ONTARIO ENERGY BOARD

Report to the Minister of Energy and Mines

Valuation of Distributed Energy Resources

MARCH 2026

Ontario Energy Board

Executive Summary

The Minister of Energy and Mines, in Ontario's first Integrated Energy Plan (IEP), *Energy for Generations*, highlighted the need for Ontario to unlock the value of distributed energy resources (DERs). To implement the IEP, the Minister directed the Ontario Energy Board (OEB) to deliver a report identifying recommendations or providing an update on actions by the OEB regarding the overall regulatory and compensation frameworks to appropriately reflect the system value of DERs (implementation directive item 11)[1]. This work is aligned with the Ontario government's emphasis on keeping energy costs affordable for businesses and families. The Minister also directed the OEB to identify roles and responsibilities for implementing these recommendations and explore opportunities for electricity distributor-led DER procurements (implementation directive item 12)[1]. This report addresses both these requests.

The OEB reviewed DER valuation as two distinct components: DER compensation and DER delivery rates. DER compensation encompasses the revenues DERs receive, or costs they avoid, through the services they provide. DER delivery rates are the OEB-approved electricity distribution and transmission rates that DERs pay. Together, these two components constitute the overall incentives available for DER proponents. Analysis of these incentives, and of the options for improving them through changes to rates, prices, programs and procurements available to DERs, are the pathway for improving the effectiveness of the regulatory framework in unlocking the value of DERs.

Improved incentives will better promote investment in new facilities, motivate proponents to select efficient locations for connecting to the electricity network, and to configure or reconfigure their operations to earn revenues for the services they can deliver.

To carry out this work, the OEB was guided by fundamental regulatory principles regarding the design of rates and prices:

- Fairness – sometimes referred to as the "beneficiary pays" principle, customers should, in general, pay rates that reflect the costs they cause; rates and compensation should be applied consistently
- Efficiency – rates and compensation should encourage efficient system use and rational system growth, including, where appropriate, capturing whether the value of a service varies by time or location

[1] The complete implementation directive issued to the OEB can be found at the following link: Minister's Directive June 11, 2025.

- Simplicity – rates and compensation should be practical, clear and free from controversy as to application or interpretation

- Effectiveness – rates should allow distributors to recover the prudently incurred costs of serving their customers and an opportunity to earn a fair return; compensation should be commensurate to the value of the service provided

Summary of DER Compensation

The OEB reviewed DER compensation to provide recommendations on compensation frameworks that appropriately reflect the system value of DERs. Its analysis focused on the balance between the revenues available to DERs and the value those resources can provide to the electricity system. The OEB, in consultation with the Independent Electricity System Operator (IESO), identified misalignments between the current compensation of DERs and their estimated value related to net metering, price-based mechanisms, compensation for transmission capacity benefits, and ability to receive compensation for multiple services (i.e., value stacking). A summary of recommendations is provided below.

Net metering:

By compensating injected electricity at the retail rate, net metering does not provide an adequate price signal for DERs. Furthermore, restrictions on net metering and community net metering limit the ability of customers to access this compensation mechanism. To provide an appropriate price-signal for electricity injected by DERs and increase accessibility of these compensation mechanisms for DER providers, the OEB recommends the Ministry of Energy and Mines, with support from the OEB, update net metering by:

- Transitioning from net metering to net billing which compensates injected electricity through a time-and location-based tariff.
- Removing regulatory restrictions on community net metering (or net billing if adopted) to enable projects in Ontario.
- Increasing the threshold at which distributors are required to accept customer net metering (or net billing if adopted) applications from one percent of annual peak load to two percent.

Price-based mechanisms:

OEB's assessment of price-based mechanisms assessed customers in accordance with the costs they pay for global adjustment.

Class B customers

The global adjustment rate paid by Class B customers not on the regulated price plan is inversely related to average monthly demand and thus does not provide an appropriate price-signal for DER deployment. To address this, the OEB recommends that the Ministry:

- Take steps to implement dynamic pricing, such as a time-of-use price plan, for Class B customers not on the regulated price plan to better align electricity prices with value provided.
- Since lower GA costs have improved the price signal these customers receive in the last year, it may be appropriate to monitor evolving commodity price dynamics before implementing dynamic pricing for this customer group.

Class A customers

Resources acquired by Class A customers to reduce consumption during bulk system peak periods as part of the Industrial Conservation Initiative (ICI) program may be able to provide distribution or transmission capacity value. To enable DERs operated by Class A customers to provide value through multiple streams where feasible, the OEB recommends the Ministry of Energy and Mines:

- Conduct a study of DERs that participate in the ICI to assess their ability to help meet distribution or transmission system needs. The IESO and OEB can support as required, including for example through the provision of data.

Compensation for transmission capacity value:

Limited compensation is available for DERs that provide transmission capacity value. Cost-effectiveness tests for demand-side management programs do not assess avoided costs or benefits to the transmission system. To enable non-wires solutions in regions with transmission system constraints, the OEB recommends that the IESO:

- Leverage procurements and/or programs within the IESO's resource adequacy framework to secure NWS with transmission benefits when they are identified as preferred solutions through the Regional Planning Process
- Include transmission avoided costs and benefits in cost-effectiveness tests for demand-side management programs when needs are identified in the Regional Planning Process.

Value stacking:

Accessing compensation for the different services DERs provide (i.e., "value stacking") is challenging for DER providers, particularly where the beneficiaries across services vary. A simplified, more accessible pathway for compensation would involve:

- Developing consistent and transparent approaches for distribution programs and/or procurements to support interoperability with the bulk system and compatibility with the IESO's resource adequacy framework. Examples of opportunities to develop consistent approaches include
    - Ontario's local electricity demand side management program (referred to as Stream 2 eDSM) and
    - the evolution of distribution system operator capabilities, led through the OEB's DSO Capabilities consultation as well as continued pilot and demonstration projects.

- Ensuring that IESO and electricity distributor programs/procurements explicitly allow for future value stacking opportunities, when resources are capable of providing multiple services (e.g., IESO's Local Generation Program allowing resources to earn revenue through other contracts).
- Considering expanding eligibility of the tariff developed for net billing to small front-of-the-meter resources that lack a value stacking pathway.

Electricity distributor-led DER Procurement
In response to IEP directive item 12, the OEB explored opportunities for electricity distributor-led DER procurements. Electricity distributors can, today, lead procurement of DERs to address distribution and/or certain transmission needs. The OEB identified how the distributor-led DER procurement will evolve through the implementation of the recommendations summarized above, and through other efforts underway to help such procurements become more common as DER value stacking is improved.

Summary of DER Delivery Rates
The OEB's review of DER Delivery Rates examines whether changes may be warranted to DER-related connection costs, base rates, specialized rates, and behind-the-meter rates.

The review draws on rate design principles as well as stakeholder feedback and considers opportunities to better align distribution and transmission delivery rate frameworks for electricity resources:

Delivery Rates for Front-of the-Meter Resources
- *Retail Transmission Service Rates:* The OEB will prioritize establishing Retail Transmission Service Rate exemptions for distribution-connected electricity storage resources that have been procured by the IESO and are, or will be, participants in the IESO-administered markets.
- *Base Rates:* In parallel, the OEB will also consider options for addressing potential exemptions to base delivery rates for front-of-the-meter DERs (such as storage) while ensuring fairness for customers and considering the impacts on electricity distributors.

Connection Costs
- The current DER connection cost responsibility framework, introduced following the Green Energy Act, allows renewable generation facilities to recover a portion their connection costs from distributors and all electricity customers. Other non-renewable DERs, including storage, must fully pay their connection costs.
- Given evolving trends in DER adoption, this report outlines three options for consideration by government on whether to maintain or alter these distinct cost-responsibility frameworks:
    a) Maintain a separate framework for renewable generation (status quo);

   b) Align storage with the treatment for renewable generation; or
   c) Harmonize connection cost responsibility framework for all DERs.
- The OEB will continue to examine its connection cost responsibility rules and will align with any updates the government may make in consideration of the recommendation above.

Behind the Meter Rates

- *Standby Rates:* The OEB will develop distributor best practices for standby rates as more electricity distributors finalize their interim standby rates.
- *Gross Load Billing and Net Load Billing:* The OEB will improve consistency in the application of Retail Transmission Service Rates for customers with behind-the-meter resources, including clarification of which DER types fall under gross load billing provisions.
- *Bypass Compensation:* The OEB will evaluate whether current rules in the Distribution System Code favour certain DER types and whether exemptions should extend beyond renewable generation to include other types of resources.

Specialized Rates

- The OEB continues to expect electricity distributors to apply consistent principles and/or methodologies for setting specialized DER rates. If any guidance is required as DER deployment grows, the OEB will aim to balance the benefits of consistency with flexibility for local circumstances.

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1. CONTEXT

Smaller, dispersed and decentralized generating resources such as solar and storage, as well as more dynamic customer demand, are already altering our electricity landscape in ways that can bring new opportunities for savings, efficiency gains and supply options for customers and system operators alike.

These resources, generally referred to as distributed energy resources, or DERs, are the subject of considerable focus in the Ministry of Energy and Mines' Integrated Energy Plan (IEP), *Energy for Generations.* The IEP highlights how "Ontario is driving high performance in the distribution sector, including through modernizing the grid to better integrate distributed energy resources and smart technologies that improve reliability, lower costs, and support greater system flexibility".[2] To achieve these objectives, DER investment must be deployed where it is most cost-effective and beneficial to local and system-wide needs.

> ***What are DERs?***
> DERs are electricity resources that generate electrical energy, store and discharge electrical energy, or dynamically modify electric load. They are connected directly to an electricity distribution system or an end-use customer's premises within a distribution system. A distinct part of their value is their location. When they are sited close to electricity loads or key delivery infrastructure, they can meet electrical demand and increase reliability all while being quick to deploy and cost-effective

The Minister of Energy and Mines issued implementation directives to the Ontario Energy Board (OEB) and the Independent Electricity System Operator (IESO) in tandem with the IEP. Item 11 in the implementation directive to the OEB states that the OEB shall:

> *Review the valuation of DER, in consultation with the IESO, as appropriate, to identify recommendations or provide an update on actions by the OEB regarding the overall regulatory and compensation frameworks to appropriately reflect the system value of DER. This report back should be completed by March 31, 2026, and could include, but is not limited to, consideration of:*
> - *Compensation mechanisms that reflect the value of DER (e.g., value of DER (VDER) tariff, adders to reflect differences in regional and temporal value).*
> - *Demand/delivery charges for resources that provide grid services (e.g., DER and storage).*

[2] Government of Ontario. June 2025. Energy for Generations.

- *Procurement and program mechanisms that support cost-effective DER deployment at local and bulk levels.*

Item 12 in the implementation directive to the OEB states that the OEB shall:

> *Consult with the IESO, as appropriate, to identify roles and responsibilities for implementing DER valuation recommendations and explore opportunities for electricity distributor-led DER procurements. This report back should be completed by June 30, 2026.*

Methodology

To prepare this report, the OEB reviewed DER valuation as two distinct components: DER compensation and DER delivery rates. DER compensation encompasses the monetary compensation DERs receive for the services they provide. The compensation that DERs receive and the delivery rates DERs pay together form the total incentives available to DERs in the province.

DER compensation can take the form of incentives (dollars paid directly to a DER provider) or bill reductions (savings from what DER providers would have paid on their electricity bills). DER delivery rates are the OEB-approved electricity distribution and transmission rates that DERs pay.

The combination of DER compensation (payments to DERs or avoided costs from DERs) and demand/delivery charges (costs DERs pay to use the electricity network) represent the overall valuation of DERs.

The goal of this review is to:

- support cost-effective DER deployment at local and bulk levels by aligning compensation for DERs with value provided;
- enhance clarity for customers and the sector;
- reduce undue barriers to DER participation; and
- identify further actions needed to ensure appropriate delivery rates for DERs.

2. DER COMPENSATION

2.1. Approach

The OEB reviewed DER compensation in Ontario through a qualitative analysis to identify potential misalignments in DER compensation relative to their estimated system value. In consultation with the IESO, the OEB developed recommendations to address those misalignments. Roles and responsibilities in the implementation of each recommendation were also identified. This information was presented to stakeholders in November 2025 to seek feedback from the sector.

DER compensation for a variety of DER types was evaluated using the value stack approach. This approach was developed in a prior study on DER compensation jointly commissioned by the OEB and the IESO (the IESO-OEB joint study).[3] The value stack identifies the different components (energy and capacity) and the different centralized power systems (i.e., "bulk systems") and local/regional systems (i.e., transmission and distribution systems), to which a DER may provide services. The approach provides a simple pathway (referred to as "stacking") to estimating the total value of a DER through a simple addition of the value provided through each component to which a DER provides services. The value of each component is assessed based on the benefit it provides to the system to which it contributes. Table 1 describes the components of the value stack used for this assessment. The full evaluation of DER compensation by DER type can be found in the stakeholder consultation materials.[4]

Table 1: DER Value Stack

Component	Description
Generation capacity	Value of the reduction in the generation capacity required to meet bulk system peak demand through distributed generation or reduced consumption during system peak hours.
Transmission capacity	Value of the reduction of regional peak demand imposed on upstream transmission assets.
Distribution capacity	Value of the reduction of local peak demand imposed on upstream distribution assets.

[3] Brattle Group, 2025. Assessment of Ontario's DER Compensation Mechanisms and Recommendations.

[4] The stakeholder consultation materials consisted of two documents: DER Valuation Stakeholder Engagement Presentation Materials and DER Valuation Stakeholder Engagement Supporting Materials. The presentation materials are a detailed summary of the OEB's review and proposed recommendations, which were presented to stakeholders at a meeting on November 24, 2025. The supporting materials were not presented during the meeting but are provided for additional context and supporting analysis.

Energy	Value of the reduction in energy required from centralized generation to meet load.
Emissions [5]	Value of the avoided emissions through the reduction in energy consumed from centralized generation.
Ancillary services	Provision of ancillary services, including frequency, regulation and operating reserves. *Ancillary services are not assessed in this study. While critical to the power system, ancillary services make up a relatively small component of all power system costs. For this reason, ancillary service benefits were not included in the assessment.*

Note that DER compensation should be informed by, but not necessarily equal to, the estimated value. The 'estimated value' as determined through the value stack is equal to the avoided cost of the traditional solution that would typically meet a system need (e.g., fulfilling a generation capacity need via a buildout of centralized generation capacity). As such, DER compensation that exactly equals estimated value has no incremental benefit to ratepayers (unless there are qualitative benefits not considered in the value stack). Additionally, compensation for the contribution of DERs to transmission capacity and bulk generation capacity should account for the availability and level of service provided by the DER (i.e., accounting for DERs that may not be available to serve both bulk and local systems at all periods).

This assessment led to an identification of various gaps and/or misalignments between current compensation of DERs and their estimated value. The full list of detailed gaps and/or misalignments identified can be found in the stakeholder consultation materials.[4] A summary of the gaps and/or misalignments is provided below.

- Net metering compensates electricity injected into the distribution system at the retail rate, which includes additional costs beyond energy delivered, such as capacity reserve to ensure supply adequacy as well as current and legacy programs for conservation, storage and industry. This results in cost recovery imbalance which shifts the financial burden of costs independent of energy volume onto non-net metered customers.
- Electricity distributors are only required to accept customer net metering applications until one percent of their annual peak load is net metered. This may

[5] In the IESO-OEB joint study, the value stack included externalities which included emissions value and beyond. This component was excluded from the assessment conducted in the value stack. For this review, the component was limited to emissions value which allowed for the inclusion of this component when assessing compensation under current mechanisms against the value stack.

be an unnecessary limit on customer ability to access this compensation mechanism.

- A Class B customer not on a regulated price plan using a DER to avoid the cost of electricity supplied via the grid is not compensated in line with the DER's value. This is a consequence of the way the Class B GA rate is determined. The Class B GA rate is inversely related to average monthly demand. Since the GA is primarily composed of out-of-market costs, the Class B GA rate is high when average wholesale market prices are low, and low when average wholesale market prices are high. This means the rate is higher during months when electricity is abundant and less expensive and lower when electricity supply conditions tighten and prices rise. In the last year, the Class B GA rate has been lower than previous years because average wholesale market prices have been higher. While this means that non-RPP Class B customers have been exposed to a more efficient price signal, the Class B GA rate is still inversely related to average wholesale market prices and dampens the effectiveness of the overall commodity price they pay.
- DERs acquired by ICI participants are primarily used to enable ICI participants to reduce demand during the peak hours of the year, and in some cases to participate in the capacity auction. There may be an opportunity to use these resources outside of these periods.
- Compensation for distribution and transmission capacity benefits provided by DERs in regions with system constraints is limited or unavailable.
- Demand-side management programs do not include transmission avoided costs and benefits in their cost-effectiveness tests.
- DER value stacking can be challenging due to the complex interactions between different compensation mechanisms. Since most mechanisms typically cover one or two components of system value, stacking requires participation in more than one mechanism. Many existing compensation mechanisms with different eligibility requirements and compensation methods make DER compensation complex and difficult to navigate. Methods for acquisition and operation of DERs by electricity distributors are not widely established and complexities in interoperability with the bulk system limit the ability of DER providers to offer multiple services and value stack.
- Front-of-the-meter DERs that cannot participate in medium or long-term procurements or the capacity auction are not compensated for generation capacity benefits. FTM resources that do not meet the eligibility requirements of any of the IESO's resource adequacy mechanisms do not have value stacking opportunities.

2.1.1. DER compensation in other jurisdictions

DER compensation mechanisms in four jurisdictions – New York state, Hawaii, Australia and California – were reviewed. These jurisdictions were chosen based on levels of DER integration, DER policy goals and regulatory reforms related to DER compensation. The detailed jurisdictional scan can be found in the stakeholder consultation materials. Included below is a summary of the key takeaways from the jurisdictional scan that informed the net metering recommendations.

Each jurisdiction reviewed has made changes to compensation for electricity injected into the distribution system. These changes involved moving away from net metering to a compensation structure that values injected electricity at a different rate from consumed electricity.

New York transitioned from net metering to the Value of DER (VDER) tariff in 2017 to establish a price signal for DER products and services that more accurately reflects the value they create for the electricity system, as well as appropriately allocate compensation costs to customers that benefit from the savings associated with the compensated DER.[6] The VDER tariff is a time and location-varying rate that applies to electricity injected into the distribution system, as opposed to net metering where electricity injected into the distribution system is valued at the retail rate.

After significant rooftop solar uptake, Australia phased out high feed-in-tariff rates in 2011 and transitioned to lower retailer-set, locational-specific rates for net solar energy injected into the grid.

After distributed solar capacity rose to approximately 12 per cent[7] of total installed capacity, Hawaii replaced net metering with a series of successive DER tariffs in 2015.[8] This shift was driven by grid reliability concerns, cross-subsidy concerns between customer groups, and the need to better align DER compensation with system value. The DER tariffs that followed allowed customers to offset their own consumption and, in some cases, export electricity to the grid at rates below the retail price. Some tariffs restricted exports to specific times of day, while others allowed utilities to curtail electricity exports during periods of grid stress or saturation. The rates available today require customers to enroll in a time-of-use rate, which incentivizes shifting energy consumption to off-peak hours. This has increased the number of battery systems paired with customer-sited generation, with 96 per cent of residential systems paired with energy storage as of 2022.[9]

After over two decades of net metering, California initiated a transition in 2022 to net billing, which compensates electricity exports at hourly rates that differ from rates

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[6] State of New York Public Service Commission. March 9, 2017. *Order on Net Metering Transition, Phase One Value of DERs, and Related Matters*.

[7] In 2014, Hawaii's total bulk generation capacity was 2,672 MW (U.S. Energy Information Administration, *Form EIA-861M*) and total distributed solar capacity was 327 MW (U.S. Energy Information Administration, *State Electricity Profiles*).

[8] Lawrence Berkeley National Laboratory. July 24, 2019. *Current Developments in Retail Rate Design: Implications for Solar and Other Distributed Energy Resources*.

[9] Lawrence Berkeley National Laboratory. September 2023. Tracking the Sun, 2023 Edition - Energy Markets & Planning.

applied to consumed electricity. While typically lower than retail prices, the rates paid for electricity injected into the distribution system under net billing can exceed retail prices during peak demand periods. This transition was undertaken to address a 2021 California Public Utilities Commission report finding that solar customers often pay less than the actual cost to serve them, leading other ratepayers to cover the difference.[10]

2.2. Review & recommendations

To address the gaps identified through the assessment of DER compensation described in Section 2.1., the OEB recommends modifying the DER compensation landscape as follows:

- **[Section 2.2.1.]** Transition from net metering to net billing which compensates injected electricity through a time-and location-based tariff.
- **[Section 2.2.2.]** Remove regulatory restrictions on community net metering (or net billing if adopted) to enable projects in Ontario.
- **[Section 2.2.3.]** Increase the threshold in the Distribution System Code (DSC) under which distributors are required to accept customer net metering applications from one percent of annual peak load to two percent.
- **[Section 2.2.4.]** Take steps to implement dynamic pricing, such as a time-of-use price plan, for Class B customers not on the regulated price plan to better align electricity prices with value provided.
- **[Section 2.2.5.]** Conduct a study of DERs that participate in the ICI to assess their ability to help meet distribution or transmission system needs (i.e. assess whether resources are located where local/regional constraints are not coincident with bulk system peaks).
- **[Section 2.2.6.]** Enable DERs to provide transmission capacity value by:
    - Including transmission avoided costs and benefits in cost-effectiveness tests for demand-side management programs when needs are identified in the Regional Planning Process.
    - Leveraging procurements and/or programs within the IESO's resource adequacy framework to secure non-wires solutions with transmission benefits when they are identified as preferred solutions through Regional Planning.
- **[Section 2.2.7.]** Enable value stacking by:
    - Developing consistent and transparent approaches for distribution programs and/or procurements to support interoperability with the bulk system and compatibility with the IESO's resource adequacy framework.
    - Ensuring that IESO and electricity distributor programs/procurements explicitly allow for future value stacking opportunities when resources

[10] California Public Utilities Commission. January 28, 2021. *Alternative Ratemaking Mechanisms for Distributed Energy Resources in California*.

are capable of providing multiple services (e.g., IESO's Local Generation Program allowing resources to earn revenues through other contracts).
  - Considering expanding the eligibility of the tariff developed for net billing to include small front-of-the-meter resources that lack a value stacking pathway.

2.2.1. Transition from net metering to net billing

Misalignment / Gap

Net metering compensates electricity injected into the distribution system at the retail rate, which includes additional costs beyond the energy value delivered, such as capacity reserve to ensure supply adequacy as well as current and legacy programs for conservation and storage. In addition, some retail rates, such as Ontario's regulated price plans are designed based on principles such as simplicity and predictability which make these rates inappropriate as compensation for injected electricity, the value of which can vary greatly by season, day and time of day. The use of retail rates to compensate for injected electricity therefore results in a cost recovery imbalance which increases financial burden onto non-net metered customers.

To appropriately reflect the value of electricity injected into the distribution system, the OEB sought stakeholder feedback on considering a transition from net metering to net billing, in which electricity injected into the distribution system is compensated at a market-reflective value. This value should be a function of the time and location electricity is injected to support the prudent expansion of DERs where they are cost-effective.

What we heard from stakeholders

Most stakeholders supported this recommendation and agreed that a transition from net metering to net billing would appropriately address the issue identified. One stakeholder said that transitioning to an approach that is more cost-reflective would send improved price signals to customers and minimize the cross-subsidization of non-participants. Another said that net billing would improve ratepayer equity and encourage prudent DER expansion.

Some stakeholders also highlighted implementation considerations such as the complexity of determining a time and location-dependent value for net billing. One stakeholder said that jurisdictions that have implemented net billing used a detailed regulatory process to define value-stack parameters, compensation levels and billing rules, and that it is unclear how to meaningfully establish locational and time value on a large scale. The stakeholder also commented that developing these frameworks is time-consuming and often contentious, with the risk of inappropriately valuing DER attributes or failing to capture system value comprehensively.

Some stakeholders recommended a gradual or staged transition to net billing and possibly "grandfathering" in current net metered customers to avoid disrupting the investment return of assets already in place or dampening the momentum of DER adoption.

One stakeholder recommended removing the 12-month limit on credit carry-over.

Discussion and next steps

The OEB recommends transitioning from net metering to net billing in which electricity injected into the distribution system is compensated at a cost-reflective time- and location-based tariff. The implementation of this recommendation will provide a price signal to enable the prudent expansion of behind-the-meter DERs (i.e., behind-the-meter DERs are deployed where the value they provide is higher than the cost of deploying them). While initially for individual behind-the-meter net billed customers, it can also be expanded to facilitate prudent expansion for community net metering (as discussed in section 2.2.2) and value stacking for small front-of-the meter resources (as discussed in section 2.2.7).

Determining appropriate timing for the implementation of the net billing tariff will need to balance the following considerations:

- As residential distribution rates do not depend on the volume of electricity consumed (therefore residential net-metered customers still pay their fair share for use of distribution assets), and the adoption rate of net metering is low (less than one percent) the cost recovery imbalance caused by net metering (described above) is currently small. However, this imbalance is expected to grow with increased DER adoption and implementation of net billing should be timed to avoid a rapid increase of this cost recovery imbalance.
- The net billing tariff has also been recommended for use in several other recommendations (community net metering, and value stacking) in this report. As such, successful implementation of these recommendations hinge on the timely implementation of the net billing tariff.

The transition to net billing should also consider a legacy provision for existing net metering customers to account for the payback period of assets already deployed and ensure these customers are provided with adequate notice for any changes to compensation.

The timeline to implement net billing should be paced to consider ongoing changes in the sector and the capacity of stakeholders to engage in the process to define compensation levels. A time- and location-based tariff paid for electricity injected at the distribution level could consist of the following:

- Energy: a dynamic energy price (e.g., locational marginal pricing)

- Generation Capacity: a forward-set price matched to an appropriate prevailing IESO-determined capacity price (e.g., capacity auction settling price)
- Transmission Capacity: a forward-set price depending on time and location (granularity to be determined, zero where no constraint exists)
- Distribution Capacity: a forward-set price depending on time and location (granularity to be determined, zero where no constraint exists)
- Emissions value: zero, unless otherwise specified by government policy.
- Ancillary services: zero. Ancillary services provided by DERs should be compensated for separately from a net billing tariff to allow for activations.

Since the net billing tariff would provide an appropriate price signal for injected electricity, consideration could also be given to removing the 12-month limit on credit carry-over currently in place for net metering as suggested by a stakeholder. Implementation for the transition to net billing would need to consider how to appropriately handle remaining customer credits. This would allow the prudent expansion of DERs without the risk of shifting costs to non-net billed customers.

A net billing tariff should continue to be mutually exclusive with IESO eDSM offerings for distributed generation as net metering is today. This is because combining these two compensation mechanisms (i.e., receiving the upfront incentive offered via eDSM and enrolling in net metering) would result in overcompensating for value provided. The compensation for both mechanisms (net billing and eDSM) is set to be approximately equal to the value provided, so combining them is effectively doubling compensation.

2.2.2. Remove restrictions on community net metering

Misalignment / Gap

Community net metering is limited by regulation to pilot or demonstration projects. Amendments to the community net metering regulation are required for each new community net metering project, which serves as a barrier for new projects. The OEB sought stakeholder feedback on amending the community net metering regulation, subject to local distribution system conditions, to:

- Remove the requirement that each community net metering project be explicitly listed in the regulation.
- Reflect any changes made to net metering compensation if a transition to net billing is made (see Section 2.2.1.).

What we heard from stakeholders

Stakeholders generally supported the recommendation to remove the requirement that each community net metering project be explicitly listed in the community net metering regulation. However, one stakeholder cautioned that significant uptake may trigger distribution upgrades which could increase ratepayer costs. Representatives of electricity distributors said that expanding eligibility would require establishing clear criteria, governance processes and safeguards against unintended cross-subsidization.

Discussion and next steps

The OEB recommends that the community net metering regulation (Ontario Regulation 679/21) be amended to be applicable beyond pilot or demonstration projects to enable community net metering projects within Ontario. The following amendments to the community net metering regulation are recommended:

- Remove the requirement that each community net metering project be explicitly listed in the regulation.
- Reflect any changes made to net metering if a transition to net billing is made (see Section 2.2.1.).

Expansion of community net metering in tandem with the net billing tariff further enables DERs where system needs exist and provides flexibility for DER providers who may not be able to implement traditional net metering solutions (e.g., residents without individually metered rooftops).

As part of the recommended amendments to community net metering, the OEB also recommends considering allowing community net metering for front-of-the-meter resources with applicable restrictions (e.g., all project loads and generation sources are on the same feeder) to enable projects where co-location of a load and generation source behind a single meter is not possible.

The OEB notes that enabling community net metering projects would also require consideration be given to eligibility requirements that limit cost increases for other customers. Examples of eligibility requirements may include local distribution system conditions as well as potential restrictions on components within a project.

2.2.3. Remove restrictions on net metering

Misalignment / Gap

Electricity distributors are only required to accept customer net meter applications until the total net metered generation equals one per cent of the distributor's three-year average annual peak load.[11] The purpose of this threshold is to mitigate potential impacts of intermittent generation and inverter-based resources which can result in increased costs or operational challenges for distribution and transmission systems (such as balancing of supply and demand, voltage control or frequency regulation as well as potentially triggering the needs for investments in distribution equipment and infrastructure). However, the existing threshold of one per cent may be lower than necessary to mitigate potential impacts of bidirectional flow and limits customer ability to

[11] Ontario Energy Board, 2025. Page 122-133. Distribution System Code.

access net metering as a compensation mechanism. The OEB sought feedback on reviewing restrictions on net metering within the DSC to ensure DERs are enabled while protecting distribution customers from increased costs due to technical impacts of increased bi-directional electricity flow.

What we heard from stakeholders

Stakeholders in general supported a review of net metering restrictions within the DSC. One stakeholder suggested that the one per cent peak threshold should be increased gradually to monitor the technical impacts of increased bi-directional flow to ensure there are no impacts to reliability. One stakeholder said that this threshold may not be a barrier since electricity distributors can exceed it at their discretion.

Discussion and next steps

The OEB reviewed the current state of net metered load by electricity distributor and found that six of them exceeded the one per cent threshold in 2024. Forecasting current trends into the future, twenty distributors may exceed the one per cent threshold by 2030 and half of all distributors (approximately thirty) may exceed the threshold by 2037.[12] Due to accelerating trends in DER adoption, this may be a conservative estimate of resources interested in net metering. However, alternate compensation mechanisms for these resources, such as upfront incentives provided by eDSM programs such as the Home Renovation Savings[13] program could lower net metering adoption.

The OEB also analyzed the jurisdictions assessed as part of the jurisdictional scan to understand if any had similar requirements for distributors to accept net metering applications. In California, utilities can reject new customer applications for net billing if net billing generating capacity exceeds five per cent of the utility's aggregate customer peak demand.[14]

As a result, the OEB proposes to amend the DSC to increase the threshold at which distributors are required to accept net billing applications from one per cent to two per cent. This modest increase will ensure DERs are enabled while protecting distribution customers from increased costs due to technical impacts of increased bi-directional electricity flow.

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[12] This forecast linearly extrapolates 2019-2024 data from OEB's Open Data repository and does not include resources with expiring microFIT contracts. While some of these resources may be interested in net metering when their contracts expire, they are not located uniformly across distributor service areas which means they would impact distributor thresholds for net metering differently. Additionally, some may be eligible for the Local Generation Program. The data used can be found in Table 1 and Table 5 at the following link: Electricity Reporting & Record Keeping Requirements: Sections 2.1.14 and 2.1.14.1. See the OEB's Open Data Guide for further information on how to import and use the OEB's Open Data files.

[13] More information on the Home Renovation Savings program can be found on the program website at the following link: Home Renovation Savings.

[14] California State Assembly Committee on Utilities and Energy. April 30, 2025. Assembly Bill 942.

2.2.4. Take steps to implement dynamic pricing for non-RPP Class B customers

Misalignment / Gap

A Class B customer not on a regulated price plan using a DER to avoid the cost of electricity supplied via the grid is not compensated in line with the DER's value. This is a consequence of the way the Class B GA rate is determined. The Class B GA rate is inversely related to average monthly demand. Since the GA is primarily composed of out-of-market costs, the Class B GA rate is high when average wholesale market prices are low, and low when average wholesale market prices are high. This means the rate is higher during months when electricity is abundant and less expensive and lower when electricity supply conditions tighten and prices rise. Therefore, avoided electricity consumption of grid supply from DERs operated by Class B customers not on the regulated price plan (non-RPP) is compensated at a lower rate when it has higher value, and at a higher rate when it has lower value. Similarly, storage DERs operated by non-RPP Class B customers must pay this rate for the electricity lost due to storage efficiency, which means they pay a higher rate to store electricity when electricity has a lower value and vice versa. Overall, the rate does not encourage efficient use of electricity system assets including DERs.

GA is one component of electricity commodity prices all customers in Ontario pay. The other component is the wholesale market price. Over the last decade, GA has made up the majority of commodity prices. In the last year, average wholesale market prices have been higher than prior years, which lowered the out-of-market costs recovered through GA. As a result, GA made up a lower share of overall commodity prices in the last year. While this means that non-RPP Class B customers have been exposed to a more efficient price signal, the Class B GA rate is still inversely related to average wholesale market prices and dampens the effectiveness of the overall commodity price they pay. Higher wholesale market prices do not structurally change the fact that the Class B GA rate is high when average wholesale market prices are low, and low when average wholesale market prices are high. Unless GA becomes a negligible component of commodity costs, the Class B GA rate will still distort the price signal communicated through commodity prices to non-RPP Class B consumers.

The OEB's work on dynamic pricing for non-RPP Class B customers has identified price plans that would provide an improved price signal to better communicate when electricity is abundant and prices are low, and when electricity supply tightens and prices are higher.[15] Implementing such a price plan would address this gap.

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[15] The OEB is exploring potential opt-in price plans for Class B consumers that are not eligible for RPP prices. More information about the price plans can be found on the Dynamic Pricing Options for Non-RPP Class B Electricity Consumers project page.

The OEB sought stakeholder feedback on encouraging efficient use of DERs by implementing dynamic pricing for non-RPP Class B electricity customers.

What we heard from stakeholders

Stakeholders expressed general support for implementing dynamic pricing for non-RPP Class B electricity customers, saying it would provide improved price signals from the status quo Class B GA rate. Some stakeholders suggested considering the potential rate impacts on other customers, particularly RPP and low-income customers. Another stakeholder recommended it should not be implemented until there is a comprehensive review of the GA to ensure there are no unforeseen impacts on other ratepayers.

Discussion and next steps

The OEB recommends taking steps to implement dynamic pricing, such as a time-of-use price plan, for non-RPP Class B customers to better align electricity prices with value provided. Dynamic pricing would provide an improved price signal to better communicate when electricity is abundant and prices are low, and when electricity supply tightens and prices are higher. This would enable efficient use of DERs for this customer class.

The OEB has assessed the impacts of dynamic pricing options for non-RPP Class B customers and found that the price plans considered minimally impact non-adopters. Data representing over 50 per cent of this customer group from 2021-2023 was analyzed to test the bill impacts of the candidate price plans. The impact of the optional price plans on non-RPP Class B customers who do not adopt was found to be less than or equal to 0.3 per cent of the GA portion of their bills.[16] Reforms could be designed to not impact RPP customers (including low-income customers). This addresses the stakeholder concern raised regarding impacts to other customers.

Based on the OEB's prior work on dynamic pricing options for non-RPP Class B customers, the Ontario government is considering implementing dynamic pricing for these customers via a new optional electricity pricing plan that would potentially establish a fixed GA price for each period of the day (i.e., a time-varying GA charge) for non-RPP Class B consumers.[17] If this pricing plan proceeds, the OEB will support implementation by:

- Setting prices for optional price plan(s),
- Issuing new regulatory accounting guidance for electricity distributors, and
- Developing communications materials.

[16] The approach and results of the bill impacts of the candidate price plans can be found at the September 9th 2025 Stakeholder Meeting presentation at the following link: https://www.rds.oeb.ca/CMWebDrawer/Record/862912/File/document

[17] More information can be found on the regulatory posting at the following link: https://www.regulatoryregistry.gov.on.ca/proposal/52855.

Any option chosen for implementation should consider the evolving dynamics of the total commodity costs these customers pay and how higher wholesale market costs in the last year have improved the price signal they receive. Further, any steps taken with respect to non-RPP customers should take into account broader industrial policy and any related pricing reforms or programs that may also be advanced by government and its agencies. Dynamic pricing for non-RPP Class B customers as set out in the OEB's separate report should be complementary to those broader reforms.

2.2.5. Assess the ability of Industrial Conservation Initiative resources to help meet distribution or transmission system needs

Misalignment / Gap

DERs acquired by ICI participants are primarily used to enable ICI participants to reduce demand during the peak hours of the year. There may be an opportunity to use these resources outside of these periods. To understand if ICI resources could be used for other system needs, the OEB sought stakeholder feedback on exploring ways to make more efficient use of ICI resources outside of bulk system peak periods, including consideration of opportunities to provide transmission and/or distribution capacity value where local or regional needs are identified.

What we heard from stakeholders

Some stakeholders expressed support for the recommendation to use ICI resources outside of bulk system peaks, saying that providing compensation for transmission or distribution value improves system value by encouraging DERs to be located where system constraints exist that are not coincident with bulk system peak periods. One stakeholder also expressed support, provided any changes are incremental to the current ICI compensation structure and no trade-offs are created as a result of making changes to the existing mechanism.

One stakeholder said that the OEB should revisit how transmission Network Service Rates are determined[18], including removing Part B of the Network Billing Demand determinant since it would create the potential for Class A customers to avoid the monthly peak, thereby providing additional system value. Comments also highlighted a need for OEB and IESO collaboration to ensure that eligibility and methodology rules for ICI participants regarding stacking of DER benefits are clear, including giving consideration to developing a tool to help ICI participants determine their value stack.

[18] The Network Service Rate is determined as a dollar per kW of Network Billing Demand Billing, which is defined as the higher of: (a) customer coincident peak demand in the hour of the month when the total hourly demand of all Provincial Transmission Service customers is highest; and (b) 85 per cent of the customer peak demand in any hour during the peak period 7 a.m. to 7 p.m. on weekdays, excluding holidays as defined by the IESO. See Decision and Order on 2026 Uniform Transmission Rates – EB-2025-0232. January 15, 2026.

One stakeholder highlighted challenges associated with using DERs installed for ICI for other uses, since there is a high probability that local system needs align with transmission system needs. Other stakeholders said that pathways for broader use may already exist, as some non-wires solutions programs administered by electricity distributors (such as Toronto Hydro's Local Demand Response) enable ICI participation.

Discussion and next steps

The OEB recommends the Ministry, with the support from the OEB and data from the IESO as appropriate, undertake a study to characterize existing ICI resources to determine the scale of the available opportunity of these resources to bring value to other system needs outside of bulk system peak periods. To streamline processes and ensure any identified solution is actionable, this study should be undertaken in the context of ongoing regional planning efforts. Efficient use of these resources is likely only possible where ICI resources are located on a constrained circuit and where the circuit constraint is not coincident with the bulk system peak demand hours of the year. A study of existing resources is necessary to understand whether sufficient opportunity exists before proceeding.

Independent of savings available through participation in ICI, these resources may still be able to bring value to other system needs outside of reducing their consumption during periods of high demand through ICI or capacity auction participation. As described in Section 2.2.4, as average wholesale market prices have increased in 2025 compared to prior years, GA has been a lower share of the commodity price for all electricity customers, including Class A. This means that the possible savings that can be achieved through ICI participation have been lower through 2025 and observable months in 2026 to date than prior years.

The determination of transmission network service rates paid by ICI participants was raised by a stakeholder and intersects with both the DER Compensation and Delivery Rates parts of this work. While the transmission charges paid by ICI participants have not been directly reviewed for this report, the OEB has noted the recommendation and may consider this issue in the future (for example, as part of the OEB's ongoing review of issues related to Uniform Transmission Rates [UTRs]).

2.2.6. Enable DERs to provide transmission capacity value

Misalignment / Gap

Compensation mechanisms for transmission capacity value provided by DERs in regions with transmission system constraints is limited or unavailable. In addition, electricity demand-side management programs, do not include transmission avoided costs and benefits in their cost-effectiveness tests.[19] While distributors may compensate

[19] The design of Ontario's local electricity demand-side management program, referred to as Stream 2 eDSM, is currently under development and is likewise proposed not to include transmission avoided costs.

local DER providers directly to address local system needs, examples of current agreements are limited. Only one example identified through this work included compensation for transmission capacity value and this was Toronto Hydro's Local Demand Response Program.[20]

The OEB sought stakeholder feedback on two proposed recommendations to address this issue:

1. Where appropriate, leverage procurements and/or programs within the IESO's resource adequacy framework to secure transmission non-wires solutions when they are identified as preferred solutions through the Regional Planning Process.
2. Incorporate a transmission-avoided cost framework in DSM cost-effectiveness tests when needs are identified in the Regional Planning Process.

What we heard from stakeholders

Some stakeholders expressed support for the recommendation to leverage IESO resource adequacy framework procurements and programs to secure transmission non-wires solutions. One stakeholder said that it would enhance the value DERs can deliver to the system by capturing costs for previously unvalued components of the value stack while maintaining access to DER compensation mechanisms. Some stakeholders said the framework should support the adoption of technically feasible and cost-effective resources, as well as adequately consider operational challenges and costs incurred by distributors.

Some stakeholders said the recommendation to incorporate a transmission-avoided cost framework in electricity DSM cost-effectiveness tests will provide a more appropriate valuation of DERs since it provides a mechanism for including previously excluded benefits for unvalued system components, and it will encourage the adoption of targeted eDSM and DERs to address transmission constraints. Some comments also highlighted the need to ensure electricity DSM cost-effectiveness tests are designed to ensure the adoption of cost-effective solutions, as well as ensure consistency in evaluating avoided transmission costs within the regional planning framework, the OEB's Benefit-Cost Analysis Framework and eDSM Stream 2 programs.

Discussion and next steps:

The OEB recommends moving forward with these recommendations. Implementation of the second recommendation, i.e., incorporation of a transmission-avoided cost framework for electricity DSM cost-effectiveness testing should ensure alignments with

[20] More information about this program can be found at the following link: https://www.torontohydro.com/local-demand-response-program

the regional planning framework, the OEB's Benefit-Cost Analysis Framework and the eDSM Stream 2 programs as appropriate.

The recommendation to leverage the IESO's resource adequacy framework to secure transmission non-wires solutions when they are identified as preferred solutions through the Regional Planning Process is a continuation of current processes. The IESO will continue to apply its non-wires alternatives guidelines[21] in all regional planning areas to ensure all plans consider and, where cost-effective, identify local solutions such as DERs which could be implemented through eDSM programs or IESO procurements. These solutions can be implemented through eDSM programs by:

- advising electricity distributors and service providers to focus their promotional efforts funded through the IESO on customers connected to the areas of need;
- providing incremental incentives in existing programs in specific areas (regional "adders"); and,
- identifying and implementing specific programming opportunities targeting local areas (Local Initiatives).

These solutions can be implemented through IESO procurements by:

- In procurements targeting energy or capacity, reserving capacity in constrained circuits only for projects that could meet the identified non-wires solution need.
- Exploring using rated criteria to encourage projects that meet the identified need while also compensating proponents for potentially higher costs of meeting the non-wires solution need in future procurements.
- Exploring the need for non-wires solution specific procurements in the future.

The recommendation to incorporate a transmission avoided cost framework in electricity demand-side management cost-effectiveness tests will further enable NWS in regions with transmission system constraints. To implement this recommendation, the IESO will build a framework for transmission avoided costs to consistently inform how regional avoided costs are considered by the electricity demand-side management cost-effectiveness tests and the OEB's Benefit-Cost Analysis Framework. The framework will evolve over time, beginning with a streamlined approach leveraging local deferral values previously identified in completed regional plans, and evolving to transparent documentation of regional avoided costs. The IESO intends to undertake the development of this more comprehensive approach through 2027 and 2028.

2.2.7. Enable value stacking

Misalignment / Gap

Value stacking refers to the ability of DER providers to access compensation for DERs that provide benefits through multiple components and/or systems (e.g., a DER that

[21] The IESO's non-wires alternatives guidelines can be found at the following link: [Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives]

provides energy to the bulk system and capacity to the distribution system). As the beneficiaries across the different services a DER provides may vary, the appropriate party for compensating the DER provider for each service also may vary. As such, value stacking typically requires DER providers to access more than one compensation mechanism, typically developed by different parties. Through the analysis conducted for this report-back, it was identified that DER value stacking can be challenging due to the complex interactions between these different compensation mechanisms. Since most mechanisms typically cover one or two components of system value, stacking requires participation in more than one mechanism.

Many existing compensation mechanisms with different eligibility requirements and compensation methods make DER compensation complex and difficult to navigate. In addition, methods for acquisition and operation of DERs by distributors are not widely established. DER deployment also requires distributors to invest in enabling infrastructure such as enhanced grid monitoring and control solutions, as well as back-office platforms to mitigate against the potential adverse impacts of increased DER deployment (e.g., grid instability, adverse power quality and reliability impacts, increased safety risks). Furthermore, complexities in interoperability with the bulk system limit the ability of DER providers to offer multiple services and value stack.

Some value stacking is possible today. Distributors are allowed to fund non-wires solutions such as DERs intended to primarily serve a specific distribution or transmission capacity need through rates, as specified in the *Non-Wires Solutions Guidelines for Electricity Distributors.*[22] This is the only pathway through which DER providers can earn compensation for distribution and/or transmission capacity benefits today and it remains somewhat rare. Eligible generation, storage and some load-modifying DERs can earn revenues through participation in the IESO's wholesale market. While 5-minute dispatchable resources larger than 1 MW in size are eligible to participate in IESO wholesale markets, smaller resources have limited opportunities.

Ongoing initiatives such as the IESO's Enabling Resources Program (ERP) and Stream 2 eDSM will improve value stacking opportunities for DERs. ERP will allow aggregated DERs to access IESO-administered markets and provide them with an opportunity to value stack with distribution level programs. Ontario's local electricity demand side management program, established through a Ministerial Directive and referred to as Stream 2 eDSM, was designed to directly enable value stacking for behind-the-meter resources. Stream 2 eDSM is expected to provide electricity distributors a funding mechanism to design and deliver behind-the-meter programs that consider generation capacity, distribution capacity and energy benefits and costs to determine the

[22] Ontario Energy Board, March 28, 2024. *Non-Wires Solutions Guidelines for Electricity Distributors, EB 2024-0118*. Available at: https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2024-04/OEB_2024%20NWS%20Guidelines_20240328.pdf

appropriate compensation level for DERs in locations with system constraints. Under this program, compensation for DERs will be allocated between distributors and the IESO based on the DERs contribution to bulk vs. local system benefits as quantified through a cost-effectiveness test (such as the OEB's BCA Framework). Future enhancements to Stream 2 eDSM may also consider transmission capacity costs and benefits. Stream 2 eDSM provides a simple model for value stacking through program design – a gap remains for a similar mechanism for front-of-the meter resources.

In the future, developing DSO capabilities may provide more opportunities for distributors to offer compensation where local constraints exist. Paired with bulk system compensation streams such as the capacity auction, for example, this would provide additional avenues for DER value stacking.

With consideration of the existing mechanisms and ongoing initiatives described above, the OEB sought stakeholder feedback on the following recommendations to improve DER value stacking:

1. Establish a cost allocation and delivery framework for front-of-the-meter and market-participating DERs that have both distribution and bulk value.
2. Enable value stacking by developing consistent and transparent approaches for distribution programs and/or procurements to support interoperability with the bulk system and compatibility with the IESO's resource adequacy framework. Areas where this work will be carried out include the evolution of the approach to distribution system operator capabilities, via the OEB's DSO Capabilities consultation, and further support for distributor-led DER acquisition via Stream 2 eDSM programs.
3. Ensuring that IESO and distributor programs/procurements explicitly allow for future value stacking opportunities, when resources are capable of providing multiple services. (e.g., IESO's Local Generation Program allowing resources to earn revenue through other contracts).
4. Develop a simplified process or tool for DER providers to easily understand and assess available mechanisms for their resources and identify best available pathways to compensation for the services they provide.

What we heard from stakeholders

Some stakeholder comments expressed strong support for the recommendation to establish a cost allocation and delivery framework for front-of-the-meter and market-participating DERs, saying it will encourage the adoption of DERs that can meet bulk and distribution system needs. Other stakeholders highlighted the need to engage distributors in the development of the framework, given their visibility into local grid constraints and customer relationships, and to ensure their operational requirements are adequately considered.

Stakeholders expressed general support for the recommendations to enable value stacking by developing consistent and transparent approaches for distribution programs and/or procurements, saying DERs should be eligible to receive compensation for each service they provide to the distribution and bulk systems. Some stakeholders said distributor and IESO programs and procurements should be standardized or mutually compatible to ensure consistent value stacking pathways for all customer classes and DER types. Conversely, one stakeholder suggested it is too early to standardize distribution procurements as non-wires solutions are still in their infancy, and the sector is still testing different approaches to using DERs as non-wires solutions. One stakeholder also recommended that compensation costs should be recovered from the customers benefiting from a DER, and consideration should be given to developing new mechanisms necessary to achieve this outcome.

One stakeholder also provided three specific recommendations for enabling value stacking. First, the OEB should provide outcomes-based cost-recovery guidance for grid modernization investments. That guidance would include establishing a dedicated regulatory mechanism to allow distributors to recover costs for qualifying grid modernization investments, defining eligible investments and requiring distributors to include grid modernization plans and progress metrics in their next Distribution System Plans. Second, regulatory guardrails for local flexibility markets should be established, including rules for DER procurement, neutrality, dispute resolution, performance assurance and appropriate market monitoring and oversight functions. Finally, to establish clear co-ordination protocols, implement the IESO's Transmission-Distribution Working Group protocols for day-ahead and real-time co-ordination, including sequential dispatch logic prioritizing distribution needs.

Other stakeholders suggested that enabling value stacking should be explicitly linked to the development of DSO capabilities, as they are critical to enabling the integration, co-ordination and dispatch of DERs to capture full value-stack benefits at both distribution and bulk system levels. Some stakeholders also said that Ontario's storage market is dependent on GA peak management, and new mechanisms are needed to unlock the broader local and bulk system services such resources can provide.

Some stakeholders also expressed support for the recommendation to develop a simplified process or tool to enable value stacking, saying it would help DER providers navigate the various compensation pathways available to them. Comments were also provided on enhanced support for smaller providers, including the use of plain language in the development of a tool, as well as establishing a single-entry point with a dedicated resource team to support navigation. One stakeholder said this recommendation is not appropriate, since it assumes that DERs always provide beneficial services and there are times when the excess power generated by DERs are surplus to the grid and may displace more reliable or less costly alternatives.

Discussion and next steps

The OEB recommends enabling value stacking by:

- Developing consistent and transparent approaches for distribution programs and/or procurements to support interoperability with the bulk system and compatibility with the IESO's resource adequacy framework. Examples of opportunities to develop consistent approaches include Ontario's local electricity demand side management program (referred to as Stream 2 eDSM) and the OEB's proposed examination of flexibility services through its DSO Capabilities consultation.
- Ensuring that IESO and distributor programs/procurements explicitly allow for future value stacking opportunities, when resources are capable of providing multiple services. (e.g., IESO's Local Generation Program allowing resources to earn revenue through other contracts).

The OEB recommends waiting to develop a simplified process or tool for DER providers to easily understand and assess available mechanisms until programs and procurements are more established.

- Five-minute dispatchable resources, either stand-alone or aggregated, will be able to value stack via participation in the wholesale energy market for energy value compensation, IESO procurement contracts or the capacity auction for bulk generation value compensation and distributor contracts for distribution capacity value. Once distribution-level markets develop, these resources may receive distribution capacity value through distribution-level markets or through distributor contracts.
- Behind-the-meter resources that are not 5-minute dispatchable will be able to value stack through eDSM Stream 2 distributor programs or the net billing tariff.
- Front-of-the-meter resources that are not 5-minute dispatchable will be able to value stack via the IESO's Local Generation Program (LGP) contracts if they meet the size thresholds of that program for energy value paired with distributor contracts for distribution capacity value.

For small front-of-the-meter resources that lack a participation pathway, the OEB proposes a third value stacking recommendation:

- Consider expanding the eligibility of the tariff developed for net billing to include small front-of-the-meter resources that do not meet the eligibility requirements of any of the IESO's Resource Adequacy mechanisms and therefore lack a value stacking pathway. Participation for these resources could be capped to limit the risk of cost commitments rising above value.

This would fill the remaining value stacking gap for front-of-the-meter resources, eliminating the need to establish a cost allocation and delivery framework for front-of-the-meter and market-participating DERs that is net new above existing mechanisms. Since the existing compensation framework for DERs in Ontario is complex, the OEB sees value in expanding the eligibility of existing mechanisms where appropriate before establishing new ones.

If the net billing tariff is successfully implemented in place of net metering for behind-the-meter resources, expanding eligibility of the tariff to small front-of-the-meter resources injecting electricity at the distribution level would provide a simple pathway to enable DERs which have limited access to other compensation mechanisms. Small front-of-the-meter resources are typically not 5-minute dispatchable and are therefore unable to participate in the IESO-administered markets. While the price signal provided by a tariff or program may be less precise than a market-based solution, as discussed in Section 2.2.1, the development of the net billing tariff may leverage market instruments such as the capacity auction clearing price and locational marginal pricing. As such, the loss of precision may be minor. The OEB views this as an acceptable trade-off to providing a simple value stacking pathway for this resource group that comprises a small portion of overall DER penetration. The gradual development and expansion of a time and location-based tariff for DERs would be similar to the approach followed in New York for the VDER tariff, which was initially introduced as an alternative to net metering and gradually expanded to other resources.

Figure 1 shows the evolution of DER value stacking opportunities by resource type in Ontario. As shown in Figure 2, planned and recommended initiatives such as Stream 2 eDSM and a net-billing tariff could provide the certainty and predictability necessary to support the prudent adoption of DERs; the recognition of distribution value within these programs will also help to drive DERs to efficient locations on the grid. As DERs penetration increases, distribution-level markets could develop according to local conditions and needs. As distribution-level markets mature, the time and location-based tariff could remain as a compensation mechanism for small passive DERs that do not participate in market activations due to size/visibility/technology limitations.

It is important to note that provision of services to distribution systems by DER providers and methods to acquire such services are not yet robustly established in Ontario. As noted above, electricity distributors can procure services from DER providers today to address local constraints, but it remains somewhat rare. The approach to value stacking laid out in Figure 2 below for most resources hinges on distributors actively pursuing these opportunities where they exist.

Value stacking for capacity services comes with specific challenges and may not always be appropriate, depending on the service required. If services are required simultaneously or if a resource is unable to meet its obligation due to participation in another program/market, challenges can arise. As such, compensation for the contribution of DERs to bulk generation capacity should account for the availability and level of service provided by the DER.

Dedicated competitive procurements for new build resources committed to providing an exclusive service (such as capacity) are generally expected to determine a sufficient price for market entry. Such a price would cover the entire cost of building and operating the resource. Therefore, any additional revenue earned through other compensation mechanisms is not value stacking but overpaying for services provided. For this reason, value stacking with competitive procurements must be considered carefully to ensure that contracts are set up to receive competitive bids with additional revenue streams already accounted for or that contracts proactively account for future additional revenue streams. To the extent that revenues not accounted for in the original contract are added later, the resource must be providing additional value (i.e. responding to demand reduction events that are not coincident with the obligations set out in their contract).

One component of the value stack that is not discussed in Figure 1 is compensation for avoided transmission capacity benefits. While transmission capacity benefits are considered in the planning process and the OEB's Benefit-Cost Analysis Framework allows for the consideration of benefits to the transmission system by distributors requesting rate funding for non-wires solutions, uptake is hampered by the absence of a standardized implementation methodology, as well as data to assess and quantify where such benefits may exist. This contributes to a lack of compensation for transmission benefits even where a DER may provide such benefits. This gap in benefits for transmission capacity is discussed in the previous section (Section 2.2.6) along with recommendations to address the gap for transmission capacity benefits. The implementation of those recommendations, as well as the quantification of transmission system benefits by distributors acquiring DERs through the BCA Framework will ensure the business case for DERs that provide benefits to the transmission system is appropriately represented during procurement decision-making.

		Current State	Near-term State *(after implementation of planned initiatives & recommendations)*	Future State *(additional stacking opportunities)*
Behind-the-meter	**5-minute dispatchable**	*DER value stacking can be challenging due to the complex interactions between different compensation mechanisms.*	Value stacking will be enabled via: • ERP will enable participation of aggregated DERs in the wholesale energy market. Wholesale energy market participation may be stacked with the capacity auction (for generation capacity compensation) and distributor contracts (for distribution capacity compensation).	Additional value stacking will be enabled via: • Interoperable distribution-level markets where they develop (for distribution capacity compensation) stacked with wholesale energy market or capacity auction (for energy and generation capacity compensation, respectively).
	All other resources		Value stacking will be enabled via: • Hourly Demand Response resources in the capacity auction may value stack with distributor contracts (for distribution capacity compensation). • eDSM Stream 2	Additional value stacking will be enabled via: • Net billing tariff • Other mechanisms may be expanded to consider compensation for avoided transmission benefits.
Front-of-the-meter	**5-minute dispatchable**		Value stacking will be enabled via: • ERP will enable participation of aggregated DERs in the wholesale energy market. Wholesale energy market participation may be stacked with the capacity auction (for generation capacity compensation) and distributor contracts (for distribution capacity compensation).	Additional value stacking will be enabled via: • Interoperable distribution-level markets where they develop (for distribution capacity compensation) stacked with wholesale energy market or capacity auction (for energy and generation capacity compensation, respectively). • Other IESO Resource Adequacy mechanisms, as appropriate. • IESO Resource Adequacy mechanisms may reflect transmissions benefits.
	All other resources		Value stacking will be enabled via: • LGP for resources that meet LGP size requirements (for energy compensation) paired with distributor contracts (for distribution capacity compensation). *Value stacking opportunities will still not exist for resources below the LGP minimum size threshold.*	Additional value stacking will be enabled via: • For small resources that lack a participation pathway, the net billing tariff could be offered as an injection tariff. Participation for these resources could be capped to limit the risk of cost commitments rising above value. • Other IESO Resource Adequacy mechanisms, as appropriate. • IESO Resource Adequacy mechanisms may reflect transmissions benefits.

Figure 1. Evolution of value stacking by resource type

2.3. Roles and responsibilities for recommendations

IEP implementation directive item 12 asked the OEB to identify roles and responsibilities for implementing DER valuation recommendations. The roles and responsibilities for the recommendations provided in Section 2.2 are provided below in Table 2.

Table 2: Roles and responsibilities for DER compensation recommendations

Recommendation	Roles and Responsibilities
Update net metering	
1. Transition from net metering to net billing which compensates injected electricity through a time- and location-based tariff.	Ministry of Energy and Mines for amendments to O. Reg. 541/05, OEB for rate design, electricity distributors for billing system updates.
2. Remove regulatory restrictions on community net metering (or net billing if adopted) to enable projects in Ontario.	Ministry of Energy and Mines for regulatory amendment, electricity distributors for implementation, OEB to provide support as needed (e.g., with eligibility requirements).
3. Increase the threshold at which distributors are required to accept customer net metering (or net billing if adopted) applications from one percent of annual peak load to two percent.	OEB for updates to the DSC.
Improve price-based mechanisms	
4. Take steps to implement dynamic pricing, such as a time-of-use price plan, for Class B customers not on the regulated price plan to better align electricity prices with value provided.	Ministry of Energy and Mines for regulation amendment, OEB for rate design, IESO for updates to GA settlement process and implementation support for electricity distributors through the Smart Metering Entity, electricity distributors for billing system updates.
5. Conduct a study of DERs which participate in the ICI to assess their ability to help meet distribution or transmission system needs (i.e., assess whether resources are located where local/regional constraints are not coincident with bulk system peaks).	Ministry of Energy and Mines, with support from OEB and data from the IESO as appropriate.
Enable value for transmission capacity benefits	

6. Leverage procurements and/or programs within the IESO's resource adequacy framework to secure transmission NWSs when they are identified as preferred solutions through the Regional Planning Process.	IESO for implementation.
7. Include transmission avoided costs in demand-side management cost-effectiveness tests when needs are identified in the Regional Planning Process.	IESO for developing framework with support from the OEB.
Enable value stacking	
8. Develop consistent and transparent approaches for distribution programs and/or procurements to support interoperability with the bulk system and compatibility with the IESO's resource adequacy framework.	OEB and electricity distributors to develop and implement with IESO input.
9. Ensure that IESO and electricity distributor programs / procurements explicitly allow for future value stacking opportunities, when resources are capable of providing multiple services. (e.g., IESO's Local Generation Program allowing resources to earn revenue through other contracts).	IESO for implementing for their programs/procurements, OEB for considering if there is a need to update the NWS Guidelines, electricity distributors for implementing for their programs/procurements.
10. Consider expanding eligibility of the tariff developed for net billing to small front-of-the-meter resources that lack a value stacking pathway.	Ministry of Energy and Mines for regulatory amendment, electricity distributors for billing system updates.

2.4. Electricity distributor-led DER procurement

IEP implementation directive item 12 also asked the OEB to explore opportunities for electricity distributor-led DER procurements. This task was completed by looking at the current state of electricity distributor-led DER procurements and examining additional opportunities in the near-term after DER compensation recommendations are implemented and in the future as distribution-level markets develop. A summary is provided in Figure 2 below followed by further detail.

Figure 2: Current, near-term and future state of electricity distributor DER procurement.

Current State	Near term-state *(after implementation of planned initiatives & recommendations)*	Future State *(additional stacking opportunities)*
Electricity distributors lead the procurement of DERs that are used for distribution and/or certain transmission system needs.	The OEB expects distributor-led DER procurements to become more common through improved DER value stacking opportunities in locations where distribution system needs exist and through the OEB's recent amendment to the DSC to enhance clarity and provide greater certainty regarding an incentive for distributors procuring third-party owned DERs.	Interoperable distribution-level markets, if developed, as well as greater standardization of resource commitment tools, such as contracts, will allow distributors to make further use of DERs in their service territories.

Current State

Today, electricity distributors lead the procurement of DERs that are used for distribution and certain transmission system needs as discussed in the Non-Wires Solution Guidelines. This applies to all distribution system needs in a distributor's own service territory. It also applies to transmission system needs if the distributor is connected downstream of the constrained transmission asset and has cost responsibility for required upgrades. Since these needs are often capacity constraints, many DERs implemented for these purposes may be designed to reduce local peak demand.

As discussed in section 2.2.7. above, examples of DERs that distributors have procured remain somewhat rare. However, the OEB has seen more electricity distributors include DERs as non-wires solutions in recent applications. This is likely due to a number of factors including distributors becoming more comfortable with implementing non-wires solutions, increased confidence that DERs can meet the local need reliably, and the OEB's recent amendment to the DSC to include an incentive for distributors procuring third-party owned non-wires solutions[23].

Procurement of DERs to meet bulk system capacity or energy needs is led by the IESO since they are the entity accountable for resource adequacy and reliability in the province.

Near-term State

Opportunities for electricity distributor-led DER procurement will increase through the implementation of the value stacking recommendations described in section 2.2.7. The OEB expects that electricity distributor-led DER procurements will increase in the near-term as distributors gain experience and familiarity with DERs as non-wires solutions

[23] More information can be found at the following link: [Framework for Energy Innovation 2.0: Non-Wires Solution Incentives (Margin on Payments) | Ontario Energy Board]

and the regulatory instruments available to deploy them. In addition to cost savings, DERs are typically faster to deploy than traditional infrastructure solutions. This has already driven DER deployments in the province and is likely a trend that will accelerate in the future given the anticipated load growth in the sector. Additional value stacking opportunities will strengthen the business case for DER providers and electricity distributors in locations with local system constraints. This is expected to encourage higher penetration of DERs, providing electricity distributors with more opportunities to make use of them to meet their system needs. The overall goal is to create a stable, predictable environment for new cost-effective investment.

Future State

As discussed in Section 2.2.7, the future state of DER value stacking in Ontario may include interoperable distribution-level markets in regions where these markets develop. As these markets develop and DSO capabilities grow, further questions regarding the role of distributors or the scope of their responsibilities may emerge. As the OEB identified in the DSO Roadmap submitted by the OEB to the Minister in December 2025, the scope of DSO Workstream 4 “will aim to retain flexibility so that the roles being determined for DSO capabilities can take into account the urgency and direction of broader sectoral change.”

3. DER DELIVERY RATES

3.1. Approach

DER delivery rates are the OEB-approved electricity distribution and transmission rates that DERs pay to access and use distribution and transmission infrastructure and services. They are an important component of the pathway for improving the regulatory framework to unlock the value of DERs.

The OEB has considered base rates and retail transmission service rates, connection costs, behind the meter rates, and specialized rates in its review of DER delivery rates.

The OEB has considered a wide range of front-of-the-meter and behind-the-meter DER types, including DERs that inject electricity into the grid, those that both inject and withdraw electricity from the grid and those that provide load displacement only.

Where applicable and appropriate, the OEB has also considered opportunities to further align Ontario's distribution and transmission delivery rates frameworks for electricity resources (such as generation and storage).

3.2. Review & updates

3.2.1. Base rates and Retail Transmission Service Rates for front-of-the-meter generation resources and storage resources

About

Base rates are the monthly fixed charges and, if applicable, the volumetric distribution rates that distribution customers pay to an electricity distributor for maintaining and operating the distribution network and delivering electricity to customers. Retail Transmission Service Rates (RTSRs) are charges that a distributor applies to its customers to recover the costs of wholesale transmission service. Base Rates and RTSRs are approved by the OEB and are outlined in the Tariff of Rates and Charges of each electricity distributor.

Observations and updates

Generation that is directly connected to a distribution system in Ontario does not pay base distribution rates or RTSRs. Base distribution rates and RTSRs are paid by load customers instead. This is consistent with how responsibility for base transmission rates is assigned in Ontario's transmission rates framework: base transmission rates are not paid by transmission-connected generation (with some relatively small exceptions, such as station service load). They are paid by load customers.[24]

By contrast, energy storage that is directly connected to a distribution system in Ontario does pay base distribution rates and RTSRs when it behaves as a load (e.g., when it uses electricity from a distribution system to charge), but not when it behaves as a generator (e.g., when it discharges electricity into the distribution system).

This differs from how base transmission rates will soon be assigned in Ontario's transmission rates framework, as set out in the OEB's March 2025 Decision on Phase 2 of the Generic Hearing on UTRs (EB-2022-0325).

Beginning in 2026, transmission-connected storage facilities will be exempt from transmission service charges when they provide services such as operating reserve, reactive power or regulation service, or respond to real-time market dispatch signals or directives from the IESO in support of transmission system reliability.

OEB staff are working with the IESO to co-ordinate the implementation of this exemption from transmission charges for transmission-connected energy storage facilities.

What we asked stakeholders

The OEB asked stakeholders for advice on whether the OEB should exempt front-of-the-meter electricity storage from base distribution rates, consistent with how front-of-the-meter generation is treated on Ontario's distribution and transmission systems and how transmission-connected storage will be treated beginning in 2026.

The OEB also asked stakeholders whether it should consider exempting front-of-the-meter electricity storage from paying RTSRs in the more immediate term to facilitate the integration of the distribution-connected front-of-the-meter electricity storage that has been recently procured by the IESO.

What we heard from stakeholders

The OEB received a range of comments on delivery rates for front of-the-meter generation and storage resources.

Front-of-the-meter generation: One stakeholder said that exporting DERs require the use of DER Management Systems and that they impose higher costs on the distribution grid than non-exporting DERs. The stakeholder recommended that the costs of DER

[24] The OEB established the exemption of transmission-connected generation from base transmission rates through its Decision on RP-1999-0044. In that Decision, the OEB reasoned that the rates would be ultimately borne by load customers through the pricing of the commodity.

Management Systems should be the responsibility of the DER owners or aggregators and not of other customers.

Another stakeholder said that it generally supports exempting front-of-the-meter generation from base distribution rates because loads typically drive distribution system costs. The stakeholder also supported exploring whether additional clarity is needed regarding co-located generation and EV charging infrastructure to ensure fair, technology-neutral treatment and to avoid discouraging innovative co-location models.

<u>Front-of-the-meter storage and RTSRs:</u> Two stakeholders said they firmly support the RTSR exemption for front-of-the-meter storage resources that are market participants in the IESO-administered markets. They said the OEB’s March 2025 Decision and Order on Phase 2 of the Generic Hearing on UTRs did not recognize that some of the energy storage resources contracted by the IESO through their various recent procurements (e.g., Expedited Long-Term and Long-Term 1) included distribution connected energy storage resources.

The same two stakeholders pointed out that these contracted market participants will participate in the IESO-administered markets and respond to IESO dispatch instructions. The stakeholders said that without an RTSR exemption, these distribution-connected energy storage resources would be disadvantaged and more costly to Ontario energy consumers.

<u>Front-of-the-meter storage and distribution rates in general:</u> Stakeholders expressed contrasting views on exempting front-of-the-meter storage from base distribution rates. Those in support argued that exemptions would ensure consistency with the treatment of transmission-connected storage. One stakeholder added that further examination was warranted for the application of exemptions for behind-the-meter storage installed by RPP customers.

Stakeholders who expressed caution for exempting front-of-the-meter storage from base distribution rates urged the OEB to ensure that distribution customers are not unfairly burdened with additional transmission costs because of storage connections and recommended that bill impacts for non-participating customers should be a paramount consideration.

For example, one stakeholder said that if a distribution-connected resource is exempt from paying certain charges, or is otherwise provided a discount relative to its properly allocated costs, the rest of a distributor's customers will have to “pick up the tab.” The stakeholder said the issue is particularly acute for smaller distributors, where such “subsidies” could lead to disproportionate bill impacts. One stakeholder suggested conducting a study of applicable costs before implementing exemptions and proposed considering a separate storage rate class to reflect their unique system usage.

Another stakeholder highlighted that exemptions would lead to higher capital contributions for new storage facilities, as distributors would lose offsetting revenue considered in economic evaluations. This could result in revenue shortfalls and necessitate recovery mechanisms, such as true-ups or additional contributions from existing storage customers.

Stakeholders further expressed their views on rate design and cost recovery options as they relate to base rate exemptions for front-of-the-meter storage. One stakeholder suggested that a broader review of rate design options for energy storage, beyond simple exemptions from base distribution or RTSR charges, could better balance incentives for storage integration with the cost of providing reliable distribution services.

Another stakeholder suggested that the principle of “costs follow benefits” should be adhered to in the design of DER compensation and distribution rates. The stakeholder added that if a DER provides both transmission and distribution value, its costs should be recovered from the same group of customers that it benefits. The stakeholder also advised that to the extent that new mechanisms may need to be created to facilitate this type of cost recovery, that work should be completed as part of the OEB’s DER valuation review.

Discussion and next steps

Stakeholder feedback highlights the importance of principled and holistic DER delivery rate design. While some stakeholders support distribution rate exemptions for front-of-the-meter resources such as storage, others caution that exemptions could lead to cross-subsidization, undue bill impacts for non-participating customers and revenue shortfalls for electricity distributors.

The OEB is persuaded by stakeholder views that some delivery rate exemptions for front-of-the-meter DERs may lead to bill impacts for non-participating customers, revenue shortfalls for electricity distributors, and that such impacts should be a key consideration in the development of DER delivery rates. The OEB is further persuaded that any value that a front-of-meter DER provides, whether to transmission customers or distribution customers, should be recovered from the same groups of customers that benefit.

The OEB considers it appropriate that beneficiaries should pay for front-of-the-meter DER delivery rates. This is already the practice in Ontario’s transmission rates framework, where transmission customers generally pay for network charges associated with transmission-connected electricity resources. Notably, those transmission customers include all electricity distributors in the province, regardless of their proximity to a particular transmission-connected electricity generator or storage facility.

Along the same lines, the OEB thinks it will be important to allocate front-of-the-meter DER delivery costs to all applicable customers in Ontario, in accordance with the benefit that the DERs provide to them. For example, the base delivery costs of a front-of-the-meter distribution-connected storage facility that serves local distribution customers as well as customers elsewhere in the province should not be borne solely by the local distribution customers (most likely applicable in the case of DERs that are participants in the IESO-administered markets). As an analogue, the transmission network charges associated with a generator or electricity storage resource in a certain electrical zone are not paid solely by the customers located in that zone, but by customers across Ontario.

It follows that any exemptions that the OEB might introduce concerning base front-of-the-meter DER delivery costs will need to be accompanied by appropriate allocation and recovery among beneficiaries. This may require the OEB to develop or adopt methods and mechanisms to implement such allocations and recoveries.

Stakeholder feedback also highlights the need to consider DER delivery rate design through an appropriate forum and process, such as a policy consultation or generic hearing. The OEB agrees - the issues deserve thorough, transparent, and timely treatment, commensurate with their complexity, impact, and urgency.

As a first and near-term step, the OEB will prioritize establishing RTSR exemptions for distribution-connected electricity storage resources that have been procured by the IESO and are (or will be) participants in the IESO-administered markets.

Storage resources located on the transmission system will soon be exempt from paying certain transmission service charges. It will be fair to also exempt distribution-connected storage resources that participate in the IESO-administered markets from paying transmission service charges (i.e., RTSRs). The method of allocating UTR obligations among beneficiaries across the province already exists (e.g., transmission costs are allocated based on OEB-approved charge determinants), as do mechanisms for addressing RTSR revenue impacts on electricity distributors (e.g., RTSR variance accounts). These will simplify and expedite implementation of focused RTSR exemptions compared to exemptions from base distribution rates.

The OEB will consider suitable options for implementing these focused RTSR exemptions and will advise stakeholders on next steps.

In parallel, the OEB will also consider options for addressing the more extensive, complicated, and longer-term question of exemptions for base delivery rates for front-of-the-meter DERs (such as storage), including bill impacts on non-participants, potential cost allocation and recovery mechanisms, and revenue impacts for electricity distributors. The OEB will advise stakeholders on next steps in due course, likely after the OEB has advanced its work in the more immediate term on RTSR exemptions for distribution-connected storage resources that participate in the IESO-administered markets.

3.2.2. Connection costs

About

Connection costs are the one-time costs that generator or load customers pay to an electricity distributor or transmitter for connecting to a distribution or transmission system. The TSC and DSC include rules governing how connection costs are allocated between connecting customers and transmitters or distributors.

Observations and updates

The OEB has consultations underway to review various aspects of transmission and distribution cost responsibility. These consultations are the Transmission Connections Review (EB-2024-0126), and the DER Connections Review, which includes cost responsibility (EB-2019-0207) for DERs connecting to the distribution grid.

Under Section 79.1 of the *Ontario Energy Board Act, 1998*, the OEB, when approving just and reasonable rates, may allow distributors to recover some of their costs of connecting eligible generation facilities from all electricity customers, mitigating the cost impact to their own customers.

Ontario Regulation 330/09 establishes a formula for calculating the amount eligible for provincial recovery. The principle is that ratepayers in a distributor’s service area should only pay for a distributor’s costs to connect a renewable generator to the extent those ratepayers benefit from the investment. The IESO compensates the distributor for costs through monthly payments collected from all electricity customers in Ontario, which offsets local rate impacts and reflects the broader system-wide benefits of connecting renewable generation.

Under the regulation, only “renewable energy generation facilities” within the meaning of the *Electricity Act, 1998* qualify for provincial recovery. The regulation leaves it to the OEB to establish in the DSC which specific connection costs are the responsibility of the distributor (and its ratepayers) and considered an “eligible investment”. A portion of the cost of that eligible investment is then spread among all electricity customers .

In 2010, the OEB established two categories of renewable-related connection costs that are eligible investments: expansion costs to connect a renewable energy generation facility, up to $90,000 / MW of nameplate capacity (renewable expansion cost cap) and certain types of system improvements to accommodate renewable energy generation connections (Renewable Enabling Improvements, or REIs). While the policy has been in place for more than a decade, the amount recovered annually from all electricity customers is modest. For 2026, the OEB determined the amount that IESO will disburse to distributors making eligible investments is about $9 million, allocated among six distributors who have made eligible investments. For context, total distribution revenues in 2024 amounted to $4.7 billion.

What we asked stakeholders

The OEB asked stakeholders for input on what it should consider when reviewing connection cost-related policies under Ontario Regulation 330/09 regarding the treatment of DERs when powered by renewable energy sources, such as REIs, Renewable Energy Expansion Cost Cap and the practice of recovering some costs from all electricity customers.

What we heard from stakeholders

Stakeholders generally agreed that a review of connection costs is warranted in relation to DERs.

Some stakeholders said that revisiting the existing framework could support incremental DER deployment and help ensure that connection cost policies reflect current technologies, operational realities, and the evolving role of DERs in Ontario's electricity system.

Stakeholders recommended that the OEB review how connection cost policies apply to various types of DERs, as well as areas of potential double compensation. For example, the Renewable Energy Expansion Cost Cap and Renewable Enabling Improvements provisions in the DSC already compensate renewable generation for the benefits they are assumed to provide. If mechanisms are introduced to further compensate DERs, then their connection costs should not also compensate them for the same benefits.

Stakeholders also raised the need for clearer cost-responsibility rules for hybrid DER projects that combine renewable generation with storage facilities. Currently, uncertainty about whether storage qualifies for the same connection cost incentives as renewables can lead distributors to treat hybrid projects differently across the sector, resulting in inconsistent applications of cost responsibility rules.

Some stakeholders suggested that the OEB, when considering the eligibility for rate funded connection costs, consider the wider system benefits of DERs such as storage, managed load, and EV-focused DERs, even if they don't meet the statutory definition of renewable generation facilities.

Discussion and next steps

The main issue for consideration on the matter of connection costs is whether to maintain the distinction in cost responsibility between renewable and non-renewable facilities, and, in turn, whether to maintain as well the ability to recover connection costs from all electricity customers and local distributors, which applies today only to renewable generation facilities. The OEB presents three options for consideration by the Ministry of Energy and Mines:

1. **Maintain a Separate Framework for Renewable Generation:** Under this option, the OEB would review the cost responsibility rules for non-renewable generation, including storage facilities. The OEB would also review the cost responsibility rules for renewable generation, including the $90,000 / MW renewable expansion cost cap and REIs, given that some assumptions underpinning the renewable generation cost responsibility rules have evolved. Ontario Regulation 330/09, provided it remained unchanged, would enable distributors to continue to have the ability to recover eligible investments to connect renewable generation facilities from all electricity customers.
    a. <u>Benefits:</u>
        i. Maintains an established regulatory framework familiar to industry and stakeholders.
    b. <u>Challenges:</u>
        i. Maintaining separate frameworks for renewable and non-renewable DERs increases regulatory complexity.
        ii. Non-renewable DERs would continue to face higher costs to connect than renewables.
        iii. Hybrid projects (renewable paired with storage), which offer greater grid stability and reliability compared to standalone renewable generation, may face unclear or inconsistent treatment, creating cost uncertainty and slowing deployment.

2. **Align Storage and Renewables**: This option would expand eligibility for cost recovery from all electricity customers to storage facilities via a change to the regulation. The OEB would align cost responsibility rules for storage and renewable generation in the DSC, enabling storage to benefit from lower connection costs. The OEB would provide further clarification for the rules applying to other non-renewable DERs.
    a. <u>Benefits</u>:
        i. Creates a level playing field between renewable generation facilities and storage facilities.

      ii. Lowers regulatory complexity and costs for storage and or hybrid DER projects.
   b. <u>Challenges</u>:
      i. Could increase total DER connection incentives, with corresponding impacts on rates.
      ii. This option does not remove the need to maintain two separate frameworks, leaving some regulatory inefficiency and potential confusion among stakeholders.

3. **Harmonize connection cost responsibility framework for all DERs**: This option would establish a single connection cost responsibility framework applicable to all DERs. The regulation could be amended to introduce changes in the mechanism to recover connection costs from all electricity customers, like removing technology-specific eligibility criteria, targeting a given level of socialization (regardless of technology type, in this case) or eliminating socialization of costs altogether. The OEB would amend cost responsibility rules in the DSC to harmonize the treatment for all DERs.
   a. <u>Benefits</u>:
      i. Simplifies regulatory requirements through a single, harmonized framework.
      ii. Creates a level playing field across all DERs.
      iii. Better supports a value-based approach where DERs are compensated based on the value they provide to the grid.
   b. <u>Challenges</u>:
      i. Would constitute a change for proponents of renewable energy, some of whom may have factored in the existence of implicit cost supports enabled via the DSC into their plans.

Building on work initiated last year, the OEB will continue its review of detailed design options for the DSC cost responsibility rules. The OEB is examining several potential approaches for allocating and sharing connection costs:

- Allocating costs by percentages determined based on the estimated value that DER connection-related investments provide to the grid. This approach would seek to ensure that the customers that may see benefits from the connection-related investments contribute towards their costs.
- Establishing separate or disaggregated rules for allocating connection costs based on asset categories (e.g., stations and feeders) or characteristics of the connecting DER (e.g., exporting and non-exporting DERs). This approach would recognize that different connection-related assets or DERs can have varying impacts on the grid.
- Applying standardized connection charges or entry costs for DERs to simplify cost allocation and improve predictability. This approach would look at options

where distributors can make investments meant to unlock DER connections and recover the costs through standardized rebates and or fees.

While this work progresses, the OEB's approach can be informed and aligned with any government decision to retain or change the framework for provincial cost recovery of connection costs in relation to renewable and non-renewable DER.

In the meantime, the OEB will continue engaging stakeholders on the design of DSC cost responsibility rules, and to assess their feasibility, benefits, and implications. The OEB will also consider broader issues to ensure that connection cost responsibility rules:

- Reflect the breadth of DER technologies and modes of operation.
- Appropriately account for the costs of incorporating DERs.
- Align with DER compensation policies.

The OEB's consultations to review transmission and distribution cost responsibility will incorporate these considerations.

3.2.3. Behind the meter rates

About

Behind the meter rates are paid by load customers that have DERs that operate on the customer side of the meter. Examples of behind the meter rates include standby rates, bypass compensation and RTSRs.

Some customers of electricity distributors have their own generation facilities that supply all or part of their electricity needs. At times when the customer-owned generation is unavailable (during a generator planned outage, for example), some or all of the customer's electricity needs are supplied by the electricity distributor. The rate used by distributors for having facilities ready to supply these customers is called a "standby rate." The standby rate is recovered from customers that have load displacement generation and that require standby service from their electricity distributor. RTSRs recover the transmission service charges that a distributor owes to transmitters.

Bypass compensation is paid by certain load customers to electricity distributors under conditions specified in the DSC, such as when the customer uses a generator to reduce its load that would otherwise be served by the electricity distributor. The DSC also specifies when bypass compensation may not be applied, such as when load reductions result from the use of embedded renewable generation.

Observations and updates

Standby rates: Ten electricity distributors in Ontario have standby rates, some on an interim basis. Standby rates are not applied to transmission-connected customers that have behind-the-meter resources. While this is a difference between the transmission and distribution delivery rates frameworks, the difference is appropriate, reflecting the specific circumstances of electricity distributors and reflecting a service that electricity distributors offer to their customers who want to use it.

The OEB held a consultation from 2023 to 2024 (EB-2023-0278) to consider standby rates given the passage of time since the OEB first declared them interim in 2006. The OEB concluded that it will not impose or recommend a default approach to pricing load displacement generation. Instead, the OEB said "if a distributor determines that a standby rate is appropriate, it should propose a design that best fits the circumstances."[25] Some electricity distributors have proposed revisions to their standby rates designs in recent years, others have finalized their interim rates.

RTSRs: Some distribution-connected load customers that have behind-the-meter generation pay a portion of their RTSRs based on their gross load, and the other portion based on their net load. This is consistent with how transmission-connected customers that have behind-the-meter generation pay transmission rates, in accordance with the Terms and Conditions of the UTR Rates Schedule.

In its review of DER delivery rates, the OEB has observed that not all electricity distributor rate schedules specify whether RTSR billing for distribution customers that have behind-the-meter DERs is on a net-load-billing or gross-load-billing basis.

Bypass compensation: The bypass compensation provisions set out in the DSC, which apply to distributors, are consistent with the bypass compensation provisions that are set out in the TSC, which apply to transmitters. Exemptions to bypass compensation (e.g., for renewables, energy efficiency, load management) were added to the DSC in 2018 (EB-2016-0003 December 18, 2018) and the TSC in 2005 (RP-2004-0220)[26].

What we asked stakeholders

The OEB asked stakeholders whether it should consider reviewing standby rates best practices and applying lessons learned as distributors propose to finalize their standby rates over time. The OEB also asked whether it should consider reviewing opportunities for greater consistency in how RTSRs are applied to distribution load customers with behind-the-meter generation, in terms of distinguishing between net load and gross load billing. Finally, the OEB asked stakeholders whether it should consider reviewing its

[25] EB-2023-0278, Consultation on Policy for Standby Rates – Finalization Letter, March 28, 2024

[26] See also RP-2002-0120, OEB Phase 1 Policy Decision with Reasons, June 8, 2004; RP-2004-0220, OEB Synopsis of Changes to the Transmission System Code, July 25, 2005.

bypass compensation exemption policy, including the question of whether exemptions should be extended to include non-renewable DERs.

What we heard from stakeholders

Standby rates: Stakeholder feedback on standby rates supports drawing insights from the experiences of electricity distributors and ensuring a fair, predictable framework

One stakeholder said that a review of best practices could lead to a more streamlined approach for electricity distributors when applying to introduce standby rates, particularly benefiting utilities that do not currently have them. The same stakeholder said that the OEB's focus should be on identifying and sharing best practices, rather than imposing standardized standby rates across distributors. The stakeholder concluded that in general, electricity distributors would support a consistent framework that allows access to standby rates in a fair and predictable manner.

Another stakeholder said that the continued existence of interim standby rates at several utilities causes significant uncertainty regarding billing. The stakeholder recommended that the OEB should accelerate the review of standby rates best practices and apply lessons learned to ensure fair and consistent application by all distributors. Another stakeholder recommended that the OEB should consider a standardized approach for all electricity distributors across Ontario.

Two stakeholders raised several end-use-specific considerations. One stakeholder emphasized that standby charges must be carefully reviewed to avoid undermining EV-related DERs, including behind-the-meter storage, vehicle-to-grid resources, virtual power plants, and charging infrastructure in multi-unit residential buildings. They noted that standby rates designed for self-generation may not be appropriate for flexible, mobile EV resources.

Another stakeholder urged the OEB to clearly distinguish between management of load (through energy efficiency, load management systems, energy use practices, or load displacement generation) and DERs that interact with the distribution system. The stakeholder said it should be made clear to electricity distributors that how customers respond to price signals by modifying their load is a matter for the customers to decide, and generally not a distributor cost for which customers pay a price to the distributor.

RTSRs: Stakeholder feedback highlights the importance of clarifying RTSR treatment for customers with behind-the-meter resources.

One stakeholder said that reviewing and enhancing consistency in the application of RTSRs can help provide clarity and fairness for customers. Another stakeholder said that overreliance on gross-load RTSR billing risks discouraging beneficial and innovative DER deployments at EV charging hubs or by DER (aggregations) of large EV fleets.

One stakeholder said there is a need for consistency in how UTRs are applied between transmission and distribution systems, where if a resource is deemed Gross Load Billing-applicable at the transmission level, a similar treatment should be afforded at the distribution system level for the same resource.

The stakeholder said that such consistency would also ensure that should a transmission-connected electricity distributor be assessed incremental UTRs by virtue of a Gross Load Billing -applicable resource connected to its distribution system, a means is available to pass a similar charge through to the applicable customer, rather than having the incremental cost be absorbed by all other distribution customers.

The stakeholder said that clarity is needed regarding which types of DERs are intended to be covered by the gross load billing framework, adding that the current language in the UTR Schedule does not specifically encompass all types of DERs, and interpretation guidance is often required from the OEB pertaining to certain resources.

As an example, the stakeholder observed that the current UTR Schedule does not exempt distribution-connected storage resources providing services to the IESO-administered markets from Gross Load Billing when connected to the distribution system. The stakeholder said that this is an example of a potential disconnect and the need for policy consistency, given that similar resources connected to the transmission system will be exempted from transmission charges (upon implementation of the OEB's Phase 2 Decision on the Generic Hearing on Uniform Transmission Rates).

<u>Bypass compensation:</u> Stakeholder feedback supports reviewing bypass compensation exemptions to ensure technology neutrality, consistency with ratemaking principles and policy alignment.

One stakeholder said that the current bypass compensation rules favour certain types of DERs over others and encouraged the OEB to review their rules to ensure they remain agnostic from a technology or fuel perspective. Another stakeholder said that the OEB should seek to ensure that any required bypass compensation is technology-neutral and supportive of broader electrification objectives and policies. The stakeholder emphasized that non-emitting DERs providing load-management or storage services should not be unfairly treated relative to renewable generation.

One stakeholder supported the review of bypass compensation if it appropriately considers costs and that no costs are shifted to ratepayers. Another said that clarification to bypass compensation rules would provide more certainty for storage customers.

Discussion and next steps

Stakeholder feedback supports additional OEB focus on behind the meter rates. While perspectives vary on standardization versus flexibility, stakeholders generally agree that greater clarity (and consistency where appropriate) could reduce uncertainty, enhance fairness and facilitate DER deployment.

The OEB will develop distributor best practices for standby rates as more electricity distributors finalize their interim standby rates. To do so, the OEB will compile lessons learned and may also explore considerations specific to end-use, such as electric vehicle integration and load management.

The OEB will determine a process for disseminating this research. Consistent with the OEB's conclusions from its most recent review of standby rates (EB-2023-0278), the OEB will not impose or recommend a default approach to pricing load displacement generation.

The OEB will improve consistency in the application of Retail Transmission Service Rates for customers with behind-the-meter resources, including clarification of which DER types fall under gross load billing provisions. The OEB envisions this work will take the form of guidance to the sector.

The OEB will evaluate whether current bypass compensation rules in the Distribution System Code favour certain DER types and whether exemptions should extend beyond renewable generation to include other types of resources. Where applicable, the OEB will also assess interactions or overlaps with DER compensation policies. If the OEB determines that changes to the DSC are required, the OEB will initiate the appropriate process to implement them.

3.2.4. Specialized rates

About

Electricity distributors charge specialized rates to DERs to recover the costs of processing DER metering information and settlement, and DER account management and billing services. Examples of specialized rates include the microFIT charge and, in a small number of instances, the Distributed Generation (DGen) charge and Monthly Generator Services charge.

Observations and updates

The OEB's assessment is that specialized rates are appropriate within their specific context. Although they are not applied by transmitters to transmission-connected electricity resources, the difference is appropriate because the specialized rates recover the costs of services that electricity distributors (uniquely) provide to their DER customers.

Looking ahead, there may be an opportunity for the OEB to provide guidance to promote greater consistency in the development of specialized DER rates, as the demand for such rates grows. The OEB has done so in the past, when it established a province-wide fixed monthly service charge for microFIT generators (which are distribution-connected generators) based on nine cost elements specified by the OEB (EB-2009-0326). The OEB continues to set the microFIT charge each year.

What we asked stakeholders

The OEB asked stakeholders whether the OEB should consider opportunities to provide guidance and facilitate consistency in how specialized rates for DERs are developed and applied by electricity distributors, in the event of greater deployment of DERs across Ontario's distribution systems.

What we heard from stakeholders

Several stakeholders expressed support for exploring a more consistent approach for specialized rates for DERs, while acknowledging that unique circumstances and requirements may apply to individual distributors.

One stakeholder said that while some level of consistency could simplify participation and reduce administrative complexity, electricity distributors may have legitimate operational, system, or customer-specific reasons to maintain flexibility in rate design. The stakeholder added that any standardization effort should carefully consider these differences to avoid unintended consequences for distribution system planning or DER integration. Rather than establishing standardized rates, the stakeholder suggested that the OEB should standardize the methodology used to set them.

Another stakeholder suggested that the key issue is distinguishing between forced standardization, on the one hand, and helping electricity distributors to avoid "re-inventing the wheel", on the other hand.

Some stakeholders also emphasized the importance of incorporating principles, such as cost causality and fairness, into any review of specialized rates for DERs.

Discussion and next steps

Stakeholder feedback supports promoting greater consistency in the development of specialized DER rates, while maintaining flexibility for local circumstances.

The OEB recognizes that specialized rates serve an important role in recovering costs associated with DER-related services provided by electricity distributors, and that sound ratemaking principles should remain central to any approach.

In the event of growth in DER deployment, the OEB will consider whether additional guidance is needed to help distributors apply consistent principles and/or methodologies for setting specialized rates, rather than prescribing uniform rates across the province. The OEB continues to expect electricity distributors to apply consistent principles and/or methodologies for setting specialized DER rates.

If any guidance is required as DER deployment grows, the OEB will aim to balance the benefits of consistency with flexibility for local circumstances. Additional guidance may not be necessary, beyond what is already provided through rate-setting processes, if the adoption of specialized rates continues to be limited among Ontario electricity distributors, as it is today.

3.2.5. Summary

The OEB will develop a work plan or plans to address the following issues that have been identified through this review of DER delivery rates, with due consideration to organizational and sector capacity and priorities. The issues may be revised, and additional issues may be raised, based on further input from stakeholders:

1. <u>Delivery rates for front-of-the-meter resources</u>

- *Retail Transmission Service Rates:* The OEB will prioritize establishing Retail Transmission Service Rate exemptions for distribution-connected electricity storage resources that have been procured by the IESO and are, or will be, participants in the IESO-administered markets.
    - The OEB will consider suitable options for implementing these focused Retail Transmission Service Rate exemptions in the near-term and will advise stakeholders on next steps.

- *Base Rates*: In parallel, the OEB will also consider options for addressing potential exemptions to base delivery rates for front-of-the-meter DERs (such as storage), including bill impacts on non-participants, potential cost allocation and recovery mechanisms, and revenue impacts for electricity distributors.
    - The OEB will advise stakeholders on next steps in due course, likely after the OEB has advanced its work in the more immediate term on Retail Transmission Service Rate exemptions for certain distribution-connected storage resources.

2. <u>Connection Costs</u>

- The OEB will leverage the DER Connections Review to work with stakeholders on updating the connection cost responsibility rules detailed in the DSC, as well as consider additional options to allocate connection costs between ratepayers and DER owners. This process will ensure that the updated connection cost responsibility rules reflect the diversity of DER technologies and operations, account for integration costs and align with DER compensation policies.
    - The OEB will work with the Ministry of Energy and Mines to align its review of DSC rules with Ministry policy decisions on cost responsibility frameworks for renewable generation, storage facilities, and non-renewable resources.
    - The OEB may leverage additional processes such as the existing Transmission Connections Review to carry out this work.

3. <u>Behind the meter rates</u>

- *Standby Rates:* The OEB will develop distributor best practices for standby rates as more electricity distributors finalize their interim standby rates.
    - To do so, the OEB will compile lessons learned and may also explore considerations specific to end-use, such as electric vehicle integration and load management.
    - Consistent with the OEB's conclusions from its most recent review of standby rates (EB-2023-0278), the OEB will not impose or recommend a default approach to pricing load displacement generation.

- *Gross Load Billing and Net Load Billing:* The OEB will improve consistency in the application of Retail Transmission Service Rates for customers with behind-the-meter resources, including clarification of which DER types fall under gross load billing provisions.
    - The OEB envisions this work will take the form of guidance to the sector.

- *Bypass Compensation:* The OEB will evaluate whether current rules in the Distribution System Code favour certain DER types and whether exemptions should extend beyond renewable generation to include other types of resources. Where applicable, the OEB will also assess interactions or overlaps with DER compensation policies.

4. <u>Specialized rates</u>

- The OEB continues to expect electricity distributors to apply consistent principles and/or methodologies for setting specialized DER rates. If any guidance is required as DER deployment grows, the OEB will aim to balance the benefits of consistency with flexibility for local circumstances.