DER connected to the local distribution system, such as a combined solar generation and battery energy storage facility capable of injecting energy, absorbing energy, and providing capacity or local flexibility services. Compensation pathways include wholesale market participation (energy, capacity, ancillary services), procurement programs, and flexibility markets.

For each archetype, the report examines both self-consumption and grid export mechanisms, evaluating how compensation applies in each scenario and identifying gaps relative to international best practices. The mapping is informed by a review of commodity charges (energy and GA), delivery charges, market and out-of-market opportunities (ancillary services, capacity auctions, local generation programs, eDSM), and the recognition of locational and network values.

2.3 Gap Identification and Recommendations Development

The final stage of the methodology synthesizes insights from the jurisdictional scan and customer archetype mapping to identify key opportunities to improve Ontario’s DER compensation framework. These are assessed in relation to the objectives of the IEP, ongoing regulatory policy consultations, market and out-of-market initiatives, and the practical needs of customers and developers.

The recommendations in this report are designed to act on these opportunities, improve system efficiency, and align Ontario’s DER compensation framework with international best practices and the strategic objectives of the IEP. The methodology ensures that each recommendation is grounded in evidence, informed by comparative analysis, and tailored to Ontario’s unique policy and market context.

3.0 JURISDICTIONAL BEST PRACTICES

3.1 Introduction and Rationale

Ontario’s consideration of how to value and compensate DERs should be informed by jurisdictions that have translated principles into repeatable practice, and which are often cited as having a coherent and comprehensive (if still evolving) approach. This section reviews New York, the United Kingdom, and Australia — three systems that have moved beyond pilots and towards institutional mechanisms with measurement, settlement, and governance discipline. Each jurisdiction offers a different organising logic for DER value recognition:

- **New York** places compensation primarily within regulated tariffs that reflect wholesale and distribution system value through defined credits (the Value Stack) and associated rules for measurement and settlement.
- The **United Kingdom** positions compensation within competitive flexibility procurement at the distribution level, coordinated with the national system operator (NESO), and standardised across Distribution System Operators (DSOs) within the RII0-ED2 price control framework.
- **Australia** uses a hybrid approach: wholesale demand response and ancillary services with dynamic export management at the distribution level, supported by technical standards that reward fast, verified performance.

The objective of this comparative analysis is not to pre-select an Ontario pathway. Rather, it is to clarify how each model works, where it performs reliably, what preconditions it requires, and what trade-offs it entails. This section therefore emphasises conditions that must be present and choices that could be made for each model to deliver value for money and system reliability.

3.2 New York: From Net Metering to a Measured Value Stack

New York’s journey toward advanced DER compensation began with the state’s Reforming the Energy Vision (REV) agenda, launched in 2014. REV was a response to the realization that traditional net metering, while effective for early DER adoption, was unsustainable at scale. Net metering’s retail-rate credits did not reflect the true system value of DER exports, nor did they send signals about when and where DERs were most beneficial. Policymakers recognized that as DER penetration grew, a more sophisticated approach was needed to avoid cross-subsidization and to ensure grid reliability.

In March 2017, the New York Public Service Commission (NYPSC) initiated the Value of Distributed Energy Resources (VDER) proceeding. This marked a formal shift away from net metering toward a layered compensation model, referred to as the Value Stack. The Value Stack was designed to reflect the full spectrum of DER value streams: energy, capacity, distribution system relief, environmental benefits, and community participation. Its development was iterative, with successive regulatory orders refining the components and rules as market experience accumulated.

A central innovation of the Value Stack was its anchoring of energy credits to the NYISO day-ahead locational-based marginal price (LBMP). This meant DER exports were valued according to actual system conditions, hour by hour, zone by zone, and incorporating losses and congestion. The capacity component (ICAP) was tailored to technology type and dispatchability, while the Demand Reduction Value (DRV) and Locational System Relief Value (LSRV) rewarded DERs for measurable contributions to peak reduction and for siting in constrained areas.

NY DER Value Stack - VDER



Energy Value: DER exports are credited at the NYISO day-ahead locational-based marginal price (LBMP), ensuring that compensation reflects real-time market conditions, including losses and congestion at the customer's zone.

Capacity Value (ICAP): DERs receive credits for their ability to reduce system peak demand, with the structure tailored to the dispatchability and technology type of the resource.

Demand Reduction Value (DRV): This component rewards DERs for measurable contributions to system peak reduction, typically during defined performance windows.

Locational System Relief Value (LSRV): DERs sited in constrained zones receive additional credits for exports that relieve local grid constraints, incentivizing optimal siting and operation.

Environmental Value: Zero-emission resources earn credits for their environmental attributes, supporting state decarbonization goals.

The transition from net metering to VDER was managed carefully to avoid market disruption. Transitional features, such as the Market Transition Credit, were introduced to stabilize developer economics and broaden eligibility, especially for community solar. In January 2019, the Market Transition Credit was retired in favor of a more durable Community Credit, ensuring continued support for mass-market participation and equitable access.

New York's model emphasizes operational discipline. Compensation is delivered via bill credits, calculated using real-time data and transparent formulas. Utilities and the New York State Energy Research and Development Authority (NYSERDA) provide calculators, fact sheets, and interactive maps to guide participants. The Joint Utilities portal aggregates utility statements, zone data, and remaining LSRV capacity, steering siting and operations. This infrastructure makes administration tractable and supports market confidence.

Governance is shared among the NYPSC, NYSERDA, and the Joint Utilities. The NYPSC sets policy and approves tariffs, NYSERDA provides technical support, and utilities implement and report. Stakeholder engagement has been robust, with regular consultations shaping the evolution of the Value Stack. This

collaborative approach has allowed for course corrections and ensured that the framework remains responsive to market realities.

New York’s experience demonstrates the importance of measurable, performance-based compensation. The Value Stack has grown more precise as the market matured, with utilities and NYSERDA now producing forward valuations for DER portfolios that reflect evolving wholesale and distribution fundamentals. The model’s transparency and scalability have made it a reference point for other jurisdictions, but ongoing refinement is needed to address data quality, telemetry compliance, and transitional equity issues.

Ontario can draw several lessons from New York’s evolution. First, compensation should be tied to measured system value, not just gross exports. Second, locational and temporal signals are essential for aligning DER behaviour with grid needs. Third, integration with wholesale markets supports efficient price formation. Finally, robust governance and stakeholder engagement are critical for successful reform.

3.3 United Kingdom: Standardizing Flexibility

The UK’s approach to DER compensation has evolved steadily over the past decade, shaped by the RIIO price control regime and a growing recognition of the need for flexibility in electricity networks. Early pilots focused on demand response and local grid support, but these were fragmented and lacked standardization. The transition to a coordinated, evidence-based system began in earnest with the latter years of RIIO-ED1 (the first price controls for electricity distributors under the “RIIO” framework that heavily influenced the OEB’s Renewed Regulatory Framework) and accelerated under RIIO-ED2 that persists today.

Launched in 2017, the Open Networks program was pivotal in harmonizing flexibility products and procurement processes across UK utilities, called Distribution Network Operators (DNOs). Lessons learned from pilots were codified into standardized products, lowering transaction costs and enabling aggregator participation. This standardization was essential for scaling flexibility procurement and making it repeatable and financeable.

DNOs began paying providers for availability and utilization during specified windows, deferring reinforcement and managing local constraints. By April 2024, leading DSOs such as UK Power Networks had formally added day-ahead flexibility auctions to their long-term tenders, allowing them to buy services closer to need. Procurement statements and annual distribution flexibility reports now show growth in volumes, clearer timetables, and tightened settlement discipline under RIIO-ED2 oversight.

UK DER Value Stack – Flexibility Markets



Availability Payments: DERs are compensated for being available to provide flexibility during defined windows, supporting grid reliability and deferral of network reinforcement.

Utilization Payments: When called upon, DERs receive payments for actual service delivery—such as load reduction, generation, or storage dispatch—during periods of system need.

Locational Signals: Flexibility tenders are targeted to specific geographic zones with published locational needs, ensuring DERs are rewarded for relieving local constraints.

Product Standardization: All flexibility services are defined by response time, duration, verification protocols, and settlement rules, enabling aggregator scale and market liquidity.

Ancillary Services Integration: DERs may also participate in ancillary service markets, coordinated with NESO to avoid conflicts and ensure whole-system optimization.

Transparency is embedded within the UK model. DSOs publish locational needs, hosting capacity maps, and tender calendars, enabling efficient siting and competitive procurement. Annual reporting under RIIO-ED2 provides stakeholders with clear visibility into market performance, product uptake, and system impacts, fostering trust and accountability.

Measurement and verification protocols are standardized across DSOs, with rigorous telemetry and data reporting requirements. Aggregators and providers must comply with these standards, ensuring that payments reflect actual service delivery. Dispute resolution mechanisms and performance audits are embedded in procurement contracts, safeguarding system reliability and consumer interests.

The UK’s transition to standardized flexibility markets required sustained collaboration among regulators, DSOs, and market participants. Harmonizing product definitions and ensuring platform interoperability were significant challenges. The move to day-ahead procurement demanded enhancements in forecasting, scheduling, and market operations. Ongoing adaptation has been necessary to maintain system reliability and market efficiency.

Ontario can learn from the UK’s experience by prioritizing standardization of local flexibility products, publishing locational needs, and integrating distribution-level markets with whole-system planning. Competitive procurement, transparency, and governance discipline are foundational to scalable DER compensation. Ontario’s DSO Capabilities consultation and BCA framework provide the policy backbone for this evolution, and should be leveraged to institutionalize best practices.

3.4 Australia: A Hybrid Approach

Australia’s energy system has experienced rapid growth in rooftop solar and distributed storage, creating both opportunities and challenges for grid management. Policymakers recognized early that static compensation mechanisms would not suffice in a system with high DER penetration. The response has been a pragmatic layering of wholesale, ancillary, and distribution-level reforms, each designed to address specific system needs.

At the wholesale level, reforms began with the Wholesale Demand Response Mechanism (WDRM), introduced in October 2021. This allowed Demand Response Service Providers to bid verified demand reductions into the National Electricity Market (NEM) alongside generators. Participation was modest at first, but the Australian Energy Market Commission’s (AEMC) October 2025 final review recommended continuing WDRM and expanding eligibility, citing efficiency benefits.

Ancillary services were modernized in two steps. First, Frequency Control Ancillary Services (FCAS) markets commenced in October 2023, creating explicit products for fast frequency response from batteries and inverter-based resources. Second, the Market Ancillary Services Specification (MASS v8.2) took effect in June 2024, updating measurement and verification across contingency and regulation services for contemporary technologies. On June 8, 2025, Frequency Performance Payments (FPP) went live, allocating positive and negative payments based on measured five-minute contribution factors. These are all still very new measures, but they demonstrate the pace of change that is possible.

At the distribution layer, static export limits proved inadequate as DER densities rose, giving way to Dynamic Operating Envelopes (DOE) where export limits are relaxed when local conditions allow. The utility SA Power Networks led the development of Flexible Exports, issuing forecast export permissions by location and time to match local headroom. Trials began live operation in September 2021 and concluded in March 2023, with public reports in 2023–2024 documenting significantly higher average exports and recommending faster, consistent national rollout. The Australian Energy Regulator’s (AER) October 2024 guidance note clarified the regulatory framework for Distribution Network Service Providers (DNSPs) to deploy DOEs, including capacity allocation, revenue treatment, and consumer safeguards.



Australia DER Value Stack – Hybrid Approach

Wholesale Demand Response: DERs can bid verified demand reductions into the National Electricity Market (NEM), earning market-based payments for energy and capacity value.

Ancillary Services (FCAS & FPP): Batteries and inverter-based resources participate in very-fast Frequency Control Ancillary Services (FCAS) markets and earn Frequency Performance Payments (FPP) for measured contributions to system frequency stability.

Dynamic Export Management (DOEs): At the distribution level, DERs receive flexible export permissions based on local headroom, with payments or curtailment signals reflecting real-time grid constraints.

Aggregator Revenue Stacking: Protocols for data exchange, event tagging, and baseline integrity enable aggregators to stack revenues across energy, ancillary, and local services, provided measurement and settlement rules are clear.

Consumer Safeguards: The stack is underpinned by regulatory guidance from the AER, ensuring transparent communication, dispute resolution, and equitable access.

Aggregator participation is enabled by clear protocols for data exchange, event tagging, and baseline integrity. Project EDGE demonstrated real-time coordination among Australian Energy Market Operator (AEMO), aggregators, and DNSPs, providing operational blueprints for scaling price-responsive DER portfolios. These protocols underpin revenue stacking across energy, ancillary, and local services, ensuring transparency and auditability.

Consumer protection is embedded in Australia’s DER reforms. Flexible export limits are designed to maximize customer value while safeguarding against curtailment risks. Dispute resolution processes, transparent billing, and targeted education campaigns support equitable participation. The AER’s guidance mandates clear communication of export permissions and curtailment policies, maintaining trust as DER penetration accelerates.

Australia’s approach has required continuous adaptation. Integrating wholesale demand response with distribution-level export management demanded enhancements in telemetry, forecasting, and settlement systems. Ensuring interoperability across states and DNSPs was essential to maintaining system reliability and market efficiency. The rapid pace of DER adoption necessitated agile policy responses and iterative regulatory updates.

Australia’s experience underscores the importance of sequencing reforms to match system readiness. Building an enduring protocol framework that includes measurement, data exchange and event tagging, should precede expansion of compensation channels. Planning for dynamic export management and

performance-linked incentives will be critical as DER penetration grows. Ontario should prioritize operational discipline, transparency, and consumer protection as it evolves its DER compensation framework.

3.5 Comparative Insights and Implications for Ontario

The three jurisdictions examined offer distinct lessons on how to value and compensate DERs. Each model reflects its system context, regulatory culture, and sequencing of reforms. Understanding these trajectories is essential for Ontario because it clarifies not only what works, but why it works and under what conditions.

	New York	UK	Australia
Energy	Day-ahead LBMP (locational marginal price)	Zonal pricing, standardized products	Wholesale demand response, dynamic export management
Capacity	ICAP credits for peak reduction	Availability & utilization payments	Market-based payments, FCAS & FPP
Locational	DRV/LSRV for constrained zones	Targeted tenders by location	Dynamic Operating Envelopes (DOEs)
Flexibility	Tariff-based, some pilots	Competitive flexibility markets	Hybrid: market + distribution
Ancillary Services	Yes, integrated	Yes, coordinated with NESO	Yes, fast frequency response

New York demonstrates the discipline of a tariff-first approach anchored in wholesale pricing. By linking energy credits to NYISO’s day-ahead prices and layering in capacity and distribution elements (DRV and LSRV), New York created a customer-facing mechanism that makes system value visible without requiring every DER to become a market participant. It also embraced incrementalism: transition credits for community solar gave way to durable components, and utilities now publish granular maps and statements to steer siting. The strength of this model lies in its transparency and scalability. The downside is the effort required to maintain it. Rigorous measurement and clear windows are required to avoid double counting when resources stack wholesale and tariff revenues.

The UK illustrates the power of standardized local markets under system-wide governance. DSOs moved from pilots to routine tenders, harmonized products through the Open Networks initiative, and introduced day-ahead auctions to buy flexibility closer to real conditions. Britain’s experience underscores that competitive procurement can reveal prices and unlock aggregator scale—but only if telemetry, baselines, and settlement rules are codified and platforms are interoperable. Without these, local markets fragment and transaction costs increase.

Australia offers a pragmatic hybrid for high DER penetrations. Its toolkit combines wholesale demand response (WDRM), modernized ancillary services (very-fast FCAS and two-sided frequency performance payments), and dynamic export limits (DOEs) to manage everyday distribution flows. This evolution was driven by necessity: static export caps were limiting rooftop solar, and frequency control needed sharper incentives for DERs. The creates an avenue for DERs to stack revenues without creating other technical challenges. For Ontario, the lesson is clear: operational tools and governance must mature in lockstep with compensation channels.

What these paths share is sequencing. New York started with tariff instruments and refined them as data and governance matured. The UK built local markets gradually, embedding standardization before scaling. Australia layered wholesale and ancillary reforms with distribution protocols to keep reliability intact. None of these jurisdictions leapt to an end-state overnight; each staged reforms to match its readiness.

For Ontario, the implication is not to copy any model in its entirety but to choose a starting point and a trajectory that reflect local conditions.

Ontario does not need to choose between New York’s tariff-first approach, the UK’s markets-first procurement, or Australia’s hybrid toolkit as if they were mutually exclusive. Each model reflects its own starting conditions and sequencing logic. The better question for Ontario is which elements to adopt first, and how to layer them over time to achieve a credible DER valuation framework.

At the same time, competitive procurement for flexibility is the logical destination if Ontario wants price discovery and technology neutrality at scale. The UK’s trajectory underscores that such markets only work when product definitions, baselines, and verification are consistent and platforms are interoperable. Ontario’s DSO Capabilities consultation and the OEB’s BCA Framework provide the policy backbone for this evolution; the challenge is to move from one-off non-wires solutions contracts to repeatable, flexibility tenders at-scale without fragmenting price signals across LDCs. A 2003 report by the OEA on DSO capabilities indicated that this is well understood and supported by its members.

Finally, operational tools will become unavoidable as DER penetration rises. Australia’s adoption of dynamic export limits and frequency performance incentives was not ideological—it was pragmatic. When rooftop solar threatened hosting capacity and inverter fleets began shaping system frequency, regulators and operators responded with protocols that made everyday operation fair and secure. Ontario may not need DOEs tomorrow, but planning for dynamic export management and technology standards now will prevent reliability risks later.

This is the essence of a credible Ontario approach: pair compensation mechanisms with enabling conditions, and let sequencing follow readiness in measurement, platforms, and institutional roles. The goal is not to replicate any single jurisdiction but to combine their lessons into a framework that is transparent, financeable, and fit for Ontario’s Integrated Energy Plan.

Beyond the DER value stack itself, several qualitative themes emerge that warrant closer examination.

First, the quality of the compensation mechanism is just as important as the quantum. The most successful DER frameworks make a small number of price signals clear and auditable. In New York, energy credits track the day-ahead locational price and are adjusted for losses and congestion; demand-based and locational prices then pin distribution value to measured performance windows and specific locations. In the UK, DSOs pay for availability and utilisation in defined places and times, and day-ahead auctions buy closer to actual conditions. In Australia, ancillary services and frequency payments reward verifiable, value-added behaviour, while dynamic operating envelopes make routine export limits transparent and predictable. All told, compensation follows what can be measured, when and where it is delivered, and how it integrates with the rest of the system.

Second, governance and readiness determinative. Jurisdictions sequence reforms to match the maturity of data, platforms, and institutional roles. New York began with tariff instruments because utilities could publish windows, zones, and values faster than they could stand up local markets. The UK built procurement standards first—baselines, windows, and verification—before introducing day-ahead auctions and strengthening whole-system governance through NESO. Australia layered wholesale demand response and modern ancillary services with distribution protocols only after trials demonstrated the benefits and national guidance clarified how to implement them. The lesson for Ontario is pragmatic: choose tools that match current capabilities, and build toward more dynamic models as telemetry and platforms mature. Investments in grid modernization will be essential in this regard.

Third, integration drives durable value. None of the jurisdictions treat tariffs, markets, and operational tools as mutually exclusive. New York’s tariff-based Value Stack is explicitly designed to coexist with wholesale participation, provided that overlap is avoided. The UK’s DSO procurements operate interchangeable to avoid conflicts with transmission-level balancing. Australia’s hybrid depends on shared baselines and event identification so DER portfolios can stack energy, ancillary, and local services effectively. For Ontario, the opportunity is not whether to be “tariff-first” or “markets-first,” but how to combine elements in a way that preserves reliability, controls costs, and remains verifiable.

Finally, the comparative lens is table stakes for Ontario. As demand grows and DER adoption accelerates, the province will face more frequent distribution constraints and more complex interactions between local services and bulk markets. Models that pay for delivered services, that standardize products and verification, and that codify Tx–Dx coordination will deliver measurable, auditable value. Models that rely on loose signals, that keep local needs opaque, or that leave coordination to ad hoc arrangements will raise costs and erode trust.

4.0 DER COMPENSATION IN ONTARIO

4.1 Ontario’s Compensation Building Blocks Organized by Tariffs, Markets, and Programs

Ontario’s mechanisms that influence and compensate DERs can be understood through three buckets—Tariffs, Markets, and Programs—which reflect who sets the rules, how value is expressed, and what is required to settle payments. These mechanisms do not operate in isolation. Customers see tariffs on bills, market participants settle in wholesale markets, and programs fill gaps where tariffs and markets do not yet convey underlying costs or where access pathways are incomplete.

Tariffs are the customer-facing instruments that recover energy, GA, transmission, and distribution costs. Their role is foundational because they govern the economics visible to most customers and therefore shape decisions about adopting and operating DERs. They provide predictable, bill-level price signals, essential for mass-market comprehension and utility cost recovery. They are less effective at reflecting real-time scarcity and locational distribution value.

Markets deliver bulk-system revenue streams for DERs (and aggregations) that qualify as market participants or enroll through intermediaries. They discover prices and set obligations for energy and capacity over various timeframes. Markets excel at transparent pricing and competitive procurement, aligning compensation with system needs hourly and seasonally. They are less accessible to small DERs due to rule design, registration and telemetry requirements.

Programs provide targeted payments to recognize distribution-level value when tariffs and markets do not yet convey underlying costs or when access pathways are incomplete. Programs can unlock local value that tariffs and markets can’t reach. However, without common product definitions and interoperable platforms, non-wires solutions remain one-offs and transaction-intensive. The Local Generation Program fills a local energy procurement gap but currently focuses on generation more than flexibility.

These three pathways are not universally accessible to all customers. Instead, the opportunities available to participate in and benefit from each mechanism are shaped by customer size, segment, and the nature of their electricity use. For example, residential and small business customers primarily interact with the system through retail tariffs such as the Regulated Price Plan and net metering, which offer predictable bill savings but limited access to market-based or programmatic compensation. By contrast, larger commercial and industrial customers can settle commodity charges at market prices and participate directly in wholesale markets or capacity auctions, unlocking more granular price signals and additional revenue streams. Meanwhile, targeted programs, such as non-wires solutions or local flexibility procurements, are often reserved for specific customer types or geographic areas where local grid needs are acute.

This segmentation means that the value and compensation available to DERs can vary significantly depending on the customer type. For the purpose of this report, four “customer archetypes” were selected to reveal the prevailing tariff, market and program opportunities and to support a corresponding analysis of what improvements would help. A unified compensation framework for DERs may not be attainable—tariff

and market design have objectives unrelated to DERs, after all—but an approach that improves harmonization should lead to a more level playing field for all customers.

4.2 DER Compensation for Selected Customer Archetypes

ARCHETYPE 1: RPP Net-Metered Customer (Residential / Small Business)

Primary signals: Retail energy offsets, net metering credits

Accessible revenues: Bill savings, net metering

Barriers: No time/location value, export cap/expiry, limited local services

In Ontario, the vast majority of the province’s 5.4 million residential and small business customers are enrolled in the OEB’s RPP. These customers rely on RPP for their energy price and, where they have rooftop solar or other eligible renewables, net metering to offset consumption with exported energy. RPP rates are loss-adjusted, compensating customers for the value of avoided distribution and transmission losses.

Under TOU and ULO, customers receive predictable signals for when energy is cheaper to consume, whereas tiered rates reward lower overall consumption. Net metering credits accrue at the retail rate for electricity and roll forward up to twelve months. Credits do not offset fixed delivery, transmission, or regulatory charges. In practice, households maximize value by aligning usage with low-price periods, sizing their solar array to meet a substantial share of consumption, and avoiding over-production towards the end of their credit window.

As a result, RPP signals influence when energy is consumed, not the marginal value of exports. Net metering’s full retail rate credit simplifies billing but masks time and locational value, which can drive installations that are suboptimal from a grid perspective (e.g., large arrays exporting primarily into low-value hours). Battery economics hinge on the spread between price bands, which is greater overnight under ULO but more modest across daytime TOU bands. Further, capacity and global adjustment costs are embedded within the RPP rate. Beyond being able to avoid these costs, there is no incentive to do more.

A household battery can reduce grid draw during on-peak periods and absorb midday solar, but compensation remains a bill-savings construct rather than a payment for measured system relief. Where a local feeder is constrained, non-wires solutions opportunities will eventually provide a path for service-based payments, but these are nascent. Moreover, delivery rates are either fully fixed monthly charges, or a blend of fixed and volumetric rates. All told, the compensated locational value of DERs for customers in this group is minimal.

ARCHETYPE 2: Non-RPP Class B Customer with On-Site DER/DR (Medium Commercial / Institutional)

Primary signals: Zonal price

Accessible revenues: Capacity auction (like via aggregator)

Barriers: No capacity-driven or real-time GA signal, telemetry requirements, limited local value

Loads in this category are typically non-dispatchable, mid-sized commercial, industrial and institutional customers. Those that have adopted advanced energy management systems and can adjust load or dispatch storage during high-price periods, but this capability is not omnipresent.

Energy is settled at the locational Ontario Zonal Price, creating granular price signals that reward responsiveness. Locational pricing improves arbitrage economics for storage and supports precision in load shifting. Global Adjustment is volumetric, which does not reward peak reduction for these customers, though this policy is currently under review and was called out in the August 2025 Brattle Report developed for the OEB and IESO. The absence of more dynamic Global Adjustment price signals for Class B dulls the incentive to reduce demand during provincial peaks, limiting the business case for behind-the-meter flexibility.

Participation in the capacity auction requires telemetry, metering, and compliance—manageable for many Class B customers but it is not trivial. Aggregators play an important role to help smaller co-located DERs access the capacity auction. Local value is driven solely by distribution rate design based on non-coincident peak demand and standby charges that encourages load displacement over export-driven opportunities. An OEB consultation on standby concluded early in 2024, confirming interim rates as final and any new proposals to be filed on a distributor-specific basis within rate applications.

ARCHETYPE 3: Class A Market Participant (Large Industrial / Dispatchable Load / ≥1 MW Storage)

Primary signals: Zonal price, GA based on peak demand factor

Accessible revenues: Wholesale energy, ancillary services, peak management

Barriers: Peak uncertainty, double counting management

Class A customers are those that have enrolled in the Industrial Conservation Initiative (ICI) as the basis to pay Global Adjustment. Under the ICI, GA is levied on the basis of the customer’s peak demand factor on days of high demand. These customers can be dispatchable market participants, own large storage, and also enroll in the Capacity Auction or ancillary services – though strong controls are in place to avoid “double counting.”

Like Class B non-RPP customers, energy settles at the Ontario Zonal Price, though a greater proportion of these types of customers would be market participants. GA costs hinge on successfully managing demand

during the top-five provincial peaks. Capacity and ancillary revenues depend on resource qualification and performance standards. Some Class A customers now consider corporate Power Purchase Agreements (PPAs) with qualifying non-emitting generation to offset GA exposure (subject to the specific regulatory conditions and coincidence requirements).

The peak demand factor construct creates a strong, investment-grade signal: reducing demand during peak windows can meaningfully lower GA for twelve months. When paired with storage or process flexibility, this can justify significant investment in DERs. The principal risk is mis-forecasting provincial peaks, which can erode GA savings. Protocol discipline is essential for stacking wholesale, capacity, and customer-side peak management without double counting.

Like other customer archetypes, the lack of standardized local flexibility markets means distribution relief is procured ad hoc, often leaving value unrecognized unless an LDC pursues a non-wires solution contract.

ARCHETYPE 4: Front-of-the-Meter (FTM) DER

Primary signals: Wholesale market participation, procurements

Accessible revenues: Energy, capacity, ancillary

Barriers: Short-term capacity signals, bespoke program access, settlement complexity

This archetype includes non-customer-hosted resources connected directly to the distribution system, and reasonably include solar generation, standalone battery energy storage systems, or hybrids (solar + storage). These assets can inject energy to the grid, absorb energy, and deliver dependable capacity or local services when qualified.

FTM assets can participate in wholesale energy markets, capacity auctions (subject to duration standards), and ancillary services if telemetry and measurement standards are met. Local value compensation is programmatic, via NWS service agreements. The Local Generation Program focuses on generation and is evolving to clarify eligibility for storage or hybrid options.

Wholesale arbitrage depends on nodal spreads and cycling costs; capacity payments provide recurring revenue but are short-term. The absence of standardized local flexibility tenders means assets rely on wholesale plus bespoke program routes, which can limit financing certainty. The same distribution tariffs and charges generally apply as non-RPP Class B.

All told, the compensation framework for this customer archetype is a patchwork, and there remains variability within this category depending on the type of asset installed. The OEB has rightfully focused on FTM resources in its Review of the Valuation of DERs.

4.3 Cross-Archetype Observations and Analysis

ENERGY PRICE SIGNALS

Wholesale energy pricing is granular and transparent. With locational pricing, participants and aggregations can dispatch storage or shape load in better alignment with actual system conditions. For Class B and Class A market participants, this improves the economics of arbitrage and load shifting overall.

At retail, RPP remains intentionally simple: beneficial for customers who prefer predictability, but limited in the signal it sends to DER-capable households. Net metering is a powerful adoption tool yet masks marginal value: a kilowatt-hour exported at a low-value hour is credited the same as one exported during scarcity, meaning credits do not reflect where exports relieve local constraints. For households with batteries, ULO's deep overnight discount can support load shifting, but export behaviour is governed by net metering credits rather than a measured contribution to system value.

Ontario's retail pricing makes DER adoption accessible but does not compensate for the highest-value behaviour. As DER penetration grows, the gap between retail simplicity and wholesale precision will matter more, especially on constrained feeders. A measured way to index export credits to time and locational value would improve alignment without forcing dynamic pricing on customers who prefer more traditional plans.

CAPACITY PRICE SIGNALS

The ICI framework provides a familiar, peak-coincident signal for customers eligible to apply. Customers who reduce demand during the top-five peaks materially lower GA for the subsequent year. This is an effective proxy for capacity at the customer level and has motivated significant investment in storage, process flexibility, and demand response.

The capacity auction delivers competitive pricing but with one-year commitments. This suits short-term flexibility and demand response but makes financing harder for expensive, long-lived assets seeking multi-year certainty. However, Class B customers have no peak-coincident GA signal, constraining the business case for mid-market load flexibility targeted at capacity value.

Ontario's capacity signals favor Class A and short-term adequacy. If the province wants more dependable DER capacity on the system, a multi-year capacity lane (e.g., 3–5 years) within the auction would provide greater certainty that draws investment. A carefully designed, optional peak-sensitive GA path for Class B customers could introduce a customer-side capacity signal without undermining simplicity for those who opt out.

LOCAL VALUE SIGNALS

Distribution locational value is mostly hidden in tariffs and only occasionally recognized through non-wires solutions. LDCs are beginning to use the BCA framework to justify payments for constraint relief or peak reduction, but product definitions and processes are not yet standardized across Ontario. LDCs now publish hosting capacity or constraint maps, but compensation pathways for DERs can contribute capacity or

reduce demand are not automatic. As electrification accelerates, local constraints will become more frequent, and the absence of enduring price signals leaves value on the table.

Ontario can evolve from bespoke non-wires solutions toward standardized local flexibility products, procured routinely against published locational needs. Doing so will lower transaction costs, enable aggregators to scale, and make local services financeable. A clear path for storage within procurements targeted at DERs or through a parallel flexibility stream would complement energy procurements with local services.

MARKET PARTICIPATION AND REVENUE STACKING

Across archetypes, many DERs seek to stack revenues—retail savings, wholesale energy, capacity payments, local services. This is feasible, but only if windows are separated, telemetry is consistent, and settlement protocols are codified. The risk is double counting or conflicting dispatch, especially for FTM assets and large customer portfolios participating simultaneously in wholesale and local procurements.

Ontario should codify dispatching rules so stacking becomes safe and repeatable. This will reduce operational conflicts and protect utilities and participants from inadvertent compliance breaches.

4.4 Concluding Observations

The analysis across Ontario’s customer archetypes reveals a clear and actionable pathway for advancing DER compensation. While the province has laid important groundwork, the diversity of customer types and compensation mechanisms means that reforms must be both targeted and sequenced.

Ontario should begin by using tariffs to reveal distribution value as quickly as possible. Measured peak and locational credits, such as those being used in leading jurisdictions, can be introduced within existing tariff structures to ensure DERs are rewarded for providing relief where and when it is most needed. This approach leverages the transparency and predictability of tariffs, making distribution value visible to customers and investors alike. A regime as robust and site-specific as New York’s may not be necessary or feasible to meet the time imperative. In this instance, a clear, rules-based regime that guides DERs to where there is value, and away from where connecting could create additional costs, is worth the effort to design and implement.

In parallel, Ontario must build interoperable local flexibility markets. This means developing common product definitions, baselines, verification protocols, interoperable platforms, and publishing locational needs. By moving beyond bespoke non-wires solutions and ad hoc procurements, local services can become recurring, financeable, and scalable. Standardization will lower transaction costs, enable aggregator participation, and support the evolution of distribution system operators. It is encouraging that the OEB has signalled an interest in addressing flexibility in the first stage of the planned DSO Capabilities consultation.

To retain dependable DERs and encourage long-term investment, Ontario should add investment-grade options in capacity procurement for a wider array of DERs than the current long-term procurements allow. Introducing multi-year lanes within the IESO Capacity Auction could provide the certainty required for DER

owners to commit resources and finance new projects. This complements short-term flexibility products and ensures the system can attract and retain the capacity needed for reliability and growth.

Operational discipline is essential as DER participation expands. Ontario must plan for robust operational protocols, including market coordination rules, dynamic export management, and telemetry standards. These measures will ensure that revenue stacking is safe and reliable, prevent double counting, and support coordinated dispatch across transmission and distribution boundaries.

Finally, retail options can evolve but must remain voluntary and intelligible, preserving simplicity for customers who prefer stability while enabling dynamic choices for those with controllable DERs. Every reform should embed consumer protections and class neutrality, ensuring that all customers benefit equitably from the transition and that no group is disadvantaged by the evolution of compensation mechanisms.

Taken together, these priorities set a practical and sequenced direction for Ontario's DER valuation framework. By acting now to reveal distribution value, standardize local markets, provide investment-grade capacity options, codify operational protocols, and safeguard consumer choice, Ontario can move from today's patchwork of compensation mechanisms to a more comprehensive and efficient framework.

5.0 RECOMMENDATIONS

5.1 Strategic Direction and End-State Vision

Ontario’s electricity sector stands at a pivotal moment. The preceding analysis has shown that while foundational elements for DER compensation are in place, the current framework remains fragmented, marked by uneven signals, targeted local programs, and limited investment certainty. Across customer archetypes, the evidence points to a practical and sequenced path forward: reveal distribution value through tariffs now, build standardized local flexibility markets, offer investment-grade capacity options, codify operational protocols, and embed consumer protections in every reform.

Translating these priorities into action requires more than incremental adjustments—it demands a coordinated set of reforms that are both ambitious and pragmatic. The recommendations that follow are designed to bridge Ontario’s current state to its desired end-state: a layered, integrated DER valuation framework that is transparent, financeable, and future-ready.

Each recommendation is grounded in the lessons of leading jurisdictions and tailored to Ontario’s unique policy context. They are organized to address immediate gaps, support scalable market evolution, and ensure that all customers, regardless of size or sophistication, can participate in and benefit from the transition. The implementation guidance accompanying each recommendation is intended to provide clear, actionable steps for policymakers, utilities, and market participants.

By following this approach, Ontario can move toward a coherent system where DERs are valued for the full spectrum of services they provide. The recommendations below set out the concrete actions needed to realize this vision, sequenced to deliver early wins, build institutional capacity, and sustain momentum over the short, medium, and long term.

5.2 Recommendations: Tariffs, Markets and Programs

TARIFFS

RECOMMENDATION 1: Introduce optional dynamic RPP pricing for DER-capable customers.

Current RPP plans (TOU, Tiered, ULO) provide predictable signals but do not reflect real-time system conditions or local constraints. More dynamic forms of pricing, such as critical peak pricing, can unlock flexibility from households and small businesses with controllable DERs (e.g., EVs, batteries).

Implementation guidance:

- Launch as an opt-in pilot with bill-impact safeguards and consumer education.
- Maintain existing plans for customers who prefer stability.
- Ensure utilities recover incremental implementation costs through OEB-approved mechanisms.

RECOMMENDATION 2: Reform net metering export credits to reflect time and network value, and remove the credit cap and expiration features.

Net metering currently compensates exports at the full retail rate, regardless of when or where they occur, and credits are capped and expire after 12 months. This obscures marginal value and can discourage optimal DER sizing and operation.

Implementation guidance:

- Index export credits to time bands aligned with the prevailing zonal price schedule.
- Add a network value credit for exports that relieve local constraints.
- Remove the export credit cap and expiration, allowing customers to benefit from long-term value.
- This recommendation aligns with the “net billing” concept introduced at the OEB’s DER Valuation proceeding

RECOMMENDATION 3: Develop a simplified locational tariff, following New York’s DRV/LSRV approach, as an interim measure while flexibility markets develop liquidity.

Ontario’s tariffs do not currently reflect the locational value of DERs. A locational tariff, taking inspiration from New York’s Demand Reduction Value (DRV) and Locational System Relief Value (LSRV) but that is comparatively straight-forward to design, implement and deliver, can provide targeted incentives that encourage DER adoption in constrained areas.

Implementation guidance:

- Use published capacity maps to identify eligible locations for the tariff.
- Consider using a single rate for any eligible location if maintaining station-specific locational rates is overly burdensome.
- Consult on the length of time the credit should apply.
- Recover credit costs through an approved rate to applies to ratepayers that benefit from the associated demand reduction and locational system relief, and account for variations in credit payments in a Deferral and Variance Account (DVA).

RECOMMENDATION 4: Modernize Global Adjustment for non-RPP customers (Class A and B).

Like RPP, develop a wider slate of options for Global Adjustment payments for non-RPP customers that includes more dynamic options.

Implementation guidance:

- Explore optional peak-sensitive GA for non-RPP Class B through consultation and pilots.

- Consult on removing the minimum demand eligibility criterion for ICI making it accessible to a broader range of customers.
- Maintain revenue neutrality and consumer protections to minimize the risk of cross-subsidization.

MARKETS

RECOMMENDATION 5: Institutionalize local flexibility markets.

Through the OEB’s DSO Capabilities consultation, local flexibility markets should be enabled and embedded as a core distribution function.

Implementation guidance:

- Explore common product definitions and interoperable platforms and requirements.
- Create recurring, transparent signals for distribution value over the long-run.
- Phase out the use of demand reduction and locational system relief tariffs as liquid markets emerge for locational flexibility services.

RECOMMENDATION 6: Add a multi-year capacity lane within the IESO Capacity Auction.

The one-year obligation limits options for DERs requiring multi-year certainty to make necessary investments, undervaluing the capacity attributes of more DER types.

Implementation guidance:

- Retain the one-year track for short-term flexibility.
- Create a parallel track of 3–5-year commitments for resources meeting duration and performance benchmarks.
- Consider pilots that jointly procure local and bulk capacity simultaneously.

RECOMMENDATION 7: Advance the IESO Enabling Resources Project (ERP).

ERP deliverables, such as telemetry standards, aggregation rules, are critical for wholesale DER participation and revenue stacking.

Implementation guidance:

- Continue consulting closely with industry on the IESO’s report back to the Minister of Energy and Mines, due March 31, 2026, and on any subsequent direction from the Minister.

PROGRAMS

RECOMMENDATION 8: Continue publishing distribution constraint maps.

Transparency is essential for DER siting and local procurement, and having access to this information aids decision making for customers and DER providers alike.

Implementation guidance:

- Continue on the current path and refine based on customer feedback.

RECOMMENDATION 9: Continue with the Local Generation Program in the short term and look for continuous improvement in the longer term.

As both LDCs and the IESO have direction to procure DERs, it will be beneficial to continue to look for opportunities to coordinate and integrate procurements to minimize overlap and potential customer confusion.

Implementation guidance:

- Align with IESO engagement timelines and ministerial directives.
- Explore opportunities to evolve program design in future iterations over the medium to long-term.

RECOMMENDATION 10: Use Stream 2 eDSM for cross-territory NWS

Grid constraints can often span multiple LDCs, such as when both have feeders emerging from the same constrained station or in cases of an LDC whose service territory is embedded within another. Stream 2 eDSM is developing an efficient, standardized framework to develop and approve local programs that could be used for multi-utility non-wires solutions purposes.

Implementation guidance:

- Finalize the eDSM stream 2 cost sharing framework.
- Increase funding to eDSM stream 2 over time.
- Consistent with the IEP Implementation Directive to the OEB.

5.3 Recommendations: Governance and Enabling Actions

RECOMMENDATION 11: Codify Tx–Dx coordination protocols to support multi-market participation.

Coordination between transmission and distribution operations is critical to avoid conflicting dispatch, unnecessary curtailment and double counting.

Implementation guidance:

- Embed TDWG outputs with in the OEB’s DSO Capabilities regulatory framework as it evolves.
- Test the feasibility of a single market platform, like the construct reviewed at the TDWG sub-group.
- Assign roles and responsibilities for dispatch as license conditions for regulated entities.

RECOMMENDATION 12: Accelerate grid modernization investments to enable DER integration and system flexibility.

Ontario’s ability to unlock the full value of DERs depends on a modernized grid equipped with advanced metering, telemetry, and control systems. These foundational investments are essential for supporting dynamic pricing, real-time dispatch, secure DER participation, and reliable system operation.

Implementation guidance:

- Establish a dedicated regulatory mechanism (e.g., a rate adder and variance account) to allow utilities to recover costs for qualifying grid modernization investments.
- Define eligible investments, including advanced metering infrastructure, distribution automation, DER management systems, and cybersecurity upgrades.
- Require utilities to include grid modernization plans in their next Distribution System Plans (DSPs).
- Align modernization investments with OEB DER Valuation outputs and IESO market integration milestones.

RECOMMENDATION 13: Maintain consumer protections and educate participants.

Policy reforms will fail without operational foundations and consumer trust. The OEB will have a vital role to ensure participants are confident in the fairness of all new markets developed for flexibility services.

Implementation guidance:

- Maintain consumer protections through transparent rules and dispute resolution.
- Educate consumers and aggregators on new options to build trust and participation.

APPENDIX: ALIGNMENT WITH CURRENT INITIATIVES

Ontario’s DER compensation framework is designed to build on, and accelerate, the province’s active regulatory and market reform agenda. The recommendations outlined above are not standalone—they are intended to align with, and reinforce, the most important consultations and initiatives currently underway. Bridging toward a more robust DER valuation framework will require coordinated action across several fronts:

Ontario Energy Board (OEB) DER Valuation Consultation:

The OEB’s DER Valuation consultation is the cornerstone for embedding cost allocation principles and service-based compensation into rate design and planning standards. This process is vital for establishing methodologies that recognize locational and temporal value, harmonize compensation mechanisms across tariffs, markets, and programs, and ensure technology neutrality. Continued engagement with stakeholders through this consultation will be essential to codify principles and drive regulatory change.

OEB Benefit-Cost Analysis (BCA) Framework:

The BCA Framework, including the Distribution System Test (DST) and Energy System Test (EST), provides the analytical foundation for evaluating non-wires solutions and DERs on an equal footing with traditional investments. Institutionalizing standardized flexibility procurements and expanding the use of BCA in utility planning will help unlock local value and support cost-effective DER deployment.

OEB DSO Capabilities Consultation:

Clarifying the roles and responsibilities of Distribution System Operators (DSOs) is critical for enabling local flexibility markets, integrating DERs into whole-system planning, and ensuring operational discipline. The DSO Capabilities consultation will guide the evolution of LDC functions, market participation, and coordination with the IESO, laying the groundwork for scalable DER integration.

IESO Enabling Resources Project (ERP) – DER Integration Project:

The ERP is central to advancing telemetry standards, aggregation rules, and market access for DERs. Accelerating ERP milestones will support wholesale participation, revenue stacking, and the development of multi-year capacity commitments. Alignment with capacity auction enhancements and dynamic retail pilots will be key to unlocking new value streams for DERs.

IESO Local Generation Program (LGP) and Non-Wires Solutions (NWS) Initiatives:

The LGP and NWS programs are evolving to address local supply needs, re-contract expiring assets, and support utility-led DER procurement. Piloting standardized local flexibility products and clarifying eligibility for storage and hybrid resources will help transition these programs from bespoke arrangements to recurring, financeable solutions.

OEB Electricity Demand-Side Management (eDSM) Stream 2:

Stream 2 provides a robust framework for local eDSM projects, cost recovery, and cross-territory non-wires solutions. Finalizing Stream 2 for locally-driven conservation could eventually bridge to flexibility procurements and facilitate broader DER participation and governance clarity.

Transmission–Distribution Coordination Working Group (TDWG):

The TDWG developed protocols for coordination between the IESO, LDCs, and DER participants, with a focus on preventing conflicting instructions and double counting. Codifying Tx–Dx coordination protocols and dual participation rules will be essential for safe and reliable revenue stacking.

Market Renewal Program (MRP):

Complementary market rule amendments under MRP are introducing new participation types, improving scheduling and pricing, and creating frameworks for DER integration into day-ahead and real-time markets. These reforms will ensure DERs can compete on equal footing with traditional resources while maintaining system reliability and efficiency.

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